PACIFIC GAS AND ELECTRIC COMPANY

ELECTRIC PROGRAM INVESTMENT CHARGE (EPIC)
2020 ANNUAL REPORT

MARCH 1, 2021

2020 EPIC ANNUAL REPORT

APPENDIX A:
PROJECT STATUS REPORT

APPENDIX B:
FINAL PROJECT REPORTS

PACIFIC GAS AND ELECTRIC COMPANY

2020 EPIC ANNUAL REPORT

Pursuant to Decision (D.) 12-05-037 – Phase 2 Decision Establishing Purposes and Governance for EPIC and Establishing Funding Collections for 2013-2020, Pacific Gas and Electric Company (PG&E or the Company) hereby files the 2020 Annual Report for the EPIC Program.

In compliance with Ordering Paragraph (OP) 16, a copy will also be served on all parties in the most recent EPIC proceedings; the most recent General Rate Cases (GRC) of PG&E, Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E); and each successful and unsuccessful applicant for an EPIC funding award during the previous calendar year.

<u>Service Lists</u>:

EPIC 2012-2014: Application (A.) 12-11-001, A.12-11-002, A.12-11-003, and A.12-11-004.

EPIC 2015-2017: A.14-05-003, A.14-05-004, A.14-05-005, and A.14-04-034.

EPIC 2018-2020: A.17-04-028, A.17-05-003, A.17-05-005, and A.17-05-009.

EPIC Research Administration Plan (RAP): A.19-04-026

EPIC Program Renewal Order Instituting Rulemaking (OIR):
Rulemaking (R.) 19-10-005

PG&E recently filed GRC: A.18-12-009.

SCE recently filed GRC: A.19-08-013.

SDG&E recently filed GRC: A.17-10-007.

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PACIFIC GAS AND ELECTRIC COMPANY
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1. Executive Summary

A. Overview of Program and Plan Highlights

Pursuant to the California Public Utilities Commission (CPUC or Commission) D.12-05-037, PG&E, and the other Administrators of the EPIC Program were directed to file annual reports each year beginning February 28, 2013 through February 28, 2020 with the Director of the CPUC's Energy Division.[1] Annual Reports shall be served on all parties in the most recent EPIC proceeding, all parties to the most recent GRC of each electric utility, and to each successful and unsuccessful applicant for an EPIC funding award during the previous calendar year. While the compliance requirement of OP 16 of D.12-05-037 has expired, since PG&E's EPIC 3 program was active in 2020, and consistent with the spirit of the OP 16, PG&E files its ninth annual report. This Annual Report employs the outline developed collaboratively by the EPIC Administrators and the Public Advocates Office at the California Public Utilities Commission.[2]

In D.12-05-037, the Commission authorized funding in the areas of applied Research and Development (R&D), Technology Demonstration and Deployment (TD&D), and Market Facilitation. The Investor-Owned Utility (IOU) Administrators' role was limited to TD&D only.

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). 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). On August 10, 2017, the CPUC issued Resolution (Res.) E-4863, which approved two of the six new EPIC projects proposed by PG&E via a Tier 3 Advice Letter (AL) 5015-E filed on February 7, 2017, between triennial EPIC

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1 The four EPIC Program Administrators are PG&E, SCE, SDG&E, and the California Energy Commission (CEC).

2 This annual report outline is based on the adopted EPIC Administrator Annual Report Outline as described in Attachment 5 of D.13-11-025.

Applications as permitted by D.15-09-005. 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). On October 25, 2018, the CPUC issued D.18-10-052, which approved the third triennial investment plan period of 2018-2020 but directed utility administrators not to spend, commit or encumber one-third of their respective EPIC program budgets until the commission approves their joint RAP application. On April 23, 2019, the utilities filed their joint RAP application, and on February 10, 2020, the Commission issued D.20-02-003 approving the RAP application and authorizing the utilities to encumber, commit, and spend the remaining one-third of their EPIC 3 budgets. EPIC Program Renewal OIR R.19-10-005 was initiated on 10/18/2019, and in Phase 1 of this rulemaking D.20-08-042 established five-year EPIC 4 and 5 cycles and set EPIC 4 funding levels for the CEC. Ongoing Phase 2 of the rulemaking will consider the roles of the IOUs in EPIC going forward. On December 30, 2020 PG&E proposed 5 new projects for inclusion in its EPIC 3 program cycle in AL 6043-E.

This report summarizes PG&E's projects' progress and status for the approved funding cycles, which includes TD&D projects in the following areas:

1) **Renewables and Distributed Energy Resource (DER) Integration** – Integrate DERs, generation and storage; improve transparency of resource information; increase generation flexibility.

2) **Grid Modernization and Optimization** – Optimize existing grid assets; prepare for emerging technologies; design and demonstrate grid operations of the future.

3) **Customer Service and Enablement** – Drive customer service excellence through new offerings for PG&E's customers that enable greater customer choice; integrate Demand-Side Management (DSM) for grid optimization.

4) **Cross Cutting/Foundational Strategies and Technologies** – Enhance and apply tools to better prepare and respond to natural disasters (e.g. wildfires), support next generation infrastructure, including smart grid architecture, cybersecurity, telecommunications and standards, as well as other "foundational" activities in support of all three program areas above.

PG&E continues to be strongly committed to the EPIC Program and the value it provides to its customers, as it offers the opportunity to cost-effectively develop and demonstrate innovative technologies which can advance the Company's core values of Safety, Reliability, Resiliency, and Affordability. Through these projects, the EPIC Program also contributes learnings that support important and ambitious California policy priorities, such as Greenhouse Gas (GHG) reduction goals, DERs, renewable energy targets, and wildfire risk and impact mitigation.

With the climate-induced challenges of increasing wildfires and extreme weather events, increased grid visibility, flexibility and advanced data-driven technology operations are key. Through its EPIC 3 project portfolio, PG&E is actively exploring technologies that can mitigate ignition risk and associated potential impact on public safety. These technologies hold significant promise to advance PG&E's wildfire risk mitigation, bolster operational capabilities, increase the flexibility of the grid, and allow for greater system resiliency.

The IOUs' EPIC programs are the main source for demonstrating and field testing on their grids to meet these critical goals. This approach supports the direct testing and demonstration that is essential to scaling up new and innovative technologies for safe, reliable and cost-effective use. Successor Program Phase 2 schedule is not yet set and the future of the IOU role, originally established in D.12-05-037, in the EPIC program has yet to be determined.

PG&E's 2020 TD&D Program Highlights

PG&E launched four EPIC 3 projects and completed its final two EPIC 2 projects between the publishing of the 2019 and 2020 annual reports, which brings the total number of completed projects to date to 36. By the end of 2020 there were eight EPIC 3 projects in flight.

For detailed information on the developments and status of each EPIC 1, EPIC 2, and EPIC 3 project, see Appendix A.

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 research, development and demonstration (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, and to advance clean energy policy objectives. Additional information on EPIC 1 projects can be found in prior annual reports and in their final reports posted at pge.com/epic. In 2020, PG&E finalized the accounting of unspent EPIC 1 funds, inclusive of accumulated interest, and is preparing to return unspent funds to customers in its 2021 rate setting process.

EPIC 2

The projects from EPIC 2 were even more focused on long-term strategic objectives and in many cases were built on the foundations developed through previous EPIC 1 projects. Most of the EPIC 2 projects closed out in 2018 and 2019, and examples of their achievements are detailed in prior annual reports and at pge.com/epic. The last two EPIC 2 projects were completed in 2020:

EPIC 2.34 - Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors demonstrated the use of RF network monitoring technology alongside Distribution Fault Anticipation (DFA) technology to effectively identify and locate degrading assets and risks of failure in the distribution system, and enable proactive maintenance and further safety and resiliency. In the field demonstration, PG&E successfully detected, located and addressed multiple examples of conductor damage, vegetation encroachment, internal transformer discharge, fault induced power line slap, gunshot conductor, and insulator and clamp issues. PG&E found the two technology systems to be complementary and effective in detecting events that may indicate degradation of electrical assets. The advanced waveform analysis technology was able to detect certain types of arcing events along a circuit, while RF technology performed well in detecting and locating persistent low energy events. PG&E plans to continue evaluation of the RF technology under expanded deployment and to refine the strategies for deployment at scale. Similarly, PG&E plans for a staged, prioritized expansion of the advanced waveform analysis DFA technology to circuits in High Fire-Threat Districts (HFTD) and a continued effort to integrate the technology into its distribution operations. Additionally, PG&E plans further work to explore the integration of these technologies with other emerging technology applications such as the EPIC 3.15 Rapid Earth Fault Current Limiter (REFCL) Project.

EPIC 2.36 - Customer Rate Design Tool demonstrated a dynamic rate design tool approach built on a cloud platform for modeling customer bill impacts. The project leveraged advanced technologies to experiment with high-level rate designs, new billing determinants, and enabled a more robust, powerful and rapid bill impact analysis process than that which is used by current models. In its current state, the tool can design high-level experimental tiered, time-of-use, and tiered time-of-use rates, as well as rates with a maximum demand charge. The dynamic rate design tool can be leveraged and further developed to significantly improve other production-grade tools for rate and bill analysis.

In 2020, PG&E finalized the accounting of unspent EPIC 2 funds, inclusive of accumulated interest, and is preparing to return unspent funds to customers in its 2021 rate setting process.

EPIC 3

In 2020 PG&E continued its focus in the EPIC 3 cycle on wildfire safety, resiliency and renewables integration by launching four additional projects to drive innovation in these areas. Additional EPIC 3 projects will be launched in 2021, including following project proposals which are subject to approval of PG&E's pending AL 6043-E, submitted on December 30, 2020:

- 3.44 Advanced Transformer Protection;
- 3.45 Automated Fire Detection from Wildfire Alert Cameras;
- 3.46 Advanced Electric Inspection Tools – Wood Poles;
- 3.47 Operational Vegetation Management Efficiency Through Novel Onsite Equipment;
- 3.48 Stored Energy Transactions Enablement Platform (SETEP).

The four projects launched in 2020 are described below:

EPIC 3.27 Multi-Purpose Meter is developing a utility-grade submeter for Electric Vehicle Supply Equipment (EVSE), also commonly referred to as an EV charging station) applications in support of Plug-In Electric Vehicle Submetering Protocol proceedings R.18-12-006[3]. The project builds upon EPIC 2.29 Mobile Meter Applications (NextGen Meter – NGM) project which

3 Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification and Closing Rulemaking 13-11-007. https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=252025566

has a granted patent. If successful, this project would reduce EVSE submetering costs, provide public and worker safety by separating high and low voltage components, reduce physical space required in customer property in both externally-mounted and internally-integrated options.

EPIC 3.32 Systems Harmonics for Power Quality Investigation is leveraging next generation SmartMeters™ to collect harmonics data on distribution system and develop an algorithm engine for analysis. Harmonics issues in the distribution system have been increasing and have the potential to cause equipment shutdowns, failures and safety issues. Higher incidence of harmonics issues is anticipated due to the growth of non-linear loads such as solar photovoltaics (PV), DER, EV and energy efficiency technologies. If successful, PG&E will implement a new operational process to proactively detect, investigate and mitigate harmonic issues instead of reacting to customer complaints and employing manual and labor intensive processes to collect, investigate and mitigate these issues. These automation and process improvements have the potential to significantly improve affordability and reliability, and also resolve issues that might have led to more serious failures and safety issues.

EPIC 3.41 Drone Enablement is demonstrating automated and beyond visual line of sight (BVLOS) drone flight operations for transmission line and substation inspections as well as verification of alerts from predictive sensors deployed on the distribution system. If successful, a scaled up version of the solution for transmission system would enable faster, repeatable, and more affordable line and substation inspections in HFTDs. A scaled up version of the solution for the distribution system would enable the integration of sensor-based alerting systems with a drone system, as a fast and much more resource efficient alternative to dispatching crews in trucks or helicopters to investigate potential grid issues.

EPIC 3.43 – Momentary Outage Analytics is developing analytical models that use Advanced Metering Infrastructure (AMI) momentary events and trap alarms and other sensor data to identify issues with customer service drops, insulator failures, and intermittent vegetation contact. The data model developed through this project, which analyzes SmartMeter data with higher granularity, could proactively predict imminent distribution equipment failures before they occur. This capability may result in more immediate or tactical recommendations for actions to mitigate distribution system risks, thereby reducing public safety risk.

Potential Benefits

PG&E filed a comprehensive summary of benefits delivered by its projects in Appendix B of Opening Brief on Phase 2 Issues filing per D.20-08-042.[4]

Upon closeout of EPIC 3 projects, PG&E will report forward-looking estimates of potential benefits if the technology is deployed in production. PG&E will also report the quantification of any benefits realized during the demonstration. PG&E will continue to provide updates on realized benefits for key projects after they have closed through its subsequent EPIC Annual Reports. This information will support the establishment of the joint EPIC database directed in D.8-10-052. EPIC 3 projects are expected to start closing in late 2021.

EPIC Intellectual Property (IP)

In 2020, a new U.S. Non-Provisional patent application and a continuation application to an existing U.S. Non-Provisional patent application were filed for following EPIC projects before the United States Patent and Trademark Office (USPTO):

- *EPIC 2.22 – Demand Reduction Through Targeted Data Analytics:* Non-Provisional patent application No. 16/775,568 titled System Server for Parallel Mixed Integer Programs for Load Management on system and server for parallel processing mixed integer programs for load management.
- *EPIC 1.14 – Demonstrate "Next Generation" SmartMeter Telecom Network Functionalities*: Continuation application to the existing Non-Provisional patent application No. 15/872,771 and titled Wire Down Detection System and Method for the development of an algorithm to help identify wires downed or functioning abnormally, in order to incorporate continuing developments of the technology.

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4 Opening brief on Phase 2 issues (filing per D.20-08-042, Sec. 7). https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M348/K070/348070830.PDF.

In 2020, a new patent was granted by the USPTO for the following EPIC project:

- *EPIC 1.14 – Demonstrate "Next Generation" SmartMeter Telecom Network Functionalities*: U.S. Patent No. 10,658,798 titled Smart Energy Metering System and Method for the development of the Smart Pole Meter and Smart Pole Meter Socket.

In prior years, PG&E was granted patents with the USPTO for the following EPIC projects:

- *EPIC 1.21 – Pilot Methods for Automatic Identification of DERs (such as Solar PV) as They Interconnect to the Grid to Improve Safety & Reliability*: U.S. Patent No. 10,557,720 titled Unauthorized Electrical Grid Connection Detection and Characterization System and Method for an algorithm which can detect unauthorized PV interconnections.
- *EPIC 2.29 – Mobile Meter Applications (NextGen Meter – NGM)*: U.S. Patent No. 10,514,273 titled Smart Energy and Data/Information Metering System and Method on mobile meter with modular housing/board assembly.

PG&E also filed a U.S. Non-Provisional patent application before the USPTO for the following EPIC project in earlier years:

- *EPIC 2.26 – Customer and Distribution Automation Open Architecture Devices*: Non-Provisional patent application No. 16/725,784 and titled Smart Energy and Data/Information Metering System and Method for algorithms to communicate and control edge devices through the AMI network.

In 2020, PG&E signed a licensing agreement with a large international meter manufacturer for the partial voltage wires down detection algorithm developed through EPIC 1.14 – Demonstrate "Next Generation" SmartMeter Telecom Network Functionalities project. PG&E expects to start generating revenue through this licensing agreement starting by Q3 of 2021. Any net revenue would be shared with PG&E's customers and shareholders,[5] 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.

Status of Programs

In D.13-11-025, the CPUC approved 27 of the 29 projects proposed by PG&E in the EPIC 1 Investment Plan, since two projects were formally withdrawn by PG&E prior to the issuance of this decision.[6] In D.15-04-020, the Commission approved the 31 projects proposed by PG&E in the EPIC 2 Plan.[7] In Res.E-4863, the Commission approved two of the six projects proposed by PG&E in the Tier 3 AL 5015-E filed between triennial EPIC Applications.[8] On April 28, 2017, PG&E filed A.17-04-028 for the third triennial investment plan period of 2018-2020 (referred to as EPIC 3) which included 43 proposed projects. On October 25, 2018 in D.18-10-052, the Commission approved the 43 projects in PG&E's proposed EPIC 3 Investment Plan with minor modifications. The Commission also required the utilities to file a joint application containing a RAP, identifying program administration improvements in response to the 2017 EPIC program evaluation within 180 days and required utilities not to commit, encumber or spend one-third of their EPIC 3 budgets until a subsequent decision that

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5 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 royalties, license fees, and other "financial benefits of IP") related to financial benefits of IP that was developed under IOU contracts with Electric Program Investment Charge funds.

6 In the EPIC 1 Plan (A.12-11-003), PG&E originally proposed 26 projects. Project 1.09 was subsequently split into three projects and project 1.10 was split into two projects, resulting in a total of 29 projects. The projects formally withdrawn by PG&E were projects 1.04 and 1.07.

7 In the EPIC 2 Plan (A.14-05-003), PG&E originally proposed 30 projects. Per, CPUC D.15-04-020 to include an assessment of the use and impact of EV energy flow capabilities, Project 2.3 was split into two projects, resulting in a total of 31 projects.

8 In the Tier 3 AL 5015-E filed between triennial EPIC applications, PG&E originally proposed six projects. CPUC Res.E-4863 approved two (Projects 2.34 and 2.36) of the six proposed projects, allowed PG&E's withdrawal of one project (Project 2.31), deferred two projects to a future investment plan (Projects 2.32 and 2.33) and rejected one project (Projects 2.35).

approved RAP. On April 23, 2019, the utilities filed their joint RAP application, and on February 10, 2020, the Commission issued D.20-02-003 approving the RAP application and authorizing the utilities to encumber, commit, and spend the remaining one-third of their EPIC 3 budgets. EPIC Program Renewal OIR R.19-10-005 was initiated on 10/18/2019, and in Phase 1 of this rulemaking D.20-08-042 established five-year EPIC 4 and 5 cycles and set EPIC 4 funding levels for the CEC. Ongoing Phase 2 of the rulemaking will consider the roles of the IOUs in EPIC going forward. On December 30, 2020 PG&E proposed 5 new projects for inclusion in its EPIC 3 program cycle in AL 6043-E.

EPIC Administrators continue to participate in regular review meetings, conduct joint webinars and workshops, and regularly collaborate on EPIC-related matters. The EPIC Administrators generally meet bi-weekly to discuss EPIC and their respective objectives for the program, as well as to ensure collaboration and avoid duplication.

After the Commission's issuance of D.20-02-003 approving the RAP application and authorizing the utilities to encumber, commit, and spend the remaining one-third of their EPIC 3 budgets, PG&E defined and prioritized a second wave of EPIC 3 projects through reevaluation of on-hold projects from the original EPIC 3 investment plan and a broad solicitation of project ideas from subject matter experts across PG&E's line of business.

Prior to selection and launch of this wave of projects, PG&E facilitated a public workshop on June 19th, 2020 with EPIC stakeholders to gather and incorporate input on the proposed projects. Projects were also reviewed with the other EPIC administrators and Electric Power Research Institute (EPRI) for additional technical feedback, collaboration possibilities and unnecessary duplication. Five of the projects that emerged from this process were not included in the original EPIC 3 investment plan, and were submitted to the Commission for approval in AL 6043-E.

The following table summarizes the projects' funding status by area and triennial investment plan program cycle as of December 31, 2020.

TABLE1: SUMMARY OF PROJECT STATUS AND FUNDING BY PROGRAM CYCLE

EPIC Program Areas	EPIC 1	EPIC 2	EPIC 3	Total
Renewables / DER Resource Integration	**Projects: 3** • 1.01 Energy Storage End Uses • 1.02 Demonstrate the Use of Distributed Energy Storage for T&D Cost Reduction • 1.05 Demonstrate New Resource Forecast Methods to Better Predict Variable Resource Output **Spent Funding: $6.7M**	**Projects: 5** • 2.02 Pilot DERMSs • 2.03A Test SI Enhanced Capabilities – PV • 2.03B Test SI Enhanced Capabilities – Vehicle to Home • 2.04 DG monitoring & Voltage Tracking • 2.05 Inertia Response Emulation for DG impact improvement **Spent Funding: $14.9M**	**Projects: 3** • 3.03 DERMS and ADMS Advanced Functionality • 3.10 – Grid of the Future Scenario Engine • 3.11 Location-Specific Options for Reliability and/or Resilience Upgrades **Committed Funding: $10.3M**	**Projects: 11** **Spent Funding: $21.6M** **Committed Funding: $10.3M**
Grid Modernization & Optimization	**Projects: 7** • 1.08 Improve Distribution System Safety & Reliability through New Data Analytics Techniques • 1.09A Test New Remote Monitoring and Control Systems for Existing Transmission & Distribution Assets: Close Proximity Switching • 1.09B/1.10B - Test New Remote Monitoring & Control System for T&D Assets / Demonstrate New Strategies and Tech to Improve the Efficacy of Existing Maintenance and Replacement Programs • 1.09C Test New Remote Monitoring and Control Systems for T&D Assets: Discrete Series Reactors • 1.14 Demonstrate “Next Generation” SmartMeter Telecom Network Function • 1.15 Demonstrate New Technologies and Strategies That Support Integrated “Customer-to-Market-to-Grid” Operations of the Future • 1.16 Demonstrate EV as a Resource to Improve Grid Power Quality and Reduce Customer Outages **Spent Funding: $17.9M**	**Projects: 5** • 2.07 Real Time Loading Data for Distribution Operations & Planning • 2.10 Emergency Preparedness Modeling • 2.14 Automatically Map Phasing Information • 2.15 Synchrophasor Applications for Generator Dynamic Model Validation • 2.34 Predictive Risk Identification with RF Added to Line Sensors **Spent Funding: $13.4M**	**Projects: 4** • 3.13 Transformer Monitoring via Field Area Network (FAN) • 3.15 Proactive Wires Down Mitigation • 3.20 Data Analytics for Predictive Maintenance • 3.43 Service Issue Identification Leveraging Momentary Outage Information **Committed Funding: $15.9M**	**Projects: 16** **Spent Funding: $31.3M** **Committed Funding: $15.9M**

TABLE1: SUMMARY OF PROJECT STATUS AND FUNDING BY PROGRAM CYCLE (CONTINUED)

EPIC Program Areas	EPIC 1	EPIC 2	EPIC 3	Total
Customer Service & Enablement	**Projects: 7** • 1.18 Demonstrate SmartMeter-Enabled Data Analytics to Provide Customers With Appliance-Level Energy Use Information • 1.19 Pilot Enhanced Data Techniques and Capabilities via the SmartMeter Platform • 1.21 Pilot Methods for Automatic Identification of DERs (Such as Solar PV) as They Interconnect to the Grid to Improve Safety & Reliability • 1.22 Demonstrate Subtractive Billing With Submetering for EVs to Increase Customer Billing Flexibility • 1.23 Demonstrate Additive Billing With Submetering for PVs to Increase Customer Billing Flexibility • 1.24 Demonstrate DSM for T&D Cost Reduction • 1.25 Develop a Tool to Map The Preferred Locations for DC Fast Charging, Based on Traffic Patterns and PG&E's Distribution System, to Address EV Drivers' Needs While Reducing the Impact on PG&E's Distribution Grid **Spent Funding: $10.0M**	**Projects: 5** • 2.19 Enable Distributed Demand-Side Strategies & Technologies • 2.21 Home Area Network (HAN) for Commercial Customers • 2.22 Demand Reduction through Targeted Data Analytics • 2.23 Integrate Demand Side Approaches into Utility Planning • 2.36 Dynamic Rate Design Tool **Spent Funding: $8.4M**	**Projects: 2** • 3.27 Multi-Purpose Meter (MPM) • 3.32 System Harmonics for Power Quality Investigations **Committed Funding: $4.7M**	**Projects: 14** **Spent Funding: $18.4M** **Committed Funding: $4.7M**
Cross-Cutting/ Foundational	**Projects: 0** **Spent Funding: $0M**	**Projects: 4** • 2.26 Customer & Distribution Automation Open Architecture Devices • 2.27 Next Generation Integrated Smart Grid Network Mgmt. • 2.28 Smart Grid Communications Path Monitoring • 2.29 Mobile Meter Applications **Spent Funding: $7.4M**	**Projects: 1** • 3.41 Drone Enablement and Operational Use **Committed Funding: $2.9M**	**Projects: 5** **Spent Funding: $7.4M** **Committed Funding: $2.9M**
Summary	**Total Funded Projects: 17** **Total Project Funding Encumbered: $22.0M** **Total Project Funding Spent: $34.8M** **Total Administrative Costs Spent: $2.9M**	**Total Funded Projects: 19** **Total Project Funding Encumbered: $24.7M** **Total Project Funding Spent: $44.0M** **Total Administrative Costs Spent: $4.5M**	**Total Funded Projects: 10** **Total Committed Funding: $36.4M** **Total Project Funding Encumbered: 7.4M** **Total Project Funding Spent to Date: $14.6M** **Total Administrative Costs Spent to Date: $2.6Mk**	**Total Funded Projects: 46** **Total Committed Funding (EPIC 3): $36.4M** **Total Project Funding Encumbered: $54.1M** **Total Project Funding Spent to Date: 94.5M** **Total Administrative Costs Spent to Date: $10.0M**

Projects are prioritized through an internal governance process in order to manage committed funding. Remaining funds may, as needed, be redirected to other approved projects in order to efficiently utilize customer funds.

2. Introduction and Overview

A. Background on EPIC

The EPIC Program is designed to assist the development of pre-commercialized, new, and emerging energy technologies in California, while providing assistance to commercially viable projects. Through EPIC, PG&E develops and demonstrates innovative technologies that advance a broad array of objectives including grid safety, resiliency and reliability as well as customer enablement, and integration of renewable and DERs.

EPIC demonstration projects aid in identifying key requirements and insights to inform full deployment in a manner that strategically aligns the integration of technologies with existing operations. Given the rapidly evolving energy landscape and the impact of climate change in California, the continuation of technology innovation programs like EPIC is critical to the continued advancements of grid capabilities to further safety and resiliency.

Funding for EPIC is authorized in Public Utilities Code (Pub. Util. Code) Section 399.8, which governed the Public Goods Charge (PGC) until expiration on January 1, 2012. The Commission opened an OIR R.11-10-003 to establish the EPIC to preserve funding for the public ratepayer benefits associated with the renewables and RD&D activities provided by the electric PGC. The rulemaking included two phases, with Phase 1 to establish the EPIC Program on an interim basis in 2012, and Phase 2 to establish purposes and governance for EPIC to continue from 2013-2020.[9] The EPIC Program Administrators include the CEC and three Electric IOUs: PG&E, SCE, and SDG&E.

In its Phase I Decision Establishing Interim RD&D and Renewables Program Funding Levels (D.11-12-035), the CPUC established 2012 funding at approximately $142 million, and authorized PG&E, SCE, and SDG&E to institute the EPIC Program, effective January 1, 2012, to collect funds for renewables programs, and RD&D programs at the same level authorized in 2011. Additionally, the surcharge was imposed on all distribution customers based on the existing rate allocation between customer classifications, and collected in the Public Purpose Program component of rates.

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9 See Phase 1 D.11-12-035 and Phase 2 D.12-05-037.

On May 24, 2012, the Commission issued its Phase 2 Decision Establishing Purposes and Governance for EPIC and Establishing Funding Collections for 2013-2020. The decision established an annual funding amount of $162 million for the 2012-2014 EPIC Program cycle (EPIC 1) and set the funding allocations among the three IOUs as 50.1 percent, 41.1 percent and 8.8 percent for PG&E, SCE, and SDG&E, respectively.[10] On April 15, 2015, the CPUC issued D.15-04-020, which approved the second triennial investment plan period of 2015-2017 (EPIC 2). On October 25, 2018 in D.18-10-052, the Commission approved the third triennial investment plan period of 2018-2020 (EPIC 3) and ordered the utilities to jointly develop and file a RAP application that identified improvements the utilities would make in response to the recommendations made in the independent EPIC program evaluation. On April 23, 2019, the utilities filed their joint RAP application, and on February 10, 2020, the Commission issued D.20-02-003 approving the RAP application and authorizing the utilities to encumber, commit, and spend the remaining one-third of their EPIC 3 budgets. EPIC Program Renewal OIR R.19-10-005 was initiated on 10/18/2019, and in Phase 1 of this rulemaking D.20-08-042 established five-year EPIC 4 and 5 cycles and set EPIC 4 funding levels for the CEC. Ongoing Phase 2 of the rulemaking will consider the roles of the IOUs in EPIC going forward. On December 30, 2020 PG&E proposed 5 new projects for inclusion in its EPIC 3 program cycle in AL 6043-E.

B. EPIC Program Components

Authorized by D.12-05-037, the EPIC Program is to fund investments in the following three areas: (1) Applied R&D; (2) TD&D; and (3) Market Facilitation which consists of market research, regulatory permitting and streamlining, and workforce development activities. PG&E and the other IOU administrators were designated to administer EPIC funds only in the area of TD&D. The CEC was designated to administer funds in all areas, including a portion of TD&D.

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10 OP 7 of D.12-05-037 requires the total collection amount to be adjusted on January 1, 2015 and January 1, 2018 commensurate with the average change in the Consumer Price Index for Urban Wage Earners and Clerical Workers for the third quarter, for the previous three years.

C. EPIC Program Regulatory Process

D.12-05-037 defines the regulatory process and governance for the EPIC Program. The decision requires EPIC Program Administrators to submit Triennial Investment Plans to cover 3-year cycles for 2012-2014, 2015-2017, and 2018-2020. The investment plans must include details about planned investments, as well as criteria for selecting and evaluating proposals. Each plan must be evaluated and approved by the Commission prior to program implementation. To date, Administrators have filed three Triennial Investment Plans for 2012-2014, 2015-2017 and 2018-2020. On October 25, 2018 in D.18-10-052, the Commission approved the EPIC 3 Investment Plan. In addition to the Triennial Investment Plans, the Administrators were required to file Annual Reports each year on February 28 through 2020, as well as Final Reports for each project. While compliance requirement of OP 16 of D.12-05-037 has expired, since PG&E's EPIC 3 program was active in 2020, and consistent with the spirit of the OP 16, PG&E files its ninth annual report.

D. Coordination

In order to ensure adequate coordination of the EPIC Program, the EPIC Administrators continue to participate in regular review meetings, conduct joint webinars and workshops, and regularly collaborate on EPIC-related matters. The EPIC Administrators generally meet bi-weekly to discuss EPIC and their respective objectives for the program, as well as to ensure collaboration and avoid duplication. PG&E's EPIC Program Management Organization (PMO) also meets with CPUC Staff to provide project and program updates on a quarterly basis.

The IOU Administrators also continue to work together to leverage consistent approaches, where feasible, for meeting the objectives of the EPIC Program. This collaboration resulted in the development of a common EPIC framework, approved by the Commission in D.13-11-025, to help guide the individual IOU investment plans.

The CPUC established the Policy + Innovation Coordination Group (PICG) in D.18-01-008 and D.18-10-052. The goal of the PICG was to identify opportunities for policy and innovation coordination, provide expertise, knowledge and analysis, and support coordination and feedback between administrators and the CPUC. Per D.18-10-052, PG&E was made responsible for administering the contract with PICG Project Coordinator and acting as the fiscal manager on behalf of the CPUC. On December 27, 2019 PG&E executed this contract and has been acting as the fiscal manager. In 2020, the PICG Coordinator identified specific priority workstreams for coordination in collaboration with the CPUC and Administrators, launched coordination meetings across these workstreams, and established the epicpartnership.org site. There have been eleven workstream coordination meetings covering Equity, Public Safety Power Shutoffs (PSPS), Transportation Electrification, and Wildfire Mitigation. PG&E presented in panels in four of these meetings. PG&E has extensively collaborated with the PICG Coordinator and EPIC Administrators and looks forward to continuing to coordinate with the EPIC Administrators, Coordinator and CPUC through this framework.

E. Transparent and Public Process

The Program's Administrators hold stakeholder workshops during the planning and implementation of the EPIC Triennial Investment Plans to ensure stakeholder feedback is received and incorporated. Additionally, Administrators continue to engage with industry stakeholders by participating in and presenting at conferences, as well as hosting workshops/symposiums annually.

After the issuance of D.20-02-003 approving the RAP application and authorizing the utilities to encumber, commit, and spend the remaining one-third of their EPIC 3 budgets, PG&E began planning to launch a second wave of EPIC 3 projects in 2021. Selection of projects started with a broad solicitation of project ideas with Subject Matter Experts (SME) across PG&E's line of business, focusing on DER integration, grid modernization & optimization, customer services & products and cross-cutting strategies & technologies. Simultaneously, the remaining on-hold projects from PG&E's approved EPIC 3 Investment Plan were reevaluated, to determine whether they still addressed contemporary issues worthy for demonstration. As a result of these two activities, 70 proposals were developed and collected in a common project proposal template. Each project's proposal described its objectives, description/scope, concern/gap addressed, path to operationalization of the technology if the project is successful, potential benefits, novelty, estimated budget, urgency, and opportunities for alternate grants or alternative funding sources. PG&E's EPIC PMO conducted an initial round of screening and consolidated projects addressing similar gaps through breakout meetings with SMEs. The resulting 17 projects were further refined and then reviewed by a committee of directors representing several Lines of Business, in two review sessions. The director committee had a chance to ask clarifying questions of project presenters before scoring each project against a pre-defined set of criteria. As a result of this stage, 12 projects, including 11 new projects and one project already approved by D.18-10-052 were selected to move forward and were presented in an online public workshop on June 19, 2020. SCE also presented a project which was about to launch in this workshop. Feedback was collected from stakeholders during and after the workshop. PG&E's 12 projects were also reviewed with the other EPIC administrators and EPRI for additional technical feedback, collaboration possibilities and to identify potential unnecessary duplication. Upon further refinement, a final set of six projects was selected, of which the five projects that were not already part of PG&E's approved EPIC 3 Investment Plan were submitted to the Commission for approval in AL 6043-E.In 2020, due to impacts from the COVID-19 pandemic, the EPIC Administrators conducted the EPIC Symposium over three days between October 19 and October 21 using an online platform. In the EPIC Symposium, PG&E presented EPIC 3.03 Distributed Energy Resource Management System (DERMS) and Advanced Distribution Management System (ADMS) Advanced Functionality project, 3.11 Location-Specific Options for Reliability and/or Resilience Upgrades, and participated in a panel on Utility Planning for Accelerating Adoption of Storage and Renewables Integration.

Furthermore, PG&E's EPIC Program continues to remain accessible to the interested public. PG&E's EPIC website (www.pge.com/epic) includes EPIC Program information and updates, as well as EPIC annual reports and projects' final reports. PG&E has started to collaborate with PICG Coordinator on the development of a joint public database and website for all EPIC work and PG&E looks forward to continuing this effort in 2021.

3. Budget

A. Authorized Budget

The following table outlines the total Program, Administrative, and CPUC regulatory oversight budget for each triennial cycle.

TABLE 2: TOTAL AUTHORIZED BUDGET BY PROGRAM CYCLE

Total Authorized Budgets	PG&E Program Budget *(TD&D only)*	PG&E Admin. Budget *(TD&D only)*	CEC Program Budget* *(TD&D, Applied R&D, & Market Facilitation)*	CEC Admin Budget* *(TD&D, Applied R&D, & Market Facilitation)*	CPUC Regulatory Oversight Budget
EPIC 1: 2012-2014	$43.3 million	$4.9 million	$166.2 million	$18.5 million	$1.2 million
EPIC 2: 2015-2017	$45.7 million	$5.1 million	$182.9 million	$20.4 million	$1.3 million
EPIC 3: 2018-2020	$49.7Million	$5.5 million	$199.1 million	$22.2 million	$1.4 million

**portion remitted by PG&E*

B. Commitments[11]/Encumbrances[12]

The following table outlines the PG&E total financial commitments and encumbrances, as well the remittances made to both the CEC and CPUC beginning from program inception through December 31, 2020.

TABLE 3: TOTAL COMMITMENTS/ENCUMBRANCES BY PROGRAM CYCLE

Commitments/ Encumbrances	PG&E Total Commitments*	PG&E Total Encumbrances	CEC Program Remittance	CEC Admin Remittance	CPUC Remittance
EPIC 1: 2012-2014	$30.8 - $37.7 million**	$22.5 million	$166.2 million	$18.5 million	$1.2 million
EPIC 2: 2015-2017	$40.2 - $45.7 million**	$24.7 million	$171.9 million	$20.4 million	$1.3 million
EPIC 3: 2018-2020	$36.3 million	$7.4 million	$69.3 million	$22.2 million	$1.4 million

**PG&E Total Commitments do not include PG&E Admin costs.*

***Commitment amounts for EPIC 1 and EPIC 2 are spent amounts.*

11 Per CPUC D.13-11-025, "committed funds" are monies budgeted for a particular project. The committed fund range is defined as the project is approved through PG&E's internal governance process.

12 Per CPUC D.13-11-025, "encumbered funds" refer to monies specified within contracts signed during a previous triennial investment plan cycle and associated with specific activities under that contract.

C. Dollars Spent on In-House Activities

The following table outlines the PG&E total in-house project expenditures and administrative costs, beginning from program inception through December 31, 2020.

TABLE 4: TOTAL DOLLARS SPENT ON IN-HOUSE ACTIVITIES BY PROGRAM CYCLE

Program Cycle	PG&E In-House TD&D Project Expenditures *	PG&E In-House Program Administrative Costs**
EPIC 1: 2012-2014	$11.5 million	$1.7 million
EPIC 2: 2015-2017	$20.3 million	$3.3 million
EPIC 3: 2018-2020	$10.4 million	$2.6 million

** Some "Funds Expended to date: Contract/Grant Amount ($)" and "Funds Expended to date: In house expenditures ($)" have been updated. PG&E transitioned to a new cost model in 2016 that included changes to the structure of the allocation of overheads resulting in a change to how certain costs settled.*

D. Fund Shifting Above 5 percent between Program Areas

All PG&E projects are within TD&D; therefore, there has been no fund shifting between program areas.

E. Uncommitted/Unencumbered Funds[13]

Projects without committed funding are pending further project and benefits analysis. The range of uncommitted funds is dependent on the range of authorized budget and committed funds as identified in Sections 3a and 3b, respectively. The following table outlines the PG&E uncommitted/unencumbered funding for each program cycle as of December 31, 2020.

TABLE 5: TOTAL UNCOMMITTED/UNENCUMBERED FUNDS BY PROGRAM CYCLE

Program Cycle	Uncommitted/Unencumbered Project Funds
EPIC 1: 2012-2014	$8.5 million
EPIC 2: 2015-2017	$1.7 million
EPIC 3: 2018-2020	$13.4 million

13 "Uncommitted" and "Unencumbered" funds refer to monies that are not identified in solicitation plans or obligated to a particular project—these funds are considered unspent.

F. Directly Awarded Funds

As filed in the RAP,[14] PG&E will provide justification for all directly-awarded contracts and provide project and summary level information in the annual report. Overarching company policy is to fill out a Direct Award Request Form, as included in Appendix B of RAP, for proposed direct award of $250,000 or greater. Starting in 2020 this threshold was adjusted to $75,000 for EPIC projects for any procurements that were not purely materials purchases. While PG&E conducted several technology RFPs in 2020, directly-awarded vendor contract amount is heavily weighted. Some projects have materials and construction procurements against supplier contracts, and other projects are building upon previous EPIC projects that engage vendors originally identified through prior bids. Justifications for individual direct awards are provided in Appendix A. The following table summarizes the PG&E directly awarded contracts executed in 2020.

TABLE 6: TOTAL DIRECTLY AWARDED FUNDS BY PROGRAM CYCLE

Program Cycle	PG&E Total Vendor Contract Amount	PG&E Directly-Awarded Vendor Contract Amount*	Directly-Awarded Contract Proportion
EPIC 3: 2018-2020	$7.4 million	$6.8 million	93%

**Includes* procurements made against existing broader PG&E supplier contracts *and contracts with companies originally identified through prior EPIC bids.*

G. Match Funding

PG&E has modified its sourcing processes and RFP scorecard template as committed in the RAP to track match funding and consider match funding in vendor proposal scoring. PG&E's EPIC 3 projects launched to-date have not received match funding. PG&E is actively working with some of its project partners on Department of Energy (DOE) funding opportunities to leverage already planned EPIC work as match funding where the scope of an EPIC project aligns with the objective of the DOE funding opportunity.

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14 Joint Application Of Southern California Edison Company (U 338-E), Pacific Gas And Electric Company (U 39-E), And San Diego Gas & Electric Company (U 902-E) For Approval Of The Research Administration Plan For The Electric Program Investment Charge https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/EPIC-3-Application-Joint.pdf.

4. Projects

A. Summary of Project Funding

For a summary of project funding please refer to Table 1 in Section 1b.

B. Project Status Report (See Appendix A)

See Project Status Report, Appendix A, with project details as of December 31, 2020. The Project Status Report is based on the format provided in Attachment 6 of D.13-11-025.

C. Project Descriptions and Updates

The project descriptions and updates included below are for EPIC 1, EPIC 2, and EPIC 3 projects. Projects that are on hold have been included in the summary.

Project #1.01 – Energy Storage End Uses

i. Investment Plan Period

- 1st Triennial (2012-2014)

ii. Assignment to Value Chain

- Grid Operation/Market Design

iii. Objective

- Develop technologies and strategies for efficient and optimized bidding and scheduling of Energy Storage Technologies (EST) in California Independent System Operator (CAISO) markets and demonstrate those strategies using PG&E's existing Sodium Sulfur (NaS) Battery Energy Storage Systems (BESS).
- This project addresses the following CPUC proceedings:
  - As applicable, operational experiences gained from this project can inform outstanding policy and implementation issues as identified in Energy Storage OIR, R.15-03-011.

iv. Scope

- Develop and deploy technology to enable automated resource response to CAISO market awards.
- Quantify the values that battery resources can capture in CAISO markets.
- Establish financial performance of battery resource participation in CAISO markets.

v. Deliverables

- Demonstrate automated and remote-control application for generic energy storage resources to interface with existing Supervisory Control and Data Acquisition (SCADA) systems.
- Report financial performance from participation in CAISO markets.
- Report comparison of actual performance vs. hypothetical performance quoted in industry reports.
- Comply with regulatory requirements and establish framework/recommendations for accounting standards applicable to energy storage.

vi. Metrics

- 1i – Nameplate capacity (megawatts (MW)) of grid-connected energy storage.
- 3a – Maintain/Reduce operations and maintenance costs.
- 6a – CAISO Non-Generator Resource financial settlements.
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360).

- 7c – Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (Pub. Util. Code § 8360).
- 7l – Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (Pub. Util. Code § 8360).
- 9c – EPIC project results referenced in regulatory proceedings and policy reports (Business Plan references: CPUC R.10-12-007).

vii. Schedule

- 2.75 years

viii. EPIC Funds Encumbered

- $ $698,506

ix. EPIC Funds Spent

- $1,833,968

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.02 – Demonstrate the Use of Distributed Energy Storage for Transmission and Distribution (T&D) Cost Reduction

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Distribution; Grid Operation/Market Design

iii. Objective
   - Demonstrate the ability of a utility operated energy storage asset to address capacity overloads on the distribution system and improve reliability.
   - This project addresses the following CPUC proceedings:
     - This project will count towards the IOU energy procurement targets as set forth in D.10-03-040, the Energy Storage Procurement Framework.
     - As applicable, operational experiences gained from this project can inform outstanding policy and implementation issues as identified in Energy Storage OIR R.15-03-011.

iv. Scope
   - Deploy utility operated energy storage asset at a single site.
   - Demonstrate peak shaving use case along with other site-specific use cases as suggested by distribution operators (DO).

v. Deliverables
   - Identify energy storage site based on project objectives.
   - Identify an economic modeling tool to compare the planned traditional utility with alternatives using distributed resources or demand-side investments.
   - Construct and integrate Energy Storage System (ESS).
   - Test system and analyze results to prove project objectives.

vi. Metrics
   - 1c – Avoided procurement and generation costs.
   - 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360).
   - 7d – Deployment and integration of cost-effective distributed resources and generation, including renewable resources (Pub. Util. Code § 8360).
   - 9c – EPIC project results referenced in regulatory proceedings and policy reports (Business Plan references: Deferring a capacity upgrade has been identified as a key potential value of EST and noted in filings with the CPUC/Assembly Bill (AB) 2514.

vii. Schedule

- 3.5 years

viii. EPIC Funds Encumbered

- $ $2,691,736

ix. EPIC Funds Spent

- $4,010,510

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- No

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in February 2018.
- Final Report included in 2017 EPIC Annual Report.

Project #1.03 – Demonstrate Priority Scenarios from the Energy Storage Framework

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Grid Operation/Market Design

iii. Objective
   - The project aims to reduce existing barriers to deployment of BESS by demonstrating whether post-EV “second life” batteries can cost-effectively perform electric distribution services. The project will demonstrate the potential for reduced ESS costs via a) the development of an integration platform for deploying such batteries (Phase 1) and b) the use of lower cost “second life” batteries in the integrated platform (Phase 2).

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update

- Project not executed

Project #1.04 – Expand Test Lab and Pilot Facilities for New ESS

i. Investment Plan Period
  - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
  - Grid operations/market design

iii. Objective
  - This project would identify ways to enhance the existing test lab facilities at PG&E's Applied Technology Services (ATS) center to provide lab test and pilot facilities for new ESS not previously lab tested. PG&E's ATS lab will be particularly helpful in working with the CEC and industry to test "next generation" technologies that have the potential to make breakthroughs in cost, performance targets, and other important parameters, in a test grid environment. This testing would be a critical step in accelerating commercialization of potential "game changing" technology. New types of technology that may be tested at ATS include, but are not limited to, advanced lithium devices, new sodium-based systems, zinc-air systems and new flow battery chemistries and formats. The funding required to add full capabilities to ATS is minimal. The costs to perform the tests will be paid by the industry or by entities that have received research grants from agencies such as the CEC or DOE.

iv. Scope
  - N/A

v. Deliverables
  - N/A

vi. Metrics
  - N/A

vii. Schedule
  - N/A

viii. EPIC Funds Encumbered
  - N/A

ix. EPIC Funds Spent
  - N/A

x. Partners (if applicable)
  - N/A

xi. Match Funding (if applicable)
  - N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Formally Withdrawn. CPUC A.12-11-003, 10/15/2013.

Project #1.05 – Demonstrate New Resource Forecast Methods to Better Predict Variable Resource Output

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Distribution

iii. Objective
   - Demonstration of emerging capabilities in mesoscale modeling to provide more granular and accurate weather forecasting input to PG&E's storm damage prediction model, and to other PG&E forecasting applications, like catastrophic wildfire risk and PV generation. The main goal is more effective and granular damage prediction, and therefore more efficient response to storm events.

iv. Scope
   - Project focus is on development, deployment, and implementation of an operational version of the Weather Research and Forecasting mesoscale model to support PG&E's forecasting program related to fire, storms and solar production.
   - Not in scope for this project are enhancements to PG&E's Restoration Work Plan (RWP), other than improved forecast damage numbers.

v. Deliverables
   - Fully functional mesoscale modeling system known as POMMS (PG&E Operational Mesoscale Modeling System) that will provide the following:
     - Detailed weather input into PG&E's damage prediction modeling system (SOPP).
     - Next generation wildfire threat awareness system.
     - Historical and forecast solar irradiance data to internal PG&E stakeholders.

vi. Metrics
   - 3a – Maintain/Reduce operations and maintenance costs.
   - 4a – GHG emissions reductions (MMTCO2e).
   - 5c – Forecast accuracy improvement.
   - 5e – Utility worker safety improvement and hazard exposure reduction.

vii. Schedule
   - 3.25 years

viii. EPIC Funds Encumbered
   - $535,055

ix. EPIC Funds Spent

- $823,890

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.06 – Demonstrate Communication Systems Allowing the CAISO to Utilize Available Renewable Generation Flexibility

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Grid Operation/Market Design

iii. Objective
   - This project would demonstrate the use of accepted communications protocols to allow the CAISO to send an operating signal to reduce output under specified conditions, as allowed by contracts.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - N/A

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project not executed.

Project #1.07 – Demonstrate Systems to Ramp Existing Gas-Fired Generation More Quickly to Adapt to Changes in Variable Energy Resources Output

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Grid operations/market design

iii. Objective
   - There are 33 General Electric (GE) 7FA gas turbines installed in combined cycle configurations in California, which is considerably more than any other turbine model. GE offers a product marketed as “OpFlex Balance” that uses advanced controls technology to improve ramp rates to as high as 40 MW per minute (or higher in some cases). As of October 2012, none of the 7FAs in California were using this product. This project proposes to demonstrate improved ramp rate capabilities on one 7FA so that it can serve as a model for the rest of the 7FA fleet. It is assumed that there would be cost share with the vendor and the selected plant owner.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - N/A

ix. EPIC Funds Spent
   - N/A

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Formally Withdrawn CPUC A.12-11-003, 10/15/2013.

Project #1.08 – Improve Distribution System Safety and Reliability Through New Data Analytics Techniques

i. Investment Plan Period

- 1st Triennial (2012-2014)

ii. Assignment to Value Chain

- Transmission; Distribution

iii. Objective

- Develop and demonstrate a new data analytics technique to improve distribution system safety and reliability. The project specifically developed and tested a System Tool for Asset Risk (STAR), which is an enterprise software application that Electric Operations will use to calculate and display (graphically and geospatially) risk scores for electric transmission, substation and distribution assets. The STAR will enable an automated, system-wide application to improve risk identification, prioritization, and investment decisions to support electric system safety.

iv. Scope

- Demonstrate whether the ever-increasing amounts of data can be mined and combined for targeted, cost-effective use for improved asset management.
- Potential scenarios include risk-based asset management, safety hazard mitigation and proactive outage prediction using self-serve and virtual integration environments.

v. Deliverables

- Overview of existing applications and data sources.
- Assessment of existing data source quality.
- High-level future business processes by functional area.
- Inventory of asset risk algorithms (formulas or complexity) for “In Scope” asset classes.
- High-level Change Management Approach.
- Prioritized and phased implementation plan.
- Cost estimate for full implementation of the STAR project.
- Proof of concept prototype.

vi. Metrics

- 7c – Dynamic optimization of grid operations and resources; including appropriate consideration for asset management and utilization of related grid operations and resource, with cost-effective full cyber security (Pub. Util. Code § 8360).
- 3a – Maintain/Reduce operations and maintenance costs: With the improved understanding of risk, there could be a better tool for evaluating projects such

as asset replacement.

vii. Schedule

- 2.25 years

viii. EPIC Funds Encumbered

- $1,249,505

ix. EPIC Funds Spent

- $2,112,640

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2015.
- Final report included in 2015 EPIC Annual Report.

Project #1.09A – Test New Remote Monitoring and Control Systems for Existing T&D Assets: Close Proximity Switching

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Transmission; Distribution

iii. Objective
   - This project explores and seeks to discover effective, new tools to safely operate "Solid Blade in Oil Rotatory Switches."

iv. Scope
   - Test new tools and techniques for safe operation of Solid Blade in Oil Rotatory Switches.
   - Evaluate alternatives to decrease probability of injury to workers and public.
   - Help design a robotic tool to allow remote operation.
   - Develop the necessary parts/adaptors to be used on various types (manufacturer, brand, age, etc.) of Solid Blade in Oil Rotatory Switches.

v. Deliverables
   - A working prototype for various Solid Blades in Oil Rotatory Switch tools.

vi. Metrics
   - 5a – Outage number, frequency and duration reductions.
   - 5e – Utility worker safety improvement and hazard exposure reduction.

vii. Schedule
   - 2.5 years

viii. EPIC Funds Encumbered
   - $301,808

ix. EPIC Funds Spent
   - $515,268

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.09B and 1.10B – Test New Remote Monitoring and Control Systems for T&D Assets/Demonstrate New Strategies and Technologies to Improve the Efficacy of Existing Maintenance and Replacement Programs

i. Investment Plan Period
- 1st Triennial (2012-2014)

ii. Assignment to Value Chain
- Transmission; Distribution

iii. Objective
- The project focus is on development, testing, deployment, and implementation of new technologies, construction methods and techniques, and cost reduction techniques in support of the SCADA monitoring systems used on the Distribution Networks. The monitoring system consists of a complex and extensive set of components used to assess the health and condition of the network transformers on a continuous basis. This research is looking at potential failure points on the monitoring system components and what technologies and improvements can be applied to increase life expectancy of these components and reduce production and maintenance costs for this system and similar systems.

iv. Scope
- Assess new technologies and feasibility of application on the Distribution Networks.
- Primary focus on technologies, components and work methods to extend the life expectancy of monitoring systems equipment and reduce long term maintenance costs.

v. Deliverables
- Modified or improved components identified for use on Distribution Network Monitoring System.
- Improved installation and construction work methods.
- Economic model for maintenance variables based on life expectancy testing of components.
- Changes to components.

vi. Metrics
- 3a – Maintain/Reduce operations and maintenance costs.
- 3b – Maintain/Reduce capital costs.
- 5d – Public safety improvement and hazard exposure reduction.
- 5e – Utility worker safety improvement and hazard exposure reduction.

vii. Schedule

- 3.25 years

viii. EPIC Funds Encumbered

- $484,250

ix. EPIC Funds Spent

- $547,681

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.09C – Test New Remote Monitoring and Control Systems for T&D Assets: Discrete Series Reactors (DSR)

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Transmission

iii. Objective
   - Gain operating experience with DSR to determine whether such devices would be cost effective and operate reliably and safely on PG&E transmission system.

iv. Scope
   - Install and test 90 DSR units on the Las Positas-Newark 230 kV line.
   - Install and test Server at PG&E's San Francisco General Office headquarters, complete with Smart Wire System Manager Software.
   - Communication links between the DSRs and server to support the DSR monitoring and control.

v. Deliverables
   - Installation, testing and analysis of DSR and server communication links.
   - Procure, construct and test the DSRs.
   - White paper describing project including go/no go recommendation.
   - Final report describing overall project, including finding from the operations and testing of DSR units and a recommendation as to whether or not to install the DSRs elsewhere in the PG&E system.

vi. Metrics
   - 3a – Maintain/Reduce operations and maintenance costs.
   - 3b – Maintain/Reduce capital costs.
   - 5a – Outage number, frequency and duration reductions.
   - 5b – Electric system power flow congestion reduction.

vii. Schedule
   - 3.25 years

viii. EPIC Funds Encumbered
   - $1,449,835

ix. EPIC Funds Spent
   - $2,459,732

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.10A – Demonstrate Automated Asset Notification and Management Systems: Dissolved Gas Analysis

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Transmission; Distribution

iii. Objective
   - Develop tools and algorithms that analyze data from monitoring equipment installed on substation equipment (distribution and transmission) that tests for dissolved gasses or other precursor data that would assist in understanding the condition of the equipment.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project not executed.

Project #1.10C – Demonstrate Automated Asset Notification and Management Systems: Underground Cable Analysis

i. Investment Plan Period
- 1st Triennial (2012-2014)

ii. Assignment to Value Chain
- Distribution

iii. Objective
- Develop tools and algorithms that analyze load and operating characteristic data from underground cables in order to develop an understanding of potential failure points, cable maintenance needs, and cable life expectancy.

iv. Scope
- N/A

v. Deliverables
- N/A

vi. Metrics
- N/A

vii. Schedule
- N/A

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- N/A

xi. Match Funding (if applicable)
- N/A

xii. Match Funding Split (if applicable)
- N/A

xiii. Funding Mechanism (if applicable)
- N/A

xiv. Treatment of IP (if applicable)
- N/A

xv. Status Update
- Project not executed.

Project #1.11 – Demonstrate Self-Correcting Tools to Improve System Records and Operations

i. Investment Plan Period
- 1st Triennial (2012-2014)

ii. Assignment to Value Chain
- Transmission; Distribution

iii. Objective
- Demonstrate tools that identify and "register" existing assets to improve the integration between utility planning and operations. As part of the demonstration, implement "self-correcting" technologies that identifies plan vs. actual discrepancies and updates system records automatically.
- High priority use cases include: (1) Mapping of transformers to primary phase; (2) Mapping of customers to transformers; and (3) Precision mapping of PG&E's overhead and underground network.

iv. Scope
- N/A

v. Deliverables
- N/A

vi. Metrics
- N/A

vii. Schedule
- N/A

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- N/A

xi. Match Funding (if applicable)
- N/A

xii. Match Funding Split (if applicable)
- N/A

xiii. Funding Mechanism (if applicable)
- N/A

xiv. Treatment of IP (if applicable)
- N/A

xv. Status Update

- Project not executed.

Project #1.12 – Demonstrate New Technologies That Improve Wildlife Safety and Protect Assets From Weather-Related Degradation

i. Investment Plan Period
  - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
  - Transmission; Distribution

iii. Objective
  - Demonstrate new strategies and technologies to improve animal and bird protection, reduce outages caused by animals and birds, and protect assets from expensive weather-related degradation such as fog-related corrosion.

iv. Scope
  - N/A

v. Deliverables
  - N/A

vi. Metrics
  - N/A

vii. Schedule
  - N/A

viii. EPIC Funds Encumbered
  - $0

ix. EPIC Funds Spent
  - $0

x. Partners (if applicable)
  - N/A

xi. Match Funding (if applicable)
  - N/A

xii. Match Funding Split (if applicable)
  - N/A

xiii. Funding Mechanism (if applicable)
  - N/A

xiv. Treatment of IP (if applicable)
  - N/A

xv. Status Update
  - Project not executed.

Project #1.13 – Demonstrate New Communication Systems to Improve Substation Automation and Interoperability

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Transmission; Distribution

iii. Objective
   - Demonstrate new strategies and technologies to convert and integrate multiple existing proprietary technologies within the substation environment for more effective operations. Substation are key operational hubs and represent significant investments, which must be further leveraged by engaging with vendors to create the next generation of interoperable substation services and products.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update

- Project not executed.

Project #1.14 – Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Distribution; Grid Operation/Market Design; DSM

iii. Objective
   - This project explores and discovers effective new network applications and devices to leverage and improve the SmartMeter communications network.

iv. Scope
   - Leverage the existing SmartMeter network to support additional applications. Inform future uses of the SmartMeter network such as message capability, security, latency, and engineering constraints. Specifically focus on:
     - Test new devices to support network functions and capabilities not previously envisioned (e.g., new data streams, faster data collection).
     - Evaluate alternatives to decrease future upgrade, maintenance and/or operational costs.
     - Demonstrate different network applications, each focused on separate use cases.

v. Deliverables
   - Evaluate new applications and devices, their associated data traffic impact on the SmartMeter network, and recommend which items warrant consideration for full-scale deployment.
   - Develop business case based on findings for full deployment consideration.

vi. Metrics
   - 7f – Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliance and consumer devices for metering, communications concerning grid operations and status, and distribution automation (Pub. Util. Code § 8360).
   - 7k – Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (Pub. Util. Code §8360).
   - Note: Each technology demonstrated may have additional specific benefits to name. For instance, the following could apply: improved communication for power restoration, improved control of streetlights, etc.

vii. Schedule
   - 3.25 years

viii. EPIC Funds Encumbered

- $3,986,281

ix. EPIC Funds Spent

- $4,144,329

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- Patents filed for –
  - Smart Pole Meter
  - Smart Pole Meter Socket and
  - An algorithm to help identify downed wires

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.15 – Demonstrate New Technologies and Strategies That Support Integrated "Customer-to-Market-to-Grid" Operations of the Future

i. Investment Plan Period
- 1st Triennial (2012-2014)

ii. Assignment to Value Chain
- Distribution; Grid Operation/Market Design; DSM

iii. Objective
- The objective of this pilot is to develop and pilot a real-time data visualization software platform for use by Electric Distribution Operations end users. Data will be integrated from various data sources and displayed on Distribution Control Center video walls and individual desktop computers, with potential for future scalability to handheld devices.

iv. Scope
- Scope includes the integration of data (network model, loading, SmartMeter devices, outages, weather, etc.) and a real-time (RT) data visualization platform for Distribution Operations.
- The Distribution Management System (DMS) platform and predictive analytics are not included in the scope.

v. Deliverables
- Demonstrate RT Data Visualization Platform, including data integration from a variety of data sources and a visual interface that includes geospatial, list, and trending layers.

vi. Metrics
- 5a – Outage number, frequency and duration reductions.
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid (Pub. Util. Code 8360).
- 3a – Maintain/Reduce operations and maintenance costs.

vii. Schedule
- 3.25 years

viii. EPIC Funds Encumbered
- $1,334,030

ix. EPIC Funds Spent
- $4,133,173

x. Partners (if applicable)
- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- IP has been created through co-development with the vendor. PG&E retains ownership rights to the IP and will provide free unlimited use rights to California IOUs per the CPUC decision

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.16 – Demonstrate EV as a Resource to Improve Grid Power Quality and Reduce Customer Outages

i. Investment Plan Period
- 1st Triennial (2012-2014)

ii. Assignment to Value Chain
- Distribution

iii. Objective
- Leverage plug-in hybrid vehicle technology emerging in PG&E fleet to generate utility-grade power, supporting distribution circuits during planned or unplanned outage events.

iv. Scope
- Develop nominally 120-kilowatt (kW) exportable power capabilities from a plug-in hybrid electric truck. Seek to create the protocols necessary to safely connect the truck to the appropriate grid connection points. The portfolio of fleet vehicles (higher and lower weight classes) may broaden the range of available power ratings demonstrated by the project.

v. Deliverables
- Develop operating requirements for the vehicle.
- Understand engineering challenges with high power export with collaborative supplier development to solve.
- Develop safety and interconnection protocols to connect the vehicle to the grid leveraging existing protocols for temporary local generator set connection.
- Define and document power requirements for different outage/usage scenarios.
- Develop operating protocols (when and how the vehicles will be used).
- Develop unplanned outage protocols.
- Develop the hardware and software (if required) to connect the vehicle to PG&E's system.
- Build vehicles for field testing.

vi. Metrics
- 5a – Outage number, frequency and duration reductions.
- 5e – Utility worker safety improvement and hazard exposure reduction.
- 3a – Maintain/Reduce operations and maintenance costs.
- 4a – GHG emissions reductions (MMTCO2e).

vii. Schedule
- 3.25 years

viii. EPIC Funds Encumbered

- $ $643,840

ix. EPIC Funds Spent

- $4,009,788

x. Partners (if applicable)

- DOE/National Renewable Energy Laboratory (NREL); Edison Electric Institute engaged for elec. utility industry staging events; Portland General Electric closely collaborating for industry-level requirements

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.17 – Leverage EPIC Funds by Participating in Multi-Utility, Industry Wide RD&D Programs Such as EPRI

i. Investment Plan Period

- 1st Triennial (2012-2014)

ii. Assignment to Value Chain

- Transmission; Distribution

iii. Objective

- PG&E can leverage EPIC dollars by participating and collaborating in multi-utility industry-wide research initiatives conducted by third party organizations experienced in the RD&D area. These programs would allow PG&E to cost effectively develop a deeper awareness of industry trends, access real world experience through pilot programs, and identify the gaps that utilities will fill or close with technology. For example, through participation in existing EPRI programs, PG&E would participate in and gain access to demonstrations, analyses, and results of the testing and study of distribution equipment and strategies. High Value EPRI programs include: IntelliGrid, Integration of Distributed Renewables, Energy Storage, Risk Mitigation Strategies, and Distribution Grid Modernization programs.

iv. Scope

- N/A

v. Deliverables

- N/A

vi. Metrics

- N/A

vii. Schedule

- N/A

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project not executed.

Project #1.18 – Demonstrate SmartMeter™-Enabled Data Analytics to Provide Customers With Appliance-Level Energy Use Information

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - DSM

iii. Objective
   - This project focuses on delivering the cost by major appliances to customers.

iv. Scope
   - This project will use the data enabled by the SmartMeter platform to provide appliance-level itemization of monthly bill charges to customers, without their completing any audit or subscribing to any new service. This project assumes that minute level meter data is available.

v. Deliverables
   - Quantify disaggregation accuracy and compare vendors.
   - Based on results, provide recommendations for deployment strategy of appliance-level billing.

vi. Metrics
   - 1f – Avoided customer energy use.
   - 1h – Customer bill savings (dollars saved).

vii. Schedule
   - 2.5 years

viii. EPIC Funds Encumbered
   - $1,399,248

ix. EPIC Funds Spent
   - $1,296,842

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.19 – Pilot Enhanced Data Techniques and Capabilities via the SmartMeter™ Platform

i. Investment Plan Period

- 1st Triennial (2012-2014)

ii. Assignment to Value Chain

- Distribution; Grid Operation/Market Design; DSM

iii. Objective

- The project is to explore and discover effective, new data that can be collected and studied for further benefits. Demonstrate the type of additional data that can be collected and/or processed through the SmartMeter platform. Evaluate impact of any increased data traffic on the SmartMeter network. Focus on new data collection that makes the SmartMeter platform more robust for more customers.

iv. Scope

- Demonstrate the collection of new data from SmartMeter devices. Example use cases include:
  - Power Quality Data (C12.19 format).
  - New Data Channels.
  - Mobile data collection methods.
  - Power theft detection methodology using SmartMeter data for revenue assurance purposes.

v. Deliverables

- Evaluate new data and analytic methodologies, their associated impact on the SmartMeter.
- Recommendation of which data warrants consideration for full-scale deployment.
- Evaluation should provide key inputs to a business case for general deployment.

vi. Metrics

- 1h – Customer bill savings (dollars saved).
- 1f – Avoided customer energy use (kilowatt-hours (kWh) saved).
- 3a – Maintain/Reduce operations and maintenance costs.
- 3b – Maintain/Reduce capital costs.
- 5d – Public safety improvement and hazard exposure reduction.
- 5e – Utility worker safety improvement and hazard exposure reduction.
- 5f – Reduced flicker and other power quality differences.

- 5i. – Increase in the number of nodes in the power system at monitoring points.
- 7f – Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliance and consumer devices for metering, communications concerning grid operations and status, and distribution automation.
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid.

vii. Schedule

- 3.25 years

viii. EPIC Funds Encumbered

- $1,051,786

ix. EPIC Funds Spent

- $1,980,499

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.20 – Demonstrate the Benefits of Providing the Competitive, Open Market With Automated Access to Customer-Authorized SmartMeter™ Data to Drive Innovation.

i. Investment Plan Period

- 1st Triennial (2012-2014)

ii. Assignment to Value Chain

- Customer Service and Enablement

iii. Objective

- This project will fund continued support of Green Button Connect (GBC). GBC provides a small number of vendors in the competitive market with automated access to recurring, machine-to-machine, programmatic data access to customer-authorized SmartMeter data in order to develop new, innovative and creative ways for customers to manage their energy consumption. GBC is a small demonstration, not scalable to support the larger customer base and wider vendor audience. PG&E is planning on implementing a robust, broader scale offering as part of its Customer Data Access project.

iv. Scope

- N/A

v. Deliverables

- N/A

vi. Metrics

- N/A

vii. Schedule

- N/A

viii. EPIC Funds Encumbered

- N/A

ix. EPIC Funds Spent

- N/A

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Formally notified CPUC on 10-31-13, project may be terminated as refined scope does not appear to meet safety, reliability, affordability guiding principles for priority R&D.

Project #1.21 – Pilot Methods for Automatic Identification of DERs (Such as Solar PV) as They Interconnect to the Grid to Improve Safety & Reliability

i. Investment Plan Period

- 1st Triennial (2012-2014)

ii. Assignment to Value Chain

- Distribution; DSM

iii. Objective

- This project aims to validate and integrate a software platform to identify PV resources by leveraging Smart Meter data. This project focuses on addressing the issue of Unauthorized Interconnections (UI) in an automated fashion by developing and algorithm to identify resources, including integration with PG&E billing and interconnection database, as well as develop an automated outreach system for identified customers.
- This project addresses CPUC proceeding, R.11-09-011 Rule 21 to support the improved distribution-level interconnection rules and regulations for certain classes of electric generators and electric storage resources.

iv. Scope

- Identify vendor to develop or pilot software.
- Develop integration and communication platform for auto-identification of UI.
- Demonstrate ability to automatically integrate software with billing and interconnection.

v. Deliverables

- Successful integration of software with PG&E's Customer Care and Billing (CC&B) system.
- Successful tracking of all UIs identified.
- Successful tracking of communication and "conversion" of UIs to interconnection.

vi. Metrics

- 5d – Public safety improvement and hazard exposure reduction.
- 5f – Reduced flicker and other power quality differences.
- 5c – Forecast accuracy improvement.

vii. Schedule

- 2.5 years

viii. EPIC Funds Encumbered

- $868,495

ix. EPIC Funds Spent

$1,337,825

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- Patent No. 10,557,720 Unauthorized Electrical Grid Connection Detection and Characterization System and Resource Mapping Server and System will be granted on February 11, 2020.

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.22 – Demonstrate Subtractive Billing With Submetering for EVs to Increase Customer Billing Flexibility

i. Investment Plan Period
   - 1st Triennial (2012-2014)

ii. Assignment to Value Chain
   - Distribution; Grid Operation/Market Design; DSM

iii. Objective
   - EV submetering pilot to test subtractive metering process and EV Service Provider business models.
   - This project addresses CPUC D.13-11-008, which requires PG&E, along with the other two California IOUs, to pursue a submetering pilot and eventual protocol.

iv. Scope
   - EV submetering pilot will entail EV Meter Data Management Agents (MDMA) delivering submeter data to IOU for subtraction from customer's primary meter to create an EV and a house bill. Customer will be responsible for both bills. In Phase 2, an additional business model will be introduced where the MDMA will be responsible for the bill to PG&E.

v. Deliverables
   - Process to receive MDMA sub-metered data.
   - Process to subtract EV data from primary meter to create two bills.
   - Inclusion of EV portion of bill on customer's monthly bill.
   - Process for billing MDMA for participant submeter charges.
   - Obtain third-party evaluator for both phases of pilot through a Request for Proposal (RFP).
   - Incentive payments to MDMA.

vi. Metrics
   - 4a – GHG emissions reductions (MMTCO2e).
   - 1h – Customer bill savings (MW-hours saved).

vii. Schedule
   - 5 years

viii. EPIC Funds Encumbered
   - $ 2,756,187

ix. EPIC Funds Spent
   - $2,299,078

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2019.
- Through this project, PG&E identified key elements of third-party EV submetering solutions that will need to be improved before they are deployed to serve the state of California. PG&E identified that for third-party solutions to meet revenue-grade metering standards, improvements will need to be made in metering accuracy. Improvements will also need to be made to data transfer reliability, and a more reliable network than residential Wi-Fi should be utilized.
- Final Report is included in 2019 EPIC Annual Report.

Project #1.23 – Demonstrate Additive Billing With Submetering for PVs to Increase Customer Billing Flexibility

i. Investment Plan Period
- 1st Triennial (2012-2014)

ii. Assignment to Value Chain
- Grid Ops and Market Design/Distribution/DSM

iii. Objective
- Initiative to obtain additional un-netted PV data to support customer call center bill experience, and provide additional service to its customers. PV generation data will be integrated with existing MyEnergy web portal for customers' benefit.
- This project addresses CPUC proceeding, Net Energy Metering R.12-11-005 and R.11-09-011 Rule 21.

iv. Scope
- Explore four different methods for obtaining PV generation data (Dedicated SmartMeter, submeter communication via ZigBee radio, third-party estimates, and data exchange with solar companies, and work with vendor to relay data to customer.

v. Deliverables
- Implement pilot program for dedicated smart meters and third-party estimates.
- Explore opportunities for submetering technology and solar company data exchange.
- Modify existing Customer Data Warehouse/MyEnergy interface to allow for additional data streams and visualization.
- Evaluate relative merits of various generation measurement/estimation approaches.

vi. Metrics
- 5c – Forecast accuracy improvements.
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid (Pub. Util. Code 8360).

vii. Schedule
- 2.5 years

viii. EPIC Funds Encumbered
- $950,313

ix. EPIC Funds Spent

- $1,323,817

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.24 – Demonstrate DSM for T&D Cost Reduction

i. Investment Plan Period

- 1st Triennial (2012-2014)

ii. Assignment to Value Chain

- Transmission; Distribution; Grid Operation/Market Design; DSM

iii. Objective

- Assess how to best utilize DSM resources to create a targeted customer- and location-specific approach to assist with distribution capacity constraints.
- This project addresses CPUC's proceeding, Distribution Resources Planning R.14-08-013, through improving efficiencies between interconnection and integration.

iv. Scope

- Improve ability to estimate Heating, Ventilation and Air Conditioning (HVAC) Direct Load Control (DLC) load impacts at the distribution feeder level to aid in better understanding of the localized impact of HVAC DLC devices on meeting distribution feeder level reliability concerns.

v. Deliverables

- Deploy data logging devices on a scientific sample of existing SmartAC™ Cycling customers, to enable real time monitoring of device performance and load impacts at feeder-level.
- Develop infrastructure to make RT data available on feeder-level load impacts of SmartAC™ cycling to distribution operations.
- Produce report describing a case study methodology of targeting and valuing customer side peak load reductions at the feeder level.

vi. Metrics

- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid (Pub. Util. Code 8360).

vii. Schedule

- 2 years

viii. EPIC Funds Encumbered

- $1,206,477

ix. EPIC Funds Spent

- $1,340,353

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.25 – Develop a Tool to Map the Preferred Locations for Direct Current (DC) Fast Charging, Based on Traffic Patterns and PG&E's Distribution System, to Address EV Drivers' Needs, While Reducing the Impact on PG&E's Distribution Grid

i. Investment Plan Period

- 1st Triennial (2012-2014)

ii. Assignment to Value Chain

- Distribution; DSM

iii. Objective

- Develop, pilot, and validate approaches that help determine the optimal location of DC fast chargers based on traffic patterns and distribution grid infrastructure.

iv. Scope

- Acquire travel pattern data and grid infrastructure capability data to identify low-cost, high utilization areas in which to integrate DC fast chargers into PG&E's distribution system.

v. Deliverables

- Develop a process to identify optimal DC fast charging sites.
- Develop a map that presents the locations of optimal DC fast charging sites in a meaningful manner to customers.

vi. Metrics

- 3a – Maintain/Reduce capital costs.
- 3d – Number of operations of various existing equipment types before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear.
- 4a – GHG emissions reductions (MMTCO2e).
- 5c – Forecast accuracy improvement.
- 5d – Public safety improvement and hazard exposure reduction.
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360).
- 7l – Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

vii. Schedule

- 2.5 years

viii. EPIC Funds Encumbered

- $391,425

ix. EPIC Funds Spent

- $440,769

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2016.
- Final Report was included in 2016 EPIC Annual Report.

Project #1.26 – Pilot Measurement and Telemetry Strategies and Technologies That Enable the Cost-Effective Integration of Mass Market Demand Response (DR) Resources Into the CAISO Wholesale Market

i. Investment Plan Period

- 1st Triennial (2012-2014)

ii. Assignment to Value Chain

- Grid Operation/Market Design and DSM.

iii. Objective

- Develop, demonstrate and validate approaches and technologies that enable the cost-effective integration (specifically, the measurement and telemetry) of mass market DR resources into the CAISO) wholesale market. While other DR projects focus on integration of DR resources into various utility and future Independent System Operator operational needs, this project intends to test alternative telemetry solutions and technologies to satisfy CAISO operational visibility requirements.

iv. Scope

- N/A

v. Deliverables

- N/A

vi. Metrics

- N/A

vii. Schedule

- N/A

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project not executed.

Project #2.01 – Evaluate Storage on the Distribution Grid

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - Grid Operations/Market Design; Transmission; Distribution; DSM

iii. Objective
   - Identify and evaluate whether system needs can be cost-effectively addressed with energy storage, including identifying a range of storage deployment locations and grid interconnection requirements on a granular level.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project not executed.

Project #2.02 – Pilot DERMS

i. Investment Plan Period
  - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
  - Grid Operation/Market Design

iii. Objective
  - Demonstrate new technology to monitor and control DERs to manage system constraints and evaluate the potential value of DER flexibility to the grid. The DERMS demonstration will drive learning about the people, process, and technology needed to operate the high DER penetration grid of 2025.
  - Objective 1: Define DERMS Product Requirements and Characterize PG&E DERMS Needs
  - Objective 2: Define Boundaries and Integrations with Internal and External Systems
  - Objective 3: Demonstrate Technical Feasibility of Utilizing DERMS to Manage DERs for Distribution Grid Services
  - Objective 4: Implement and Evaluate Economic Optimizations and Market Mechanisms for DER-Provided Distribution Services
  - Objective 5: Perform DERMS Deployment Readiness Assessment and Create Deployment Strategy
  - This project informs CPUC proceeding, Distribution Resources Plan (DRP) R.14-08-013 to inform distribution planning by demonstrating DER integration into planning and operations.

iv. Scope
  - Demonstrate minimum viable DERMS operation at PG&E to address key DER management use cases.
  - The demonstration will take place in a limited geography with a diverse set of DERs being monitored and controlled by the DERMS demonstration.

v. Deliverables
  - The functional integration of a DERMS software minimum viable product and operational demonstration of the identified use cases.
  - A report that:
    - Determines the most important characteristics of a full deployment solution including detailed functional and technical requirements.
    - Identifies best practices and required internal capabilities for a full deployment solution.
    - Develops operational processes that can be scaled to a wider system deployment.

- Defines boundaries and integrations with other PG&E systems (e.g., DRMS, DMS, market systems).
- Develops a point of view on the utility role in managing DERs for grid and economic benefits.

vi. Metrics

- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360).
- 7d – Deployment and integration of cost-effective distributed resources and generation, including renewable resources (Pub. Util. Code § 8360).

vii. Schedule

- 2.75 years

viii. EPIC Funds Encumbered

- $2,535,324

ix. EPIC Funds Spent

- $6,785,305

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- $419,000

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in January 2019
- The project provided an opportunity for PG&E to define and deploy a DERMS and supporting technology to uncover barriers and specify requirements to prepare for the increasing challenges and opportunities of DERs at scale. The DERMS Demo was a field demonstration of optimal control of a portfolio of 3rd party aggregated behind-the-meter (BTM) solar and energy storage and utility front-of-the-meter energy storage to provide distribution capacity and voltage support services while also allowing for participation of these same DERs in the CAISO wholesale market.
- Additionally, the DERMS Demo explored the ability to manage DERs that participate in wholesale markets to also provide distribution and customer

services to enable DER value stacking, often referred to as multiple use applications.

- Final Report included in 2018 EPIC Annual Report.

Project #2.03A – Test Smart Inverter (SI) Enhanced Capabilities –PV

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Distribution; DSM

iii. Objective

- This project will explore the use and impact of aggregated customer-sited SIs to help inform emerging industry standards, as well as define the operational and communication requirements to support the advancement and deployment of new inverter technologies.
- This project addresses CPUC proceeding, DRP R.14-08-013, by informing DERs modeling by incorporating SIs. The findings of this report will also support and inform PG&E's position within the Rule 21 open proceeding.

iv. Scope

- Evaluate the technical ability of SIs to influence secondary and primary voltage through field demonstrations in two distinct locations, by adjusting reactive and real power output autonomously.
- Measure customer curtailment from Volt-VAR/Volt-Watt function activation.
- Demonstrate and evaluate the reliability of communications to provide visibility, monitoring and change settings for SI-equipped PV using both a vendor-specific aggregation platform and a vendor-agnostic utility aggregation platform.
- Clarify SI technology requirements to integrate and operate SIs, and characterize challenges to deployment at scale relative to today.
- Through lab testing, understand SI performance under a range of distribution grid conditions.
- Through a vendor-led modeling effort, evaluate the impact of BTM residential PV and PV + Storage with and without SIs and perform an economic analysis of SIs on PG&E's system as compared to traditional distribution grid upgrades.

v. Deliverables

- Identify feeder(s) where SIs will be installed for demonstration.
- Demonstrate the use of residential and commercial SIs on multiple distribution feeders to demonstrate the inverters' local voltage control capabilities and power quality impacts related to high penetration of customer-sited solar PV.
- Develop necessary communications software/hardware/technologies between the utility and two different third-party SI aggregators.

- Design and implement data architectures to support satellite and cellular interaction with remote SIs.
- Quantify and qualify performance of multiple SI models from different manufacturers in lab testing.
- Implement automated Volt-VAR and Volt-Watt curves, with a quantification of ability to perform different grid services.
- Lab-test EV service equipment performance under a large range of harmonic content, to identify any chance of poor behavior.
- Through a modeling effort, provide an economic assessment of SI functions' effectiveness in deferring certain distribution upgrades associated with high DER penetration.

vi. Metrics

- 3a – Maintain/Reduce operations and maintenance costs.
- 3b – Maintain/Reduce capital costs.
- 3e – Non-energy economic benefits
- 5f – Reduced flicker and other power quality differences
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360)
- 7d – Deployment and integration of cost-effective distributed resources and generation, including renewable resources (Pub. Util. Code § 8360)

vii. Schedule

- 3.5 years

viii. EPIC Funds Encumbered

- $2,879,961

ix. EPIC Funds Spent

- $4,977,141

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in February 2019.
- This project demonstrated the functionality and grid impacts of SIs through a field demonstration, a lab testing, and modeling.
- The field demonstration targeted high voltage issues attributed to high PV penetration as well as an evaluation of a vendor-agnostic aggregation platform that allowed for the remote management of SI-enabled PV assets.
- The demonstration also used PG&E laboratory facilities to evaluate the ability of multiple vendors' SI products to execute Rule 21 SI functions and employed the EPRI to model SI performance and economic analysis on simulated PG&E distribution feeders.
- Final Report included in 2018 EPIC Annual Report.

Project #2.03B – Test SI Enhanced Capabilities – Vehicle to Home

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - Distribution; DSM

iii. Objective
   - Assessment of the use and impact of EV energy flow capabilities as a complement to the SI assessment related to PVs in project 2.03A SIs for PV.

iv. Scope
   - Technology demonstration for charging and discharging of the EV in response to DR or hard islanding events.
   - Testing multiple test modes.
   - Technology assessment from customer and ratepayer perspectives through a customer survey and a cost-benefit evaluation.

v. Deliverables
   - Evaluation of the performance of the EV energy flow capabilities to support residential load during DR and hard islanding events.
   - Cost-benefit evaluation

vi. Metrics
   - 3a – Maintain/Reduce operations and maintenance costs.
   - 7d – Deployment and integration of cost-effective distributed resources and generation, including renewable resources.

vii. Schedule
   - 2 years

viii. EPIC Funds Encumbered
   - $225,158

ix. EPIC Funds Spent
   - $534,113

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in February 2018.
- The project demonstrated that a bi-directional EV and charger can support critical household loads through an outage. However, the project also determined that, in addition to the technology not being commercially available, it is not cost effective for customers to adopt. This was supported by the project's customer survey results which indicate the current cost estimate is roughly four times higher than an optimal price for consumers. Therefore, even though the project use cases were technically proven-- they are not currently feasible due to technology cost, limited market value, and other restrictions between actors (e.g. EV battery warranty coverage).
- Final Report included in 2017 EPIC Annual Report.

Project #2.04 – Distributed Generation (DG) Monitoring & Voltage Tracking

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Grid Operations/Market Design

iii. Objective

- Utilization of the voltage measurement capabilities of SmartMeter devices to monitor DG output and identify voltage fluctuations caused by the intermittent nature of distributed renewable resources.
- Use of data analytics techniques and AMI (and other) data to determine the impact of PV penetration on Rule 2 violations and
- Create rating for the probability that a Rule 2 violation is caused by DG.

iv. Scope

- Create an algorithmic process output rating on the likelihood of a voltage violation (on a given transformer) being caused by DG fluctuations.

v. Deliverables

- Develop an analytics process/algorithm to analyze AMI and other data for high penetration DG feeders, as well as some low penetration feeders for baselining.
- Evaluate impact of DG penetration on voltage.

vi. Metrics

- 3a – Maintain/Reduce operations and maintenance costs.
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid (Pub. Util. Code § 8360).
- 7d – Deployment and integration of cost-effective distributed resources and generation, including renewable resources.

vii. Schedule

- 2 years

viii. EPIC Funds Encumbered

- $741,202

ix. EPIC Funds Spent

- $1,233,293

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2017.
- This project demonstrated an algorithmic process for analyzing new data sources (including SmartMeter devices and databases of solar irradiance) to predict the likelihood that a Rule 2 voltage violation was caused by distributed solar generation. Solar energy is by nature intermittent, and ebbs and surges of generation can change the voltage for neighboring, downstream customers. This functionality, if integrated into a larger grid analytics platform, might improve decision making for power quality engineers responding to customer issues.
- Final Report included in 2017 EPIC Annual Report.

Project #2.05 – Inertia Response Emulation for DG Impact Improvement

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Grid Operations/Market Design; Transmission

iii. Objective

- 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, improve the grid performance and reliability, and advance California energy policy to increase the amounts of renewable and DG on the grid.

iv. Scope

- Develop computer models to evaluate inverter capabilities and demonstrate possible future system needs for new inertia support solutions.
- Analyze and optimize the present technology's energy storage inertial response capabilities via Power-Hardware-In-Loop testing.

v. Deliverables

- Evaluation of the power system's need for reliability support, including identifying threshold conditions.
- Assessment of the capabilities of present energy storage inverters for inertial frequency response functions.
- Provide recommendations for future inverter and interconnection requirements to provide inertial response.

vi. Metrics

- 1a. – Number and total nameplate capacity of DG facilities
- 1b. – Total electricity deliveries from grid-connected DG facilities
- 1i. – Nameplate capacity (MW) of grid-connected energy storage
- 3e. – Non-energy economic benefits (reliability)
- 5a. – Outage number, frequency and duration reductions
- 7b. – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360)
- 7d. – Deployment and integration of cost-effective distributed resources and generation, including renewable resources (Pub. Util. Code § 8360)
- 7h. – Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid EVs, and thermal-storage air-conditioning (Pub. Util. Code § 8360)

vii. Schedule

- 2 years

viii. EPIC Funds Encumbered

- $589,375

ix. EPIC Funds Spent

- $1,398,027

x. Partners (if applicable)

- NREL selected as testing and demonstration provider.

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in February 2019.
- This project explored the capabilities of inverter-based energy resources to provide a set of functions related to system inertia which support the electric system.
- The project demonstrated via transmission system modeling and Power-Hardware-In-Loop testing that advanced inverter control methods can provide active power support that improves the system's frequency response in the face of reduced conventional inertia from synchronous machine generators.
- Inverter control methods were explored including inertia-like response (derivative control) and grid-forming (voltage source) modes for respective benefits in bulk system and isolated distribution system use cases.
- Final Report included in 2018 EPIC Annual Report.

Project #2.06 – Intelligent Universal Transformer (IUT)

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Distribution; Grid Operation/Market Design; DSM

iii. Objective

- Develop and demonstrate a solid-state transformer field prototype Medium Voltage Fast Charger system, as an application use case of solid-state transformers for DC fast charging of PEVs, featuring intelligent controls and multiple fast charging of PEVs.

iv. Scope

- Test demonstration and communication to the same DC solid-state transformer with two protocols.

v. Deliverables

- Develop a proof of concept that may demonstrate:
  1. An IUT can be used in lieu of other equipment to connect to DC Fast Charge protocols, and
  2. An IUT can communicate back to the utility.

vi. Metrics

- 3a – Maintain/Reduce operations and maintenance costs.
- 3b – Maintain/Reduce capital costs.
- 5d – Public safety improvement and hazard exposure reduction.
- 7k – Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
- 7l – Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

vii. Schedule

- 2.25 years

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project put on hold after determining the product (IUT) was not mature enough for a technology demonstration through EPIC. Project not executed.

Project #2.07 – RT Loading Data for Distribution Operations and Planning

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - Grid Operation/Market Design; Distribution

iii. Objective
   - This demonstration will leverage interval data to improve feeder modeling, inform near real time load allocation throughout the distribution grid and transformer loading profiles, and identify opportunities to enhance current load forecasting processes for distribution transformers, feeders and substation transformers.

iv. Scope
   - Utilize AMI, SCADA, PV, Geographic Information System (GIS), weather and other data sources to develop an algorithm to improve the prediction of grid loading.
   - Develop a platform to demonstrate the ability to conduct load forecasting at scale and in near RT.

v. Deliverables
   - Develop a unique loading algorithm and metrics for assessing forecast stability and confidence.

vi. Metrics
   - 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid.

vii. Schedule
   - 3.5 years

viii. EPIC Funds Encumbered
   - $1,822,317

ix. EPIC Funds Spent
   - $2,550,035

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in December 2018
- This project developed analytical methods for generating near RT load forecast information. The project successfully built and demonstrated a platform to ingest and process SmartMeter, SCADA, PV generation, GIS, and weather data for two of the eight Areas of Responsibility within PG&E's service territory.
- Final Report included in 2018 EPIC Annual Report.

Project #2.08 – "Smart" Monitoring and Analysis Tools

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Transmission

iii. Objective

- Demonstrate strategies and technologies for real time, online monitoring of substation equipment; Demonstrate communication protocols and equipment to support the smart devices; Develop visualization techniques for improved monitoring; and evaluate new vendor technologies that enable data correlation and predictive analysis to better identify and respond to potential safety, reliability and/or operational issues.

iv. Scope

- N/A

v. Deliverables

- N/A

vi. Metrics

- N/A

vii. Schedule

- N/A

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. 2018 Status Update

- Project not executed

Project #2.09 – Distributed Series Impedance (DSI) Phase 2

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Transmission

iii. Objective

- Demonstrate congestion mitigation by installing DSIs on parallel transmission facilities to demonstrate the next generation of the Distributed Series Reactor (DSR) devices from the First EPIC Triennial Plan, which may allow for better control of transmission line loading.

iv. Scope

- N/A

v. Deliverables

- N/A

vi. Metrics

- N/A

vii. Schedule

- N/A

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project not executed

Project #2.10 – Emergency Preparedness Modeling

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Transmission; Distribution

iii. Objective

- Incorporate natural hazard damage model information into one integrated algorithm/tool, which would provide the ability to quickly estimate the impacts of natural hazards on PG&E’s facilities to enable faster response and restoration.
- Provide the ability to prepare for these hazards by proactively modeling the impacts of potential hazards, to understand system vulnerabilities and restoration resource requirements.
- Incorporate work optimization algorithms to more efficiently allocate crews.
- Utilize artificial intelligence and statistical methods to model productive rates and automatically develop restoration plans.

iv. Scope

- Develop optimization algorithms and visualization tool that includes asset locations and conditions with multiple potential hazards, which allows for the aggregation of equipment damage estimates (via damage models, outage information systems, and damage assessments), est. hours to repair, and recommended allocation of work resources to efficiently respond to a natural hazard.

v. Deliverables

- Complete algorithms that aggregate data from multiple sources to feed into application.
- Incorporate multiple algorithms into a proof of concept visualization tool.
- Develop recommendation for deployment strategy.

vi. Metrics

- 3a – Maintain/Reduce operations and maintenance costs.
- 4a – GHG emissions reductions (MMTCO2e).
- 5a – Outage number, frequency and duration reductions.
- 5d – Public safety improvement and hazard exposure reduction.
- 5e – Utility worker safety improvement and hazard exposure reduction.
- 5c – Forecast accuracy improvement.

vii. Schedule

- 3.5 years

viii. EPIC Funds Encumbered

- $2,713,522

ix. EPIC Funds Spent

- $4,227,128

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- PG&E will receive perpetual, transferable sublicenses to all Work Product to use for current and future PG&E business.

xv. Status Update

- Project completed in February 2019.
- This project developed the RWP system to demonstrate rapid and accurate restoration plan development for emergencies
- The project demonstrated the ability to aggregate equipment damage estimates via damage models, assessments, and outage information systems.
- It also was able to determine time needed for restoration and optimal work resources through a machine learning performance model that predicts accurate work demand and resource performance.
- A mixed integer linear programming (MILP) optimization model that considered multiple stochastic damage scenarios was built to provide resource positioning recommendations that are fast and transparent and more cost-effective and efficient.
- Final Report included in 2018 EPIC Annual Report.

Project #2.11 – New Mobile Technology & Visualization Applications

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - Distribution

iii. Objective
   - Demonstrate tailored, advanced mobile applications for PG&E field operations that build upon Grid Operations Situational Intelligence (Project #15) demonstration projects in the EPIC First Triennial Plan as well as existing "baseline" mobile deployments underway.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project not executed

Project #2.12 – New Emergency Management Mobile Applications

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - Transmission; Distribution

iii. Objective
   - Develop new mobile applications to enhance PG&E's emergency preparedness and response capabilities.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project not executed

Project #2.13 – Digital Substation/Substation Automation

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - Transmission; Distribution

iii. Objective
   - Investigate and evaluate sustainable protection and control technologies for future "digital" substations, which may include testing technologies in a lab setting, and performing a pilot implementation to demonstrate technology adoption and integration with legacy substation protection and control technologies.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project not executed

Project #2.14 – Automatically Map Phasing Information

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Distribution; DSM

iii. Objective

- This project aims to explore a variety of pre-commercial analytics and/or hardware options to automatically map 3-phase electrical power information in order to improve the distribution network models.

iv. Scope

- Project seeks to improve distribution network models through automatic mapping of 3-phase electrical power information.

v. Deliverables

- Develop algorithm or novel process to use AMI data and other sources to determine the assignment of phases to meters and transformers.

vi. Metrics

- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid.

vii. Schedule

- 2.75 years

viii. EPIC Funds Encumbered

- $1,566,518

ix. EPIC Funds Spent

- $1,937,344

x. Partners (if applicable)

- PG&E worked with University of California Riverside to test an alternate algorithm-based approach which was evaluated against other solutions demonstrated in the project

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in December 2018
- This project successfully developed and demonstrated automated analytical methods for determining meter phasing and meter-to-transformer connectivity using SmartMeter, SCADA, and GIS data.
- The in-house method developed by PG&E delivered promising results and PG&E is currently working towards further improving the performance of the algorithms, so that an automated solution may be implemented at scale.
- Final Report included in this 2018 EPIC Annual Report

Project #2.15 – Synchrophasor Applications for Generator Dynamic Model Validation

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Transmission

iii. Objective

- This project will demonstrate new synchrophasor analysis applications that can perform generator dynamic model parameter estimation and validation using disturbance data recorded by the synchrophasor system. New synchrophasor applications could perform mandated generator model validation without requiring time- and labor-intensive on-site tests, and could detect sub-synchronous resonance and other conditions which can cause generator outages.

iv. Scope

- Scope is limited to confirming that analysis of Phasor Measurement Unit (PMU) data is better than costly on-site model validation in the target geography. Scope does not include widespread deployment of PMUs.

v. Deliverables

- Install synchrophasors (or “PMUs”) on generators or generator tie-lines, and demonstrate new data analysis software applications.
- Evaluate the application’s ability to perform generator dynamic model validation by analyzing synchrophasor data following transient disturbances on the transmission system.

vi. Metrics

- 3a – Maintain/Reduce operations and maintenance costs.
- 5a – Outage number, frequency and duration reductions.
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid (Pub. Util. Code 8360).

vii. Schedule

- 3 years

viii. EPIC Funds Encumbered

- $620,157

ix. EPIC Funds Spent

- $739,948

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in December 2018.
- The integration of PMUs on generators for dynamic model validation is a new technology and the project did not result in a tool that is production ready. As applications evolve, installation of PMUs at generating stations could potentially allow utilities to enhance their generator model validation processes.
- Final Report included in 2018 EPIC Annual Report.

Project #2.16 – Enhanced Synchrophasor Analytics & Applications

i. Investment Plan Period
- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
- Transmission

iii. Objective
- Demonstrate new techniques to synthesize Synchrophasor data and utilize the data for advanced RT system applications, such as wide-area monitoring, protection, and control systems, which could help move Synchrophasor applications beyond planning, forensics, and visualization to enhanced wide-area monitoring, protection, and control applications.

iv. Scope
- N/A

v. Deliverables
- N/A

vi. Metrics
- N/A

vii. Schedule
- N/A

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- N/A

xi. Match Funding (if applicable)
- N/A

xii. Match Funding Split (if applicable)
- N/A

xiii. Funding Mechanism (if applicable)
- N/A

xiv. Treatment of IP (if applicable)
- N/A

xv. Status Update
- Project not executed

Project #2.17 – Geomagnetic Disturbance (GMD) Evaluation

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - Transmission

iii. Objective
   - Evaluate system vulnerability to GMD by modeling GMD that occurs during a geomagnetic storm and evaluating the impact on transmission lines, interconnection lines, substations and system voltages.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project not executed

Project #2.18 – Optical Instrument Transformers and Sensors for Protection and Control Systems

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - Transmission

iii. Objective
   - Demonstrate newer technologies, such as optical sensors, as well as strategies and technologies to configure appropriate protection settings, including the coordination required between both new and conventional instrumentation.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project not executed

Project #2.19 – Enable Distributed Demand-Side Strategies & Technologies

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Distribution; DSM

iii. Objective

- Demonstrate distributed energy storage and approaches to address local and flexible resource needs.
- This project addresses CPUC proceeding, DRP R.14-08-013, by demonstrating DER locational benefits and addressing capacity constraints through aggregated BTM customer energy storage.

iv. Scope

- Deploy an aggregation of BTM customer energy storage resources to reduce peak loading or absorb DG on a utility distribution feeder(s).

v. Deliverables

- Demonstrate and test field results for effectiveness of the use of aggregated customer-sited BTM energy storage resources to peak load reduction and/or absorb DG on a utility distribution feeder(s).
- Demonstrate communications with aggregated resources for visualization and control.
- Evaluate cost-effectiveness and reliability of BTM energy storage for addressing capacity constraints.

vi. Metrics

- 1c – Avoided procurement and generation costs.
- 1i – Nameplate Capacity of Grid-Connected Storage.
- 3f – Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management.
- 5b – Electric system power flow congestion reduction.
- 5d – Public safety improvement and hazard exposure reduction.
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid.
- 7d – Deployment and integration of cost-effective distributed resources and generation, including renewable resources.

vii. Schedule

- 2.75 years

viii. EPIC Funds Encumbered

- $1,678,045

ix. EPIC Funds Spent

- $2,182,049

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A – No current evidence of IP development

xv. Status Update

- Project completed in February 2018.
- Final Report included in 2017 EPIC Annual Report.

Project #2.20 – RT Energy Usage Feedback to Customers

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - Grid Operations/Market Design; Distribution; DSM

iii. Objective
   - Evaluate innovative feedback technologies to provide near RT energy usage information to customers and to drive greater customer performance during DR events.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project not executed

Project #2.21 – Home Area Network (HAN) for Commercial Customers

i. Investment Plan Period
  - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
  - DSM

iii. Objective
  - This project will demonstrate the application of HAN technology to PG&E's commercial customers.

iv. Scope
  - This project will enable the Zigbee HAN radio on Large Commercial and Industrial (LCI) meters, to facilitate LCI customer access to real time usage data, as well as testing of the integration with existing Energy Management Systems (EMS).

v. Deliverables
  - Install Zigbee HAN devices with selected LCI customers and connect devices to their SmartMeter.
  - Monitor customer usage and issue/collect customer surveys.
  - Complete report with identified issues and recommendations for how to integrate with an existing EMS.

vi. Metrics
  - 1e – Peak load reduction (MWs) from summer and winter programs.
  - 1f – Avoided customer energy use (kWh saved).
  - 1h – Customer bill savings (dollars saved).
  - 3a – Maintain / Reduce operations and maintenance costs.
  - 4a – GHG emissions reductions (MMTCO2e).
  - 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360).

vii. Schedule
  - 2.25 years

viii. EPIC Funds Encumbered
  - $8,451

ix. EPIC Funds Spent
  - $223,476

x. Partners (if applicable)

- Rainforest Automation providing development of the cloud service application used by the customers

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in February 2018.
- Final Report included in 2017 EPIC Annual Report.

Project #2.22 – Demand Reduction Through Targeted Data Analytics

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Distribution; DSM

iii. Objective

- Identify strategic customers and target demand reduction in local areas by combining and integrating multiple DSM technologies (e.g., EE, DR, Distributed Energy Storage, and Consumer-oriented Energy Tools).
- Investigate whether PG&E can achieve a sufficient amount of demand reduction through visibility into the customer-side resources and improve the reliability of customer-side resources at the local level in order to reschedule local capacity expansion expenditures.
- This project addresses CPUC proceeding, DRP R.14-08-013, by supporting the fair and transparent processes for DER deployment and integration.

iv. Scope

- Develop a solution/tool that determines needed customer demand reduction individually and in aggregate at asset level, leveraging interval and SCADA data.
- Develop cross-DER customer targeting to address forecasted capacity challenges at specific assets, for specific days and times of year, leveraging interval data and other customer attributes.

v. Deliverables

- Create a data analytics platform capable of combining and analyzing multi-structured data, linking to a variety of data sources.
- Develop a method for identification, valuation, implementation, and tracking of targeted DERs.
- Create a quantitative screening/rank order tool.
- Develop actionable DER recommendations to customer outreach teams for reaching demand reduction goals.

vi. Metrics

- 3a – Maintain/Reduce capital costs.
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid.
- 7e – Development and incorporation of cost-effective DR, demand-side resource, and energy efficient resources.
- 7h – Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies.

vii. Schedule

- 2.5 years

viii. EPIC Funds Encumbered

- $656,887

ix. EPIC Funds Spent

- $1,741,477

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- Filed for provisional patent for system and server for parallel processing mixed integer programs for load management in January 2019.

xv. Status Update

- Project completed in February 2019
- This project may result in the enhancement of utility distribution planning tools and processes by facilitating the identification of the lowest cost portfolio capable of deferring, or completely mitigating, asset upgrades. Project tools produced by EPIC 2.22 consider both traditional wires solutions and DER portfolios and allows Distribution Planners to complete advanced scenario analysis.
- Following the development of these new capabilities, EPIC 2.22 tools and platforms were used to support PG&E's first DDOR. EPIC 2.22 was leveraged by PG&E to complete detailed analysis and scenario comparisons at low costs, in a timely fashion, and with a level of analytical rigor that exceed regulatory requirements.
- Final Report included in this 2018 EPIC Annual Report.

Project #2.23 – Integrate Demand Side Approaches Into Utility Planning

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Distribution; DSM

iii. Objective

- This project will enhance PG&E's ability to incorporate the growing usage of DER into distribution planning tools by developing new customer class load shapes that incorporate DERs, and a methodology for modeling DER deployment uncertainty at the circuit level.
- The execution of this project addresses issues as identified in the following proceedings: DRP R.14-08-013 and AB 327 Section 769, which requires transparent and consistent methods to integrate cost-effective DERs into the distribution planning process.

iv. Scope

- Integrate a broader range of customer-side technologies and DER approaches into grid planning and operations in a least cost framework by enhancing distribution load forecasting tools to include new customer load shapes based on the usage of DERs and to model the uncertainty of DER deployment at the circuit level.

v. Deliverables

- Develop enhanced Customer and DER Load Shapes Catalog in PG&E's load forecasting program (LoadSEER) Planning Tool.
- Incorporate DER Scenario Projections into LoadSEER.
- Develop interface between LoadSEER and CYME (software name) for batch processing integration.

vi. Metrics

- 1c – Avoided procurement and generation costs.
- 3f – Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management.
- 5c – Forecast accuracy improvement.
- 7e – Development and incorporation of cost-effective DR, demand-side resources, and energy-efficient resources (Pub. Util. Code § 8360).

vii. Schedule

- 2.25 years

viii. EPIC Funds Encumbered

- $1,831,735

ix. EPIC Funds Spent

- $3,111,449

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2017.
- Final Report included in 2017 EPIC Annual Report.

Project #2.24 – Appliance Level Bill Disaggregation for Non-Residential Customers

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - DSM

iii. Objective
   - Demonstrate the ability to use sub-minute level usage information to determine appliance load for non-residential customers.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project not executed

Project #2.25 – Enhanced Smart Grid Communications

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Grid Operations/Market Design; Distribution; DSM

iii. Objective

- Evaluate license spectrum providers that have developed technologies offered on the Federal Communications Commission license frequency range/spectrum.

iv. Scope

- N/A

v. Deliverables

- N/A

vi. Metrics

- N/A

vii. Schedule

- N/A

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project not executed

Project #2.26 – Customer & Distribution Automation Open Architecture Devices

i. Investment Plan Period
   - 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
   - Distribution; Grid Operation/Market Design; DSM

iii. Objective
   - Demonstrate the means by which new customer and distribution devices could interoperate with PG&E's AMI network (IPv6).

iv. Scope
   - Demonstrate the methodology, protocols, and standards for customers and vendors to connect and communicate various new devices and applications (e.g., electric distribution equipment, DER equipment, Radio Frequency Identification (RFID) reader, smart home devices, etc.) with the AMI network (IPv6) in an effective manner.

v. Deliverables
   - Conduct testing that will demonstrate customer and utility open architecture devices/applications that are AMI compatible, secure and interoperable.
   - Provide physical and application interfaces, as a proof of concept, which may permit customer, utility and third-party devices to connect to PG&E's AMI network(s).

vi. Metrics
   - 3f – Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management.
   - 5i – Increase in the number of nodes in the power system at monitoring points.
   - 7j – Provide consumers with timely information and control options.

vii. Schedule
   - 3.25 years

viii. EPIC Funds Encumbered
   - $1,505,338

ix. EPIC Funds Spent
   - $3,448,342

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- Non-provisional patent filed for AMI network Open Architecture System

xv. 2018 Status Update

- Project completed in February 2019.
- This project successfully demonstrated in laboratory and field tests, the ability to communicate with, monitor, and control PG&E and third-party devices in five use cases.
  - These use cases involved SIs, sensors, SCADA and other distribution intelligent electric devices, RFID equipment and Direct Acquisition and Control Telemetry.
  - These use cases were selected for their potential to improve system reliability, reduce costs, or both.
  - This project was successful in demonstrating that PG&E's AMI network can be leveraged for these additional use cases and is suitable for connecting and transmitting data from customer and utility devices.
- Final report included in 2018 EPIC Annual report.

Project #2.27 – Next Generation Integrated Smart Grid Network Management

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Grid Operations/Market Design; Distribution; DSM

iii. Objective

- Evaluate new technologies to holistically monitor, control and evolve the communications network and supporting infrastructure as a platform to enable Smart Grid solutions.

iv. Scope

- Demonstrate a new AMI Network management system to holistically monitor, control, and evolve the existing AMI network and infrastructure from a billing-centric platform to a fully operational AMI solutions platform that will meet evolving customer and grid needs.

v. Deliverables

- Demonstrate an integrated, multi-tenant network management system that may include the following features:
    - Integrated network management and control that will monitor and prioritize data traffic.
    - Automate trouble ticketing creation process for workflow management.
    - Asset management of meter and network equipment regardless of meter or network types.

vi. Metrics

- 3a – Maintain/Reduce operations and maintenance costs.
- 5a – Outage number, frequency and duration reductions.
- 5d – Public safety improvement and hazard exposure reduction.
- 5e – Utility worker safety improvement and hazard exposure reduction.

vii. Schedule

- 3 years

viii. EPIC Funds Encumbered

- $576,433

ix. EPIC Funds Spent

- $1,134,144

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in August 2018.
- Developed a demonstration grade management platform that successfully identified inventory, configuration, and performance data for all three AMI networks including both networking elements and metering endpoints.
- The project learned the complexity of adding functions needed such as additional Head-End Network Management functions, integration with GIS layers (i.e., data sources like CC&B, Meter Data Management Systems), and integration with various PG&E ticketing systems (Remedy, FAS(a software name)). Based on this complexity, an enterprise management system will be needed to scale the functions demonstrated through this project.
- Final report included in 2018 EPIC Annual report.

Project #2.28 – Smart Grid Communications Path Monitoring

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Grid Operation/Market Design

iii. Objective

- Evaluate communication paths for AMI related messages, including methods to clear potential interference, congestion, validate proper authorizations, and grant clearances for sending message over a secured communication path.

iv. Scope

- Determine the ability to identify, analyze, and diagnose RF interference that can occur along the communication path from the meter through the data collectors to the AMI vendors' control system.

v. Deliverables

- Establish the baseline noise floor.
- Develop and demonstrate an application with an algorithm which can automatically and continuously identify, monitor, and confirm RF interferences for multiple spectrums.
- Provide an end-end process for identifying, confirming and mitigating detected interferences with the AMI-network.

vi. Metrics

- 1h – Customer bill savings (dollars saved).
- 3e – Non-energy economic benefits – reduction operational hours to fix estimated bills due to RF Interference.

vii. Schedule

- 1 years

viii. EPIC Funds Encumbered

- $58,518

ix. EPIC Funds Spent

- $251,869

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in February 2018.
- Final Report included in 2017 EPIC Annual Report.

Project #2.29 – Mobile Meter Applications

i. Investment Plan Period
- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
- Grid Operations/Market Design; Distribution; DSM

iii. Objective
- Demonstrate the utility's ability to enable dynamic electric mobile metering.

iv. Scope
- Develop and test a mobile meter prototype on various applications that can be used to capture and monitor RT energy transactions and usage (e.g. PEV, DG, mobile storage, etc.).

v. Deliverables
- Design specification of mobile meter.
- Demonstration of mobile meter hardware prototype.
- End-to-end meter to cash testing using existing AMI or cellular based network.
- Demonstration of use-cases on DG applications and PEV metering, including remote and near RT tracking of vehicle charge locations and energy flow.

vi. Metrics
- 3a – Maintain/Reduce operations and maintenance costs (Affordability).
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Reliability).
- 7j – Provide consumers with timely information and control options (Customer).

vii. Schedule
- 3.5 years

viii. EPIC Funds Encumbered
- $1,709,700

ix. EPIC Funds Spent
- $2,537,662

x. Partners (if applicable)
- Lawrence Livermore National Lab providing technical support for product development

xi. Match Funding (if applicable)
- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- Non-Provisional patent Resource Meter System And Method (16/143,295) filed for the multi-purpose mobile meter (NGM).

xv. Status Update

- Project completed in February 2019.
- Conducted functional and acceptance testing on alpha and beta NGM prototypes.
- Demonstrated mobile application of NGM prototype at PG&E
- Refined integration of accelerometer into the NGM
- Designed, implemented, and tested C12.19 and head end applications into NGM
- Final report included in 2018 EPIC Annual report.

Project #2.30 – Leverage EPIC Funds to Participate in Industry-Wide RD&D Programs

i. Investment Plan Period
- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
- Grid Operations/Market Design; Transmission; Distribution; DSM

iii. Objective
- Leverage EPIC dollars by participating and collaborating in multi-utility, industry-wide research, demonstration and deployment initiatives conducted by third-party organizations.

iv. Scope
- N/A

v. Deliverables
- N/A

vi. Metrics
- N/A

vii. Schedule
- N/A

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- N/A

xi. Match Funding (if applicable)
- N/A

xii. Match Funding Split (if applicable)
- N/A

xiii. Funding Mechanism (if applicable)
- N/A

xiv. Treatment of IP (if applicable)
- N/A

xv. Status Update
- Project not executed

Project #2.31 – Aggregated BTM Storage Market/Retail Optimization

i. Investment Plan Period
- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
- Grid Operations/Market Design; DSM

iii. Objective
- Demonstrate how aggregated BTM ESS that are operated by a third-party dispatcher may address wholesale market needs, while also operating as a customer resource to reduce customers' retail electric bills.

iv. Scope
- N/A

v. Deliverables
- N/A

vi. Metrics
- N/A

vii. Schedule
- N/A

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- N/A

xi. Match Funding (if applicable)
- N/A

xii. Match Funding Split (if applicable)
- N/A

xiii. Funding Mechanism (if applicable)
- N/A

xiv. Treatment of IP (if applicable)
- N/A

xv. Status Update
- Formally Withdrawn by PG&E on 07/31/2017 via PG&E Comments on Draft Res.E-4863.

Project #2.32 – Electric Load Management for Ridesharing Electrification

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Grid Operations/Market Design; Distribution; DSM

iii. Objective

- Evaluate grid impacts from EV charging used for ridesharing applications, to assess the ability to manage the resulting load using active demand management.

iv. Scope

- N/A

v. Deliverables

- N/A

vi. Metrics

- N/A

vii. Schedule

- N/A

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Deferred to a future investment plan by CPUC. Res.E-4863. 08/10/2017.
- Re-assigned as EPIC 3.42.

Project #2.33 – Service Issue Identification Leveraging Momentary Outage Information

i. Investment Plan Period
- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
- Grid Operations/Market Design; Distribution

iii. Objective
- Leverage multiple sources of data, including but not limited to SmartMeter, time of day, location and weather data, to proactively identify potential problems in the Electric T&D system, specifically related to identifying locations with high incidences of momentary outages which may be caused by imminent failures of conductors, insulators, transformers and/or vegetation contact.

iv. Scope
- N/A

v. Deliverables
- N/A

vi. Metrics
- N/A

vii. Schedule
- N/A

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- N/A

xi. Match Funding (if applicable)
- N/A

xii. Match Funding Split (if applicable)
- N/A

xiii. Funding Mechanism (if applicable)
- N/A

xiv. Treatment of IP (if applicable)
- N/A

xv. Status Update

- Deferred to a future investment plan by CPUC. Res.E-4863. 08/10/2017.
- Re-assigned as EPIC 3.43.

Project #2.34 – Predictive Risk Identification with RF Added to Line Sensors

i. Investment Plan Period
- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
- Grid Operations/Market Design; Distribution

iii. Objective
- Demonstrate distribution sensor products that provide indicators of imminent asset failure and RT monitoring of PG&E rights-of-way

iv. Scope
- Assess technical feasibility of various sensor products and validate opportunity for business benefits
- Develop solution designs, develop test plans, and conduct testing at ATS
- Conduct field demonstrations of various products and develop post-EPIC roadmaps for integrating capabilities in production

v. Deliverables
- Roadmap for integrating additional sensor technologies in production

vi. Metrics
- 3a – Maintain / Reduce operations and maintenance costs
- 5a – Outage number, frequency and duration reductions
- 5d – Public safety improvement and hazard exposure reduction

vii. Schedule
- 2 years

viii. EPIC Funds Encumbered
- $2,370,131

ix. EPIC Funds Spent
- $3,897,352

x. Partners (if applicable)
- N/A

xi. Match Funding (if applicable)
- N/A

xii. Match Funding Split (if applicable)
- N/A

xiii. Funding Mechanism (if applicable)
- N/A

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2020.
- This project investigated the use of RF-based Distribution Reliability Line Monitor and Early Fault Detection technologies and compared their performance with DFA technology for predictive maintenance and risk reduction on electric distribution circuits.
- The demonstration successfully detected, located and addressed multiple examples of conductor damage, vegetative encroachment, internal transformer discharge, fault induced conductor slap, and insulator and clamp issues.
- The project concluded that effective grid asset health and performance monitoring can be achieved through an ensemble approach and further work is necessary to improve and integrate sensor technologies into an analytics platform or DMS.
- Final Report is included in 2020 EPIC Annual Report.

Project #2.35 – Call Center Staffing Optimization

i. Investment Plan Period
- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain
- Grid Operations/Market Design

iii. Objective
- Optimize call center staffing by developing a RT algorithm that integrates with and improves upon existing call center staffing software to potentially predict variability in call volume impacts in near RT.

iv. Scope
- N/A

v. Deliverables
- N/A

vi. Metrics
- N/A

vii. Schedule
- N/A

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- N/A

xi. Match Funding (if applicable)
- N/A

xii. Match Funding Split (if applicable)
- N/A

xiii. Funding Mechanism (if applicable)
- N/A

xiv. Treatment of IP (if applicable)
- N/A

xv. Status Update
- Rejected by CPUC. Res.E-4863. 08/10/2017.

Project #2.36 – Dynamic Rate Design Tool

i. Investment Plan Period

- 2nd Triennial (2015-2017)

ii. Assignment to Value Chain

- Grid Operations/Market Design; DSM

iii. Objective

- Develop a new rate design tool that will enable complex rate design such as for DER adoption, with a more robust, quicker and powerful rate design approach than the current rate design process. Leveraging big data technologies, the tool will provide rapid optimization, analysis and evaluation of hypothetical new rate structures which will enable PG&E and parties in a rate case to make rate design decisions based on full information and nuanced sensitivity analysis.

iv. Scope

- Design and build cost of service database
- Design and build rate design model engine and API
- Build functionality and ability to run DER scenarios

v. Deliverables

- Technical architecture specifications
- Data model and databases
- Rate design model engine and API

vi. Metrics

6a. Reduction of time to complete the process of designing, optimizing, and analyzing the impact of a hypothetical rate design

vii. Schedule

- 1.25 years

viii. EPIC Funds Encumbered

- $585,440

ix. EPIC Funds Spent

- $1,107,409

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- N/A

xv. Status Update

- Project completed in 2020.
- This project demonstrated a dynamic rate design tool approach built on a cloud platform for modeling customer bill impacts.
- The project leveraged advanced technologies to experiment with high-level rate designs, new billing determinants, and enabled a more robust, powerful and rapid bill impact analysis process than that which is used by current models.
- In its current state, the tool can design high-level experimental tiered, time-of-use, and tiered time-of-use rates as well as rates with a maximum demand charge.
- The dynamic rate design tool can be leveraged and further developed to significantly improve other production-grade tools for rate and bill analysis.
- Final Report is included in 2020 EPIC Annual Report.

Project #3.01 – Automated DER Impact & Long-Term Dynamics Evaluation

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/Market Design; Distribution

iii. Objective

- Automate the DER impact and long-term dynamics evaluation processes leveraged in detailed engineering analysis in order to aim to reduce DER study timelines and costs, while also seeking to support distribution engineers to better understand and manage the voltage impacts caused by multiple DERs on a single circuit and on LTC operations. The automated evaluation modules would produce a report showing device loading, steady state voltage analysis, and voltage flicker analysis. The long-term dynamics module could potentially further identify potential voltage issues that may lead to Electric Rule 2 violations.

iv. Scope

- TBD

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- TBD

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.02 – Utility Aggregated Resources With Market Participation

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operations/Market Design; Distribution

iii. Objective
   - Demonstrate multi-technology DER aggregation (e.g., solar, storage) for wholesale market operations with potential to explore multiple uses including distribution support, retail, and/or T&D interfaces for control center operations. Developing this more automated optimization solution may enable realization of additional value from DERs with minimal operator intervention or disruption to operations. This equals more effective utilization of DG assets, which may include enhanced bidding in RT to enable realization of additional wholesale market value from DERs or enhanced reliability by providing an indication of whether the current state of the grid is configured in a way that allows bidding into the CAISO market.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.03 – DERMS and ADMS Advanced Functionality

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/Market Design; Distribution; Transmission; DSM

iii. Objective

- To incorporate additional DER technologies and grid management approaches into DERMS and/or ADMS to build upon efforts from the EPIC 2.02 DERMS project to support improvements to safe and reliable grid operations at the T&D market interface, while also enabling the presence of high penetrations of market participating DERs. This would demonstrate the orchestration of a comprehensive DER portfolio and also address the new operational challenges for DOs caused by emerging opportunities for DERs to participate in wholesale markets via the DERP tariff.

iv. Scope

Project Phase 1 – DER Registration, Verification, and Monitoring:

- Design, assess, procure, and deploy a standardized SI head-end platform to communicate with a minimum of 2 individual DERs or Aggregator cloud platforms. The interface must be compliant with CSIP 2.1 requirements to enable vendor agnostic communication and be cybersecure.
- Design, develop, and deploy an interface between SI head-end platform and DMS/SCADA to enable operator visibility of DER telemetry information.
- Conduct a field demonstration for the following foundational capability with multiple (at least two) individual DERs or Aggregators:
  - Dispatch registration data request to SI-based DERs, and ingest monitoring and registration data from DERs.
  - Display DER telemetry data in distribution DMS/SCADA for operator visibility

Project Phase 2 – Integration with EMS/DMS/SCADA and DER dispatch:

- Expand SI head-end platform capabilities to dispatch control signals to SI-based DERs either directly or through Aggregator cloud platforms. The interface must be compliant with CSIP 2.1 requirements and the control capabilities must include:
  - Dispatch of RT signal to connect/disconnect DERs
  - Dispatch of RT signal to limit maximum active power
  - Dispatch of day-ahead capacity constraint signals
  - Dispatch of seasonal or day-ahead load/generation schedule
  - Dispatch short term distribution grid capacity constraints

- Design, configure and deploy customized dashboards for DOs to visualize, dispatch, and control DERs for both the remote grid application, and the non-wires alternative solution.

Note: The distribution grid constraint for DERs participating as a NWA resource will be generated using a substation load/generation forecasting model that will be developed outside of EPIC 3.03 scope.

Conduct a field demonstration of the following capabilities with multiple (at least two) individual DERs or Aggregators that enable the use cases defined above:

- Display DER situational awareness data for DERs operating in off-grid stand-alone systems and allow operators targeted control options to manage the DERs.
- Based on operator request, perform a day-ahead scheduled load/generation dispatch of DER resources directly or through an Aggregator platform. Confirm and verify the DER response.
- Dispatch day-ahead or seasonal capacity constraints to DER resource interconnected with constrained generation agreement. Confirm and verify the DER response.
- Dispatch short term capacity constraints to DER resources directly or through an aggregator platform. Confirm and verify the DER response.
- If the response of DER resources do not conform with the constraints provided, disconnect the DER or curtail generation.

v. Deliverables

- PHASE I
  - Detailed scope and charter created and approved
  - Location/feeder selection finalized for each use case
  - Initial solution design completed, and RFP released for DERMS vendor
  - DERMS vendor selected and contract terms finalized June
  - Multiple (at least two) individual DERs and/or aggregators contracted for participating in field demonstration –
  - Vendor software acceptance test completed for Phase 1 functionalities
  - DER assets deployed, and Aggregator platforms prepared for field demonstration
  - Demonstration of Phase 1 functionalities completed – April 2020
  - Established operating protocol and procedure. Prepared path to production documentation for Phase 1 functionalities

- PHASE II
  - System requirements developed to expand the SI Head-end platform capabilities to establish two-way communication for demonstrating Phase 2 use cases
  - Vendor software acceptance test completed for Phase 2 functionalities
  - DER assets deployed, and Aggregator platforms prepared for field demonstration at one remote grid site and one Non-Wires alternative site. The NWA field demonstration will be conducted in an area that will allow PG&E to de-risk the grid and/or PG&E customers. The field demonstration will be located either serve a grid need in an area with high potential to be affected by PSPS but not eligible as a resilience zone or in an area that is part of a disadvantaged community (DAC). The business sponsor will review and agree on site selection for both field deployments before they occur.
  - Demonstration of Phase 2 functionalities completed
  - Established operating protocol and procedure. Prepared path to production documentation for Phase 2 functionalities

vi. Metrics

7-b: Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360)

7-c: Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (Pub. Util. Code § 8360)

7-d: Deployment and integration of cost-effective distributed resources and generation, including renewable resources (Pub. Util. Code § 8360)

7-j: Provide consumers with timely information and control options (Pub. Util. Code § 8360)

7-l: Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (Pub. Util. Code § 8360)

9-c: Number of times reports are cited in scientific journals and trade publications for selected projects.

9-d: Successful project outcomes ready for use in California IOU grid (Path to market)

vii. Schedule

- 2 Years

viii. EPIC Funds Encumbered

- $636,451

ix. EPIC Funds Spent

- $2,270,909

x. Partners (if applicable)

- Blue Lake Rancheria

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Completed design and installation of an IEEE 2030.5 DER Headend Server (CSIP certification pending)
- To build a market for remote site gateway devices for DER developers, PG&E selected two vendors for development of additional third-party remote site gateways meeting PG&E standards and requirements. This also set up a pathway for future vendors to develop their own remote site gateways.
- Factory acceptance testing for the gateway device to be installed at the first pilot site at Blue Lake Rancheria has been completed.
- Installation of headend server at PG&E has been completed.
- Installation of the gateway device at the pilot site is scheduled for early 2021.
- Third-party site gateway vendors have begun interoperability testing with the headend server.
- Field testing to be completed in 2021.

Project #3.04 – Multi-Nodal Distributed Digital Ledger

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/Market Design; Distribution; Generation; DSM

iii. Objective

- Demonstrate and evaluate a multi-nodal digital distributed ledger (i.e., Blockchain) as an enabling technology that may facilitate greater efficiency, transparency, and security for customers. The project results may illuminate certain blockchain use cases that provide the most benefit to the utility and its customers and provide greater understanding regarding challenges associated with technology scalability, the blockchain interface with the grid, and current business processes and the application of smart contracts and other similar algorithms in a distributed environment.

iv. Scope

- Build blockchain solution for materials traceability by tracking the Company's use of steel reels.
- Build blockchain solution for the trading of incremental EV credits in the residential market for LCFS.

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- 18 months

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $(52)

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.05 – Virtual DER Markets for Capacity and Other Attributes

i. Investment Plan Period
  - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
  - Grid Operations/Market Design; Distribution; DSM

iii. Objective
  - To demonstrate the feasibility and the technological and/or economic performance of autonomous distributed economic dispatch in the context of DER markets for capacity and other attributes. There is no technology standard in the industry today for responding to multiple conflicting signals across the Generation-Transmission-Distribution-Customer value chain. The objective of the project is to test flexible demand, generation and storage, and reward local people and businesses for being more flexible with their energy.

iv. Scope
  - TBD

v. Deliverables
  - TBD

vi. Metrics
  - TBD

vii. Schedule
  - TBD

viii. EPIC Funds Encumbered
  - $0

ix. EPIC Funds Spent
  - $0

x. Partners (if applicable)
  - TBD

xi. Match Funding (if applicable)
  - TBD

xii. Match Funding Split (if applicable)
  - TBD

xiii. Funding Mechanism (if applicable)
  - TBD

xiv. Treatment of IP (if applicable)
  - TBD

xv. Status Update

- Project is currently on hold.

Project #3.06 – Auto Identification (AutoID) of BTM Storage

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/Market Design; Distribution; DSM

iii. Objective

- To bridge the knowledge gap for storage's charge and discharge behavior in the field, as well as system impacts by analyzing storage charge/discharge patterns.
- Under current Net Energy Metering Policy, BTM Storage is not required to be on a separate submeter. This could lead to a situation where the utility would not be aware of the presence of storage, which could potentially impact safety and reliability of the distribution network. Additionally, understanding of the "net" storage impact at the feeder-level and secondary circuit level is important as distribution planning engineers begin to include DERs in their load forecasts.

iv. Scope

- TBD

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- TBD

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.07 – Utility Scale Storage for Load Balancing

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operations/Market Design

iii. Objective
   - To demonstrate phase load balancing by leveraging large, utility-owned batteries. Removing manual work to rebalance loads improves operational efficiency by reduced manual hours spent, improves reliability by optimizing asset utilization across phases with faster adjustment of controls, and improves safety by removing manual labor for managing large loads.

iv. Scope
   - TBD.

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update
   - Project is currently on hold.

Project #3.08 – Second-Life Batteries for Grid Needs

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/Market Design; Distribution; DSM

iii. Objective

- To demonstrate technology that enables second-life energy storage for key utility functions, such as DR and/or frequency regulation, which may lower energy storage costs and support EV business cases with residual value.
- Technology may also be developed for ensuring that second-life batteries can successfully interface with the grid. Building off PG&E's prior energy storage EPIC pilots, this project may identify significant technical or performance differentiations between a second-life storage system and an installation with new batteries, and

iv. Scope

- TBD

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- TBD

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.09 – Dynamic Near-Term DER Load Forecasting

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/Market Design, Distribution; Generation, Transmission, DSM

iii. Objective

- This project proposes to collect and combine SI data with other data streams (e.g., local weather, customer demographics, and/or customer usage) to create an algorithm that can better predict customer gross and net usage/load, DER generation, back-feed at distribution assets, and impact on system level or local short-term energy supply needs. Beginning in September 2017, California's Rule 21 requires SIs for all new customer-connected generation and storage devices.
- Having better insight into the impact of DERs on generation and distribution system needs, the utility, in coordination with the CAISO, may be able to reduce the generation purchasing buffer required. Further, the utility could better understand and model/predict the impact of DERs on the distribution system. This could reduce operating cost and in turn potentially lower customer bills.

iv. Scope

- TBD

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- TBD

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.10 – Grid of the Future Scenario Engine

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Transmission; Distribution; DSM

iii. Objective

- To develop a wide-scale distribution and/or transmission grid simulator for analyzing multiple scenarios and potential future stressors to the grid, such as changes in usage behavior, increased DER integration rates and more to facilitate better informed grid planning.

iv. Scope

- TBD

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- TBD

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $3,486

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is in planning phase.
- Business plan is being drafted to scope and identify the deliverables of the project.

Project #3.11 – Location-Specific Options for Reliability and/or Resilience Upgrades

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operation/ market design; Distribution; DSM

iii. Objective
   - To create the processes and demonstrate the scoping, specification, and deployment of multiple DER technology configurations that could potentially serve as location-specific options for distribution system reliability and/or resilience upgrades.

iv. Scope
   - Technology configurations to be evaluated for their ability to provide distribution service reliability and/or resilience may include distributed battery storage, distributed solar and other DG, microgrid controllers, and isolation and protection equipment enabling islanding.
   - If a microgrid alternative is identified and selected in the -41- distribution planning process, this project may include a field deployment and evaluation of the selected alternative.
   - The relatively immature microgrid market is characterized by a wide range of custom projects with little standardization in technology and design. This project may help identify deployment options and test the efficacy of microgrid-related technologies (e.g., DERs, controllers, communications, and isolation and protective devices) in enhancing reliability and/or resilience in specific locations.

v. Deliverables
   1. Initial microgrid designs and Wholesale Interconnection application support completed
   2. Testbed design plan and initial DER component procurement
   3. Experimental tariff frameworks for microgrid infrastructure cost recovery and islanding generation support (Initial Design)
   4. Cybersecurity Protocols (initial Design with project partners) Interconnection and service planning requests completed
   5. Test protocols for grid connected and islanded planned and unplanned simulations developed
   6. The physical microgrid DER components in a PHIL simulation environment, including protections and local communication are developed
   7. Field site and host circuit upgrades completed
   8. Microgrid controller testing and verification completed

9. All microgrid components staged and ready for field deployment
10. Training for field and control center personnel completed
11. SCADA integration, automatic and manual operating protocol and procedure are established
12. Arcata airport microgrid field deployment and installation
13. Microgrid commissioning
14. Initial data collection and use-cases testing are completed
15. Public final report delivered

vi. Metrics

- 5a – Outage number, frequency and duration reductions
- 5d – Public safety improvement and hazard exposure reduction
- 9a – Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for wide spread deployment or technologies included in adopted building standards

vii. Schedule

- 2 Years

viii. EPIC Funds Encumbered

- $390,417

ix. EPIC Funds Spent

- $1,699,106

x. Partners (if applicable)

- CEC
- Redwood Coast Energy Authority
- Schatz Energy Research Center

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is in Build/Test phase.
- Location of the demonstration has been identified (Arcata/Eureka airport).
- Lab-scale testing of the microgrid controllers and battery storage solutions are

in progress at PG&E ATS.

- Interconnect and design studies have been completed by PG&E, Humboldt State University, and Redwood Coast Energy Authority.
- Receipt of FAA permit for the project caused a project delay. Construction is now expected to commence in 2Q21.

Project #3.12 – Advanced Volt/Var Optimization (VVO) Functionalities

i. Investment Plan Period
  - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
  - Grid Operation/ market design; Transmission; Distribution

iii. Objective
  - This project would seek to demonstrate enhanced algorithms to leverage VVO for grid management services.

iv. Scope
  - TBD

v. Deliverables
  - TBD

vi. Metrics
  - TBD

vii. Schedule
  - TBD

viii. EPIC Funds Encumbered
  - $0

ix. EPIC Funds Spent
  - $0

x. Partners (if applicable)
  - TBD

xi. Match Funding (if applicable)
  - TBD

xii. Match Funding Split (if applicable)
  - TBD

xiii. Funding Mechanism (if applicable)
  - TBD

xiv. Treatment of IP (if applicable)
  - TBD

xv. Status Update
  - Project is currently on hold.

Project #3.13 – Transformer Monitoring via FAN

i. Investment Plan Period
  - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
  - Grid Operations/ market design; Distribution

iii. Objective
  - This project will seek to demonstrate equipment that can be quickly and safely mounted on the casing of a pole-top distribution transformer to enable monitoring of equipment health. Additionally, it may test new communication devices and processes for delivering sensor data through PG&E's FAN.

iv. Scope
  - TBD

v. Deliverables
  - TBD

vi. Metrics
  - TBD

vii. Schedule
  - TBD

viii. EPIC Funds Encumbered
  - $0

ix. EPIC Funds Spent
  - $84,056

x. Partners (if applicable)
  - TBD

xi. Match Funding (if applicable)
  - TBD

xii. Match Funding Split (if applicable)
  - TBD

xiii. Funding Mechanism (if applicable)
  - TBD

xiv. Treatment of IP (if applicable)
  - TBD

xv. Status Update
  - Project is in planning phase.
  - Business plan is being drafted to plan for a field demonstration of

approximately 500 temperature sensors to be installed on operational service transformers.

- Project is planned to start in Q2 2021.

Project #3.14 – Maintenance Prioritization for Imminent Asset Risk

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operation/ market design; Transmission; Distribution

iii. Objective
   - To demonstrate the convergence of asset and operational data with historical maintenance information and proactive identification of potential equipment failures.

iv. Scope
   - N/A

v. Deliverables
   - N/A

vi. Metrics
   - N/A

vii. Schedule
   - N/A

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - N/A

xi. Match Funding (if applicable)
   - N/A

xii. Match Funding Split (if applicable)
   - N/A

xiii. Funding Mechanism (if applicable)
   - N/A

xiv. Treatment of IP (if applicable)
   - N/A

xv. Status Update
   - Project merged with 3.20

Project #3.15 – Proactive Wires Down Mitigation

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operation/ market design; Distribution

iii. Objective

- Demonstrate methods for automatically & rapidly reducing the flow of current and risk of ignition in single phase to ground faults in PG&E's high risk fire areas. This project would test the hypothesis that resonance grounding can mitigate single line to ground fire ignition risk for 3-wire circuits in high fire risk areas. A secondary objective is to improve reliability during wildfire season over status quo, "trip feeder and drive entire line."

iv. Scope

- This project would seek to demonstrate technology that could identify a falling conductor in sub-second response time, to enable proactive circuit isolation. If proven successful, the algorithm could be integrated with grid management systems to minimize safety risks in wires down situations.

v. Deliverables

Build, test, and make operationally ready the REFCL technology.

- Phase 1: Engineering and Construction
  - Project design
  - Equipment order
  - Test in Proof of Concept RTDS Lab
  - Field and substation work
  - Train and educate all departments affected by this technology
- Phase 2: Field Demonstration & Operation
  - Commissioning & testing
  - Fault location testing

vi. Metrics

- 3a – Maintain/Reduce operations and maintenance costs.
- 4a – GHG Emissions Reductions (MMTCO2e)
- 5a – Outage number, frequency and duration reductions

vii. Schedule

- 2.5 years

viii. EPIC Funds Encumbered

- $4,214,771

ix. EPIC Funds Spent

- $8,279,236

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is in Build/Test Phase
- Construction at the demonstration site was initiated in 2020. Nearby fires delayed construction activities, but all the key system elements were installed by EOY 2020.
- Commissioning will begin 1Q21. Testing will also begin in 1Q21 and be complete by 3Q21.

Project #3.16 – Advanced Condition Monitoring for Remote Diagnostics

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operation/ market design; Transmission; Distribution

iii. Objective
   - To demonstrate advanced RT sensors for monitoring asset conditions, enabling an increasingly proactive maintenance and grid management operational model. If proven successful, these sensors could help PG&E estimate equipment's remaining service life, and predict when it may fail.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update
   - Project is currently on hold.

Project #3.17 – Generic Universal Distribution Controller (UDC) for Relay, Regulator, LTC, Capacitor, Interrupter Control

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operation/ market design; Distribution

iii. Objective

- Design and demonstrate a UDC that can act as a generic controller for use in electric distribution line equipment. This approach could potentially standardize controller hardware across operational control functions insuring interoperability and reducing the need for -51- redundant maintenance and management for multiple vendors. It may also permit customization of features through software development control specific to the utility's needs.

iv. Scope

- TBD

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- TBD

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.18 – Transformer Health Monitoring

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Transmission; Distribution

iii. Objective
   - To develop and demonstrate new algorithms for determining and actively monitoring transformer health and performance based on Synchrophasor or other technology to detect conditions, such as arcing, breaker mis-operation, or total fault energy over time. The project could enable higher accuracy asset monitoring and predictive failure analytics.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update
   - Project is currently on hold.

Project #3.19 – Unified Network Solution

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operations/ market design; Transmission; Distribution

iii. Objective
   - To demonstrate a platform for unified communication among disparate networks both in the field, as well as across the enterprise. This project may improve reliability by ensuring communication service across multiple service platforms and help to reduce reliability risk by ensuring that the systems can rely on each other's backhaul for redundancy.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update
   - Project is currently on hold.

Project #3.20 – Data Analytics for Predictive Maintenance

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/ market design; Distribution; DSM

iii. Objective

- To develop predictive maintenance algorithms for identifying potential asset failures before they occur by using SmartMeter voltage data and other utility data sources at service points downstream of equipment. The project would potentially improve system reliability and safety by reducing unplanned outages by proactively identifying and mitigating equipment failure.

iv. Scope

- The project would define a set of failing equipment use cases that have impact on downstream voltage, and develop analytics algorithms to identify the voltage signatures associated with these upcoming failures. Examples of potential equipment use cases include primary side loose neutrals and overloaded or near-failure transformers, and stressed or near-failure cables.

v. Deliverables

- The output of the project would be an analytics process that would correlate and detect pattern signatures that are associated to malfunctioning or failing system assets, a set of heuristics for identifying these signatures, and an evaluation of this technology's efficacy versus traditional condition-based maintenance systems.

vi. Metrics

- 3a – Maintain / Reduce operations and maintenance costs
- 5a – Outage number, frequency and duration reductions
- 5d – Public safety improvement and hazard exposure reduction
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360)

vii. Schedule

- 1.75 years

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $1,884,072

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is in Build/Test phase.
- Identified three use cases to develop predictive analytics model and completed the first use case around identifying customer power quality issues in 2020
- Use cases on network transformers, regulators and fuses initiated. Work on underground assets deferred to focus on wildfire related failures. Early results are favorable, particularly for fuse failures.
- In 2021, model development will be initiated for service transformers based on historical failure data followed by grid event issues will be modeled using historical data.

Project #3.21 – Advanced Vegetation Management Insights Using Prescriptive Analytics

i. Investment Plan Period
- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
- Grid Operations/market design; Transmission; Distribution

iii. Objective
- To demonstrate a prescriptive analytics model that predicts tree growth rates and areas at highest risk for vegetation-related outages by leveraging Light Detection and Ranging (LiDAR), other remote sensing data, and historical vegetation-based outages for proactive and targeted mitigation. The model could be used for routine maintenance activities, reliability-focused project planning, or planning and staging in anticipation of strong weather systems impacting the PG&E service system.

iv. Scope
- TBD

v. Deliverables
- TBD

vi. Metrics
- TBD

vii. Schedule
- TBD

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- TBD

xi. Match Funding (if applicable)
- TBD

xii. Match Funding Split (if applicable)
- TBD

xiii. Funding Mechanism (if applicable)
- TBD

xiv. Treatment of IP (if applicable)
- TBD

xv. Status Update

- Project has been deprioritized and is currently on hold.

Project #3.22 – Abnormal State Configuration Risk and Mitigation

i. Investment Plan Period
- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
- Grid Operations/market design; Distribution

iii. Objective
- To demonstrate an algorithm for understanding the comparative risk of abnormal state configurations to proactively prioritize mitigation of these issues. The project would explore the use of system data to analyze risk impact and attempt to demonstrate an algorithmic approach to automate the impact score. This project may also explore the best approaches to integrate this algorithm into utility systems and processes, as well as potentially automate the resolution of these issues.

iv. Scope
- TBD

v. Deliverables
- TBD

vi. Metrics
- TBD

vii. Schedule
- TBD

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- TBD

xi. Match Funding (if applicable)
- TBD

xii. Match Funding Split (if applicable)
- TBD

xiii. Funding Mechanism (if applicable)
- TBD

xiv. Treatment of IP (if applicable)
- TBD

xv. Status Update

- Project is currently on hold.

Project #3.23 – Enhanced Distribution Line Equipment Device Settings Management

i. Investment Plan Period
- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
- Grid Operations/market design; Distribution

iii. Objective
- To demonstrate the increased efficiency, quality assurance, and flexibility of technology to manage transmission and substation distribution protection relay device settings to all distribution line equipment relays and controllers.

iv. Scope
- TBD

v. Deliverables
- TBD

vi. Metrics
- TBD

vii. Schedule
- TBD

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- TBD

xi. Match Funding (if applicable)
- TBD

xii. Match Funding Split (if applicable)
- TBD

xiii. Funding Mechanism (if applicable)
- TBD

xiv. Treatment of IP (if applicable)
- TBD

xv. Status Update
- Project is currently on hold.

Project #3.24 – Automatic Power Factor (PF) Management

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operations/ market design; Distribution; Transmission

iii. Objective
   - To demonstrate a software algorithm to achieve Automatic PF Management to keep power factor within the mandated CAISO guideline.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update
   - Project is currently on hold.

Project #3.25 – Electric Grid Monitoring Meter

i. Investment Plan Period
  - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
  - Grid Operations/ market design; Distribution

iii. Objective
  - To develop and demonstrate a modular-designed meter with the capability to monitor electric grid operations and report real time outage and restoration, as well as function as a SCADA metering point during the critical and initial 10-30 minutes of a power outage. This may help keep PG&E distribution system operators well-informed of grid outage conditions and assist them in taking appropriate actions to restore customer power quickly.
  - The new meter demonstrated in this project could enable potential reduction of equipment costs for replacements due to its modular design. The base mechanical meter would more rarely need replacement, typically leaving just the replacement of the solid-state meter and communication core component as needed.

iv. Scope
  - TBD

v. Deliverables
  - TBD

vi. Metrics
  - TBD

vii. Schedule
  - TBD

viii. EPIC Funds Encumbered
  - $0

ix. EPIC Funds Spent
  - $0

x. Partners (if applicable)
  - TBD

xi. Match Funding (if applicable)
  - TBD

xii. Match Funding Split (if applicable)
  - TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.26 – Predictive Data Analytics for Proactive Meter Replacement

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Distribution

iii. Objective
   - To develop and demonstrate a predictive analytics tool for remotely diagnosing meter health, to target and prioritize proactive meter replacements. The project will seek to explore the development and demonstration of an algorithm, software application/tool, and/or system interfaces to predict when a meter has a potentially unsafe condition, identify service connection issues, and/or identify when a meter is failing.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.27 –MPM

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/market design; Distribution

iii. Objective

- To develop a utility-grade submeter for (EVSE, also commonly referred to as an EV charging station) applications in support of Plug-In Electric Vehicle Submetering Protocol proceedings R.18-12-006[1] and the State's transportation electrification goals. Project builds upon EPIC 2.29 Mobile Meter Applications (NextGen Meter – NGM) project which has a granted patent. If successful, this project would reduce EVSE submetering costs, provide public and worker safety by separating high and low voltage components, reduce physical space required in customer property in both externally-mounted and internally-integrated options.

iv. Scope

- The project would develop a utility-grade submeter prototype for integration into an Electric Vehicle Supply Equipment (EVSE) charging station, thereby eliminating the need for a separate external utility meter and associated equipment. PG&E, the other California IOUs and industry influencers will update the EV submetering standard for CPUC adoption, including the use of this prototype.

v. Deliverables

Primary deliverables include:

- Pluggable utility grade meter utilizing the current PG&E Electric SmartMeter Network and utilizing existing UtilityIQ integrations for this meter
- Docking adapter for integration into EVSE
- Implementation of the CPUC's EV submetering standard protocol
- Pilot of 25-50 EVSEs in PG&E service yards
- Revise the CPUC's EV submetering standard to reflect the design of this prototype
- Provide recommendations and handoff on path to production

vi. Metrics

- Meter asset cost reduction ($) in comparison to the number of expected meter replacements due to malfunction using current meter technology.
- Number of additional submetered EVSEs now possible due to lowered submetering footprint including the elimination of electrical panels and otherwise required equipment.
- Customer cost reduction ($) due to the elimination of electrical panels and otherwise required equipment (and associated labor costs)

vii. Schedule

- 2 years

viii. EPIC Funds Encumbered

- $1,852,836

ix. EPIC Funds Spent

- $1,105,751

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is in the Design/Engineer phase.
- In 2020 the team initiated contracts to revise the EPIC 2.29 project design to support this EVSE submetering application and will initiate the remainder of the required contracts in 2021. In addition, in 2021 the team will produce prototypes of internally-integratable and externally-mountable versions of this EVSE submeter, engage with EVSE manufacturers on the design and accommodation to utilize this EVSE submeter, and operate a limited-scale demonstration of these EVSE submeters in PG&E service yards.

Project #3.28 – RT Load-Based Charging

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/ market design; Distribution; DSM

iii. Objective

- The project would attempt to develop a smart-charging algorithm based on time, capacity, locations, and other inputs. The algorithm would aim to coordinate EV charging so that specific grid assets are not overly taxed. This project could design controls to coordinate EV charging in a local area in order to facilitate higher EV adoption and charging without the need for distribution system upgrades.

iv. Scope

- TBD

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- TBD

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.29 – Advanced Customer Bill Scenario Calculator

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/ market design

iii. Objective

- To demonstrate an online tool with a streamlined graphical user interface to allow customers to more easily understand how behavioral changes and technology investments may affect their energy bill. The proposed tool is targeted towards the group of more engaged customers. PG&E's customer research shows that the more engaged customers want to understand how technologies may affect their bills. In response to this market need, this tool would allow consumers to engage with their energy usage and conservation options through an interactive and more in-depth manner.

iv. Scope

- TBD

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- TBD

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- After nearly completing the business plan, this project was put on hold and is still currently on hold.

Project #3.30 – Connected Device RT Pricing-Based Control

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operations/ market design; DSM

iii. Objective
   - To demonstrate the technical feasibility, utility benefits, and customer value of RT pricing services through evaluating how PG&E can send signals to connected devices to control their operation based on pricing signals and/or grid conditions. This project aims to investigate the strategies for potential future dynamic pricing options enabled by recent communication infrastructure solutions that tie RT locational marginal electricity price to retail RT pricing transmission at the interval level.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update

- Project is currently on hold.

Project #3.31 – RT DER Price Signals

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - DSM

iii. Objective
   - To design and demonstrate a locational net benefit rate design structure for DERs in order to valuate DER grid services to incentivize optimal DER siting and dispatch.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update
   - Project is currently on hold.

Project #3.32 – System Harmonics for Power Quality Investigations

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/market design; Distribution; Transmission

iii. Objective

- To leverage SmartMeter data to assist in identifying system harmonics that may cause power quality issues for customers.

iv. Scope

- Install and test the feasibility of using next generation meters to collect harmonics data on distribution system, develop algorithm engine for analysis, and if successful, create a new operational process for PG&E utilizing the next generation metering technology to detect, investigate and mitigate harmonic issues.

v. Deliverables

- Installation of next generation meters at 192 selected locations
- Establish communication with deployed next generation meters
- Validate harmonics data from next generation meters
- Refine parameters on next generation meters
- Build methodology to convert harmonics data to engineering application

vi. Metrics

- Outage number, frequency and duration reductions
- Reduction in system harmonics
- Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360)
- Reduction in truck rolls out to install additional monitors
- Reduction in turnaround time for resolving customer voltage complaint related to harmonics issues.

vii. Schedule

- 2 Years

viii. EPIC Funds Encumbered

- $137,580

ix. EPIC Funds Spent

- $82,695

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Pay for Performance

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is in Build/Test phase
- Project finalized field installation plan including meter installation locations
- Completed RFP, selected meter hardware that met the requirements to provide the necessary harmonics data , and executed a contract with the meter hardware vendor

Project #3.33 – Cyber-Physical Integrated Security

i. Investment Plan Period
- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
- Grid Operations/market design; Distribution; Transmission

iii. Objective
- To demonstrate a unified security solution which matches physical access to system access to aid in the blocking of unauthorized access to PG&E's critical infrastructure.

iv. Scope
- TBD

v. Deliverables
- TBD

vi. Metrics
- TBD

vii. Schedule
- TBD

viii. EPIC Funds Encumbered
- $0

ix. EPIC Funds Spent
- $0

x. Partners (if applicable)
- TBD

xi. Match Funding (if applicable)
- TBD

xii. Match Funding Split (if applicable)
- TBD

xiii. Funding Mechanism (if applicable)
- TBD

xiv. Treatment of IP (if applicable)
- TBD

xv. Status Update
- Project is currently on hold.

Project #3.34 – Local Wireless Security for Critical Facilities

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operations/market design; Distribution; Transmission

iii. Objective
   - To develop and demonstrate a next-generation wireless security solution which would monitor airwaves around PG&E's electric facilities to detect rogue access points installed within physically secured generation/substation facilities, which could provide bad actors access to the critical infrastructure networks.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update
   - Project is currently on hold.

Project #3.35 – Advance Security of Internet of Things Communications

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operations/market design; Distribution; Transmission

iii. Objective
   - To demonstrate an open architecture standard for secure communications between a utility and customer devices using third party communication channels (e.g., home internet connections, cellular networks, private-built field area networks).

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update
   - Project is currently on hold.

Project #3.36 – Cybersecurity for Industrial Control Systems (ICS)

i. Investment Plan Period
    - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
    - Grid Operations/market design; Transmission

iii. Objective
    - This EPIC project is proposed as a joint EPIC Administrator collaborative project that seeks to evaluate potential demonstrations that build on the foundation of machine to machine automated threat response by including adaptive controls & dynamic zoning for ICS. These would help to contain or thwart cyberattacks.

iv. Scope
    - TBD

v. Deliverables
    - TBD

vi. Metrics
    - TBD

vii. Schedule
    - TBD

viii. EPIC Funds Encumbered
    - $0

ix. EPIC Funds Spent
    - $0

x. Partners (if applicable)
    - TBD

xi. Match Funding (if applicable)
    - TBD

xii. Match Funding Split (if applicable)
    - TBD

xiii. Funding Mechanism (if applicable)
    - TBD

xiv. Treatment of IP (if applicable)
    - TBD

xv. Status Update
    - Project is currently on hold.

Project #3.37 – Augmented Reality

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/market design; Distribution

iii. Objective

- To demonstrate technology for visualizing grid and asset data integrated with the GIS data, superimposed on a device to provide support and guidance for activities, such as asset investigations and maintenance. Augmented reality is a broad technology category which could improve the efficiency and affordability of field operations by providing faster access to key asset information during inspections and maintenance. Just as importantly, this could eventually improve field crew safety by providing hands-free information displays (e.g., through a heads-up display).

iv. Scope

- TBD

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- TBD

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.38 – Voltage Checks

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/market design; Distribution

iii. Objective

- To develop and demonstrate a tool for field workers to perform remote voltage checks and identify low or no-power line situations while on-site without the need to call the central office or manually measure the line. This could potentially enable a field or dispatch employee to identify Service Points and other voltage-checkable equipment in the surrounding area, click on one of the pieces of equipment, and request the current voltage flowing through this equipment to diagnose an issue.

iv. Scope

- TBD

v. Deliverables

- TBD

vi. Metrics

- TBD

vii. Schedule

- TBD

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $0

x. Partners (if applicable)

- TBD

xi. Match Funding (if applicable)

- TBD

xii. Match Funding Split (if applicable)

- TBD

xiii. Funding Mechanism (if applicable)

- TBD

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is currently on hold.

Project #3.39 – Optimized Dispatch for Restoration Events

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Transmission; Distribution

iii. Objective
   - To optimize crew movements and responses during outage dispatch to support restoration operations.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update
   - Project is currently on hold.

Project #3.40 – Advanced Field Reference Tool

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operations/ market design

iii. Objective
   - To develop a voice guided and/or free-form entry reference for field workers to ask questions and receive guidance based on PG&E's equipment libraries, safety practices, and other critical documentation.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $0

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update
   - Project is currently on hold.

Project #3.41 – Drone Enablement and Operational Use

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/ market design; Distribution; Transmission

iii. Objective

- To develop and demonstrate a foundational utility-focused Drone enablement systems and initial use cases to form the foundation for future utility Drone operations. These devices have the potential to revolutionize monitoring, inspection, and RT awareness utility infrastructure..

iv. Scope

- This project would partner with an industry-leading drone solution vendor to develop and demonstrate automated and BVLOS drone operations at a limited scale within PG&E's service territory. The first phase of the field demonstration will focus on flight automation within LOS. The second phase will extend to demonstrating automation BVLOS.

v. Deliverables

Transmission & Substation Inspections:

- Automated drone operation system for transmission tower and substation imagery data capture, demonstrated on 3-5 transmission towers and 1 substation.
- 1 instance of remote charging solution
- Data manually transferred from drone SD card to AWS and analyzed in Sherlock
- FAA approval for BVLOS inspection of transmission towers.

Distribution Alert Verification:

- Automated drone operation system for investigation of distribution alerts, demonstrated at 1-2 distribution feeders, with drones residing at the associated substation(s)
- 1 instance of remote charging solution
- Limited integration with the distribution sensor alert systems
- Data manually transferred from drone SD card to AWS and analyzed in Sherlock
- FAA approval for BVLOS drone operation over distribution feeders.

vi. Metrics

- 1.h. Customer bill savings (dollars saved)
- 3.a. Maintain / Reduce operations and maintenance costs

- 4.b. Criteria air pollution emission reductions.
- 5.d. Public safety improvement and hazard exposure reduction
- 5.e. Utility worker safety improvement and hazard exposure reduction

vii. Schedule

- 2 Years

viii. EPIC Funds Encumbered

- $125,000

ix. EPIC Funds Spent

- $153,546

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- N/A

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Project is in the Design/Engineer Phase.
- In 2020, the project was initiated, the team was formed, a high-level project plan was established, and the team began to flesh out the Concept of Operations (CONOPS) behind each of the project's proposed use cases for automated and BVLOS drone operations.
- In 2021, the team will coordinate with the FAA feedback on the operational concept, conduct an RFP for a drone solution partner, file waivers and obtain FAA approvals for the proposed BVLOS demonstration, and begin the demonstration upon FAA approval.

Project #3.42 – Electric Load Management for Ridesharing Electrification

i. Investment Plan Period
   - 3rd Triennial (2018-2020)

ii. Assignment to Value Chain
   - Grid Operations/Market Design; Distribution; DSM

iii. Objective
   - To test and demonstrate the hypothesis that AMI momentary events ("blinks") and trap alarms correlate to and can be used to identify specific equipment failures and/or vegetation contact. The project will use the Agile methodology to develop analytical models that use AMI momentary events and trap alarms to identify issues with customer service drops, distribution equipment, and intermittent vegetation contact.

iv. Scope
   - TBD

v. Deliverables
   - TBD

vi. Metrics
   - TBD

vii. Schedule
   - TBD

viii. EPIC Funds Encumbered
   - $0

ix. EPIC Funds Spent
   - $(3)

x. Partners (if applicable)
   - TBD

xi. Match Funding (if applicable)
   - TBD

xii. Match Funding Split (if applicable)
   - TBD

xiii. Funding Mechanism (if applicable)
   - TBD

xiv. Treatment of IP (if applicable)
   - TBD

xv. Status Update

- Previously defined as EPIC 2.32. Deferred to EPIC 3 by CPUC Res.E-4863 8/10/2017.
- Project has been deprioritized and is currently on hold.

Project #3.43 – Service Issue Identification Leveraging Momentary Outage Information

i. Investment Plan Period

- 3rd Triennial (2018-2020)

ii. Assignment to Value Chain

- Grid Operations/Market Design; Distribution

iii. Objective

- To test and demonstrate the hypothesis that AMI momentary events ("blinks") and trap alarms correlate to and can be used to identify specific equipment failures and/or vegetation contact. The project will use the Agile methodology to develop analytical models that use AMI momentary events and trap alarms to identify issues with customer service drops, distribution equipment, and intermittent vegetation contact.

iv. Scope

- Leverage multiple sources of data, including but not limited to SmartMeter, time of day, location and weather data, to proactively identify potential problems in the Electric Distribution system, specifically related to identifying locations with high incidences of momentary outages which may be caused by imminent failures of conductors, insulators, transformers and/or vegetation contact.

v. Deliverables

Primary deliverables include:

- Correlation of events to geographic locations, equipment classes, and vintages, to identify areas and assets with systemic issues and/or higher likelihood of failures.
- Development of analytical models to predict & identify the equipment source of momentary events “meter blinks” and voltage sags/swells as well as momentary loss of voltage.
- Evaluation of performance of models on historical failures of assets or time frames which have been excluded from model development processes.
- Field verifications/inspections of assets identified to be responsible for smart meter anomalies to validate the models’ performance.

vi. Metrics

- 3a – Maintain/Reduce operations and maintenance costs
- 5a – Outage number, frequency and duration reductions
- 5d – Public safety improvement and hazard exposure reduction
- 7b – Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Pub. Util. Code § 8360)

vii. Schedule

- 1.75 Years

viii. EPIC Funds Encumbered

- $0

ix. EPIC Funds Spent

- $119,954

x. Partners (if applicable)

- N/A

xi. Match Funding (if applicable)

- N/A

xii. Match Funding Split (if applicable)

- N/A

xiii. Funding Mechanism (if applicable)

- Per for Performance

xiv. Treatment of IP (if applicable)

- TBD

xv. Status Update

- Previously defined as EPIC 2.33. Deferred to EPIC 3 by CPUC Res.E-4863 8/10/2017.
- Work in 2020 focused deploying a back-office Smart Meter data collection tool with the goal of substantially increasing data types and temporal granularity.
- This deployment will continue into early 2021 along with predictive analytics development. Additionally, a 2nd generation Smart Meter with edge-processing capability and a behind the meter commercial fire-risk sensor will be introduced into the data analytics mix.

5. Conclusion

A. Key Results for the Year for PG&E EPIC Programs

In 2020, PG&E's EPIC Program completed final two projects and started four new EPIC 3 projects.

In 2020 PG&E continued its focus in the EPIC 3 cycle on wildfire safety, resiliency and renewables integration by launching four additional projects that aim to address these challenges. Additional EPIC 3 projects will be launched in 2021, some of which are subject to approval of PG&E's AL 6043-E, submitted on December 30, 2020.

PG&E has established and maintained strong program management practices to provide oversight of the EPIC Program and ensure the maximum value of the projects to its customer base. PG&E continues to build on its administrative best practices in response to 2017 EPIC program evaluation. Several improvements are detailed in the Utilities' joint RAP application. In addition to oversight, PG&E's EPIC Program Management Office provides:

- Communications with interested vendors and diverse suppliers through channels such as referrals and industry events (e.g., Grid Edge Executive Council, Silicon Valley Leadership Group, DistribuTECH, etc.);
- Coordination with the other IOUs and CEC through regularly scheduled administrator meetings and collaboration;
- Benchmarking and new technology solution vetting;
- Collaboration with research entities, such as the EPRI, CIATI, Schatz Energy Research Center & National Labs;
- Administrator-coordinated execution of industry-wide EPIC workshops and symposiums;
- Other EPIC Program support, such as providing comments and/or Letters of Support to select CEC Grant Funding Opportunities;
- Coordination with DAC; and
- Participating PICG workstreams around Equity, Public Safety Power Shutoffs, Transportation Electrification, and Wildfire Mitigation.

PG&E's portfolio of EPIC 3 projects continue to address challenges of the changing grid landscape and the threat of climate change, including wildfire safety, resiliency and renewables integration. Eight of PG&E's EPIC projects are part of the new and emerging technology chapter of Wildfire Mitigation Plan. Achievements through EPIC projects, and the future path forward for those technologies that are proven ready to scale, help pave the way for the grid of the future, advancing California policy objectives, and ultimately, improving the safety, reliability, resiliency, and affordability of the electric grid.

B. Next Steps for EPIC Investment Plan

PG&E, in conjunction with the other EPIC Administrators, will continue to host annual stakeholder workshops and symposiums, as well as workshops specifically for DAC. These industry events will focus on the sharing of progress, results, and future plans as well as understanding stakeholder needs and incorporating stakeholder input into the scoping of EPIC projects. PG&E will also continue to promote the EPIC Program through participation in both internal and external public forums and other industry events. We also look forward to exploring the applicability of CEC developed benefits quantification tools as we prepare and share the benefit estimates from EPIC 3 projects as they close.

The most urgent challenge today is adapting the electric grid to address climate changes. In recent years, California has experienced strong storm and wind events, highly variable precipitation patterns, as well as an unprecedented expansion in high-fire threat areas. This has resulted in an increased frequency of wildfires and the devastation that those fires have brought to California communities. To meet this challenge, the electric grid needs to be hardened and made more flexible and adaptable to changing conditions. While PG&E has intensified its focus on demonstrating technologies that further resiliency and reduce wildfire risk in its EPIC 3 program, continued research and demonstration of pre-commercial technologies will be needed in EPIC 4 and beyond.

The IOUs' EPIC programs are the main source for demonstrating and field testing on their grids to meet these critical goals. This approach supports the direct testing and demonstration that is essential to scaling up new and innovative technologies for safe, reliable and cost-effective use. Successor Program Phase 2 schedule is not yet set and the future of the IOU role, originally established in D.12-05-037, in the EPIC program has yet to be determined.

C. Issues That May Have Major Impact on Progress in Projects

Inherent to the RD&D nature of the EPIC Program, market dynamics can change rapidly. Some potential factors that can impact the projects' progress include:

- Changes in the marketplace that may have made the project obsolete (or relatively less important to pursue);
- Different technologies have emerged that could produce better insights for the industry and PG&E customers, making some of the original proposed projects no longer the best use of available program funds;
- The technology may prove to not yet be ready for commercialization and/or not yet ready nor capable to support the later stages of the original project objective; and
- The vendor interest may drop due to the small-scale demonstration size of the project or the vendor may revise their business model such that it is no longer aligned with the projects' objectives.

Although these dynamics may impact a project's progress, it is important to keep in mind that part of the value of RD&D is in both proving what is and what is not ready to scale. While the more obvious goal of technology demonstration is to help advance pre-commercial technologies, there are cases where success may be defined as determining that a project should not proceed to full scale until additional development takes place. This avoids more costly full production deployment before a technology is ready, and also provides insight for the industry on what may need to be further developed.

PG&E mitigates some of the risk of this rapidly evolving technology landscape by managing the EPIC projects proactively. PG&E continually coordinates—both internally and externally—to stay aware of the latest technology demonstration needs, and practices enablement-focused governance over the project portfolio to help ensure successful and cost-effective technology demonstrations that emphasize continuous learning.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

PROJECT STATUS REPORT

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
1	1st Triennial (2012-2014)	PG&E	1.01 - Energy Storage End Uses	Renewables/DER Resource Integration	• Develop technologies and strategies for efficient and optimized bidding and scheduling of Energy Storage Technologies (EST) in California Independent System Operator (CAISO) markets and demonstrate those strategies using PG&E's existing Sodium Sulfur Battery Energy Storage Systems (NaS BESS). • This project addresses the following CPUC proceedings: - As applicable, operational experiences gained from this project can inform outstanding policy and implementation issues as identified in Energy Storage Order Instituting Rulemaking 15 03 011.
2	1st Triennial (2012-2014)	PG&E	1.02 - Demonstrate the Use of Distributed Energy Storage for T&D Cost Reduction	Renewables/DER Resource Integration	• Demonstrate the ability of a utility operated energy storage asset to address capacity overloads on the distribution system and improve reliability. • This project addresses the following California Public Utilities Commission (CPUC) proceedings: - This project will count towards the Investor Owned Utility energy procurement targets as set forth in D.10 03 040, the Energy Storage Procurement Framework. - As applicable, operational experiences gained from this project can inform outstanding policy and implementation issues as identified in Energy Storage OIR R.15 03 011.
3	1st Triennial (2012-2014)	PG&E	1.03 - Demonstrate Priority Scenarios from the Energy Storage Framework	Renewables/DER Resource Integration	• The project aims to reduce existing barriers to deployment of battery energy storage systems by demonstrating whether post-electric vehicle (EV) "second life" batteries can cost-effectively perform electric distribution services. The project will demonstrate the potential for reduced energy storage system costs via a) the development of an integration platform for deploying such batteries (Phase 1) and b) the use of lower cost "second life" batteries in the integrated platform (Phase 2).

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
1	1st Triennial (2012-2014)	PG&E	1.01 - Energy Storage End Uses	• Develop and deploy technology to enable automated resource response to CAISO market awards. • Quantify the values that battery resources can capture in CAISO markets. • Establish financial performance of battery resource participation in CAISO markets.
2	1st Triennial (2012-2014)	PG&E	1.02 - Demonstrate the Use of Distributed Energy Storage for T&D Cost Reduction	• Deploy utility operated energy storage asset at a single site. • Demonstrate peak shaving use case along with other site-specific use cases as suggested by distribution operators.
3	1st Triennial (2012-2014)	PG&E	1.03 - Demonstrate Priority Scenarios from the Energy Storage Framework	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
1	1st Triennial (2012-2014)	PG&E	1.01 - Energy Storage End Uses	• Demonstrate automated and remote control application for generic energy storage resources to interface with existing SCADA systems. • Report financial performance from participation in CAISO markets. • Report comparison of actual performance vs. hypothetical performance quoted in industry reports. • Comply with regulatory requirements and establish a framework/recommendations for accounting standards applicable to energy storage.	2.75 years	9/19/2013	No	Grid Operation/Market Design	$ 698,506	$1,660,000 - $2,030,000
2	1st Triennial (2012-2014)	PG&E	1.02 - Demonstrate the Use of Distributed Energy Storage for T&D Cost Reduction	• Identify energy storage site based on project objectives. • Identify an economic modeling tool to compare the planned traditional utility with alternatives using distributed resources or demand-side investments. • Construct and integrate energy storage system. • Test system and analyze results to prove project objectives.	3.5 years	7/25/2014	No	Distribution; Grid Operation/Market Design	$ 2,691,736	$3,610,000 - $4,412,000
3	1st Triennial (2012-2014)	PG&E	1.03 - Demonstrate Priority Scenarios from the Energy Storage Framework	N/A	N/A	NA	No	Grid Operation/Market Design	$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
1	1st Triennial (2012-2014)	PG&E	1.01 - Energy Storage End Uses	$ 779,833	$ 1,054,135	$ 1,833,968	$ -	Leveraged battery assets that was funded by Energy Regulators Regional Association (ERRA). Leveraged $163K, as well as software and expertise from PG&E's hydro generation group.	N/A	N/A	N/A
2	1st Triennial (2012-2014)	PG&E	1.02 - Demonstrate the Use of Distributed Energy Storage for T&D Cost Reduction	$ 2,764,097	$ 1,246,413	$ 4,010,510	$ -	No	N/A	No	N/A
3	1st Triennial (2012-2014)	PG&E	1.03 - Demonstrate Priority Scenarios from the Energy Storage Framework	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
1	1st Triennial (2012-2014)	PG&E	1.01 - Energy Storage End Uses	Pay for performance	N/A	Sole Source: •Power Settlements Consulting (sole vendor that could provide solution without modification or required hardware). • Trimark Associates (enhancements were made to their equipment for this EPIC project, as they were the original vendor under the capital project for the Yerba Buena and Vaca batteries).	N/A	N/A
2	1st Triennial (2012-2014)	PG&E	1.02 - Demonstrate the Use of Distributed Energy Storage for T&D Cost Reduction	Pay for Performance	N/A	Competitive Bid	11	Cupertino Electric
3	1st Triennial (2012-2014)	PG&E	1.03 - Demonstrate Priority Scenarios from the Energy Storage Framework	N/A	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	B	C	X	Y	Z	AA	AB	AC
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
1	1st Triennial (2012-2014)	PG&E	1.01 - Energy Storage End Uses	N/A	N/A	Column applicable to CEC only	Yes. •Power Settlements Consulting - California-based • Trimark Associates - California-based	Column applicable to CEC only	• 1i - Nameplate capacity (megawatts) of grid-connected energy storage. • 3a - Maintain/Reduce operations and maintenance costs. • 6a - CAISO NGR financial settlements. • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Public Utilities Code (Pub. Util. Code) § 8360). • 7c - Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (Pub. Util. Code § 8360). • 7l - Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (Pub. Util. Code § 8360). • 9c - EPIC project results referenced in regulatory proceedings and policy reports (Business Plan references: CPUC R.10-12-007).
2	1st Triennial (2012-2014)	PG&E	1.02 - Demonstrate the Use of Distributed Energy Storage for T&D Cost Reduction	1	N/A	Column applicable to CEC only	Yes - California-based.	Column applicable to CEC only	• 1c - Avoided procurement and generation costs. • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Public Utilities Code (Pub. Util. Code) § 8360). • 7d - Deployment and integration of cost-effective distributed resources and generation, including renewable resources (Pub. Util. Code § 8360). • 9c - EPIC project results referenced in regulatory proceedings and policy reports (Business Plan references: Deferring a capacity upgrade has been identified as a key potential value of Energy Storage Technologies (ESTs) and noted in filings with the CPUC/Assembly Bill 2514.
3	1st Triennial (2012-2014)	PG&E	1.03 - Demonstrate Priority Scenarios from the Energy Storage Framework	N/A	N/A	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
4	1st Triennial (2012-2014)	PG&E	1.04 - Expand Test Lab and Pilot Facilities for New Energy Storage Systems.	Renewables/DER Resource Integration	• This project would identify ways to enhance the existing test lab facilities at PG&E's Applied Technology Services (ATS) center to provide lab test and pilot facilities for new energy storage systems not previously lab tested. PG&E's ATS lab will be particularly helpful in working with the CEC and industry to test "next generation" technologies that have the potential to make breakthroughs in cost, performance targets, and other important parameters, in a test grid environment. This testing would be a critical step in accelerating commercialization of potential "game changing" technology. New types of technology that may be tested at ATS include, but are not limited to, advanced lithium devices, new sodium-based systems, zinc-air systems and new flow battery chemistries and formats. The funding required to add full capabilities to ATS is minimal. The costs to perform the tests will be paid by the industry or by entities that have received research grants from agencies such as the CEC or Department of Energy (DOE).
5	1st Triennial (2012-2014)	PG&E	1.05 - Demonstrate New Resource Forecast Methods to Better Predict Variable Resource Output	Renewables/DER Resource Integration	• Demonstration of emerging capabilities in mesoscale modeling to provide more granular and accurate weather forecasting input to Pacific Gas and Electric Company's (PG&E) storm damage prediction model, and to other PG&E forecasting applications, like catastrophic wildfire risk and Photovoltaic (PV) generation. The main goal is more effective and granular damage prediction, and therefore more efficient response to storm events.
6	1st Triennial (2012-2014)	PG&E	1.06 - Demonstrate Communication Systems Allowing the CAISO to Utilize Available Renewable Generation Flexibility	Renewables/DER Resource Integration	• This project would demonstrate the use of accepted communications protocols to allow the California Independent System Operator (CAISO) to send an operating signal to reduce output under specified conditions, as allowed by contracts.
7	1st Triennial (2012-2014)	PG&E	1.07 - Demonstrate Systems to Ramp Existing Gas-Fired Generation More Quickly to Adapt to Changes in Variable Energy Resources Output	Renewables/DER Resource Integration	• There are 33 General Electric 7FA gas turbines installed in combined cycle configurations in California, which is considerably more than any other turbine model. GE offers a product marketed as "OpFlex Balance" that uses advanced controls technology to improve ramp rates to as high as 40 MW per minute (or higher in some cases). As of October 2012, none of the 7FAs in California were using this product. This project proposes to demonstrate improved ramp rate capabilities on one 7FA so that it can serve as a model for the rest of the 7FA fleet. It is assumed that there would be cost share with the vendor and the selected plant owner.
8	1st Triennial (2012-2014)	PG&E	1.08 - Improve Distribution System Safety and Reliability through New Data Analytics Techniques	Grid Modernization and Optimization	• Develop and demonstrate a new data analytics technique to improve distribution system safety and reliability. The project specifically developed and tested a System Tool for Asset Risk (STAR), which is an enterprise software application that Electric Operations will use to calculate and display (graphically and geospatially) risk scores for electric transmission, substation and distribution assets. The STAR will enable an automated, system-wide application to improve risk identification, prioritization, and investment decisions to support electric system safety.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	B	C	E2
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
4	1st Triennial (2012-2014)	PG&E	1.04 - Expand Test Lab and Pilot Facilities for New Energy Storage Systems.	N/A
5	1st Triennial (2012-2014)	PG&E	1.05 - Demonstrate New Resource Forecast Methods to Better Predict Variable Resource Output	• Project focus is on development, deployment, and implementation of an operational version of the Weather Research and Forecasting (WRF) mesoscale model to support PG&E's forecasting program related to fire, storms and solar production. • Not in scope for this project are enhancements to PG&E's Restoration Work Plan other than improved forecast damage numbers.
6	1st Triennial (2012-2014)	PG&E	1.06 - Demonstrate Communication Systems Allowing the CAISO to Utilize Available Renewable Generation Flexibility	N/A
7	1st Triennial (2012-2014)	PG&E	1.07 - Demonstrate Systems to Ramp Existing Gas-Fired Generation More Quickly to Adapt to Changes in Variable Energy Resources Output	N/A
8	1st Triennial (2012-2014)	PG&E	1.08 - Improve Distribution System Safety and Reliability through New Data Analytics Techniques	• Demonstrate whether the ever-increasing amounts of data can be mined and combined for targeted, cost-effective use for improved asset management. • Potential scenarios include risk-based asset management, safety hazard mitigation and proactive outage prediction using self-serve and virtual integration environments.

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	*B*	*C*	*E3*	*E4*	*F*	*G*	*H*	*I*	*J*
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
4	1st Triennial (2012-2014)	PG&E	1.04 - Expand Test Lab and Pilot Facilities for New Energy Storage Systems.	N/A	N/A	NA	No	Grid operations/market design	$ -	$ -
5	1st Triennial (2012-2014)	PG&E	1.05 - Demonstrate New Resource Forecast Methods to Better Predict Variable Resource Output	• Fully functional mesoscale modeling system known as POMMS (PG&E Operational Mesoscale Modeling System) that will provide the following: - Detailed weather input into PG&E's damage prediction modeling system (SOPP). - Next generation wildfire threat awareness system. - Historical and forecast solar irradiance data to internal PG&E stakeholders.	3.25 years	9/19/2013	No	Distribution	$ 535,055	$720,000 - $880,000
6	1st Triennial (2012-2014)	PG&E	1.06 - Demonstrate Communication Systems Allowing the CAISO to Utilize Available Renewable Generation Flexibility	N/A	N/A	NA	No	Grid Operation/Market Design	$ -	$ -
7	1st Triennial (2012-2014)	PG&E	1.07 - Demonstrate Systems to Ramp Existing Gas-Fired Generation More Quickly to Adapt to Changes in Variable Energy Resources Output	N/A	N/A	NA	No	Grid operations/market design	$ -	$ -
8	1st Triennial (2012-2014)	PG&E	1.08 - Improve Distribution System Safety and Reliability through New Data Analytics Techniques	• Overview of existing applications and data sources. • Assessment of existing data source quality. • High-level future business processes by functional area. • Inventory of asset risk algorithms (formulas or complexity) for "In Scope" asset classes. • High-level Change Management Approach. • Prioritized and phased implementation plan. • Cost estimate for full implementation of the STAR project. • Proof of concept prototype.	2.25 years	9/19/2013	No	Transmission; Distribution	$ 1,249,505	$1,900,000 - $2,320,000

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
4	1st Triennial (2012-2014)	PG&E	1.04 - Expand Test Lab and Pilot Facilities for New Energy Storage Systems.	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
5	1st Triennial (2012-2014)	PG&E	1.05 - Demonstrate New Resource Forecast Methods to Better Predict Variable Resource Output	$ 511,681	$ 312,209	$ 823,890	$ -	N/A	N/A	N/A	N/A
6	1st Triennial (2012-2014)	PG&E	1.06 - Demonstrate Communication Systems Allowing the CAISO to Utilize Available Renewable Generation Flexibility	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
7	1st Triennial (2012-2014)	PG&E	1.07 - Demonstrate Systems to Ramp Existing Gas-Fired Generation More Quickly to Adapt to Changes in Variable Energy Resources Output	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
8	1st Triennial (2012-2014)	PG&E	1.08 - Improve Distribution System Safety and Reliability through New Data Analytics Techniques	$ 1,796,618	$ 316,022	$ 2,112,640	$ -	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
4	1st Triennial (2012-2014)	PG&E	1.04 - Expand Test Lab and Pilot Facilities for New Energy Storage Systems.	N/A	N/A	N/A	N/A	N/A
5	1st Triennial (2012-2014)	PG&E	1.05 - Demonstrate New Resource Forecast Methods to Better Predict Variable Resource Output	Pay for performance	N/A	Competitive Bid & Sole Source • 1st award to create raw, gridded weather forecast data: competitive. • 2nd award to develop map of variables from data: completive. • 3rd award: Sole source to Clean Power Research due to obtain PV estimation for inclusion in solar irradiance use case.	• 1st award: 6 • 2nd award: 6	• 1st award: Weather Decision Technologies • 2nd award: Vertum Partners
6	1st Triennial (2012-2014)	PG&E	1.06 - Demonstrate Communication Systems Allowing the CAISO to Utilize Available Renewable Generation Flexibility	N/A	N/A	N/A	N/A	N/A
7	1st Triennial (2012-2014)	PG&E	1.07 - Demonstrate Systems to Ramp Existing Gas-Fired Generation More Quickly to Adapt to Changes in Variable Energy Resources Output	N/A	N/A	N/A	N/A	N/A
8	1st Triennial (2012-2014)	PG&E	1.08 - Improve Distribution System Safety and Reliability through New Data Analytics Techniques	Pay for performance	N/A	Competitive Bid	• 11 total bidders • 7 passed initial screen	Space Time Insight

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	B	C	X	Y	Z	AA	AB	AC
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
4	1st Triennial (2012-2014)	PG&E	1.04 - Expand Test Lab and Pilot Facilities for New Energy Storage Systems.	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
5	1st Triennial (2012-2014)	PG&E	1.05 - Demonstrate New Resource Forecast Methods to Better Predict Variable Resource Output	• 1st award: 1 • 2nd award: 1	N/A	Column applicable to CEC only	• Weather Decision Technologies: No • Vertum Partners: Yes - California-based • Clean Power Research: Yes - California-based	Column applicable to CEC only	• 3a - Maintain/Reduce operations and maintenance costs. • 4a - GHG emissions reductions (MMTCO2e). • 5c - Forecast accuracy improvement. • 5e - Utility worker safety improvement and hazard exposure reduction.
6	1st Triennial (2012-2014)	PG&E	1.06 - Demonstrate Communication Systems Allowing the CAISO to Utilize Available Renewable Generation Flexibility	N/A	N/A	N/A	N/A	N/A	N/A
7	1st Triennial (2012-2014)	PG&E	1.07 - Demonstrate Systems to Ramp Existing Gas-Fired Generation More Quickly to Adapt to Changes in Variable Energy Resources Output	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
8	1st Triennial (2012-2014)	PG&E	1.08 - Improve Distribution System Safety and Reliability through New Data Analytics Techniques	1	N/A	Column applicable to CEC only	Yes - California-based	Column applicable to CEC only	• 7c - Dynamic optimization of grid operations and resources; including appropriate consideration for asset management and utilization of related grid operations and resource, with cost-effective full cyber security (Public Utilities Code §8360). • 3a - Maintain/Reduce operations and maintenance costs: With the improved understanding of risk, there could be a better tool for evaluating projects such as asset replacement.

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
9	1st Triennial (2012-2014)	PG&E	1.09A - Test New Remote Monitoring and Control Systems for Existing Transmission & Distribution Assets: Close Proximity Switching	Grid Modernization and Optimization	• This project explores and seeks to discover effective, new tools to safely operate "Solid Blade in Oil Rotatory Switches."
10	1st Triennial (2012-2014)	PG&E	1.09B and 1.10B - Test New Remote Monitoring and Control Systems for T&D Assets / Demonstrate New Strategies and Technologies to Improve the Efficacy of Existing Maintenance and Replacement Programs	Grid Modernization and Optimization	• The project focus is on development, testing, deployment, and implementation of new technologies, construction methods and techniques, and cost reduction techniques in support of the Supervisory Control and Data Acquisition (SCADA) monitoring systems used on the Distribution Networks. The monitoring system consists of a complex and extensive set of components used to assess the health and condition of the network transformers on a continuous basis. This research is looking at potential failure points on the monitoring system components and what technologies and improvements can be applied to increase life expectancy of these components and reduce production and maintenance costs for this system and similar systems.
11	1st Triennial (2012-2014)	PG&E	1.09C - Test New Remote Monitoring and Control Systems for T&D Assets: Discrete Series Reactors	Grid Modernization and Optimization	• Gain operating experience with Discrete Series Reactors (DSR) to determine whether such devices would be cost effective and operate reliably and safely on Pacific Gas and Electric Company's (PG&E) transmission system.
12	1st Triennial (2012-2014)	PG&E	1.10A - Demonstrate Automated Asset Notification and Management Systems: Dissolved Gas Analysis	Grid Modernization and Optimization	• Develop tools and algorithms that analyze data from monitoring equipment installed on substation equipment (distribution and transmission) that tests for dissolved gasses or other precursor data that would assist in understanding the condition of the equipment.
13	1st Triennial (2012-2014)	PG&E	1.10C - Demonstrate Automated Asset Notification and Management Systems: Underground Cable Analysis	Grid Modernization and Optimization	• Develop tools and algorithms that analyze load and operating characteristic data from underground cables in order to develop an understanding of potential failure points, cable maintenance needs, and cable life expectancy.
14	1st Triennial (2012-2014)	PG&E	1.11 - Demonstrate Self-Correcting Tools to Improve System Records and Operations	Grid Modernization and Optimization	• Demonstrate tools that identify and "register" existing assets to improve the integration between utility planning and operations. As part of the demonstration, implement "self-correcting" technologies that identifies plan vs. actual discrepancies and updates system records automatically. High priority use cases include: (1) Mapping of transformers to primary phase; (2) Mapping of customers to transformers; and (3) Precision mapping of Pacific Gas and Electric Company's overhead and underground network.
15	1st Triennial (2012-2014)	PG&E	1.12 - Demonstrate New Technologies that Improve Wildlife Safety and Protect Assets from Weather-Related Degradation	Grid Modernization and Optimization	• Demonstrate new strategies and technologies to improve animal and bird protection, reduce outages caused by animals and birds, and protect assets from expensive weather related degradation such as fog related corrosion.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	B	C	E2
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
9	1st Triennial (2012-2014)	PG&E	1.09A - Test New Remote Monitoring and Control Systems for Existing Transmission & Distribution Assets: Close Proximity Switching	• Test new tools and techniques for safe operation of Solid Blade in Oil Rotatory Switches. • Evaluate alternatives to decrease probability of injury to workers and public. • Help design a robotic tool to allow remote operation. • Develop the necessary parts/adaptors to be used on various types (manufacturer, brand, age, etc.) of Solid Blade in Oil Rotatory Switches.
10	1st Triennial (2012-2014)	PG&E	1.09B and 1.10B - Test New Remote Monitoring and Control Systems for T&D Assets / Demonstrate New Strategies and Technologies to Improve the Efficacy of Existing Maintenance and Replacement Programs	• Assess new technologies and feasibility of application on the Distribution Networks. • Primary focus on technologies, components and work methods to extend the life expectancy of monitoring systems equipment and reduce long term maintenance costs.
11	1st Triennial (2012-2014)	PG&E	1.09C - Test New Remote Monitoring and Control Systems for T&D Assets: Discrete Series Reactors	• Install and test 90 DSR units on the Las Positas-Newark 230 kV line. • Install and test Server at PG&E's San Francisco General Office (SFGO) headquarters, complete with Smart Wire System Manager Software. • Communication links between the DSRs and server to support the DSR monitoring and control.
12	1st Triennial (2012-2014)	PG&E	1.10A - Demonstrate Automated Asset Notification and Management Systems: Dissolved Gas Analysis	N/A
13	1st Triennial (2012-2014)	PG&E	1.10C - Demonstrate Automated Asset Notification and Management Systems: Underground Cable Analysis	N/A
14	1st Triennial (2012-2014)	PG&E	1.11 - Demonstrate Self-Correcting Tools to Improve System Records and Operations	N/A
15	1st Triennial (2012-2014)	PG&E	1.12 - Demonstrate New Technologies that Improve Wildlife Safety and Protect Assets from Weather-Related Degradation	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	*B*	*C*	*E3*	*E4*	*F*	*G*	*H*	*I*	*J*
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
9	1st Triennial (2012-2014)	PG&E	1.09A - Test New Remote Monitoring and Control Systems for Existing Transmission & Distribution Assets: Close Proximity Switching	• A working prototype for the various Solid Blade in Oil Rotatory Switch tools.	2.5 years	9/19/2013	No	Transmission; Distribution	$ 301,808	$464,000 - $567,000
10	1st Triennial (2012-2014)	PG&E	1.09B and 1.10B - Test New Remote Monitoring and Control Systems for T&D Assets / Demonstrate New Strategies and Technologies to Improve the Efficacy of Existing Maintenance and Replacement Programs	• Modified or improved components identified for use on Distribution Network Monitoring System. • Improved installation and construction work methods. • Economic model for maintenance variables based on life expectancy testing of components. • Changes to components.	3.25 years	9/19/2013	No	Transmission; Distribution	$ 484,250	$450,000 - $550,000
11	1st Triennial (2012-2014)	PG&E	1.09C - Test New Remote Monitoring and Control Systems for T&D Assets: Discrete Series Reactors	• Installation, testing and analysis of DSR and server communication links. • Procure, construct and test the DSRs. • White paper describing project including go/no go recommendation. • Final report describing overall project, including finding from the operations and testing of DSR units and a recommendation as to whether or not to install the DSRs elsewhere in the PG&E system.	3.25 years	9/19/2013	No	Transmission	$ 1,449,835	$2,2100,00 - $2,710,000
12	1st Triennial (2012-2014)	PG&E	1.10A - Demonstrate Automated Asset Notification and Management Systems: Dissolved Gas Analysis	N/A	N/A	NA	No	Transmission; Distribution	$ -	$ -
13	1st Triennial (2012-2014)	PG&E	1.10C - Demonstrate Automated Asset Notification and Management Systems: Underground Cable Analysis	N/A	N/A	NA	No	Distribution	$ -	$ -
14	1st Triennial (2012-2014)	PG&E	1.11 - Demonstrate Self-Correcting Tools to Improve System Records and Operations	N/A	N/A	NA	No	Transmission; Distribution	$ -	$ -
15	1st Triennial (2012-2014)	PG&E	1.12 - Demonstrate New Technologies that Improve Wildlife Safety and Protect Assets from Weather-Related Degradation	N/A	N/A	NA	No	Transmission; Distribution	$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
9	1st Triennial (2012-2014)	PG&E	1.09A - Test New Remote Monitoring and Control Systems for Existing Transmission & Distribution Assets: Close Proximity Switching	$ 383,991	$ 131,277	$ 515,268	$ -	N/A	N/A	N/A	N/A
10	1st Triennial (2012-2014)	PG&E	1.09B and 1.10B - Test New Remote Monitoring and Control Systems for T&D Assets / Demonstrate New Strategies and Technologies to Improve the Efficacy of Existing Maintenance and Replacement Programs	$ 543,414	$ 4,267	$ 547,681	$ -	N/A	N/A	N/A	N/A
11	1st Triennial (2012-2014)	PG&E	1.09C - Test New Remote Monitoring and Control Systems for T&D Assets: Discrete Series Reactors	$ 1,557,351	$ 902,381	$ 2,459,732	$ -	N/A	N/A	N/A	N/A
12	1st Triennial (2012-2014)	PG&E	1.10A - Demonstrate Automated Asset Notification and Management Systems: Dissolved Gas Analysis	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
13	1st Triennial (2012-2014)	PG&E	1.10C - Demonstrate Automated Asset Notification and Management Systems: Underground Cable Analysis	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
14	1st Triennial (2012-2014)	PG&E	1.11 - Demonstrate Self-Correcting Tools to Improve System Records and Operations	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
15	1st Triennial (2012-2014)	PG&E	1.12 - Demonstrate New Technologies that Improve Wildlife Safety and Protect Assets from Weather-Related Degradation	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
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Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
9	1st Triennial (2012-2014)	PG&E	1.09A - Test New Remote Monitoring and Control Systems for Existing Transmission & Distribution Assets: Close Proximity Switching	Pay for Performance	N/A	Competitive Bid	4	Two vendors chosen from RFP: • Inertia Switch • Trayer Issued Direct Award for Remote Solutions. They not respond to RFP, but shortly after competitive bid process completed, they announced independent creation of similar product.
10	1st Triennial (2012-2014)	PG&E	1.09B and 1.10B - Test New Remote Monitoring and Control Systems for T&D Assets / Demonstrate New Strategies and Technologies to Improve the Efficacy of Existing Maintenance and Replacement Programs	Pay for performance	N/A	Competitive Bid	Phase I: 5 bids Phase 2: 8 bids	Phase 1: Black and Veach Phase 2: Exponent
11	1st Triennial (2012-2014)	PG&E	1.09C - Test New Remote Monitoring and Control Systems for T&D Assets: Discrete Series Reactors	Pay for Performance	N/A	Sole Source - Smart Wires, Inc. selected as they are the developer and sole supplier of DSR devices.	N/A	N/A
12	1st Triennial (2012-2014)	PG&E	1.10A - Demonstrate Automated Asset Notification and Management Systems: Dissolved Gas Analysis	N/A	N/A	N/A	N/A	N/A
13	1st Triennial (2012-2014)	PG&E	1.10C - Demonstrate Automated Asset Notification and Management Systems: Underground Cable Analysis	N/A	N/A	N/A	N/A	N/A
14	1st Triennial (2012-2014)	PG&E	1.11 - Demonstrate Self-Correcting Tools to Improve System Records and Operations	N/A	N/A	N/A	N/A	N/A
15	1st Triennial (2012-2014)	PG&E	1.12 - Demonstrate New Technologies that Improve Wildlife Safety and Protect Assets from Weather-Related Degradation	N/A	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
9	1st Triennial (2012-2014)	PG&E	1.09A - Test New Remote Monitoring and Control Systems for Existing Transmission & Distribution Assets: Close Proximity Switching	The two RFP vendors tied for first.	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 5a - Outage number, frequency and duration reductions. • 5e - Utility worker safety improvement and hazard exposure reduction.
10	1st Triennial (2012-2014)	PG&E	1.09B and 1.10B - Test New Remote Monitoring and Control Systems for T&D Assets / Demonstrate New Strategies and Technologies to Improve the Efficacy of Existing Maintenance and Replacement Programs	Phase 1: 1 Phase 2: 1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 3a - Maintain/Reduce operations and maintenance costs. • 3b - Maintain/Reduce capital costs. • 5d - Public safety improvement and hazard exposure reduction. • 5e - Utility worker safety improvement and hazard exposure reduction.
11	1st Triennial (2012-2014)	PG&E	1.09C - Test New Remote Monitoring and Control Systems for T&D Assets: Discrete Series Reactors	N/A	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 3a - Maintain/Reduce operations and maintenance costs. • 3b - Maintain/Reduce capital costs. • 5a - Outage number, frequency and duration reductions. • 5b - Electric system power flow congestion reduction.
12	1st Triennial (2012-2014)	PG&E	1.10A - Demonstrate Automated Asset Notification and Management Systems: Dissolved Gas Analysis	N/A	N/A	N/A	N/A	N/A	N/A
13	1st Triennial (2012-2014)	PG&E	1.10C - Demonstrate Automated Asset Notification and Management Systems: Underground Cable Analysis	N/A	N/A	N/A	N/A	N/A	N/A
14	1st Triennial (2012-2014)	PG&E	1.11 - Demonstrate Self-Correcting Tools to Improve System Records and Operations	N/A	N/A	N/A	N/A	N/A	N/A
15	1st Triennial (2012-2014)	PG&E	1.12 - Demonstrate New Technologies that Improve Wildlife Safety and Protect Assets from Weather-Related Degradation	N/A	N/A	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
16	1st Triennial (2012-2014)	PG&E	1.13 - Demonstrate New Communication Systems to Improve Substation Automation and Interoperability	Grid Modernization and Optimization	• Demonstrate new strategies and technologies to convert and integrate multiple existing proprietary technologies within the substation environment for more effective operations. Substation are key operational hubs and represent significant investments, which must be further leveraged by engaging with vendors to create the next generation of interoperable substation services and products.
17	1st Triennial (2012-2014)	PG&E	1.14 - Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities (includes 1.14.17 Smart Pole Meter)	Grid Modernization and Optimization	• This project explores and discovers effective new network applications and devices to leverage and improve the SmartMeter™ communications network.
18	1st Triennial (2012-2014)	PG&E	1.15 - Demonstrate New Technologies and Strategies That Support Integrated "Customer-to-Market-to-Grid" Operations of the Future	Grid Modernization and Optimization	• The objective of this pilot is to develop and pilot a real-time data visualization software platform for use by Electric Distribution Operations end users. Data will be integrated from various data sources and displayed on Distribution Control Center video walls and individual desktop computers, with potential for future scalability to handheld devices.
19	1st Triennial (2012-2014)	PG&E	1.16 - Demonstrate Electric Vehicle as a Resource to Improve Grid Power Quality and Reduce Customer Outages	Grid Modernization and Optimization	• Leverage plug-in hybrid vehicle technology emerging in Pacific Gas and Electric Company (PG&E) fleet to generate utility-grade power, supporting distribution circuits during planned or unplanned outage events.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	B	C	E2
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
16	1st Triennial (2012-2014)	PG&E	1.13 - Demonstrate New Communication Systems to Improve Substation Automation and Interoperability	N/A
17	1st Triennial (2012-2014)	PG&E	1.14 - Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities (includes 1.14.17 Smart Pole Meter)	• Leverage the existing SmartMeter™ network to support additional applications. Inform future uses of the SmartMeter™ network such as message capability, security, latency, and engineering constraints. Specifically focus on: - Test new devices to support network functions and capabilities not previously envisioned (e.g., new data streams, faster data collection). - Evaluate alternatives to decrease future upgrade, maintenance and/or operational costs. - Demonstrate different network applications, each focused on separate use cases.
18	1st Triennial (2012-2014)	PG&E	1.15 - Demonstrate New Technologies and Strategies That Support Integrated "Customer-to-Market-to-Grid" Operations of the Future	• Scope includes the integration of data (network model, loading, SmartMeter™ devices, outages, weather, etc.) and a real-time data visualization platform for Distribution Operations. • The Distribution Management System (DMS) platform and predictive analytics are not included in the scope.
19	1st Triennial (2012-2014)	PG&E	1.16 - Demonstrate Electric Vehicle as a Resource to Improve Grid Power Quality and Reduce Customer Outages	• Develop nominally 120 kilowatt exportable power capabilities from a plug in hybrid electric truck. Seek to create the protocols necessary to safely connect the truck to the appropriate grid connection points. The portfolio of fleet vehicles (higher and lower weight classes) may broaden the range of available power ratings demonstrated by the project.

APPENDIX A
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(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
16	1st Triennial (2012-2014)	PG&E	1.13 - Demonstrate New Communication Systems to Improve Substation Automation and Interoperability	N/A	N/A	NA	No	Transmission; Distribution	$ -	$ -
17	1st Triennial (2012-2014)	PG&E	1.14 - Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities (includes 1.14.17 Smart Pole Meter)	• Evaluate new applications and devices, their associated data traffic impact on the SmartMeter™ network, and recommend which items warrant consideration for full scale deployment. • Develop business case based on findings for full deployment consideration.	3.25years	9/19/2013	No	Distribution; Grid Operation/Market Design; Demand-Side Management	$ 3,986,281	$3,780,000 - $4,550,000
18	1st Triennial (2012-2014)	PG&E	1.15 - Demonstrate New Technologies and Strategies That Support Integrated "Customer-to-Market-to-Grid" Operations of the Future	• Demonstrate Real-time Data Visualization Platform, including data integration from a variety of data sources and a visual interface that includes geospatial, list, and trending layers.	3.25 years	9/19/2013	No	Distribution; Grid Operation/Market Design; Demand-Side Management	$ 1,334,030	$3,780,000 - $4,620,000
19	1st Triennial (2012-2014)	PG&E	1.16 - Demonstrate Electric Vehicle as a Resource to Improve Grid Power Quality and Reduce Customer Outages	• Develop operating requirements for the vehicle. • Understand engineering challenges with high power export with collaborative supplier development to solve. • Develop safety and interconnection protocols to connect the vehicle to the grid leveraging existing protocols for temporary local generator set connection. • Define and document power requirements for different outage/usage scenarios. • Develop operating protocols (when and how the vehicles will be used). • Develop unplanned outage protocols. • Develop the hardware and software (if required) to connect the vehicle to PG&E's system. • Build vehicles for field testing.	3.25 years	9/19/2013	No	Distribution	$ 643,840	$3,600,000 - $4,400,000

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
16	1st Triennial (2012-2014)	PG&E	1.13 - Demonstrate New Communication Systems to Improve Substation Automation and Interoperability	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
17	1st Triennial (2012-2014)	PG&E	1.14 - Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities (includes 1.14.17 Smart Pole Meter)	$ 3,334,863	$ 809,376	$ 4,144,239	$ -	No	N/A	N/A	N/A
18	1st Triennial (2012-2014)	PG&E	1.15 - Demonstrate New Technologies and Strategies That Support Integrated "Customer-to-Market-to-Grid" Operations of the Future	$ 1,605,622	$ 2,527,552	$ 4,133,173	$ -	N/A	N/A	N/A	N/A
19	1st Triennial (2012-2014)	PG&E	1.16 - Demonstrate Electric Vehicle as a Resource to Improve Grid Power Quality and Reduce Customer Outages	$ 2,488,160	$ 1,521,628	$ 4,009,788	$ 125	Department of Energy (DOE) provided test services using National Renewable Energy Lab (NREL) facilities. Approximate cost share to date: $120,000.	DOE/NREL; Edison Electric Institute engaged for elec. utility industry staging events; Portland General Electric closely collaborating for industry-level requirements	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
16	1st Triennial (2012-2014)	PG&E	1.13 - Demonstrate New Communication Systems to Improve Substation Automation and Interoperability	N/A	N/A	N/A	N/A	N/A
17	1st Triennial (2012-2014)	PG&E	1.14 - Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities (includes 1.14.17 Smart Pole Meter)	Pay for Performance	• U.S. Patent No. 10,658,798 titled Smart Energy Metering System and Method for the development of the Smart Pole Meter and Smart Pole Meter Socket granted. Signed a licensing agreement related to this patent. • Continuation application to the existing Non-Provisional patent application No. 15/872,771 and titled Wire Down Detection System and Method for the development of an algorithm to help identify wires downed or functioning abnormally, in order to incorporate continuing developments of the technology.	Sole Source - Silver Springs Network selected as they solutions provider for PG&E's AMI electric network. It is necessary to work with SSN to ensure that devices and applications can communicate across the AMI network.	N/A	N/A
18	1st Triennial (2012-2014)	PG&E	1.15 - Demonstrate New Technologies and Strategies That Support Integrated "Customer-to-Market-to-Grid" Operations of the Future	Pay For Performance	New Intellectual Property (IP) has been created through co-development with the vendor. PG&E retains ownership rights to the IP and will provide free unlimited use rights to CA IOUs per the CPUC decision	Competitive Bid	3	BitStew
19	1st Triennial (2012-2014)	PG&E	1.16 - Demonstrate Electric Vehicle as a Resource to Improve Grid Power Quality and Reduce Customer Outages	Pay for performance	N/A	• Phase 1 (Mule Phase): 2 Direct Awards - Efficient Drivetrains, Inc. (EDI) and Electric Vehicle International (EVI) selected due to short-term availability of prototype driveline and capability of generating utility-grade export power on F550 - diesel/gasoline configuration • Phase 2 (Alpha Phase): Based on results of Mule phase, moved forward with EDI, which was designed to help formulate specs for Phase 3 • Phase 3 (Beta Phase): Competitive solicitation. 10 potential bidders. Received 2 final bids.	2 (Phase 3 - Beta Phase)	Efficient Drivetrains, Inc. (EDI) (Phase 3 - Beta Phase)

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
16	1st Triennial (2012-2014)	PG&E	1.13 - Demonstrate New Communication Systems to Improve Substation Automation and Interoperability	N/A	N/A	N/A	N/A	N/A	N/A
17	1st Triennial (2012-2014)	PG&E	1.14 - Demonstrate "Next Generation" SmartMeter™ Telecom Network Functionalities (includes 1.14.17 Smart Pole Meter)	N/A	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 7f - Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliance and consumer devices for metering, communications concerning grid operations and status, and distribution automation (Public Utilities Code (Pub. Util. Code) §8360). • 7k - Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid (Pub. Util. Code §8360). • Note: Each technology demonstrated may have additional specific benefits to name. For instance, the following could apply: improved communication for power restoration, improved control of streetlights, etc.
18	1st Triennial (2012-2014)	PG&E	1.15 - Demonstrate New Technologies and Strategies That Support Integrated "Customer-to-Market-to-Grid" Operations of the Future	1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 5a - Outage number, frequency and duration reductions. • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid (Public Utilities Code 8360). • 3a - Maintain/Reduce operations and maintenance costs.
19	1st Triennial (2012-2014)	PG&E	1.16 - Demonstrate Electric Vehicle as a Resource to Improve Grid Power Quality and Reduce Customer Outages	1 (Phase 3 - Beta Phase)	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	• 5a - Outage number, frequency and duration reductions. • 5e - Utility worker safety improvement and hazard exposure reduction. • 3a - Maintain/Reduce operations and maintenance costs. • 4a – Greenhouse Gas emissions reductions (MMTCO2e).

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
20	1st Triennial (2012-2014)	PG&E	1.17 - Leverage EPIC Funds by Participating in Multi-Utility, Industry Wide RD&D Programs Such as EPRI	Grid Modernization and Optimization	• PG&E can leverage EPIC dollars by participating and collaborating in multi-utility industry-wide research initiatives conducted by third party organizations experienced in the RD&D area. These programs would allow PG&E to cost effectively develop a deeper awareness of industry trends, access real world experience through pilot programs, and identify the gaps that utilities will fill or close with technology. For example, through participation in existing EPRI programs, PG&E would participate in and gain access to demonstrations, analyses, and results of the testing and study of distribution equipment and strategies. High Value EPRI programs include: IntelliGrid, Integration of Distributed Renewables, Energy Storage, Risk Mitigation Strategies, and Distribution Grid Modernization programs.
21	1st Triennial (2012-2014)	PG&E	1.18 - Demonstrate SmartMeter™-Enabled Data Analytics to Provide Customers With Appliance-Level Energy Use Information	Customer Service and Enablement	• This project focuses on delivering the cost by major appliances to customers.
22	1st Triennial (2012-2014)	PG&E	1.19 - Pilot Enhanced Data Techniques and Capabilities via the SmartMeter™ Platform	Customer Service and Enablement	• The project is to explore and discover effective, new data that can be collected and studied for further benefits. Demonstrate the type of additional data that can be collected and/or processed through the SmartMeter™ platform. Evaluate impact of any increased data traffic on the SmartMeter™ network. Focus on new data collection that makes the SmartMeter™ platform more robust for more customers.
23	1st Triennial (2012-2014)	PG&E	1.20 - Demonstrate the Benefits of Providing the Competitive, Open Market With Automated Access to Customer-Authorized SmartMeter™ Data to Drive Innovation.	Customer Service and Enablement	• This project will fund continued support of Green Button Connect (GBC). GBC provides a small number of vendors in the competitive market with automated access to recurring, machine-to-machine, programmatic data access to customer-authorized SmartMeter™ data in order to develop new, innovative and creative ways for customers to manage their energy consumption. GBC is a small demonstration, not scalable to support the larger customer base and wider vendor audience. PG&E is planning on implementing a robust, broader scale offering as part of its Customer Data Access (CDA) project.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
20	1st Triennial (2012-2014)	PG&E	1.17 - Leverage EPIC Funds by Participating in Multi-Utility, Industry Wide RD&D Programs Such as EPRI	N/A
21	1st Triennial (2012-2014)	PG&E	1.18 - Demonstrate SmartMeter™-Enabled Data Analytics to Provide Customers With Appliance-Level Energy Use Information	• This project will use the data enabled by the SmartMeter™ platform to provide appliance level itemization of monthly bill charges to customers, without their completing any audit or subscribing to any new service. This project assumes that minute level meter data is available.
22	1st Triennial (2012-2014)	PG&E	1.19 - Pilot Enhanced Data Techniques and Capabilities via the SmartMeter™ Platform	• Demonstrate the collection of new data from SmartMeter™ devices. Example use cases include: - Power Quality Data (C12.19 format). - New Data Channels. - Mobile data collection methods. - Power theft detection methodology using SmartMeter™ data for revenue assurance purposes.
23	1st Triennial (2012-2014)	PG&E	1.20 - Demonstrate the Benefits of Providing the Competitive, Open Market With Automated Access to Customer-Authorized SmartMeter™ Data to Drive Innovation.	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
20	1st Triennial (2012-2014)	PG&E	1.17 - Leverage EPIC Funds by Participating in Multi-Utility, Industry Wide RD&D Programs Such as EPRI	N/A	N/A	NA	No	Transmission; Distribution	$ -	$ -
21	1st Triennial (2012-2014)	PG&E	1.18 - Demonstrate SmartMeter™-Enabled Data Analytics to Provide Customers With Appliance-Level Energy Use Information	• Quantify disaggregation accuracy and compare vendors. • Based on results, provide recommendations for deployment strategy of appliance level billing.	2.5years	9/19/2013	No	Demand-Side Management	$ 1,399,248	$1,080,000 - $1,320,000
22	1st Triennial (2012-2014)	PG&E	1.19 - Pilot Enhanced Data Techniques and Capabilities via the SmartMeter™ Platform	• Evaluate new data and analytic methodologies, their associated impact on the SmartMeter™. • Recommendation of which data warrants consideration for full-scale deployment. • Evaluation should provide key inputs to a business case for general deployment.	3.25 years	9/19/2013	No	Distribution; Grid Operation/Market Design; Demand-Side Management	$ 1,051,786	$1,780,000 - $2,180,000
23	1st Triennial (2012-2014)	PG&E	1.20 - Demonstrate the Benefits of Providing the Competitive, Open Market With Automated Access to Customer-Authorized SmartMeter™ Data to Drive Innovation.	N/A	N/A	NA	No	Demand-Side Management	$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
20	1st Triennial (2012-2014)	PG&E	1.17 - Leverage EPIC Funds by Participating in Multi-Utility, Industry Wide RD&D Programs Such as EPRI	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
21	1st Triennial (2012-2014)	PG&E	1.18 - Demonstrate SmartMeter™-Enabled Data Analytics to Provide Customers With Appliance-Level Energy Use Information	$ 1,231,202	$ 65,640	$ 1,296,842	$ -	N/A	N/A	N/A	N/A
22	1st Triennial (2012-2014)	PG&E	1.19 - Pilot Enhanced Data Techniques and Capabilities via the SmartMeter™ Platform	$ 841,884	$ 1,138,615	$ 1,980,499	$ -	Leveraging existing AMI network investments.	N/A	N/A	N/A
23	1st Triennial (2012-2014)	PG&E	1.20 - Demonstrate the Benefits of Providing the Competitive, Open Market With Automated Access to Customer-Authorized SmartMeter™ Data to Drive Innovation.	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
20	1st Triennial (2012-2014)	PG&E	1.17 - Leverage EPIC Funds by Participating in Multi-Utility, Industry Wide RD&D Programs Such as EPRI	N/A	N/A	N/A	N/A	N/A
21	1st Triennial (2012-2014)	PG&E	1.18 - Demonstrate SmartMeter™-Enabled Data Analytics to Provide Customers With Appliance-Level Energy Use Information	Pay for performance	N/A	Sole Source - Silver Springs Network, as they are the solutions provider for PG&E's AMI electric network. It is necessary to work with SSN to ensure that devices and applications can communicate across the AMI network.	N/A	N/A
22	1st Triennial (2012-2014)	PG&E	1.19 - Pilot Enhanced Data Techniques and Capabilities via the SmartMeter™ Platform	Pay for Performance	N/A	Competitive Bid	3	BitStew & Primestone
23	1st Triennial (2012-2014)	PG&E	1.20 - Demonstrate the Benefits of Providing the Competitive, Open Market With Automated Access to Customer-Authorized SmartMeter™ Data to Drive Innovation.	N/A	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	B	C	X	Y	Z	AA	AB	AC
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
20	1st Triennial (2012-2014)	PG&E	1.17 - Leverage EPIC Funds by Participating in Multi-Utility, Industry Wide RD&D Programs Such as EPRI	N/A	N/A	N/A	N/A	N/A	N/A
21	1st Triennial (2012-2014)	PG&E	1.18 - Demonstrate SmartMeter™-Enabled Data Analytics to Provide Customers With Appliance-Level Energy Use Information	N/A	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 1f - Avoided customer energy use. • 1h - Customer bill savings (dollars saved).
22	1st Triennial (2012-2014)	PG&E	1.19 - Pilot Enhanced Data Techniques and Capabilities via the SmartMeter™ Platform	Tie for first	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 1h - Customer bill savings (dollars saved). • 1f - Avoided customer energy use (kilowatt-hours saved). • 3a - Maintain/Reduce operations and maintenance costs. • 3b - Maintain/Reduce capital costs. • 5d - Public safety improvement and hazard exposure reduction. • 5e - Utility worker safety improvement and hazard exposure reduction. • 5f - Reduced flicker and other power quality differences. • 5i. Increase in the number of nodes in the power system at monitoring points. • 7f - Deployment of cost-effective smart technologies, including real time, automated, interactive technologies that optimize the physical operation of appliance and consumer devices for metering, communications concerning grid operations and status, and distribution automation. • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid.
23	1st Triennial (2012-2014)	PG&E	1.20 - Demonstrate the Benefits of Providing the Competitive, Open Market With Automated Access to Customer-Authorized SmartMeter™ Data to Drive Innovation.	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
24	1st Triennial (2012-2014)	PG&E	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	Customer Service and Enablement	• This project aims to validate and integrate a software platform to identify photovoltaic (PV) resources by leveraging Smart Meter™ data. This project focuses on addressing the issue of unauthorized interconnections in an automated fashion by developing and algorithm to identify resources, including integration with Pacific Gas and Electric Company (PG&E) billing and interconnection database, as well as develop an automated outreach system for identified customers. • This project addresses California Public Utilities Commission proceeding, R.11 09 011 Rule 21 to support the improved distribution level interconnection rules and regulations for certain classes of electric generators and electric storage resources.
25	1st Triennial (2012-2014)	PG&E	1.22 - Demonstrate Subtractive Billing With Submetering for EVs to Increase Customer Billing Flexibility	Customer Service and Enablement	• EV submetering pilot to test subtractive metering process and Electric Vehicle Service Provider (EVSP) business models. • This project addresses CPUC D.13-11-008, which requires Pacific Gas and Electric Company (PG&E), along with the other two California Investor Owned Utilities (IOU), to pursue a submetering pilot and eventual protocol.
26	1st Triennial (2012-2014)	PG&E	1.23 - Demonstrate Additive Billing With Submetering for PVs to Increase Customer Billing Flexibility	Customer Service and Enablement	• Initiative to obtain additional un-netted Photovoltaic (PV) data to support customer call center bill experience, and provide additional service to its customers. PV generation data will be integrated with existing MyEnergy web portal for customers' benefit. • This project addresses California Public Utilities Commission proceeding, Net Energy Metering R.12-11-005 and R.11 09 011 Rule 21.
27	1st Triennial (2012-2014)	PG&E	1.24 - Demonstrate Demand-Side Management (DSM) for Transmission and Distribution (T&D) Cost Reduction	Customer Service and Enablement	• Assess how to best utilize DSM resources to create a targeted customer- and location-specific approach to assist with distribution capacity constraints. • This project addresses California Public Utilities Commission proceeding, Distribution Resources Planning R.14 08 013, through improving efficiencies between interconnection and integration.
28	1st Triennial (2012-2014)	PG&E	1.25 - Develop a Tool to Map The Preferred Locations for DC Fast Charging, Based on Traffic Patterns and PG&E's Distribution System, to Address EV Drivers' Needs While Reducing the Impact on PG&E's Distribution Grid	Customer Service and Enablement	• Develop, pilot, and validate approaches that help determine the optimal location of DC fast chargers based on traffic patterns and distribution grid infrastructure.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	B	C	E2
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
24	1st Triennial (2012-2014)	PG&E	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	• Identify vendor to develop or pilot software. • Develop integration and communication platform for auto identification of Unauthorized Interconnections (UI). • Demonstrate ability to automatically integrate software with billing and interconnection.
25	1st Triennial (2012-2014)	PG&E	1.22 - Demonstrate Subtractive Billing With Submetering for EVs to Increase Customer Billing Flexibility	• Electric Vehicle (EV) submetering pilot will entail EV Meter Data Management Agents (MDMA) delivering submeter data to IOU for subtraction from customer's primary meter to create an EV and a house bill. Customer will be responsible for both bills. In Phase 2, an additional business model will be introduced where the MDMA will be responsible for the bill to PG&E.
26	1st Triennial (2012-2014)	PG&E	1.23 - Demonstrate Additive Billing With Submetering for PVs to Increase Customer Billing Flexibility	• Explore four different methods for obtaining PV generation data (Dedicated SmartMeter™, submeter communication via ZigBee radio, third party estimates, and data exchange with solar companies, and work with vendor to relay data to customer.
27	1st Triennial (2012-2014)	PG&E	1.24 - Demonstrate Demand-Side Management (DSM) for Transmission and Distribution (T&D) Cost Reduction	• Improve ability to estimate Heating, Ventilation and Air Conditioning (HVAC) Direct Load Control (DLC) load impacts at the distribution feeder level to aid in better understanding of the localized impact of HVAC DLC devices on meeting distribution feeder level reliability concerns.
28	1st Triennial (2012-2014)	PG&E	1.25 - Develop a Tool to Map The Preferred Locations for DC Fast Charging, Based on Traffic Patterns and PG&E's Distribution System, to Address EV Drivers' Needs While Reducing the Impact on PG&E's Distribution Grid	• Acquire travel pattern data and grid infrastructure capability data to identify low cost, high utilization areas in which to integrate DC fast chargers into Pacific Gas and Electric Company's (PG&E) distribution system.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
24	1st Triennial (2012-2014)	PG&E	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	• Successful integration of software with PG&E's Customer Care and Billing (CC&B) system. • Successful tracking of all UIs identified. • Successful tracking of communication and "conversion" of UIs to interconnection.	2.5years	5/1/2014	No	Distribution; Demand-Side Management	$ 868,495	$1,200,000 - $1,460,000
25	1st Triennial (2012-2014)	PG&E	1.22 - Demonstrate Subtractive Billing With Submetering for EVs to Increase Customer Billing Flexibility	• Process to receive MDMA submetered data. • Process to subtract EV data from primary meter to create two bills. • Inclusion of EV portion of bill on customer's monthly bill. • Process for billing MDMA for participant submeter charges. • Obtain third party evaluator for both phases of pilot through a Request for Proposal (RFP). • Incentive payments to MDMA.	5years	11/14/2013	No	Distribution; Grid Operation/Market Design; Demand-Side Management	$ 2,756,187	$1,730,000 - $2,120,000
26	1st Triennial (2012-2014)	PG&E	1.23 - Demonstrate Additive Billing With Submetering for PVs to Increase Customer Billing Flexibility	• Implement pilot program for dedicated smart meters and third party estimates. • Explore opportunities for submetering technology and solar company data exchange. • Modify existing Customer Data Warehouse (CDW)/MyEnergy interface to allow for additional data streams and visualization. • Evaluate relative merits of various generation measurement/estimation approaches.	2.5 years	5/1/2014	No	Grid Ops and Mkt. Design / Distribution / DSM	$ 950,313	$1,200,000 - $1,460,000
27	1st Triennial (2012-2014)	PG&E	1.24 - Demonstrate Demand-Side Management (DSM) for Transmission and Distribution (T&D) Cost Reduction	• Deploy data logging devices on a scientific sample of existing SmartAC™ Cycling customers, to enable real time monitoring of device performance and load impacts at feeder level. • Develop infrastructure to make real-time data available on feeder-level load impacts of SmartAC™ Cycling to distribution operations. • Produce report describing a case study methodology of targeting and valuing customer side peak load reductions at the feeder level.	2 years	5/1/2014	No	Transmission; Distribution; Grid Operation/Market Design; Demand-Side Management	$ 1,206,477	$1,327,000 - $1,621,000
28	1st Triennial (2012-2014)	PG&E	1.25 - Develop a Tool to Map The Preferred Locations for DC Fast Charging, Based on Traffic Patterns and PG&E's Distribution System, to Address EV Drivers' Needs While Reducing the Impact on PG&E's Distribution Grid	• Develop a process to identify optimal DC fast charging sites. • Develop a map that presents the locations of optimal DC fast charging sites in a meaningful manner to customers.	2.5 years	5/1/2014	No	Distribution; Demand-Side Management	$ 391,425	$400,000 - $490,000

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
24	1st Triennial (2012-2014)	PG&E	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	$ 902,652	$ 435,173	$ 1,337,825	$ -	N/A	N/A	N/A	N/A
25	1st Triennial (2012-2014)	PG&E	1.22 - Demonstrate Subtractive Billing With Submetering for EVs to Increase Customer Billing Flexibility	$ 2,042,779	$ 256,299	$ 2,299,078	$ -	N/A	N/A	N/A	N/A
26	1st Triennial (2012-2014)	PG&E	1.23 - Demonstrate Additive Billing With Submetering for PVs to Increase Customer Billing Flexibility	$ 873,453	$ 450,363	$ 1,323,817	$ -	N/A	N/A	N/A	N/A
27	1st Triennial (2012-2014)	PG&E	1.24 - Demonstrate Demand-Side Management (DSM) for Transmission and Distribution (T&D) Cost Reduction	$ 1,262,770	$ 77,583	$ 1,340,353	$ -	N/A	N/A	N/A	N/A
28	1st Triennial (2012-2014)	PG&E	1.25 - Develop a Tool to Map The Preferred Locations for DC Fast Charging, Based on Traffic Patterns and PG&E's Distribution System, to Address EV Drivers' Needs While Reducing the Impact on PG&E's Distribution Grid	$ 308,232	$ 132,537	$ 440,769	$ -	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
24	1st Triennial (2012-2014)	PG&E	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	Pay for performance	U.S. Patent No. 10,557,720 titled Unauthorized Electrical Grid Connection Detection and Characterization System and Method for an algorithm which can detect unauthorized PV interconnections.	Sole Source - Nexant selected due to expertise in PG&E's CC&B database, PV generation data analysis and AMI network.	N/A	N/A
25	1st Triennial (2012-2014)	PG&E	1.22 - Demonstrate Subtractive Billing With Submetering for EVs to Increase Customer Billing Flexibility	Pay for Performance	N/A	Competitive Bid	15	Nexant, Inc.
26	1st Triennial (2012-2014)	PG&E	1.23 - Demonstrate Additive Billing With Submetering for PVs to Increase Customer Billing Flexibility	Pay for performance	N/A	• Sole Source - - Opower - PG&E's customer facing web portal, My Energy. Given the project is integrated PV generation interval data into My Energy, it was necessary to work with them. - Clean Power Research - Purchased subscription to estimated generation data.	N/A	N/A
27	1st Triennial (2012-2014)	PG&E	1.24 - Demonstrate Demand-Side Management (DSM) for Transmission and Distribution (T&D) Cost Reduction	Pay for performance	N/A	Sole sourced - Enetics is a consulting firm that performed a study that assessed the available technologies that would best address the need of the project and determined Enetics provides that solution. They were also willing to make enhancements to their device to further meet the need of PG&E and were the lowest cost and immediately available.	N/A	N/A
28	1st Triennial (2012-2014)	PG&E	1.25 - Develop a Tool to Map The Preferred Locations for DC Fast Charging, Based on Traffic Patterns and PG&E's Distribution System, to Address EV Drivers' Needs While Reducing the Impact on PG&E's Distribution Grid	Pay for Performance	N/A	Competitive Bid	4	Energy and Environmental Economics, Inc. (E3)

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	B	C	X	Y	Z	AA	AB	AC
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
24	1st Triennial (2012-2014)	PG&E	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	N/A	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 5d - Public safety improvement and hazard exposure reduction. • 5f - Reduced flicker and other power quality differences. • 5c - Forecast accuracy improvement.
25	1st Triennial (2012-2014)	PG&E	1.22 - Demonstrate Subtractive Billing With Submetering for EVs to Increase Customer Billing Flexibility	1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 4a - GHG emissions reductions (MMTCO2e). • 1h - Customer bill savings (megawatt hours saved).
26	1st Triennial (2012-2014)	PG&E	1.23 - Demonstrate Additive Billing With Submetering for PVs to Increase Customer Billing Flexibility	N/A	N/A	Column applicable to CEC only	Opower - No Clean Power Research - Yes: California-based	Column applicable to CEC only	• 5c - Forecast accuracy improvements. • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid (Public Utilities Code 8360).
27	1st Triennial (2012-2014)	PG&E	1.24 - Demonstrate Demand-Side Management (DSM) for Transmission and Distribution (T&D) Cost Reduction	N/A	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 7b - Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid (Public Utilities Code 8360).
28	1st Triennial (2012-2014)	PG&E	1.25 - Develop a Tool to Map The Preferred Locations for DC Fast Charging, Based on Traffic Patterns and PG&E's Distribution System, to Address EV Drivers' Needs While Reducing the Impact on PG&E's Distribution Grid	1	N/A - E3 was the highest scoring vendor.	Column applicable to CEC only	Yes - California-based, small business, and Minority Based Enterprise (MBE).	Column applicable to CEC only	• 3a - Maintain/Reduce capital costs. • 3d - Number of operations of various existing equipment types before and after adoption of a new smart grid component, as an indicator of possible equipment life extensions from reduced wear and tear. • 4a - Greenhouse Gas emissions reductions (MMTCO2e). • 5c - Forecast accuracy improvement. • 5d - Public safety improvement and hazard exposure reduction. • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Public Utilities Code § 8360). • 7l - Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
29	1st Triennial (2012-2014)	PG&E	1.26 - Pilot Measurement and Telemetry Strategies and Technologies That Enable the Cost-Effective Integration of Mass Market Demand Response (DR) Resources into the CAISO Wholesale Market	Customer Service and Enablement	• Develop, demonstrate and validate approaches and technologies that enable the cost effective integration (specifically, the measurement and telemetry) of mass market DR resources into the California Independent System Operator (CAISO) wholesale market. While other DR projects focus on integration of DR resources into various utility and future Independent System Operator operational needs, this project intends to test alternative telemetry solutions and technologies to satisfy CAISO operational visibility requirements.
30	2nd Triennial (2015-2017)	PG&E	2.01 - Evaluate Storage on the Distribution Grid	Renewables/DER Resource Integration	• Identify and evaluate whether system needs can be cost-effectively addressed with energy storage, including identifying a range of storage deployment locations and grid interconnection requirements on a granular level.
31	2nd Triennial (2015-2017)	PG&E	2.02 - Pilot Distributed Energy Resource Management Systems (DERMS)	Renewables/DER Resource Integration	Demonstrate new technology to monitor and control Distributed Energy Resources (DER) to manage system constraints and evaluate the potential value of DER flexibility to the grid. The DERMS pilot will drive learning about the people, process, and technology needed to operate the high DER penetration grid of 2025. • Define boundaries and integrations with other PG&E and external systems such as Demand Response Management System (DRMS), Advanced Distribution Management System (ADMS) and CAISO market systems among others. • Enable informed choice for long-term strategic vendor in 2017+ (demonstration is not choosing the long term vendor). • Identify limitations of existing as-built models and field telemetry data • Evaluate the performance of aggregated DERs providing distribution services • Create, test, and iterate on future DERMS requirements (e.g., communication requirements for PG&E and third party owned DERs). • Learn about business process change and personnel skills & knowledge needed to implement DERMS. • This project informs California Public Utilities Commission proceeding, Distribution Resources Plan R.14 08 013 to inform distribution planning by demonstrating DER integration into planning and operations.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
29	1st Triennial (2012-2014)	PG&E	1.26 - Pilot Measurement and Telemetry Strategies and Technologies That Enable the Cost-Effective Integration of Mass Market Demand Response (DR) Resources into the CAISO Wholesale Market	N/A
30	2nd Triennial (2015-2017)	PG&E	2.01 - Evaluate Storage on the Distribution Grid	N/A
31	2nd Triennial (2015-2017)	PG&E	2.02 - Pilot Distributed Energy Resource Management Systems (DERMS)	• Demonstrate minimum viable DERMS operation at Pacific Gas and Electric Company (PG&E) to address key DER management use cases. • The demonstration will take place in a limited geography with a diverse set of DERs being monitored and controlled by the DERMS demonstration.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	*B*	*C*	*E3*	*E4*	*F*	*G*	*H*	*I*	*J*
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
29	1st Triennial (2012-2014)	PG&E	1.26 - Pilot Measurement and Telemetry Strategies and Technologies That Enable the Cost-Effective Integration of Mass Market Demand Response (DR) Resources into the CAISO Wholesale Market	N/A	N/A	NA	No	Grid Operation/Market Design and Demand-side Management.	$ -	$ -
30	2nd Triennial (2015-2017)	PG&E	2.01 - Evaluate Storage on the Distribution Grid	N/A	N/A	NA	No	Grid Operations/Market Design; Transmission; Distribution; DSM	$ -	$ -
31	2nd Triennial (2015-2017)	PG&E	2.02 - Pilot Distributed Energy Resource Management Systems (DERMS)	• The functional integration of a DERMS software minimum viable product and operational demonstration of the identified use cases. • A report that: - Determines the most important characteristics of a full deployment solution including detailed functional and technical requirements. - Identifies best practices and required internal capabilities for a full deployment solution. - Develops operational processes that can be scaled to a wider system deployment. - Defines boundaries and integrations with other PG&E systems (e.g., DRMS, DMS, market systems). - Develops a point of view on the utility role in managing DERs for grid and economic benefits.	2.75years	9/15/2015	No	Grid Operation/Market Design	$ 2,535,324	$6,000,000 - $7,320,000

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
29	1st Triennial (2012-2014)	PG&E	1.26 - Pilot Measurement and Telemetry Strategies and Technologies That Enable the Cost-Effective Integration of Mass Market Demand Response (DR) Resources into the CAISO Wholesale Market	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
30	2nd Triennial (2015-2017)	PG&E	2.01 - Evaluate Storage on the Distribution Grid	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
31	2nd Triennial (2015-2017)	PG&E	2.02 - Pilot Distributed Energy Resource Management Systems (DERMS)	$ 3,064,371	$ 3,720,934	$ 6,785,305	$ 18,437	N/A	N/A	$419,000	N/A

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
29	1st Triennial (2012-2014)	PG&E	1.26 - Pilot Measurement and Telemetry Strategies and Technologies That Enable the Cost-Effective Integration of Mass Market Demand Response (DR) Resources into the CAISO Wholesale Market	N/A	N/A	N/A	N/A	N/A
30	2nd Triennial (2015-2017)	PG&E	2.01 - Evaluate Storage on the Distribution Grid	N/A	N/A	N/A	N/A	N/A
31	2nd Triennial (2015-2017)	PG&E	2.02 - Pilot Distributed Energy Resource Management Systems (DERMS)	Pay for performance	N/A	Competitive Bid	5	GE Alstom

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
29	1st Triennial (2012-2014)	PG&E	1.26 - Pilot Measurement and Telemetry Strategies and Technologies That Enable the Cost-Effective Integration of Mass Market Demand Response (DR) Resources into the CAISO Wholesale Market	N/A	N/A	N/A	N/A	N/A	N/A
30	2nd Triennial (2015-2017)	PG&E	2.01 - Evaluate Storage on the Distribution Grid	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
31	2nd Triennial (2015-2017)	PG&E	2.02 - Pilot Distributed Energy Resource Management Systems (DERMS)	1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Public Utilities Code (Pub. Util. Code) § 8360). • 7d - Deployment and integration of cost-effective distributed resources and generation, including renewable resources (Pub. Util. Code § 8360).

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
32	2nd Triennial (2015-2017)	PG&E	2.03A - Test Smart Inverter Enhanced Capabilities - Photovoltaics (PV)	Renewables/DER Resource Integration	• This project will explore the use and impact of aggregated customer-sited smart inverters to help inform emerging industry standards, as well as define the operational and communication requirements to support the advancement and deployment of new inverter technologies. • This project addresses California Public Utilities Commission proceeding, Distribution Resources Plan R.14 08 013, by informing Distributed Energy Resources modeling by incorporating Smart Inverters. The findings of this report will also support and inform PG&E's position within the Rule 21 open proceeding.
33	2nd Triennial (2015-2017)	PG&E	2.03B - Test Smart Inverter Enhanced Capabilities - Vehicle to Home	Renewables/DER Resource Integration	• Assessment of the use and impact of EV energy flow capabilities as a complement to the smart inverter assessment related to Photovoltaics (PV) in project 2.03A. Smart Inverters for PV
34	2nd Triennial (2015-2017)	PG&E	2.04 - DG Monitoring & Voltage Tracking	Renewables/DER Resource Integration	• Utilization of the voltage measurement capabilities of SmartMeter™ devices to monitor Distributed Generation (DG) output and identify voltage fluctuations caused by the intermittent nature of distributed renewable resources. • Use of data analytics techniques and Advanced Metering Infrastructure (AMI) (and other) data to determine the impact of PV penetration on Rule 2 violations and • Create a rating for the probability that a Rule 2 violation is caused by DG.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	B	C	E2
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
32	2nd Triennial (2015-2017)	PG&E	2.03A - Test Smart Inverter Enhanced Capabilities - Photovoltaics (PV)	• Evaluate the technical ability of Smart Inverters to influence secondary and primary voltage through field demonstrations in two distinct locations, by adjusting reactive and real power output autonomously. • Measure customer curtailment from Volt-VAR/Volt-Watt function activation. • Demonstrate and evaluate the reliability of communications to provide visibility, monitoring and change settings for Smart Inverter-equipped PV using both a vendor-specific aggregation platform and a vendor-agnostic utility aggregation platform. • Clarify SI technology requirements to integrate and operate SIs, and characterize challenges to deployment at scale relative to today. • Through lab testing, understand Smart Inverter performance under a range of distribution grid conditions. • Through a vendor-led modeling effort, evaluate the impact of BTM residential PV and PV + Storage with and without Smart Inverters and perform an economic analysis of SIs on PG&E's system as compared to traditional distribution grid upgrades.
33	2nd Triennial (2015-2017)	PG&E	2.03B - Test Smart Inverter Enhanced Capabilities - Vehicle to Home	• Technology demonstration for charging and discharging of the Electric Vehicle (EV) in response to demand response or hard islanding events. • Testing multiple test modes. • Technology assessment from customer and ratepayer perspectives through a customer survey and a cost-benefit evaluation.
34	2nd Triennial (2015-2017)	PG&E	2.04 - DG Monitoring & Voltage Tracking	• Create an algorithmic process output rating on the likelihood of a voltage violation (on a given transformer) being caused by DG fluctuations.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
32	2nd Triennial (2015-2017)	PG&E	2.03A - Test Smart Inverter Enhanced Capabilities - Photovoltaics (PV)	• Identify feeder(s) where Smart Inverters will be installed for demonstration. • Demonstrate the use of residential and commercial Smart Inverters on multiple distribution feeders to demonstrate the inverters' local voltage control capabilities and power quality impacts related to high penetration of customer sited solar PV. • Develop necessary communications software/hardware/technologies between the utility and two different third party Smart Inverter aggregators. • Design and implement data architectures to support satellite and cellular interaction with remote Smart Inverters. • Quantify and qualify performance of multiple Smart Inverter models from different manufacturers in lab testing. • Implement automated Volt-VAR and Volt-Watt curves, with a quantification of ability to perform different grid services. • Lab-test electric vehicle service equipment (EVSE) performance under a large range of harmonic content, to identify any chance of poor behavior. • Through a modeling effort, provide an economic assessment of Smart Inverter functions' effectiveness in deferring certain distribution upgrades associated with high Distributed Energy Resource (DER) penetration.	3.5years	4/10/2015	No	Distribution; Demand-Side Management	$ 2,879,961	$4,767,300 - $5,826,700
33	2nd Triennial (2015-2017)	PG&E	2.03B - Test Smart Inverter Enhanced Capabilities - Vehicle to Home	• Evaluation of the performance of the EV energy flow capabilities to support residential load during DR and hard islanding events. • Cost-benefit evaluation	2years	1/8/2016	No	Distribution; Demand-Side Management	$ 225,158	$414,000 - $506,000
34	2nd Triennial (2015-2017)	PG&E	2.04 - DG Monitoring & Voltage Tracking	• Develop an analytics process/algorithm to analyze AMI and other data for high penetration DG feeders, as well as some low penetration feeders for baselining. • Evaluate impact of DG penetration on voltage.	2years	4/10/2015	No	Grid Operations/Market Design	$ 741,202	$1,110,000 - $1,360,000

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
32	2nd Triennial (2015-2017)	PG&E	2.03A - Test Smart Inverter Enhanced Capabilities - Photovoltaics (PV)	$ 2,430,138	$ 2,547,003	$ 4,977,141	$30,737	This project is leveraging funds from the PG&E Smart Grid Volt/Var Optimization (VVO) pilot given they are completing the testing of the functionality of the smart inverter technologies. The results of the testing will impact this project's opportunity to launch.	N/A	N/A	N/A
33	2nd Triennial (2015-2017)	PG&E	2.03B - Test Smart Inverter Enhanced Capabilities - Vehicle to Home	$ 260,177	$ 273,936	$ 534,113	$ 13,506	N/A	N/A	N/A	N/A
34	2nd Triennial (2015-2017)	PG&E	2.04 - DG Monitoring & Voltage Tracking	$ 818,830	$ 414,463	$ 1,233,293	$ 7,583	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
32	2nd Triennial (2015-2017)	PG&E	2.03A - Test Smart Inverter Enhanced Capabilities - Photovoltaics (PV)	Pay for Performance	N/A	Sole Source - SolarCity selected due to their large residential market share and large amount of customers on impacted distribution circuits that is most relevant to test their technologies.	N/A	N/A
33	2nd Triennial (2015-2017)	PG&E	2.03B - Test Smart Inverter Enhanced Capabilities - Vehicle to Home	Pay for Performance	N/A	Quick Bid	4	Navigant
34	2nd Triennial (2015-2017)	PG&E	2.04 - DG Monitoring & Voltage Tracking	Pay for Performance	N/A	Competitive Bid	12	Nexant, Inc.

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
32	2nd Triennial (2015-2017)	PG&E	2.03A - Test Smart Inverter Enhanced Capabilities - Photovoltaics (PV)	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	• 3a – Maintain/Reduce operations and maintenance costs. • 3b - Maintain / Reduce capital costs. • 3e – Non-energy economic benefits • 5f – Reduced flicker and other power quality differences • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) • 7d - Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360)
33	2nd Triennial (2015-2017)	PG&E	2.03B - Test Smart Inverter Enhanced Capabilities - Vehicle to Home	1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 3a - Maintain/Reduce operations and maintenance costs. • 7d - Deployment and integration of cost-effective distributed resources and generation, including renewable resources.
34	2nd Triennial (2015-2017)	PG&E	2.04 - DG Monitoring & Voltage Tracking	1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 3a - Maintain/Reduce operations and maintenance costs. • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid (Public Utilities Code 8360). • 7d - Deployment and integration of cost-effective distributed resources and generation, including renewable resources.

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
35	2nd Triennial (2015-2017)	PG&E	2.05 - Inertia Response Emulation for DG Impact Improvement	Renewables/DER Resource Integration	• Demonstrate the capability to emulate inertia injection and support primary frequency control using energy storage and smart inverter technologies to potentially mitigate the impacts of large-scale Distributed Generation (DG) to the grid, improve the grid performance and reliability, and advance California energy policy to increase the amounts of renewable and distributed generation on the grid.
36	2nd Triennial (2015-2017)	PG&E	2.06 - Intelligent Universal Transformer (IUT)	Renewables/DER Resource Integration	• Develop and demonstrate a solid-state transformer field prototype Medium Voltage Fast Charger (MVFC) system, as an application use case of solid-state transformers for Direct Current (Direct Current) fast charging of Plug In Electric Vehicles (PEV), featuring intelligent controls and multiple fast charging of PEVs.
37	2nd Triennial (2015-2017)	PG&E	2.07 - Real-Time Loading Data for Distribution Operations and Planning	Grid Modernization and Optimization	• This demonstration will leverage interval data to improve feeder modeling, inform near real time load allocation throughout the distribution grid and transformer loading profiles, and identify opportunities to enhance current load forecasting processes for distribution transformers, feeders and substation transformers.
38	2nd Triennial (2015-2017)	PG&E	2.08 - "Smart" Monitoring and Analysis Tools	Grid Modernization and Optimization	• Demonstrate strategies and technologies for real time, online monitoring of substation equipment; Demonstrate communication protocols and equipment to support the smart devices; Develop visualization techniques for improved monitoring; and evaluate new vendor technologies that enable data correlation and predictive analysis to better identify and respond to potential safety, reliability and/or operational issues.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
35	2nd Triennial (2015-2017)	PG&E	2.05 - Inertia Response Emulation for DG Impact Improvement	• Develop computer models to evaluate inverter capabilities and demonstrate possible future system needs for new inertia support solutions. • Analyze and optimize the present technology's energy storage inertial response capabilities via Power-Hardware-In-Loop testing.
36	2nd Triennial (2015-2017)	PG&E	2.06 - Intelligent Universal Transformer (IUT)	• Test demonstration and communication to the same DC solid-state transformer with two protocols.
37	2nd Triennial (2015-2017)	PG&E	2.07 - Real-Time Loading Data for Distribution Operations and Planning	• Utilize AMI and other data sources to develop an algorithm to improve the prediction of grid loading. • Demonstrate the aggregation of this loading up through the distribution model to enhance distribution planning as well as real time distribution grid operations.
38	2nd Triennial (2015-2017)	PG&E	2.08 - "Smart" Monitoring and Analysis Tools	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	*B*	*C*	*E3*	*E4*	*F*	*G*	*H*	*I*	*J*
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
35	2nd Triennial (2015-2017)	PG&E	2.05 - Inertia Response Emulation for DG Impact Improvement	• Evaluation of the power system's need for reliability support, including identifying threshold conditions. • Assessment of the capabilities of present energy storage inverters for inertial frequency response functions. • Provide recommendations for future inverter and interconnection requirements to provide inertial response.	2years	1/6/2017	No	Grid Operations/ Market Design; Transmission	$ 589,375	$1,450,000 - $1,780,000
36	2nd Triennial (2015-2017)	PG&E	2.06 - Intelligent Universal Transformer (IUT)	• Develop a proof of concept that may demonstrate: 1. an Intelligent Universal Transformer (IUT) can be used in lieu of other equipment to connect to Direct Current Fast Charge (DCFC) protocols, and 2. an IUT can communicate back to the utility.	2.25years	9/15/2015	No	Distribution; Grid Operation/Market Design; Demand-Side Management	$ -	$ -
37	2nd Triennial (2015-2017)	PG&E	2.07 - Real-Time Loading Data for Distribution Operations and Planning	• Develop a unique loading algorithm and rubrics for determining cost effective data sources and cadences.	3.5 years	4/10/2015	No	Grid Operation/Market Design; Distribution	$ 1,822,317	$2,420,000 - $2,958,000
38	2nd Triennial (2015-2017)	PG&E	2.08 - "Smart" Monitoring and Analysis Tools	N/A	N/A	N/A	No	Transmission	$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
35	2nd Triennial (2015-2017)	PG&E	2.05 - Inertia Response Emulation for DG Impact Improvement	$ 587,426	$ 810,601	$ 1,398,027	$15,981	N/A	National Renewable Energy Laboratory selected as testing and demonstration provider.	N/A	N/A
36	2nd Triennial (2015-2017)	PG&E	2.06 - Intelligent Universal Transformer (IUT)	$ -	$ -	$ -	$0	N/A	N/A	N/A	N/A
37	2nd Triennial (2015-2017)	PG&E	2.07 - Real-Time Loading Data for Distribution Operations and Planning	$ 1,621,152	$ 928,884	$ 2,550,035	$ 10,592	N/A	N/A	N/A	N/A
38	2nd Triennial (2015-2017)	PG&E	2.08 - "Smart" Monitoring and Analysis Tools	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	*B*	*C*	*S*	*T*	*U*	*V*	*W*
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
35	2nd Triennial (2015-2017)	PG&E	2.05 - Inertia Response Emulation for DG Impact Improvement	Pay for performance	N/A	Quick Bid	4	NREL
36	2nd Triennial (2015-2017)	PG&E	2.06 - Intelligent Universal Transformer (IUT)	N/A	N/A	N/A	N/A	N/A
37	2nd Triennial (2015-2017)	PG&E	2.07 - Real-Time Loading Data for Distribution Operations and Planning	Pay for Performance	N/A	Competitive Bid	12	Trove Predictive Data
38	2nd Triennial (2015-2017)	PG&E	2.08 - "Smart" Monitoring and Analysis Tools	N/A	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
35	2nd Triennial (2015-2017)	PG&E	2.05 - Inertia Response Emulation for DG Impact Improvement	1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 1a. Number and total nameplate capacity of distributed generation facilities • 1b. Total electricity deliveries from grid-connected distributed generation facilities • 1i. Nameplate capacity (MW) of grid-connected energy storage • 3e. Non-energy economic benefits (reliability) • 5a. Outage number, frequency and duration reductions • 7b. Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) • 7d. Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) • 7h. Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air-conditioning (PU Code § 8360)
36	2nd Triennial (2015-2017)	PG&E	2.06 - Intelligent Universal Transformer (IUT)	TBD	TBD	Column applicable to CEC only	N/A	Column applicable to CEC only	• 3a - Maintain/Reduce operations and maintenance costs. • 3b - Maintain/Reduce capital costs. • 5d - Public safety improvement and hazard exposure reduction. • 7k - Develop standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid. • 7l - Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.
37	2nd Triennial (2015-2017)	PG&E	2.07 - Real-Time Loading Data for Distribution Operations and Planning	1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid.
38	2nd Triennial (2015-2017)	PG&E	2.08 - "Smart" Monitoring and Analysis Tools	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
39	2nd Triennial (2015-2017)	PG&E	2.09 - Distributed Series Impedance (DSI) Phase 2	Grid Modernization and Optimization	• Demonstrate congestion mitigation by installing DSIs on parallel transmission facilities to demonstrate the next generation of the Distributed Series Reactor (DSR) devices from the First EPIC Triennial Plan, which may allow for better control of transmission line loading.
40	2nd Triennial (2015-2017)	PG&E	2.10 - Emergency Preparedness Modeling	Grid Modernization and Optimization	• Incorporate natural hazard damage model information into one integrated algorithm/tool, which would provide the ability to quickly estimate the impacts of natural hazards on Pacific Gas and Electric Company facilities to enable faster response and restoration. • Provide the ability to prepare for these hazards by proactively modeling the impacts of potential hazards, to understand system vulnerabilities and restoration resource requirements. • Incorporate work optimization algorithms to more efficiently allocate crews. • Utilize artificial intelligence and statistical methods to model productive rates and automatically develop restoration plans.
41	2nd Triennial (2015-2017)	PG&E	2.11 - New Mobile Technology & Visualization Applications	Grid Modernization and Optimization	• Demonstrate tailored, advanced mobile applications for Pacific Gas and Electric Company field operations that build upon Grid Operations Situational Intelligence (Project #15) demonstration projects in the EPIC First Triennial Plan as well as existing "baseline" mobile deployments underway.
42	2nd Triennial (2015-2017)	PG&E	2.12 - New Emergency Management Mobile Applications	Grid Modernization and Optimization	• Develop new mobile applications to enhance Pacific Gas and Electric Company's emergency preparedness and response capabilities.
43	2nd Triennial (2015-2017)	PG&E	2.13 - Digital Substation/Substation Automation	Grid Modernization and Optimization	• Investigate and evaluate sustainable protection and control technologies for future "digital" substations, which may include testing technologies in a lab setting, and performing a pilot implementation to demonstrate technology adoption and integration with legacy substation protection and control technologies.
44	2nd Triennial (2015-2017)	PG&E	2.14 - Automatically Map Phasing Information	Grid Modernization and Optimization	• This project aims to explore a variety of pre-commercial analytics and/or hardware options to automatically map 3-phase electrical power information in order to improve the distribution network models.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
39	2nd Triennial (2015-2017)	PG&E	2.09 - Distributed Series Impedance (DSI) Phase 2	N/A
40	2nd Triennial (2015-2017)	PG&E	2.10 - Emergency Preparedness Modeling	• Develop optimization algorithms and visualization tool that includes asset locations and conditions with multiple potential hazards, which allows for the aggregation of equipment damage estimates (via damage models, outage information systems, and damage assessments), est. hours to repair, and recommended allocation of work resources to efficiently respond to a natural hazard.
41	2nd Triennial (2015-2017)	PG&E	2.11 - New Mobile Technology & Visualization Applications	N/A
42	2nd Triennial (2015-2017)	PG&E	2.12 - New Emergency Management Mobile Applications	N/A
43	2nd Triennial (2015-2017)	PG&E	2.13 - Digital Substation/Substation Automation	N/A
44	2nd Triennial (2015-2017)	PG&E	2.14 - Automatically Map Phasing Information	• Project seeks to improve distribution network models through automatic mapping of 3 phase electrical power information.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
39	2nd Triennial (2015-2017)	PG&E	2.09 - Distributed Series Impedance (DSI) Phase 2	N/A	N/A	N/A	No	Transmission	$ -	$ -
40	2nd Triennial (2015-2017)	PG&E	2.10 - Emergency Preparedness Modeling	• Complete algorithms that aggregate data from multiple sources to feed into application. • Incorporate multiple algorithms into a proof of concept visualization tool. • Develop recommendation for deployment strategy.	3.5years	4/10/2015	No	Transmission; Distribution	$ 2,713,522	$3,993,000 - $4,881,000
41	2nd Triennial (2015-2017)	PG&E	2.11 - New Mobile Technology & Visualization Applications	N/A	N/A	N/A	No	Distribution	$ -	$ -
42	2nd Triennial (2015-2017)	PG&E	2.12 - New Emergency Management Mobile Applications	N/A	N/A	N/A	No	Transmission; Distribution	$ -	$ -
43	2nd Triennial (2015-2017)	PG&E	2.13 - Digital Substation/Substation Automation	N/A	N/A	N/A	No	Transmission; Distribution	$ -	$ -
44	2nd Triennial (2015-2017)	PG&E	2.14 - Automatically Map Phasing Information	• Develop algorithm or novel process to use AMI data and other sources to determine the assignment of Phases to conducting components.	2.75 years	9/15/2015	No	Distribution; Demand-Side Management	$ 1,566,518	$1,660,000 - $2,030,000

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
39	2nd Triennial (2015-2017)	PG&E	2.09 - Distributed Series Impedance (DSI) Phase 2	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
40	2nd Triennial (2015-2017)	PG&E	2.10 - Emergency Preparedness Modeling	$ 2,872,630	$ 1,354,498	$ 4,227,128	$ 1,538	N/A	N/A	N/A	N/A
41	2nd Triennial (2015-2017)	PG&E	2.11 - New Mobile Technology & Visualization Applications	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
42	2nd Triennial (2015-2017)	PG&E	2.12 - New Emergency Management Mobile Applications	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
43	2nd Triennial (2015-2017)	PG&E	2.13 - Digital Substation/Substation Automation	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
44	2nd Triennial (2015-2017)	PG&E	2.14 - Automatically Map Phasing Information	$ 1,505,937	$ 431,407	$ 1,937,344	$ 17,575	N/A	PG&E is working with University of California, Riverside to test an alternate algorithm based approach which will be evaluated against other solutions demonstrated in project	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
39	2nd Triennial (2015-2017)	PG&E	2.09 - Distributed Series Impedance (DSI) Phase 2	N/A	N/A	N/A	N/A	N/A
40	2nd Triennial (2015-2017)	PG&E	2.10 - Emergency Preparedness Modeling	Pay for Performance	PG&E will receive perpetual, transferable sublicenses to all Work Product to use for current and future PG&E business.	Competitive Bid	3	IBM
41	2nd Triennial (2015-2017)	PG&E	2.11 - New Mobile Technology & Visualization Applications	N/A	N/A	N/A	N/A	N/A
42	2nd Triennial (2015-2017)	PG&E	2.12 - New Emergency Management Mobile Applications	N/A	N/A	N/A	N/A	N/A
43	2nd Triennial (2015-2017)	PG&E	2.13 - Digital Substation/Substation Automation	N/A	N/A	N/A	N/A	N/A
44	2nd Triennial (2015-2017)	PG&E	2.14 - Automatically Map Phasing Information	Pay for performance	N/A	• Sole Source - - Silver Springs Network selected as they are the solutions provider for PG&E's AMI electric network. It is necessary to work with SSN to ensure that devices and applications can communicate across the AMI network. - Navigant selected due to industry expertise and familiarity with PG&E-specific systems - Consulting branch of UC Riverside selected per industry expertise	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	B	C	X	Y	Z	AA	AB	AC
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
39	2nd Triennial (2015-2017)	PG&E	2.09 - Distributed Series Impedance (DSI) Phase 2	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
40	2nd Triennial (2015-2017)	PG&E	2.10 - Emergency Preparedness Modeling	1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 3a - Maintain/Reduce operations and maintenance costs. • 4a - Greenhouse Gas emissions reductions (MMTCO2e). • 5a - Outage number, frequency and duration reductions. • 5d - Public safety improvement and hazard exposure reduction. • 5e - Utility worker safety improvement and hazard exposure reduction. • 5c - Forecast accuracy improvement.
41	2nd Triennial (2015-2017)	PG&E	2.11 - New Mobile Technology & Visualization Applications	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
42	2nd Triennial (2015-2017)	PG&E	2.12 - New Emergency Management Mobile Applications	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
43	2nd Triennial (2015-2017)	PG&E	2.13 - Digital Substation/Substation Automation	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
44	2nd Triennial (2015-2017)	PG&E	2.14 - Automatically Map Phasing Information	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	• 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid.

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
45	2nd Triennial (2015-2017)	PG&E	2.15 - Synchrophasor Applications for Generator Dynamic Model Validation	Grid Modernization and Optimization	• This project will demonstrate new synchrophasor analysis applications that can perform generator dynamic model parameter estimation and validation using disturbance data recorded by the synchrophasor system. New synchrophasor applications could perform mandated generator model validation without requiring time and labor intensive on-site tests, and could detect subsynchronous resonance and other conditions which can cause generator outages.
46	2nd Triennial (2015-2017)	PG&E	2.16 - Enhanced Synchrophasor Analytics & Applications	Grid Modernization and Optimization	• Demonstrate new techniques to synthesize Synchrophasor data and utilize the data for advanced real-time system applications, such as wide-area monitoring, protection, and control systems, which could help move Synchrophasor applications beyond planning, forensics, and visualization to enhanced wide-area monitoring, protection, and control applications.
47	2nd Triennial (2015-2017)	PG&E	2.17 - Geomagnetic Disturbance (GMD) Evaluation	Grid Modernization and Optimization	• Evaluate system vulnerability to GMD by modeling GMD that occurs during a geomagnetic storm and evaluating the impact on transmission lines, interconnection lines, substations and system voltages.
48	2nd Triennial (2015-2017)	PG&E	2.18 - Optical Instrument Transformers and Sensors for Protection and Control Systems	Grid Modernization and Optimization	• Demonstrate newer technologies, such as optical sensors, as well as strategies and technologies to configure appropriate protection settings, including the coordination required between both new and conventional instrumentation.
49	2nd Triennial (2015-2017)	PG&E	2.19 - Enable Distributed Demand-Side Strategies & Technologies	Customer Service and Enablement	• Demonstrate distributed energy storage and approaches to address local and flexible resource needs. • This project addresses California Public Utilities Commission proceeding, Distribution Resources Plan R.14 08 013, by demonstrating DER locational benefits and addressing capacity constraints through aggregated behind the meter (BTM) customer energy storage.
50	2nd Triennial (2015-2017)	PG&E	2.20 - Real-Time Energy Usage Feedback to Customers	Customer Service and Enablement	• Evaluate innovative feedback technologies to provide near real-time energy usage information to customers and to drive greater customer performance during DR events.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	B	C	E2
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
45	2nd Triennial (2015-2017)	PG&E	2.15 - Synchrophasor Applications for Generator Dynamic Model Validation	• Scope is limited to confirming that analysis of Phasor Measurement Unit (PMU) data is better than costly on-site model validation in the target geography. Scope does not include widespread deployment of PMUs.
46	2nd Triennial (2015-2017)	PG&E	2.16 - Enhanced Synchrophasor Analytics & Applications	N/A
47	2nd Triennial (2015-2017)	PG&E	2.17 - Geomagnetic Disturbance (GMD) Evaluation	N/A
48	2nd Triennial (2015-2017)	PG&E	2.18 - Optical Instrument Transformers and Sensors for Protection and Control Systems	N/A
49	2nd Triennial (2015-2017)	PG&E	2.19 - Enable Distributed Demand-Side Strategies & Technologies	• Deploy an aggregation of BTM customer energy storage resource to reduce peak loading or absorb distributed generation on a utility distribution feeder(s).
50	2nd Triennial (2015-2017)	PG&E	2.20 - Real-Time Energy Usage Feedback to Customers	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
45	2nd Triennial (2015-2017)	PG&E	2.15 - Synchrophasor Applications for Generator Dynamic Model Validation	• Install synchrophasors (or "PMUs") on generators or generator tie-lines, and demonstrate new data analysis software applications. • Evaluate the applications' ability to perform generator dynamic model validation by analyzing synchrophasor data following transient disturbances on the transmission system.	3 years	4/10/2015	No	Transmission	$ 620,157	$654,000 - $799,000
46	2nd Triennial (2015-2017)	PG&E	2.16 - Enhanced Synchrophasor Analytics & Applications	N/A	N/A	N/A	No	Transmission	$ -	$ -
47	2nd Triennial (2015-2017)	PG&E	2.17 - Geomagnetic Disturbance (GMD) Evaluation	N/A	N/A	N/A	No	Transmission	$ -	$ -
48	2nd Triennial (2015-2017)	PG&E	2.18 - Optical Instrument Transformers and Sensors for Protection and Control Systems	N/A	N/A	N/A	No	Transmission	$ -	$ -
49	2nd Triennial (2015-2017)	PG&E	2.19 - Enable Distributed Demand-Side Strategies & Technologies	• Demonstrate and test field results for effectiveness of the use of aggregated customer-sited BTM energy storage resources to peak load reduction and/or absorb distributed generation on a utility distribution feeder(s). • Demonstrate communications with aggregated resources for visualization and control. • Evaluate cost-effectiveness and reliability of BTM energy storage for addressing capacity constraints.	2.75 years	4/10/2015	No	Distribution; Demand-Side Management	$ 1,678,045	$2,615,000 - $3,197,000
50	2nd Triennial (2015-2017)	PG&E	2.20 - Real-Time Energy Usage Feedback to Customers	N/A	N/A	N/A	No	Grid Operations/ Market Design; Distribution; Demand-Side Management	$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
45	2nd Triennial (2015-2017)	PG&E	2.15 - Synchrophasor Applications for Generator Dynamic Model Validation	$ 567,444	$ 172,504	$ 739,948	$ 1,022	N/A	N/A	N/A	N/A
46	2nd Triennial (2015-2017)	PG&E	2.16 - Enhanced Synchrophasor Analytics & Applications	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
47	2nd Triennial (2015-2017)	PG&E	2.17 - Geomagnetic Disturbance (GMD) Evaluation	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
48	2nd Triennial (2015-2017)	PG&E	2.18 - Optical Instrument Transformers and Sensors for Protection and Control Systems	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
49	2nd Triennial (2015-2017)	PG&E	2.19 - Enable Distributed Demand-Side Strategies & Technologies	$ 1,471,957	$ 710,092	$ 2,182,049	$ 31,151	N/A	N/A	N/A	N/A
50	2nd Triennial (2015-2017)	PG&E	2.20 - Real-Time Energy Usage Feedback to Customers	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
45	2nd Triennial (2015-2017)	PG&E	2.15 - Synchrophasor Applications for Generator Dynamic Model Validation	Pay for performance	N/A	• Sole Source - - MathWorks was selected as the software tool because they are the only commercial vendor of this type of parameter estimation tool required for the project. - Schweitzer Engineering Labs was selected as the PMU vendor because they are the only vendor to offer a module to measure generator rotor angle which was necessary for the modeling effort.	N/A	N/A
46	2nd Triennial (2015-2017)	PG&E	2.16 - Enhanced Synchrophasor Analytics & Applications	N/A	N/A	N/A	N/A	N/A
47	2nd Triennial (2015-2017)	PG&E	2.17 - Geomagnetic Disturbance (GMD) Evaluation	N/A	N/A	N/A	N/A	N/A
48	2nd Triennial (2015-2017)	PG&E	2.18 - Optical Instrument Transformers and Sensors for Protection and Control Systems	N/A	N/A	N/A	N/A	N/A
49	2nd Triennial (2015-2017)	PG&E	2.19 - Enable Distributed Demand-Side Strategies & Technologies	Pay for Performance	N/A	Competitive Bid	10	Solar City (for residential customers); Green Charge Networks (for commercial customers)
50	2nd Triennial (2015-2017)	PG&E	2.20 - Real-Time Energy Usage Feedback to Customers	N/A	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	B	C	X	Y	Z	AA	AB	AC
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
45	2nd Triennial (2015-2017)	PG&E	2.15 - Synchrophasor Applications for Generator Dynamic Model Validation	N/A	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 3a - Maintain/Reduce operations and maintenance costs. • 5a - Outage number, frequency and duration reductions. • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security and efficiency of the electric grid (Public Utilities Code 8360).
46	2nd Triennial (2015-2017)	PG&E	2.16 - Enhanced Synchrophasor Analytics & Applications	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
47	2nd Triennial (2015-2017)	PG&E	2.17 - Geomagnetic Disturbance (GMD) Evaluation	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
48	2nd Triennial (2015-2017)	PG&E	2.18 - Optical Instrument Transformers and Sensors for Protection and Control Systems	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
49	2nd Triennial (2015-2017)	PG&E	2.19 - Enable Distributed Demand-Side Strategies & Technologies	1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 1c - Avoided procurement and generation costs. • 1i - Nameplate Capacity of Grid-Connected Storage. • 3f - Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management. • 5b - Electric system power flow congestion reduction. • 5d - Public safety improvement and hazard exposure reduction. • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid. • 7d - Deployment and integration of cost-effective distributed resources and generation, including renewable resources.
50	2nd Triennial (2015-2017)	PG&E	2.20 - Real-Time Energy Usage Feedback to Customers	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
51	2nd Triennial (2015-2017)	PG&E	2.21 - Home Area Network (HAN) for Commercial Customers	Customer Service and Enablement	• This project will demonstrate the application of HAN technology to Pacific Gas and Electric Company's commercial customers.
52	2nd Triennial (2015-2017)	PG&E	2.22 - Demand Reduction through Targeted Data Analytics	Customer Service and Enablement	• Identify strategic customers and target demand reduction in local areas by combining and integrating multiple Demand Side Management technologies (e.g., Energy Efficiency (EE), Demand Response (DR), Distributed Energy Storage, Consumer oriented Energy Tools). • Investigate whether Pacific Gas and Electric Company can achieve a sufficient amount of demand reduction through visibility into the customer-side resources, and improve the reliability of customer-side resources at the local level in order to reschedule local capacity expansion expenditures. • This project addresses California Public Utilities Commission proceeding, Distribution Resources Plan R.14 08 013, by supporting the fair and transparent processes for Distributed Energy Resource (DER) deployment and integration.
53	2nd Triennial (2015-2017)	PG&E	2.23 - Integrate Demand Side Approaches Into Utility Planning	Customer Service and Enablement	• This project will enhance Pacific Gas and Electric Company's ability to incorporate the growing usage of Distributed Energy Resources (DER) into distribution planning tools by developing new customer class load shapes that incorporate DERs, and a methodology for modeling DER deployment uncertainty at the circuit level. • The execution of this project addresses issues as identified in the following proceedings: Distribution Resources Plan R.14-08-013 and Assembly Bill 327 Section 769, which requires transparent and consistent methods to integrate cost effective DERs into the distribution planning process.
54	2nd Triennial (2015-2017)	PG&E	2.24 - Appliance Level Bill Disaggregation for Non-Residential Customers	Customer Service and Enablement	• Demonstrate the ability to use sub-minute level usage information to determine appliance load for non-residential customers.
55	2nd Triennial (2015-2017)	PG&E	2.25 - Enhanced Smart Grid Communications	Cross-Cutting/Foundational	• Evaluate license spectrum providers that have developed technologies offered on the Federal Communications Commission (FCC) license frequency range/spectrum.

APPENDIX A
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Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
51	2nd Triennial (2015-2017)	PG&E	2.21 - Home Area Network (HAN) for Commercial Customers	• This project will enable the Zigbee HAN radio on Large Commercial and Industrial (LCI) meters, to facilitate LCI customer access to real time usage data, as well as testing of the integration with existing Energy Management Systems (EMS).
52	2nd Triennial (2015-2017)	PG&E	2.22 - Demand Reduction through Targeted Data Analytics	• Develop a solution/tool that determines needed customer demand reduction individually and in aggregate at asset level, leveraging interval and Supervisory Control and Data Acquisition (SCADA) data. • Develop cross DER customer targeting to address forecasted capacity challenges at specific assets, for specific days and times of year, leveraging interval data and other customer attributes.
53	2nd Triennial (2015-2017)	PG&E	2.23 - Integrate Demand Side Approaches Into Utility Planning	• Integrate a broader range of customer-side technologies and DER approaches into grid planning and operations in a least cost framework by enhancing distribution load forecasting tools to include new customer load shapes based on the usage of DERs and to model the uncertainty of DER deployment at the circuit level.
54	2nd Triennial (2015-2017)	PG&E	2.24 - Appliance Level Bill Disaggregation for Non-Residential Customers	N/A
55	2nd Triennial (2015-2017)	PG&E	2.25 - Enhanced Smart Grid Communications	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
51	2nd Triennial (2015-2017)	PG&E	2.21 - Home Area Network (HAN) for Commercial Customers	• Install Zigbee HAN devices with selected LCI customers and connect devices to their SmartMeter™. • Monitor customer usage and issue/collect customer surveys. • Complete report with identified issues and recommendations for how to integrate with an existing EMS.	2.25years	9/15/2015	No	Demand-Side Management	$ 8,451	$180,000 - $220,000
52	2nd Triennial (2015-2017)	PG&E	2.22 - Demand Reduction through Targeted Data Analytics	• Create a data analytics platform capable of combining and analyzing multi structured data, linking to a variety of data sources. • Develop a method for identification, valuation, implementation, and tracking of targeted DERs. • Create a quantitative screening/rank order tool. • Develop actionable DER recommendations to customer outreach teams for reaching demand reduction goals.	2.5years	9/15/2015	No	Distribution; Demand-Side Management	$ 656,887	$1,734,000 - $2,120,000
53	2nd Triennial (2015-2017)	PG&E	2.23 - Integrate Demand Side Approaches Into Utility Planning	• Develop enhanced Customer and DER Load Shapes Catalog in PG&E's LoadSEER Planning Tool. • Incorporate DER Scenario Projections into LoadSEER. • Develop interface between LoadSEER and CYME for batch processing integration.	2.25 years	4/10/2015	No	Distribution; Demand-Side Management	$ 1,831,735	$2,831,000 - $3,461,000
54	2nd Triennial (2015-2017)	PG&E	2.24 - Appliance Level Bill Disaggregation for Non-Residential Customers	N/A	N/A	N/A	No	Demand-Side Management	$ -	$ -
55	2nd Triennial (2015-2017)	PG&E	2.25 - Enhanced Smart Grid Communications	N/A	N/A	N/A	No	Grid Operations/ Market Design; Distribution; Demand-Side Management	$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
51	2nd Triennial (2015-2017)	PG&E	2.21 - Home Area Network (HAN) for Commercial Customers	$ 22,302	$ 201,174	$ 223,476	$ 3,193	N/A	Rainforest Automation providing development of the cloud service application used by the customers	N/A	N/A
52	2nd Triennial (2015-2017)	PG&E	2.22 - Demand Reduction through Targeted Data Analytics	$ 753,699	$ 987,777	$ 1,741,477	$ 14,902	N/A	N/A	N/A	N/A
53	2nd Triennial (2015-2017)	PG&E	2.23 - Integrate Demand Side Approaches Into Utility Planning	$ 1,807,067	$ 1,304,382	$ 3,111,449	$ 8,188	N/A	N/A	N/A	N/A
54	2nd Triennial (2015-2017)	PG&E	2.24 - Appliance Level Bill Disaggregation for Non-Residential Customers	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
55	2nd Triennial (2015-2017)	PG&E	2.25 - Enhanced Smart Grid Communications	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
51	2nd Triennial (2015-2017)	PG&E	2.21 - Home Area Network (HAN) for Commercial Customers	Pay for Performance	N/A	Sole Source to Rainforest Automation for purchase of energy monitoring devices that connect to the SmartMeter™.	N/A	N/A
52	2nd Triennial (2015-2017)	PG&E	2.22 - Demand Reduction through Targeted Data Analytics	N/A	Non-Provisional patent application No. 16/775,568 titled System Server for Parallel Mixed Integer Programs for Load Management onfor system and server for parallel processing mixed integer programs for load management.	Sole Source to Teradata to reduce unnecessary IT redundancy by leveraging existing data platform and data connections rather than re-create them.	N/A	N/A
53	2nd Triennial (2015-2017)	PG&E	2.23 - Integrate Demand Side Approaches Into Utility Planning	Pay for Performance	N/A	Sole Source to Integral Analytics (IA) given they are the developer/vendor for LoadSEER, which is the tool that is being modified to achieve the goals of this project.	N/A	N/A
54	2nd Triennial (2015-2017)	PG&E	2.24 - Appliance Level Bill Disaggregation for Non-Residential Customers	N/A	N/A	N/A	N/A	N/A
55	2nd Triennial (2015-2017)	PG&E	2.25 - Enhanced Smart Grid Communications	N/A	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	B	C	X	Y	Z	AA	AB	AC
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
51	2nd Triennial (2015-2017)	PG&E	2.21 - Home Area Network (HAN) for Commercial Customers	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	• 1e - Peak load reduction (megawatts) from summer and winter programs. • 1f - Avoided customer energy use (kilowatt hours saved). • 1h - Customer bill savings (dollars saved). • 3a - Maintain / Reduce operations and maintenance costs. • 4a - GHG emissions reductions (MMTCO2e). • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Public Utilities Code § 8360).
52	2nd Triennial (2015-2017)	PG&E	2.22 - Demand Reduction through Targeted Data Analytics	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	• 3a - Maintain/Reduce capital costs. • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid. • 7e - Development and incorporation of cost-effective demand response, demand side resource, and energy efficient resources. • 7h - Deployment and integration of cost-effective advanced electricity storage and peak-shaving technologies.
53	2nd Triennial (2015-2017)	PG&E	2.23 - Integrate Demand Side Approaches Into Utility Planning	N/A	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 1c - Avoided procurement and generation costs. • 3f - Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management. • 5c - Forecast accuracy improvement. • 7e - Development and incorporation of cost-effective demand response, demand side resources, and energy-efficient resources (Public Utilities Code § 8360).
54	2nd Triennial (2015-2017)	PG&E	2.24 - Appliance Level Bill Disaggregation for Non-Residential Customers	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
55	2nd Triennial (2015-2017)	PG&E	2.25 - Enhanced Smart Grid Communications	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
56	2nd Triennial (2015-2017)	PG&E	2.26 - Customer & Distribution Automation Open Architecture Devices	Cross-Cutting/Foundational	• Demonstrate the means by which new customer and distribution devices could interoperate with Pacific Gas and Electric Company's Advanced Metering Infrastructure (AMI) network (IPv6).
57	2nd Triennial (2015-2017)	PG&E	2.27 - Next Generation Integrated Smart Grid Network Management	Cross-Cutting/Foundational	• Evaluate new technologies to holistically monitor, control and evolve the communications network and supporting infrastructure as a platform to enable Smart Grid solutions.
58	2nd Triennial (2015-2017)	PG&E	2.28 - Smart Grid Communications Path Monitoring	Cross-Cutting/Foundational	• Evaluate communication paths for AMI related messages, including methods to clear potential interference, congestion, validate proper authorizations, and grant clearances for sending message over a secured communication path.
59	2nd Triennial (2015-2017)	PG&E	2.29 - Mobile Meter Applications	Cross-Cutting/Foundational	• Demonstrate the utility's ability to enable dynamic electric mobile metering.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
56	2nd Triennial (2015-2017)	PG&E	2.26 - Customer & Distribution Automation Open Architecture Devices	• Demonstrate the methodology, protocols, and standards for customers and vendors to connect and communicate various new devices and applications (e.g., Home Area Network, Electric Vehicle charging, smart appliances, etc.) with the AMI network (IPv6) in an effective manner.
57	2nd Triennial (2015-2017)	PG&E	2.27 - Next Generation Integrated Smart Grid Network Management	• Demonstrate a new Advanced Metering Infrastructure (AMI) Network management system to holistically monitor, control, and evolve the existing AMI network and infrastructure from a billing-centric platform to a fully operational AMI solutions platform that will meet evolving customer and grid needs.
58	2nd Triennial (2015-2017)	PG&E	2.28 - Smart Grid Communications Path Monitoring	• Determine the ability to identify, analyze, and diagnose Radio Frequency interference that can occur along the communication path from the meter through the data collectors to the AMI vendors' control system.
59	2nd Triennial (2015-2017)	PG&E	2.29 - Mobile Meter Applications	• Develop and test a mobile meter prototype on various applications that can be used to capture and monitor real-time energy transactions and usage (e.g. Plug-In Electric Vehicles (PEV), Distributed Generation (DG), mobile storage, etc.).

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	*B*	*C*	*E3*	*E4*	*F*	*G*	*H*	*I*	*J*
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
56	2nd Triennial (2015-2017)	PG&E	2.26 - Customer & Distribution Automation Open Architecture Devices	• Conduct testing that will certify customer open architecture devices/applications that are AMI compatible, secure and interoperable. • Provide physical and application interfaces, as a proof of concept, which may permit customer and third party devices to connect to our AMI network(s).	3.25 years	9/15/2015	No	Distribution; Grid Operation/Market Design; Demand-Side Management	$ 1,505,338	$3,015,000 - $3,685,000
57	2nd Triennial (2015-2017)	PG&E	2.27 - Next Generation Integrated Smart Grid Network Management	• Demonstrate an integrated, multi-tenant network management system that may include the following features: - Integrated network management & control that will monitor and prioritize data traffic. - Automate trouble ticketing creation process for workflow management. - Asset management of meter and network equipment regardless of meter or network types.	3 years	4/10/2015	No	Grid Operations/Market Design; Distribution; Demand-Side Management	$ 576,433	$1,008,000 - $1,232,000
58	2nd Triennial (2015-2017)	PG&E	2.28 - Smart Grid Communications Path Monitoring	• Establish the base line noise floor. • Develop and demonstrate an application with an algorithm which can automatically and continuously identify, monitor, and confirm RF interferences for multiple spectrums. • Provide an end-end process for identifying, confirming and mitigating detected interferences with the AMI-network.	1 year	1/6/2017	No	Grid Operation/Market Design	$ 58,518	$227,000 - $277,000
59	2nd Triennial (2015-2017)	PG&E	2.29 - Mobile Meter Applications	• Design specification of mobile meter. • Demonstration of mobile meter hardware prototype. • End-to-end meter to cash testing using existing AMI or cellular based network. • Demonstration of use cases on DG applications and PEV metering, including remote and near real-time tracking of vehicle charge locations and energy flow.	3.5years	4/10/2015	No	Grid Operations/Market Design; Distribution; Demand-Side Management	$ 1,709,700	$2,610,000 - $3,190,000

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
56	2nd Triennial (2015-2017)	PG&E	2.26 - Customer & Distribution Automation Open Architecture Devices	$ 1,132,920	$ 2,315,421	$ 3,448,342	$ 109,170	N/A	N/A	N/A	N/A
57	2nd Triennial (2015-2017)	PG&E	2.27 - Next Generation Integrated Smart Grid Network Management	$ 564,635	$ 569,510	$ 1,134,144	$ 6,363	N/A	N/A	N/A	N/A
58	2nd Triennial (2015-2017)	PG&E	2.28 - Smart Grid Communications Path Monitoring	$ 63,687	$ 188,182	$ 251,869	$ 7,236	N/A	N/A	N/A	N/A
59	2nd Triennial (2015-2017)	PG&E	2.29 - Mobile Meter Applications	$ 1,653,126	$ 884,536	$ 2,537,662	$ 56,768	In-kind services for resource time from Lawrence Livermore National Lab (LLNL) on technical specification calls	Lawrence Livermore National Lab providing technical support for product development	N/A	N/A

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Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
56	2nd Triennial (2015-2017)	PG&E	2.26 - Customer & Distribution Automation Open Architecture Devices	Pay for performance	Non-Provisional patent application No. 16/725,784 and titled Smart Energy and Data/Information Metering System and Method for algorithms to communicate and control edge devices through the Advanced Metering Infrastructure (AMI) network.	Compeititive Bid	N/A	Errigal Inc.
57	2nd Triennial (2015-2017)	PG&E	2.27 - Next Generation Integrated Smart Grid Network Management	Pay for Performance	N/A	Competitive Bid	8	Errigal Inc.
58	2nd Triennial (2015-2017)	PG&E	2.28 - Smart Grid Communications Path Monitoring	N/A	N/A	N/A	N/A	N/A
59	2nd Triennial (2015-2017)	PG&E	2.29 - Mobile Meter Applications	Pay for Performance	U.S. Patent No. 10,514,273 titled Smart Energy and Data/Information Metering System and Method on mobile meter with modular housing/board assembly.	Competitive Bid	8	Ofer Communications

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
56	2nd Triennial (2015-2017)	PG&E	2.26 - Customer & Distribution Automation Open Architecture Devices	2	Supplier selected had best prices for Use Cases that were selected for award.	Column applicable to CEC only	No	Column applicable to CEC only	• 3f - Improvements in system operation efficiencies stemming from increased utility dispatchability of customer demand side management. • 5i - Increase in the number of nodes in the power system at monitoring points. • 7j - Provide consumers with timely information and control options.
57	2nd Triennial (2015-2017)	PG&E	2.27 - Next Generation Integrated Smart Grid Network Management	1	N/A	Column applicable to CEC only	Yes	Column applicable to CEC only	• 3a - Maintain/Reduce operations and maintenance costs. • 5a - Outage number, frequency and duration reductions. • 5d - Public safety improvement and hazard exposure reduction. • 5e - Utility worker safety improvement and hazard exposure reduction.
58	2nd Triennial (2015-2017)	PG&E	2.28 - Smart Grid Communications Path Monitoring	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	• 1h - Customer bill savings (dollars saved). • 3e - Non-energy economic benefits – reduction operational hours to fix estimated bills due to RF Interference.
59	2nd Triennial (2015-2017)	PG&E	2.29 - Mobile Meter Applications	1	N/A	Column applicable to CEC only	No	Column applicable to CEC only	• 3a - Maintain/Reduce operations and maintenance costs (Affordability). • 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (Reliability). • 7j - Provide consumers with timely information and control options (Customer).

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
60	2nd Triennial (2015-2017)	PG&E	2.30 - Leverage EPIC Funds to Participate in Industry-Wide RD&D Programs	Grid Modernization and Optimization	• Leverage EPIC dollars by participating and collaborating in multi-utility, industry wide research, demonstration and deployment initiatives conducted by third party organizations.
61	2nd Triennial (2015-2017)	PG&E	2.31 - Aggregated Behind-The-Meter Storage Market / Retail Optimization	Renewables/DER Resource Integration	• Demonstrate how aggregated behind-the-meter energy storage systems that are operated by a third party dispatcher may address wholesale market needs, while also operating as a customer resource to reduce customers' retail electric bills.
62	2nd Triennial (2015-2017)	PG&E	2.32 - Electric Load Management for Ridesharing Electrification	Renewables/DER Resource Integration	• Evaluate grid impacts from Electric Vehicle (EV) charging used for ridesharing applications, to assess the ability to manage the resulting load using active demand management.
63	2nd Triennial (2015-2017)	PG&E	2.33 - Service Issue Identification Leveraging Momentary Outage Information	Grid Modernization and Optimization	• Leverage multiple sources of data, including but not limited to SmartMeter™, time of day, location and weather data, to proactively identify potential problems in the Electric Transmission and Distribution (T&D) system, specifically related to identifying locations with high incidences of momentary outages which may be caused by imminent failures of conductors, insulators, transformers and/or vegetation contact.
64	2nd Triennial (2015-2017)	PG&E	2.34 - Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors	Grid Modernization and Optimization	• Demonstrate distribution sensor products that provide indicators of imminent asset failure and real-time monitoring of PG&E rights-of-way
65	2nd Triennial (2015-2017)	PG&E	2.35 - Call Center Staffing Optimization	Grid Modernization and Optimization	• Optimize call center staffing by developing a real-time algorithm that integrates with and improves upon existing call center staffing software to potentially predict variability in call volume impacts in near real-time.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	B	C	E2
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
60	2nd Triennial (2015-2017)	PG&E	2.30 - Leverage EPIC Funds to Participate in Industry-Wide RD&D Programs	N/A
61	2nd Triennial (2015-2017)	PG&E	2.31 - Aggregated Behind-The-Meter Storage Market / Retail Optimization	N/A
62	2nd Triennial (2015-2017)	PG&E	2.32 - Electric Load Management for Ridesharing Electrification	N/A
63	2nd Triennial (2015-2017)	PG&E	2.33 - Service Issue Identification Leveraging Momentary Outage Information	N/A
64	2nd Triennial (2015-2017)	PG&E	2.34 - Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors	• Assess technical feasibility of various sensor products and validate opportunity for business benefits • Develop solution designs, develop test plans, and conduct testing at ATS • Conduct field demonstrations of various products and develop post-EPIC roadmaps for integrating capabilities in production
65	2nd Triennial (2015-2017)	PG&E	2.35 - Call Center Staffing Optimization	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
60	2nd Triennial (2015-2017)	PG&E	2.30 - Leverage EPIC Funds to Participate in Industry-Wide RD&D Programs	N/A	N/A	NA	No	Grid Operations/ Market Design; Transmission; Distribution; Demand-Side Management	$ -	$ -
61	2nd Triennial (2015-2017)	PG&E	2.31 - Aggregated Behind-The-Meter Storage Market / Retail Optimization	N/A	N/A	NA	N/A	Grid Operations/Market Design; Demand Side Management	$ -	$ -
62	2nd Triennial (2015-2017)	PG&E	2.32 - Electric Load Management for Ridesharing Electrification	N/A	N/A	NA	N/A	Grid Operations/Market Design; Distribution; Demand Side Management	$ -	$ -
63	2nd Triennial (2015-2017)	PG&E	2.33 - Service Issue Identification Leveraging Momentary Outage Information	N/A	N/A	NA	N/A	Grid Operations/Market Design; Distribution	$ -	$ -
64	2nd Triennial (2015-2017)	PG&E	2.34 - Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors	• Roadmap for integrating additional sensor technologies in production	3years	8/10/2017	No	Grid Operations/Market Design; Distribution	$ 2,370,131	$ 2,778,906
65	2nd Triennial (2015-2017)	PG&E	2.35 - Call Center Staffing Optimization	N/A	N/A	NA	N/A	Grid Operations/Market Design	$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
60	2nd Triennial (2015-2017)	PG&E	2.30 - Leverage EPIC Funds to Participate in Industry-Wide RD&D Programs	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
61	2nd Triennial (2015-2017)	PG&E	2.31 - Aggregated Behind-The-Meter Storage Market / Retail Optimization	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
62	2nd Triennial (2015-2017)	PG&E	2.32 - Electric Load Management for Ridesharing Electrification	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
63	2nd Triennial (2015-2017)	PG&E	2.33 - Service Issue Identification Leveraging Momentary Outage Information	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A
64	2nd Triennial (2015-2017)	PG&E	2.34 - Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors	$ 2,045,253	$ 1,852,099	$ 3,897,352	$ 46,920	N/A	N/A	N/A	N/A
65	2nd Triennial (2015-2017)	PG&E	2.35 - Call Center Staffing Optimization	$ -	$ -	$ -	$ -	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
60	2nd Triennial (2015-2017)	PG&E	2.30 - Leverage EPIC Funds to Participate in Industry-Wide RD&D Programs	N/A	N/A	N/A	N/A	N/A
61	2nd Triennial (2015-2017)	PG&E	2.31 - Aggregated Behind-The-Meter Storage Market / Retail Optimization	N/A	N/A	N/A	N/A	N/A
62	2nd Triennial (2015-2017)	PG&E	2.32 - Electric Load Management for Ridesharing Electrification	N/A	N/A	N/A	N/A	N/A
63	2nd Triennial (2015-2017)	PG&E	2.33 - Service Issue Identification Leveraging Momentary Outage Information	N/A	N/A	N/A	N/A	N/A
64	2nd Triennial (2015-2017)	PG&E	2.34 - Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors	N/A	N/A	Direct Award to Texas A&M to compare DFA technology to IND.T's EFD technology. Rather than detecting RF signals, these substation-mounted devices use pattern recognition and advanced signal processing of voltage and current waveforms. It is considered an alternative solution for incipient fault detection Direct Award to IND.T due to good fit with objective of project and pre-commercial state of technology.	N/A	N/A
65	2nd Triennial (2015-2017)	PG&E	2.35 - Call Center Staffing Optimization	N/A	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
60	2nd Triennial (2015-2017)	PG&E	2.30 - Leverage EPIC Funds to Participate in Industry-Wide RD&D Programs	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
61	2nd Triennial (2015-2017)	PG&E	2.31 - Aggregated Behind-The-Meter Storage Market / Retail Optimization	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
62	2nd Triennial (2015-2017)	PG&E	2.32 - Electric Load Management for Ridesharing Electrification	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
63	2nd Triennial (2015-2017)	PG&E	2.33 - Service Issue Identification Leveraging Momentary Outage Information	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A
64	2nd Triennial (2015-2017)	PG&E	2.34 - Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	• 3a - Maintain / Reduce operations and maintenance costs • 5a - Outage number, frequency and duration reductions • 5d - Public safety improvement and hazard exposure reduction
65	2nd Triennial (2015-2017)	PG&E	2.35 - Call Center Staffing Optimization	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
66	2nd Triennial (2015-2017)	PG&E	2.36 - Dynamic Rate Design Tool	Customer Service and Enablement	• Develop a new rate design tool that will enable complex rate design such as for DER adoption, with a more robust, quicker and powerful rate design approach than the current rate design process. Leveraging big data technologies the tool will provide rapid optimization, analysis and evaluation of hypothetical new rate structures which will enable PG&E and parties in a rate case to make rate design decisions based on full information and nuanced sensitivity analysis
67	3rd Triennial (2018-2020)	PG&E	3.01 - Automated DER impact	Renewables/DER Resource Integration	Automate the DER impact and long term dynamics evaluation processes leveraged in detailed engineering analysis in order to aim to reduce DER study timelines and costs, while also seeking to support distribution engineers to better understand and manage the voltage impacts caused by multiple DERs on a single circuit and on Load Tap Changer (LTC) operations. The automated evaluation modules would produce a report showing device loading, steady state voltage analysis, and voltage flicker analysis. The long term dynamics module could potentially further identify potential voltage issues that may lead to Electric Rule 2 violations.
68	3rd Triennial (2018-2020)	PG&E	3.02 - DER to Market	Renewables/DER Resource Integration	Demonstrate multi-technology DER aggregation (e.g., solar, storage) for wholesale market operations with potential to explore multiple uses including distribution support, retail, and/or T&D interfaces for control center operations. Developing this more automated optimization solution may enable realization of additional value from DERs with minimal operator intervention or disruption to operations. This equals more effective utilization of distributed generation assets, which may include enhanced bidding in real-time to enable realization of additional wholesale market value from DERs or enhanced reliability by providing an indication of whether the current state of the grid is configured in a way that allows bidding into the CAISO market.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
66	2nd Triennial (2015-2017)	PG&E	2.36 - Dynamic Rate Design Tool	• Design and build cost of service database • Design and build rate design model engine and API • Build functionality and ability to run DER scenarios
67	3rd Triennial (2018-2020)	PG&E	3.01 - Automated DER impact	TBD
68	3rd Triennial (2018-2020)	PG&E	3.02 - DER to Market	Develop a wholesale market optimization model for DERs, using an aggregation of two or more DERs.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	*B*	*C*	*E3*	*E4*	*F*	*G*	*H*	*I*	*J*
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
66	2nd Triennial (2015-2017)	PG&E	2.36 - Dynamic Rate Design Tool	• Technical architecture specifications • Data model and databases • Rate design model engine and API	3years	8/10/2017	No	Grid Operations/Market Design; Demand Side Management	$ 585,440	$1,913,000 - $2,338,000
67	3rd Triennial (2018-2020)	PG&E	3.01 - Automated DER impact	TBD	TBD	N/A	N/A		$ -	$ -
68	3rd Triennial (2018-2020)	PG&E	3.02 - DER to Market	TBD	TBD	N/A	N/A		$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
66	2nd Triennial (2015-2017)	PG&E	2.36 - Dynamic Rate Design Tool	$ 511,723	$ 595,686	$ 1,107,409	$ 3,255	N/A	N/A	N/A	N/A
67	3rd Triennial (2018-2020)	PG&E	3.01 - Automated DER impact	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
68	3rd Triennial (2018-2020)	PG&E	3.02 - DER to Market	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
66	2nd Triennial (2015-2017)	PG&E	2.36 - Dynamic Rate Design Tool	Pay for Performance	N/A	N/A	N/A	N/A
67	3rd Triennial (2018-2020)	PG&E	3.01 - Automated DER impact	TBD	TBD	TBD	TBD	TBD
68	3rd Triennial (2018-2020)	PG&E	3.02 - DER to Market	TBD	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
66	2nd Triennial (2015-2017)	PG&E	2.36 - Dynamic Rate Design Tool	N/A	N/A	Column applicable to CEC only	N/A	Column applicable to CEC only	6a. Reduction of time to complete the process of designing, optimizing, and analyzing the impact of a hypothetical rate design
67	3rd Triennial (2018-2020)	PG&E	3.01 - Automated DER impact	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
68	3rd Triennial (2018-2020)	PG&E	3.02 - DER to Market	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
69	3rd Triennial (2018-2020)	PG&E	3.03 - Advanced DERMS and ADMS	Renewables/DER Resource Integration	To incorporate additional DER technologies and grid management approaches into DERMS and/or ADMS to build upon efforts from the EPIC 2.02 DERMS project to support improvements to safe and reliable grid operations at the T&D market interface, while also enabling the presence of high penetrations of market participating DERs. This would demonstrate the orchestration of a comprehensive DER portfolio and also address the new operational challenges for Distribution Operators (DOs) caused by emerging opportunities for DERs to participate in wholesale markets via the DERP tariff.
70	3rd Triennial (2018-2020)	PG&E	3.04 - Digital Ledger	Renewables/DER Resource Integration	Demonstrate and evaluate a multi-nodal digital distributed ledger (i.e., Blockchain) as an enabling technology that may facilitate greater efficiency, transparency, and security for customers. The project results may illuminate certain blockchain use cases that provide the most benefit to the utility and its customers and provide greater understanding regarding challenges associated with technology scalability, the blockchain interface with the grid, and current business processes and the application of smart contracts and other similar algorithms in a distributed environment.
71	3rd Triennial (2018-2020)	PG&E	3.05 - Virtual DER Markets	Renewables/DER Resource Integration	To demonstrate the feasibility and the technological and/or economic performance of autonomous distributed economic dispatch in the context of DER markets for capacity and other attributes. There is no technology standard in the industry today for responding to multiple conflicting signals across the Generation-Transmission-Distribution-Customer (GTDC) value chain. The objective of the project is to test flexible demand, generation and storage, and reward local people and businesses for being more flexible with their energy.
72	3rd Triennial (2018-2020)	PG&E	3.06 - Auto ID of BTM Storage	Renewables/DER Resource Integration	To bridge the knowledge gap for storage's charge and discharge behavior in the field, as well as system impacts by analyzing storage charge/discharge patterns. Under current Net Energy Metering Policy, BTM Storage is not required to be on a separate sub-meter. This could lead to a situation where the utility would not be aware of the presence of storage, which could potentially impact safety and reliability of the distribution network. Additionally, understanding of the "net" storage impact at the feeder-level and secondary circuit level is important as distribution planning engineers begin to include DERs in their load forecasts.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	B	C	E2
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
69	3rd Triennial (2018-2020)	PG&E	3.03 - Advanced DERMS and ADMS	Project Phase 1 – DER Registration, Verification, and Monitoring: -Design, assess, procure, and deploy a standardized SI head-end platform to communicate with a minimum of 2 individual DERs or Aggregator cloud platforms. The interface must be compliant with CSIP 2.1 requirements to enable vendor agnostic communication and be cybersecure. -Design, develop, and deploy an interface between SI head-end platform and DMS/SCADA to enable operator visibility of DER telemetry information. Conduct a field demonstration for the following foundational capability with multiple (at least two) individual DERs or Aggregators: -Dispatch registration data request to SI-based DERs, and ingest monitoring and registration data from DERs. -Display DER telemetry data in distribution DMS/SCADA for operator visibility Project Phase 2 – Integration with EMS/DMS/SCADA and DER dispatch: -Expand SI head-end platform capabilities to dispatch control signals to SI-based DERs either directly or through Aggregator cloud platforms. The interface must be compliant with CSIP 2.1 requirements and the control capabilities must include: oDispatch of real-time signal to connect/disconnect DERs oDispatch of real-time signal to limit maximum active power oDispatch of day-ahead capacity constraint signals oDispatch of seasonal or day-ahead load/generation schedule oDispatch short term distribution grid capacity constraints -Design, configure and deploy customized dashboards for distribution operators to visualize, dispatch, and control DERs for both the remote grid application, and the non-wires alternative solution. Note: The distribution grid constraint for DERs participating as a NWA resource will be generated using a substation load/generation forecasting model that will be developed outside of EPIC 3.03 scope. Conduct a field demonstration of the following capabilities with multiple (at least two) individual DERs or Aggregators that enable the use cases defined above: -Display DER situational awareness data for DERs operating in off-grid stand-alone systems and allow operators targeted control options to manage the DERs. -Based on operator request, perform a day-ahead scheduled load/generation dispatch of DER resources directly or through an Aggregator platform. Confirm and verify the DER response. -Dispatch day-ahead or seasonal capacity constraints to DER resource interconnected with constrained generation agreement. Confirm and verify the DER response. -Dispatch short term capacity constraints to DER resources directly or through an aggregator platform. Confirm and verify the DER response. -If the response of DER resources do not conform with the constraints provided, disconnect the DER or curtail generation.
70	3rd Triennial (2018-2020)	PG&E	3.04 - Digital Ledger	Build blockchain solution for materials traceability by tracking the company's use of steel reels. Build blockchain solution for the trading of incremental EV credits in the residential market for LCFS.
71	3rd Triennial (2018-2020)	PG&E	3.05 - Virtual DER Markets	TBD
72	3rd Triennial (2018-2020)	PG&E	3.06 - Auto ID of BTM Storage	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	*B*	*C*	*E3*	*E4*	*F*	*G*	*H*	*I*	*J*
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
69	3rd Triennial (2018-2020)	PG&E	3.03 - Advanced DERMS and ADMS	PHASE I -Detailed scope and charter created and approved -Location/feeder selection finalized for each use case -Initial solution design completed, and RFP released for DERMS vendor -DERMS vendor selected and contract terms finalized June -Multiple (at least two) individual DERs and/or aggregators contracted for participating in field demonstration – -Vendor software acceptance test completed for Phase 1 functionalities -DER assets deployed, and Aggregator platforms prepared for field demonstration -Demonstration of Phase 1 functionalities completed – April 2020 -Established operating protocol and procedure. Prepared path to production documentation for Phase 1 functionalities PHASE II -System requirements developed to expand the SI Head-end platform capabilities to establish two-way communication for demonstrating Phase 2 use cases -Vendor software acceptance test completed for Phase 2 functionalities -DER assets deployed, and Aggregator platforms prepared for field demonstration at one remote grid site and one Non-Wires alternative site. The NWA field demonstration will be conducted in an area that will allow PG&E to de-riskthe grid and/or PG&E customers. The field demonstration will be located either serve a grid need in an area with high potential to be affected by PSPS but not eligible as a resilience zone or in an area that is part of a disadvantaged community. The business sponsor will review and agree on site selection for both field deployments before they occur. -Demonstration of Phase 2 functionalities completed -Established operating protocol and procedure. Prepared path to production documentation for Phase 2 functionalities	2 Years	6/13/2019	Yes	Distribution, Grid Operation/Market Design, Demand-Side Management	$ 636,451	$ 3,940,743
70	3rd Triennial (2018-2020)	PG&E	3.04 - Digital Ledger	TBD	18 months	N/A	N/A		$ -	$ -
71	3rd Triennial (2018-2020)	PG&E	3.05 - Virtual DER Markets	TBD	TBD	N/A	N/A		$ -	$ -
72	3rd Triennial (2018-2020)	PG&E	3.06 - Auto ID of BTM Storage	TBD	TBD	N/A	N/A		$ -	$ -

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
69	3rd Triennial (2018-2020)	PG&E	3.03 - Advanced DERMS and ADMS	$ 308,242	$ 1,962,667	$ 2,270,909	$ 8,422	N/A	Blue Lake Rancheria	N/A	N/A
70	3rd Triennial (2018-2020)	PG&E	3.04 - Digital Ledger		$ (52)	$ (52)	$ -	TBD	TBD	TBD	TBD
71	3rd Triennial (2018-2020)	PG&E	3.05 - Virtual DER Markets	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
72	3rd Triennial (2018-2020)	PG&E	3.06 - Auto ID of BTM Storage	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	*B*	*C*	*S*	*T*	*U*	*V*	*W*
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
69	3rd Triennial (2018-2020)	PG&E	3.03 - Advanced DERMS and ADMS	Pay for performance	TBD	Competitive Bid and Direct Award Competitive Bid Top 3 Awards to Kitu, Applied Systems Engineering, and a third company that negotiations are ongoing. Direct Award to DLC Systems Rationale: 1) The other possible vendor will not be able to work within the EPIC 3.03 timeline 2) PG&E does not have any IT infrastructure for other possible vendor. Difficulties deploying and integrating the other possible platform. Direct Award to Layline Automation Rationale: Staff Augmentation due to staff family leave. Direct Award to various vendors: Award <$75K, direct awarded for speed and saving admin cost	5	Kitu, and Applied Systems Engineering
70	3rd Triennial (2018-2020)	PG&E	3.04 - Digital Ledger	TBD	TBD	TBD	TBD	TBD
71	3rd Triennial (2018-2020)	PG&E	3.05 - Virtual DER Markets	TBD	TBD	TBD	TBD	TBD
72	3rd Triennial (2018-2020)	PG&E	3.06 - Auto ID of BTM Storage	TBD	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	B	C	X	Y	Z	AA	AB	AC
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
69	3rd Triennial (2018-2020)	PG&E	3.03 - Advanced DERMS and ADMS	1,3 Negotiations with #2 is ongoing.	N/A	Column applicable to CEC only	Kitu, Applied Systems Engineering, Layline Automation, and DLC Systems are CA entities. Kitu is also a DGS Small Business.	Column applicable to CEC only	7-b: Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) 7-c: Dynamic optimization of grid operations and resources, including appropriate consideration for asset management and utilization of related grid operations and resources, with cost-effective full cyber security (PU Code § 8360) 7-d: Deployment and integration of cost-effective distributed resources and generation, including renewable resources (PU Code § 8360) 7-j: Provide consumers with timely information and control options (PU Code § 8360) 7-l: Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services (PU Code § 8360) 9-c: Number of times reports are cited in scientific journals and trade publications for selected projects. 9-d: Successful project outcomes ready for use in California IOU grid (Path to market)
70	3rd Triennial (2018-2020)	PG&E	3.04 - Digital Ledger	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
71	3rd Triennial (2018-2020)	PG&E	3.05 - Virtual DER Markets	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
72	3rd Triennial (2018-2020)	PG&E	3.06 - Auto ID of BTM Storage	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
73	3rd Triennial (2018-2020)	PG&E	3.07 - Storage for Load Balancing	Renewables/DER Resource Integration	To demonstrate phase load balancing by leveraging large, utility-owned batteries. Removing manual work to rebalance loads improves operational efficiency by reduced manual hours spent, improves reliability by optimizing asset utilization across phases with faster adjustment of controls, and improves safety by removing manual labor for managing large loads.
74	3rd Triennial (2018-2020)	PG&E	3.08 - Second Life Batteries	Renewables/DER Resource Integration	To demonstrate technology that enables second-life energy storage for key utility functions, such as DR and/or frequency regulation, which may lower energy storage costs and support EV business cases with residual value. Technology may also be developed for ensuring that second-life batteries can successfully interface with the grid. Building off PG&E's prior energy storage EPIC pilots, this project may identify significant technical or performance differentiations between a second-life storage system and an installation with new batteries, and
75	3rd Triennial (2018-2020)	PG&E	3.09 - Dynamic DER Forecasting	Renewables/DER Resource Integration	This project proposes to collect and combine smart inverter data with other data streams (e.g., local weather, customer demographics, and/or customer usage) to create an algorithm that can better predict customer gross and net usage/load, DER generation, back-feed at distribution assets, and impact on system level or local short-term energy supply needs. Beginning in September 2017, California's Rule 21 requires smart inverters for all new customer-connected generation and storage devices. Having better insight into the impact of DERs on generation and distribution system needs, the utility, in coordination with the CAISO, may be able to reduce the generation purchasing buffer required. Further, the utility could better understand and model/predict the impact of DERs on the distribution system. This could reduce operating cost and in turn potentially lower customer bills.
76	3rd Triennial (2018-2020)	PG&E	3.10 - Scenario Engine	Renewables/DER Resource Integration	To develop a wide-scale distribution and/or transmission grid simulator for analyzing multiple scenarios and potential future stressors to the grid, such as changes in usage behavior, increased DER integration rates and more to facilitate better informed grid planning.

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
73	3rd Triennial (2018-2020)	PG&E	3.07 - Storage for Load Balancing	TBD
74	3rd Triennial (2018-2020)	PG&E	3.08 - Second Life Batteries	TBD
75	3rd Triennial (2018-2020)	PG&E	3.09 - Dynamic DER Forecasting	TBD
76	3rd Triennial (2018-2020)	PG&E	3.10 - Scenario Engine	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
73	3rd Triennial (2018-2020)	PG&E	3.07 - Storage for Load Balancing	TBD	TBD	N/A	N/A		$ -	$ -
74	3rd Triennial (2018-2020)	PG&E	3.08 - Second Life Batteries	TBD	TBD	N/A	N/A		$ -	$ -
75	3rd Triennial (2018-2020)	PG&E	3.09 - Dynamic DER Forecasting	TBD	TBD	N/A	N/A		$ -	$ -
76	3rd Triennial (2018-2020)	PG&E	3.10 - Scenario Engine	TBD	TBD	N/A	N/A	Transmission, Distribution, Grid Operation/Market Design, Demand-Side Management	$ -	$ 2,900,000

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	*B*	*C*	*K*	*L*	*M*	*N*	*O*	*P*	*Q*	*R*
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
73	3rd Triennial (2018-2020)	PG&E	3.07 - Storage for Load Balancing	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
74	3rd Triennial (2018-2020)	PG&E	3.08 - Second Life Batteries	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
75	3rd Triennial (2018-2020)	PG&E	3.09 - Dynamic DER Forecasting	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
76	3rd Triennial (2018-2020)	PG&E	3.10 - Scenario Engine	$ 29.90	$ 3,456.17	$ 3,486.07	$ -	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	*B*	*C*	*S*	*T*	*U*	*V*	*W*
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
73	3rd Triennial (2018-2020)	PG&E	3.07 - Storage for Load Balancing	TBD	TBD	TBD	TBD	TBD
74	3rd Triennial (2018-2020)	PG&E	3.08 - Second Life Batteries	TBD	TBD	TBD	TBD	TBD
75	3rd Triennial (2018-2020)	PG&E	3.09 - Dynamic DER Forecasting	TBD	TBD	TBD	TBD	TBD
76	3rd Triennial (2018-2020)	PG&E	3.10 - Scenario Engine	TBD	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
73	3rd Triennial (2018-2020)	PG&E	3.07 - Storage for Load Balancing	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
74	3rd Triennial (2018-2020)	PG&E	3.08 - Second Life Batteries	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
75	3rd Triennial (2018-2020)	PG&E	3.09 - Dynamic DER Forecasting	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
76	3rd Triennial (2018-2020)	PG&E	3.10 - Scenario Engine	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
77	3rd Triennial (2018-2020)	PG&E	3.11 - Location Targeted DERs	Renewables/DER Resource Integration	To create the processes and demonstrate the scoping, specification, and deployment of multiple DER technology configurations that could potentially serve as location-specific options for distribution system reliability and/or resilience upgrades.
78	3rd Triennial (2018-2020)	PG&E	3.12 - Advanced VVO	Grid Modernization and Optimization	This project would seek to demonstrate enhanced algorithms to leverage VVO for grid management services.
79	3rd Triennial (2018-2020)	PG&E	3.13 - Transformer Monitoring - Sensors	Grid Modernization and Optimization	This project will seek to demonstrate equipment that can be quickly and safely mounted on the casing of a pole-top distribution transformer to enable monitoring of equipment health. Additionally, it may test new communication devices and processes for delivering sensor data through PG&E's FAN.
80	3rd Triennial (2018-2020)	PG&E	3.14 - Imminent Asset Risk	Grid Modernization and Optimization	To demonstrate the convergence of asset and operational data with historical maintenance information and proactive identification of potential equipment failures

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
77	3rd Triennial (2018-2020)	PG&E	3.11 - Location Targeted DERs	Technology configurations to be evaluated for their ability to provide distribution service reliability and/or resilience may include distributed battery storage, distributed solar and other distributed generation, microgrid controllers, and isolation and protection equipment enabling islanding. If a microgrid alternative is identified and selected in the -41- distribution planning process, this project may include a field deployment and evaluation of the selected alternative. The relatively immature microgrid market is characterized by a wide range of custom projects with little standardization in technology and design. This project may help identify deployment options and test the efficacy of microgrid-related technologies (e.g., DERs, controllers, communications, and isolation and protective devices) in enhancing reliability and/or resilience in specific locations.
78	3rd Triennial (2018-2020)	PG&E	3.12 - Advanced VVO	TBD
79	3rd Triennial (2018-2020)	PG&E	3.13 - Transformer Monitoring - Sensors	TBD
80	3rd Triennial (2018-2020)	PG&E	3.14 - Imminent Asset Risk	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
77	3rd Triennial (2018-2020)	PG&E	3.11 - Location Targeted DERs	1.Initial microgrid designs and Wholesale Interconnection application support completed 2.Testbed design plan and initial DER component procurement 3.Experimental tariff frameworks for microgrid infrastructure cost recovery and islanding generation support (Initial Design) 4.Cybersecurity Protocols (initial Design with project partners) Interconnection and service planning requests completed 5.Test protocols for grid connected and islanded planned and unplanned simulations developed 6.The physical microgrid DER components in a PHIL simulation environment, including protections and local communication are developed 7.Field site and host circuit upgrades completed 8.Microgrid controller testing and verification completed 9.All microgrid components staged and ready for field deployment 10.Training for field and control center personnel completed 11.SCADA integration, automatic and manual operating protocol and procedure are established 12.Arcata airport microgrid field deployment and installation 13.Microgrid commissioning 14.Initial data collection and use-cases testing are completed 15.Public final report delivered	2 Years	4/1/2019	Yes	Grid Operations/ Market Design; Distribution; Demand-Side Management	$ 390,417	$ 3,404,061
78	3rd Triennial (2018-2020)	PG&E	3.12 - Advanced VVO	TBD	TBD	N/A	N/A		$ -	$ -
79	3rd Triennial (2018-2020)	PG&E	3.13 - Transformer Monitoring - Sensors	TBD	TBD	N/A	N/A	Distribution, Grid Operation/Market Design	$ -	$ 1,330,000
80	3rd Triennial (2018-2020)	PG&E	3.14 - Imminent Asset Risk	TBD	TBD	N/A	N/A		$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
77	3rd Triennial (2018-2020)	PG&E	3.11 - Location Targeted DERs	$ 415,398	$ 1,283,708	$ 1,699,106	$ 4,051	N/A	CEC Redwood Coast Energy Authority Schatz Energy Research Center	N/A	N/A
78	3rd Triennial (2018-2020)	PG&E	3.12 - Advanced VVO	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
79	3rd Triennial (2018-2020)	PG&E	3.13 - Transformer Monitoring - Sensors	$ 319.07	$ 83,737.17	$ 84,056.24	$ -	TBD	TBD	TBD	TBD
80	3rd Triennial (2018-2020)	PG&E	3.14 - Imminent Asset Risk	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
77	3rd Triennial (2018-2020)	PG&E	3.11 - Location Targeted DERs	Pay for performance	TBD	Direct award to Tesla for a 57kW (228kWh) Powerpack 2.5 system Justification: - Tesla identified as the market leader in battery storage solutions. Also Tesla unit was selected to represent what will be deployed in the field. Direct Award to ICF Resources Justification: PG&E initially attempted to develop these agreements on its own. After many months of effort, PG&E and its partners realized that additional specialized expertise was necessary. The only near-similar agreement in the United States was crafted by the principals of this engagement with ICF. Various direct awards <$75K to a variety of companies for materials purchases, direct awarded for speed and saving admin cost	TBD	TBD
78	3rd Triennial (2018-2020)	PG&E	3.12 - Advanced VVO	TBD	TBD	TBD	TBD	TBD
79	3rd Triennial (2018-2020)	PG&E	3.13 - Transformer Monitoring - Sensors	TBD	TBD	TBD	TBD	TBD
80	3rd Triennial (2018-2020)	PG&E	3.14 - Imminent Asset Risk	TBD	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
77	3rd Triennial (2018-2020)	PG&E	3.11 - Location Targeted DERs	TBD	TBD	Column applicable to CEC only	Tesla and ICF Resources are a CA entities.	Column applicable to CEC only	• 5a – Outage number, frequency and duration reductions • 5d – Public safety improvement and hazard exposure reduction • 9a – Description/documentation of projects that progress deployment, such as Commission approval of utility proposals for wide spread deployment or technologies included in adopted building standards
78	3rd Triennial (2018-2020)	PG&E	3.12 - Advanced VVO	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
79	3rd Triennial (2018-2020)	PG&E	3.13 - Transformer Monitoring - Sensors	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	% of automated alerts validated by field inspection/teardown (true positives) % of automated alerts shown by field inspection/teardown to not have been needed (false positives) % of issues/failures that should have triggered automated alerts but didn't (false negatives) 3.a. Maintain / Reduce operations and maintenance costs 5.a. Outage number, frequency and duration reductions 5.d. Public safety improvement and hazard exposure reduction
80	3rd Triennial (2018-2020)	PG&E	3.14 - Imminent Asset Risk	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
81	3rd Triennial (2018-2020)	PG&E	3.15 - Proactive Wire Down	Grid Modernization and Optimization	Demonstrate methods for automatically & rapidly reducing the flow of current and risk of ignition in single phase to ground faults in PG&E's high risk fire areas. This project would test the hypothesis that resonance grounding can mitigate single line to ground fire ignition risk for 3-wire circuits in high fire risk areas. A secondary objective is to improve reliability during wildfire season over status quo, "trip feeder and drive entire line."
82	3rd Triennial (2018-2020)	PG&E	3.16 - Remote Diagnostics	Grid Modernization and Optimization	To demonstrate advanced real-time sensors for monitoring asset conditions, enabling an increasingly proactive maintenance and grid management operational model. If proven successful, these sensors could help PG&E estimate equipment's remaining service life, and predict when it may fail.
83	3rd Triennial (2018-2020)	PG&E	3.17 - Generic UDC	Grid Modernization and Optimization	Design and demonstrate a Universal Distribution Controller (UDC) that can act as a generic controller for use in electric distribution line equipment. This approach could potentially standardize controller hardware across operational control functions insuring interoperability and reducing the need for -51- redundant maintenance and management for multiple vendors. It may also permit customization of features through software development control specific to the utility's needs.
84	3rd Triennial (2018-2020)	PG&E	3.18 - Transformer Monitoring - Analytics	Grid Modernization and Optimization	To develop and demonstrate new algorithms for determining and actively monitoring transformer health and performance based on Synchrophasor or other technology to detect conditions, such as arcing, breaker mis-operation, or total fault energy over time. The project could enable higher accuracy asset monitoring and predictive failure analytics.
85	3rd Triennial (2018-2020)	PG&E	3.19 - Unified Communications	Grid Modernization and Optimization	To demonstrate a platform for unified communication among disparate networks both in the field, as well as across the enterprise. This project may improve reliability by ensuring communication service across multiple service platforms and help to reduce reliability risk by ensuring that the systems can rely on each other's backhaul for redundancy.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
81	3rd Triennial (2018-2020)	PG&E	3.15 - Proactive Wire Down	This project would seek to demonstrate technology that could identify a falling conductor in sub-second response time, to enable proactive circuit isolation. If proven successful, the algorithm could be integrated with grid management systems to minimize safety risks in wires down situations.
82	3rd Triennial (2018-2020)	PG&E	3.16 - Remote Diagnostics	TBD
83	3rd Triennial (2018-2020)	PG&E	3.17 - Generic UDC	TBD
84	3rd Triennial (2018-2020)	PG&E	3.18 - Transformer Monitoring - Analytics	TBD
85	3rd Triennial (2018-2020)	PG&E	3.19 - Unified Communications	TBD

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	*B*	*C*	*E3*	*E4*	*F*	*G*	*H*	*I*	*J*
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
81	3rd Triennial (2018-2020)	PG&E	3.15 - Proactive Wire Down	Build, test, and make operationally ready the Rapid Earth Fault Current Limiter (REFCL) technology. Phase 1: Engineering and Construction • Project design •Equipment order • Test in Proof of Concept RTDS Lab • Field and substation work • Train and educate all departments affected by this technology Phase 2: Field Demonstration & Operation • Commissioning & testing • Fault location testing	2.5 years	11/28/2018	No	Grid Operations/Market Design; Distribution	$ 4,214,771	$ 11,800,000
82	3rd Triennial (2018-2020)	PG&E	3.16 - Remote Diagnostics	TBD	TBD	N/A	N/A		$ -	$ -
83	3rd Triennial (2018-2020)	PG&E	3.17 - Generic UDC	TBD	TBD	N/A	N/A		$ -	$ -
84	3rd Triennial (2018-2020)	PG&E	3.18 - Transformer Monitoring - Analytics	TBD	TBD	N/A	N/A		$ -	$ -
85	3rd Triennial (2018-2020)	PG&E	3.19 - Unified Communications	TBD	TBD	N/A	N/A		$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
81	3rd Triennial (2018-2020)	PG&E	3.15 - Proactive Wire Down	$ 4,094,181	$ 4,185,146	$ 8,279,326	$ 4,380	N/A	N/A	N/A	N/A
82	3rd Triennial (2018-2020)	PG&E	3.16 - Remote Diagnostics	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
83	3rd Triennial (2018-2020)	PG&E	3.17 - Generic UDC	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
84	3rd Triennial (2018-2020)	PG&E	3.18 - Transformer Monitoring - Analytics	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
85	3rd Triennial (2018-2020)	PG&E	3.19 - Unified Communications	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	*B*	*C*	*S*	*T*	*U*	*V*	*W*
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
81	3rd Triennial (2018-2020)	PG&E	3.15 - Proactive Wire Down	Pay for performance	TBD	Competitive Bid and Direct Award •Competitive bid to Schneider Electric •Direct Award to Swedish Neutral North America Justification: Supplier has a unique or highly specialized offering that is required for this individual project. Swedish Neutral is the only REFCL supplier with proven field installations of REFCL technology globally. PG&E is collaborating closely with Australian utilities who have deployed this technology in the field, and using the same supplier of the equipment is critical for this collaboration to work as PG&E moves forward with demonstrating and operationalizing this technology for reducing wildfire risk. Direct award is the best business decision until PG&E has a better understanding of this technology and other suppliers have proven themselves. The Victorian government has performed extensive testing of the Swedish Neutral GFN, and if PG&E went with a different supplier, it would add substantial testing cost to the project, which has been identified as out of scope in the business plan. •Direct Award to Siemens Industry Justification: Award <$250K (PG&E program threshold for 2019), direct awarded for speed and saving admin cost •Direct Award to Chain Link Fence & Supply Justification: Award <$250K (PG&E program threshold for 2019), direct awarded for speed and saving admin cost •Direct Award to Outback Contractors Justification (>$75K PG&E program threshold for 2020): Construction work with an approved negotiated vendor, not a technology award •Direct Award to Cooper Power Systems Justification (>$75K	2	Schneider Electric
82	3rd Triennial (2018-2020)	PG&E	3.16 - Remote Diagnostics	TBD	TBD	TBD	TBD	TBD
83	3rd Triennial (2018-2020)	PG&E	3.17 - Generic UDC	TBD	TBD	TBD	TBD	TBD
84	3rd Triennial (2018-2020)	PG&E	3.18 - Transformer Monitoring - Analytics	TBD	TBD	TBD	TBD	TBD
85	3rd Triennial (2018-2020)	PG&E	3.19 - Unified Communications	TBD	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
81	3rd Triennial (2018-2020)	PG&E	3.15 - Proactive Wire Down	1	N/A	Column applicable to CEC only	Onesource Supply, Chain Link Fence & Supply, Outback Contractors, Swedish Neutral North America, Wrathall & Krusi are CA based entities. Onesource Supply, Outback Contractors, and Wrathall & Krusi are Women Owned Businesses	Column applicable to CEC only	• 3a – Maintain/Reduce operations and maintenance costs. • 4a – GHG Emissions Reductions (MMTCO2e) • 5a – Outage number, frequency and duration reductions
82	3rd Triennial (2018-2020)	PG&E	3.16 - Remote Diagnostics	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
83	3rd Triennial (2018-2020)	PG&E	3.17 - Generic UDC	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
84	3rd Triennial (2018-2020)	PG&E	3.18 - Transformer Monitoring - Analytics	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
85	3rd Triennial (2018-2020)	PG&E	3.19 - Unified Communications	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
86	3rd Triennial (2018-2020)	PG&E	3.20 - Maintenance Analytics	Grid Modernization and Optimization	• To develop predictive maintenance algorithms for identifying potential asset failures before they occur by using SmartMeter™ voltage data and other utility data sources at service points downstream of equipment. The project would potentially improve system reliability and safety by reducing unplanned outages by proactively identifying and mitigating equipment failure.
87	3rd Triennial (2018-2020)	PG&E	3.21 - Vegetation Analytics	Grid Modernization and Optimization	To demonstrate a prescriptive analytics model that predicts tree growth rates and areas at highest risk for vegetation-related outages by leveraging Light Detection and Ranging (LiDAR), other remote sensing data, and historical vegetation based outages for proactive and targeted mitigation. The model could be used for routine maintenance activities, reliability-focused project planning, or planning and staging in anticipation of strong weather systems impacting the PG&E service system.
88	3rd Triennial (2018-2020)	PG&E	3.22 - Abnormal State Configurations	Grid Modernization and Optimization	To demonstrate an algorithm for understanding the comparative risk of abnormal state configurations to proactively prioritize mitigation of these issues. The project would explore the use of system data to analyze risk impact and attempt to demonstrate an algorithmic approach to automate the impact score. This project may also explore the best approaches to integrate this algorithm into utility systems and processes, as well as potentially automate the resolution of these issues.
89	3rd Triennial (2018-2020)	PG&E	3.23 - Enhanced Line Settings	Grid Modernization and Optimization	To demonstrate the increased efficiency, quality assurance, and flexibility of technology to manage transmission and substation distribution protection relay device settings to all distribution line equipment relays and controllers
90	3rd Triennial (2018-2020)	PG&E	3.24 - Power Factor	Grid Modernization and Optimization	To demonstrate a software algorithm to achieve Automatic Power Factor Management to keep power factor within the mandated CAISO guideline.
91	3rd Triennial (2018-2020)	PG&E	3.25 - Grid Monitoring Meter	Customer Service and Enablement	• To develop and demonstrate a modular-designed meter with the capability to monitor electric grid operations and report real time outage and restoration, as well as function as a SCADA metering point during the critical and initial 10-30 minutes of a power outage. This may help keep PG&E distribution system operators well-informed of grid outage conditions and assist them in taking appropriate actions to restore customer power quickly. • The new meter demonstrated in this project could enable potential reduction of equipment costs for replacements due to its modular design. The base mechanical meter would more rarely need replacement, typically leaving just the replacement of the solid state meter and communication core component as needed.
92	3rd Triennial (2018-2020)	PG&E	3.26 - Analytics for Meter Replacement	Customer Service and Enablement	To develop and demonstrate a predictive analytics tool for remotely diagnosing meter health, to target and prioritize proactive meter replacements. The project will seek to explore the development and demonstration of an algorithm, software application/tool, and/or system interfaces to predict when a meter has a potentially unsafe condition, identify service connection issues, and/or identify when a meter is failing.

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	B	C	E2
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
86	3rd Triennial (2018-2020)	PG&E	3.20 - Maintenance Analytics	• The project would define a set of failing equipment use cases that have impact on downstream voltage, and develop analytics algorithms to identify the voltage signatures associated with these upcoming failures. Examples of potential equipment use cases include primary side loose neutrals and overloaded or near-failure transformers, and stressed or near-failure cables.
87	3rd Triennial (2018-2020)	PG&E	3.21 - Vegetation Analytics	TBD
88	3rd Triennial (2018-2020)	PG&E	3.22 - Abnormal State Configurations	TBD
89	3rd Triennial (2018-2020)	PG&E	3.23 - Enhanced Line Settings	TBD
90	3rd Triennial (2018-2020)	PG&E	3.24 - Power Factor	TBD
91	3rd Triennial (2018-2020)	PG&E	3.25 - Grid Monitoring Meter	TBD
92	3rd Triennial (2018-2020)	PG&E	3.26 - Analytics for Meter Replacement	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
86	3rd Triennial (2018-2020)	PG&E	3.20 - Maintenance Analytics	• The output of the project would be an analytics process that would correlate and detect pattern signatures that are associated to malfunctioning or failing system assets, a set of heuristics for identifying these signatures, and an evaluation of this technology's efficacy versus traditional condition based maintenance systems.	1.75 years	4/20/2019	Yes	Grid Operations/Market Design; Distribution	$ -	$ 2,089,960
87	3rd Triennial (2018-2020)	PG&E	3.21 - Vegetation Analytics	TBD	TBD	N/A	N/A		$ -	
88	3rd Triennial (2018-2020)	PG&E	3.22 - Abnormal State Configurations	TBD	TBD	N/A	N/A		$ -	$ -
89	3rd Triennial (2018-2020)	PG&E	3.23 - Enhanced Line Settings	TBD	TBD	N/A	N/A		$ -	$ -
90	3rd Triennial (2018-2020)	PG&E	3.24 - Power Factor	TBD	TBD	N/A	N/A		$ -	$ -
91	3rd Triennial (2018-2020)	PG&E	3.25 - Grid Monitoring Meter	TBD	TBD	N/A	N/A		$ -	$ -
92	3rd Triennial (2018-2020)	PG&E	3.26 - Analytics for Meter Replacement	TBD	TBD	N/A	N/A		$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
86	3rd Triennial (2018-2020)	PG&E	3.20 - Maintenance Analytics	$ 5,759	$ 1,878,312	$ 1,884,072	$ -	N/A	N/A	N/A	N/A
87	3rd Triennial (2018-2020)	PG&E	3.21 - Vegetation Analytics	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
88	3rd Triennial (2018-2020)	PG&E	3.22 - Abnormal State Configurations	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
89	3rd Triennial (2018-2020)	PG&E	3.23 - Enhanced Line Settings	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
90	3rd Triennial (2018-2020)	PG&E	3.24 - Power Factor	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
91	3rd Triennial (2018-2020)	PG&E	3.25 - Grid Monitoring Meter	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
92	3rd Triennial (2018-2020)	PG&E	3.26 - Analytics for Meter Replacement	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
86	3rd Triennial (2018-2020)	PG&E	3.20 - Maintenance Analytics	Pay for performance	TBD	TBD	TBD	TBD
87	3rd Triennial (2018-2020)	PG&E	3.21 - Vegetation Analytics	TBD	TBD	TBD	TBD	TBD
88	3rd Triennial (2018-2020)	PG&E	3.22 - Abnormal State Configurations	TBD	TBD	TBD	TBD	TBD
89	3rd Triennial (2018-2020)	PG&E	3.23 - Enhanced Line Settings	TBD	TBD	TBD	TBD	TBD
90	3rd Triennial (2018-2020)	PG&E	3.24 - Power Factor	TBD	TBD	TBD	TBD	TBD
91	3rd Triennial (2018-2020)	PG&E	3.25 - Grid Monitoring Meter	TBD	TBD	TBD	TBD	TBD
92	3rd Triennial (2018-2020)	PG&E	3.26 - Analytics for Meter Replacement	TBD	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	B	C	X	Y	Z	AA	AB	AC
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
86	3rd Triennial (2018-2020)	PG&E	3.20 - Maintenance Analytics	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	•3a - Maintain / Reduce operations and maintenance costs •5a - Outage number, frequency and duration reductions •5d - Public safety improvement and hazard exposure reduction •7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)
87	3rd Triennial (2018-2020)	PG&E	3.21 - Vegetation Analytics	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
88	3rd Triennial (2018-2020)	PG&E	3.22 - Abnormal State Configurations	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
89	3rd Triennial (2018-2020)	PG&E	3.23 - Enhanced Line Settings	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
90	3rd Triennial (2018-2020)	PG&E	3.24 - Power Factor	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
91	3rd Triennial (2018-2020)	PG&E	3.25 - Grid Monitoring Meter	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
92	3rd Triennial (2018-2020)	PG&E	3.26 - Analytics for Meter Replacement	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
93	3rd Triennial (2018-2020)	PG&E	3.27 - Multi Purpose Meter	Customer Service and Enablement	To develop a multi-purpose meter docking station with a utility grade EV charging submeter in support of Plug-In Electric Vehicle Submetering Protocol proceedings R.18-12-006 . Project will build upon EPIC 2.29 Mobile Meter Applications (NextGen Meter – NGM) project which has a granted patent. If successful, this project would reduce meter component replacement costs, provide public and worker safety by separating high and low voltage components, and reduce physical space required in customer property through modular design and highly connected configuration.
94	3rd Triennial (2018-2020)	PG&E	3.28 - Load Based Charging	Customer Service and Enablement	The project would attempt to develop a smart-charging algorithm based on time, capacity, locations, and other inputs. The algorithm would aim to coordinate EV charging so that specific grid assets are not overly taxed. This project could design controls to coordinate EV charging in a local area in order to facilitate higher EV adoption and charging without the need for distribution system upgrades.
95	3rd Triennial (2018-2020)	PG&E	3.29 - Customer Bill Calculator	Customer Service and Enablement	To demonstrate an online tool with a streamlined graphical user interface to allow customers to more easily understand how behavioral changes and technology investments may affect their energy bill. The proposed tool is targeted towards the group of more engaged customers. PG&E's customer research shows that the more engaged customers want to understand how technologies may affect their bills. In response to this market need, this tool would allow consumers to engage with their energy usage and conservation options through an interactive and more in depth manner.
96	3rd Triennial (2018-2020)	PG&E	3.30 - Pricing Signals	Customer Service and Enablement	To demonstrate the technical feasibility, utility benefits, and customer value of real-time pricing services through evaluating how PG&E can send signals to connected devices to control their operation based on pricing signals and/or grid conditions. This project aims to investigate the strategies for potential future dynamic pricing options enabled by recent communication infrastructure solutions that tie real-time locational marginal electricity price to retail real-time pricing transmission at the interval level.
97	3rd Triennial (2018-2020)	PG&E	3.31 - Real Time DER Rates	Customer Service and Enablement	To design and demonstrate a locational net benefit rate design structure for DERs in order to valuate DER grid services to incentivize optimal DER siting and dispatch.
98	3rd Triennial (2018-2020)	PG&E	3.32 - System Harmonics	Customer Service and Enablement	To leverage SmartMeter™ data to assist in identifying system harmonics that may cause power quality issues for customers.
99	3rd Triennial (2018-2020)	PG&E	3.33 - Cyber-Physical Correlation	Cross-Cutting/Foundational	To demonstrate a unified security solution which matches physical access to system access to aid in the blocking of unauthorized access to PG&E's critical infrastructure.

APPENDIX A
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(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
93	3rd Triennial (2018-2020)	PG&E	3.27 - Multi Purpose Meter	The project would develop a utility-grade submeter prototype for integration into an Electric Vehicle Supply Equipment (EVSE) charging station, thereby eliminating the need for a separate external utility meter and associated equipment. PG&E, the other California IOUs and industry influencers will update the EV submetering standard for CPUC adoption, including the use of this prototype.
94	3rd Triennial (2018-2020)	PG&E	3.28 - Load Based Charging	TBD
95	3rd Triennial (2018-2020)	PG&E	3.29 - Customer Bill Calculator	TBD
96	3rd Triennial (2018-2020)	PG&E	3.30 - Pricing Signals	TBD
97	3rd Triennial (2018-2020)	PG&E	3.31 - Real Time DER Rates	TBD
98	3rd Triennial (2018-2020)	PG&E	3.32 - System Harmonics	Install and test the feasibility of using next generation meters to collect harmonics data on distribution system, develop algorithm engine for analysis, and if successful, create a new operational process for PG&E utilizing the next generation metering technology to detect, investigate and mitigate harmonic issues.
99	3rd Triennial (2018-2020)	PG&E	3.33 - Cyber-Physical Correlation	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
93	3rd Triennial (2018-2020)	PG&E	3.27 - Multi Purpose Meter	Primary deliverables include: • Pluggable utility grade meter utilizing the current PG&E Electric SmartMeter Network and utiliizing existing UtilityIQ integrations for this meter • Docking adapter for integration into EVSE • Implementation of the CPUC's EV submetering standard protocol • Pilot of 25-50 EVSEs in PG&E service yards • Revise the CPUC's EV submetering standard to reflect the design of this prototype • Provide recommendations and handoff on path to production	2 years	7/14/2020	No	Grid Operation/Market Design, Demand-Side Management	$ 1,852,836	$ 3,540,000
94	3rd Triennial (2018-2020)	PG&E	3.28 - Load Based Charging	TBD	TBD	N/A	N/A		$ -	$ -
95	3rd Triennial (2018-2020)	PG&E	3.29 - Customer Bill Calculator	TBD	TBD	N/A	N/A		$ -	$ -
96	3rd Triennial (2018-2020)	PG&E	3.30 - Pricing Signals	TBD	TBD	N/A	N/A		$ -	$ -
97	3rd Triennial (2018-2020)	PG&E	3.31 - Real Time DER Rates	TBD	TBD	N/A	N/A		$ -	$ -
98	3rd Triennial (2018-2020)	PG&E	3.32 - System Harmonics	•Installation of next generation meters at 192 selected locations •Establish communication with deployed next generation meters •Validate harmonics data from next generation meters •Refine parameters on next generation meters •Build methodology to convert harmonics data to engineering application	2 Years	5/1/2020	No	Distribution, Grid Operation/Market Design	$ 137,580	$ 1,154,440
99	3rd Triennial (2018-2020)	PG&E	3.33 - Cyber-Physical Correlation	TBD	TBD	N/A	N/A		$ -	$ -

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
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(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
93	3rd Triennial (2018-2020)	PG&E	3.27 - Multi Purpose Meter	$ 449,089	$ 656,662	$ 1,105,751	$ -	N/A	N/A	N/A	N/A
94	3rd Triennial (2018-2020)	PG&E	3.28 - Load Based Charging	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
95	3rd Triennial (2018-2020)	PG&E	3.29 - Customer Bill Calculator	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
96	3rd Triennial (2018-2020)	PG&E	3.30 - Pricing Signals	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
97	3rd Triennial (2018-2020)	PG&E	3.31 - Real Time DER Rates	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
98	3rd Triennial (2018-2020)	PG&E	3.32 - System Harmonics	$ 2,561.46	$ 80,133.63	$ 82,695.09	$ 291.40	N/A	N/A	N/A	N/A
99	3rd Triennial (2018-2020)	PG&E	3.33 - Cyber-Physical Correlation	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
93	3rd Triennial (2018-2020)	PG&E	3.27 - Multi Purpose Meter	Pay for performance	TBD	Direct Award to Ofer Communication Justification (>$75K PG&E program threshold for 2020): Project builds upon EPIC 2.29 project. This company was was originally selected with competitive bid for 2.29 project. Using the same vendor streamlines work and has the engineering resources to be able to work on the project without re-education needs. Direct Award to Itron Justification (>$75K PG&E program threshold for 2020): Itron is the designer of the Network Interface Card (NIC) used for PG&E's AMI network. The EVSE submeter being developed for this project uses PG&E's AMI network.	TBD	TBD
94	3rd Triennial (2018-2020)	PG&E	3.28 - Load Based Charging	TBD	TBD	TBD	TBD	TBD
95	3rd Triennial (2018-2020)	PG&E	3.29 - Customer Bill Calculator	TBD	TBD	TBD	TBD	TBD
96	3rd Triennial (2018-2020)	PG&E	3.30 - Pricing Signals	TBD	TBD	TBD	TBD	TBD
97	3rd Triennial (2018-2020)	PG&E	3.31 - Real Time DER Rates	TBD	TBD	TBD	TBD	TBD
98	3rd Triennial (2018-2020)	PG&E	3.32 - System Harmonics	Pay for performance	TBD	Competitive Bid	Only bidder that met technical meter criteria	Aclara Meters was selected through an RFP. To simplify contracting, a third party vendor is engaged to supply Aclara products.
99	3rd Triennial (2018-2020)	PG&E	3.33 - Cyber-Physical Correlation	TBD	TBD	TBD	TBD	TBD

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ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	B	C	X	Y	Z	AA	AB	AC
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
93	3rd Triennial (2018-2020)	PG&E	3.27 - Multi Purpose Meter	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	1) Meter asset cost reduction ($) in comparison to the number of expected meter replacements due to malfunction using current meter technology. 2) Number of additional submetered EVSEs now possible due to lowered submetering footprint including the elimination of electrical panels and otherwise required equipment. 3) Customer cost reduction ($) due to the elimination of electrical panels and otherwise required equipment (and associated labor costs)
94	3rd Triennial (2018-2020)	PG&E	3.28 - Load Based Charging	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
95	3rd Triennial (2018-2020)	PG&E	3.29 - Customer Bill Calculator	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
96	3rd Triennial (2018-2020)	PG&E	3.30 - Pricing Signals	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
97	3rd Triennial (2018-2020)	PG&E	3.31 - Real Time DER Rates	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
98	3rd Triennial (2018-2020)	PG&E	3.32 - System Harmonics	1	TBD	Column applicable to CEC only		Column applicable to CEC only	•Outage number, frequency and duration reductions •Reduction in system harmonics •Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360) •Reduction in truck rolls out to install additional monitors •Reduction in turnaround time for resolving customer voltage complaint related to harmonics issues.
99	3rd Triennial (2018-2020)	PG&E	3.33 - Cyber-Physical Correlation	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	*B*	*C*	*D*	*E1*
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
100	3rd Triennial (2018-2020)	PG&E	3.34 - Wireless Security	Cross-Cutting/Foundational	To develop and demonstrate a next-generation wireless security solution which would monitor airwaves around PG&E's electric facilities to detect rogue access points installed within physically secured generation / substation facilities, which could provide bad actors access to the critical infrastructure networks
101	3rd Triennial (2018-2020)	PG&E	3.35 - Advanced Security for IoT	Cross-Cutting/Foundational	To demonstrate an open architecture standard for secure communications between a utility and customer devices using third party communication channels (e.g., home internet connections, cellular networks, private-built field area networks).
102	3rd Triennial (2018-2020)	PG&E	3.36 - Cyber for ICS	Cross-Cutting/Foundational	This EPIC project is proposed as a joint EPIC Administrator collaborative project that seeks to evaluate potential demonstrations that build on the foundation of machine to machine automated threat response by including adaptive controls & dynamic zoning for ICS. These would help to contain or thwart cyberattacks
103	3rd Triennial (2018-2020)	PG&E	3.37 - Augmented Reality	Cross-Cutting/Foundational	To demonstrate technology for visualizing grid and asset data integrated with the geographic information system (GIS) data, superimposed on a device to provide support and guidance for activities, such as asset investigations and maintenance. Augmented reality is a broad technology category which could improve the efficiency and affordability of field operations by providing faster access to key asset information during inspections and maintenance. Just as importantly, this could eventually improve field crew safety by providing hands-free information displays (e.g., through a heads up display).
104	3rd Triennial (2018-2020)	PG&E	3.38 - Voltage Checks	Cross-Cutting/Foundational	To demonstrate technology for visualizing grid and asset data integrated with the geographic information system (GIS) data, superimposed on a device to provide support and guidance for activities, such as asset investigations and maintenance. Augmented reality is a broad technology category which could improve the efficiency and affordability of field operations by providing faster access to key asset information during inspections and maintenance. Just as importantly, this could eventually improve field crew safety by providing hands-free information displays (e.g., through a heads up display).
105	3rd Triennial (2018-2020)	PG&E	3.39 - Optimized Restoration	Cross-Cutting/Foundational	To develop and demonstrate a tool for field workers to perform remote voltage checks and identify low or no-power line situations while on-site without the need to call the central office or manually measure the line. This could potentially enable a field or dispatch employee to identify Service Points and other voltage-checkable equipment in the surrounding area, click on one of the pieces of equipment, and request the current voltage flowing through this equipment to diagnose an issue
106	3rd Triennial (2018-2020)	PG&E	3.40 - Advanced Reference Tool	Cross-Cutting/Foundational	To optimize crew movements and responses during outage dispatch to support restoration operations.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	B	C	E2
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
100	3rd Triennial (2018-2020)	PG&E	3.34 - Wireless Security	TBD
101	3rd Triennial (2018-2020)	PG&E	3.35 - Advanced Security for IoT	TBD
102	3rd Triennial (2018-2020)	PG&E	3.36 - Cyber for ICS	TBD
103	3rd Triennial (2018-2020)	PG&E	3.37 - Augmented Reality	TBD
104	3rd Triennial (2018-2020)	PG&E	3.38 - Voltage Checks	TBD
105	3rd Triennial (2018-2020)	PG&E	3.39 - Optimized Restoration	TBD
106	3rd Triennial (2018-2020)	PG&E	3.40 - Advanced Reference Tool	TBD

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	B	C	E3	E4	F	G	H	I	J
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
100	3rd Triennial (2018-2020)	PG&E	3.34 - Wireless Security	TBD	TBD	N/A	N/A		$ -	$ -
101	3rd Triennial (2018-2020)	PG&E	3.35 - Advanced Security for IoT	TBD	TBD	N/A	N/A		$ -	$ -
102	3rd Triennial (2018-2020)	PG&E	3.36 - Cyber for ICS	TBD	TBD	N/A	N/A		$ -	$ -
103	3rd Triennial (2018-2020)	PG&E	3.37 - Augmented Reality	TBD	TBD	N/A	N/A		$ -	$ -
104	3rd Triennial (2018-2020)	PG&E	3.38 - Voltage Checks	TBD	TBD	N/A	N/A		$ -	$ -
105	3rd Triennial (2018-2020)	PG&E	3.39 - Optimized Restoration	TBD	TBD	N/A	N/A		$ -	$ -
106	3rd Triennial (2018-2020)	PG&E	3.40 - Advanced Reference Tool	TBD	TBD	N/A	N/A		$ -	$ -

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
100	3rd Triennial (2018-2020)	PG&E	3.34 - Wireless Security	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
101	3rd Triennial (2018-2020)	PG&E	3.35 - Advanced Security for IoT	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
102	3rd Triennial (2018-2020)	PG&E	3.36 - Cyber for ICS	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
103	3rd Triennial (2018-2020)	PG&E	3.37 - Augmented Reality	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
104	3rd Triennial (2018-2020)	PG&E	3.38 - Voltage Checks	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
105	3rd Triennial (2018-2020)	PG&E	3.39 - Optimized Restoration	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD
106	3rd Triennial (2018-2020)	PG&E	3.40 - Advanced Reference Tool	$ -	$ -	$ -	$ -	TBD	TBD	TBD	TBD

APPENDIX A
ELECTRIC PROGRAM INVESTMENT CHARGE
2020 ANNUAL REPORT
(CONTINUED)

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
100	3rd Triennial (2018-2020)	PG&E	3.34 - Wireless Security	TBD	TBD	TBD	TBD	TBD
101	3rd Triennial (2018-2020)	PG&E	3.35 - Advanced Security for IoT	TBD	TBD	TBD	TBD	TBD
102	3rd Triennial (2018-2020)	PG&E	3.36 - Cyber for ICS	TBD	TBD	TBD	TBD	TBD
103	3rd Triennial (2018-2020)	PG&E	3.37 - Augmented Reality	TBD	TBD	TBD	TBD	TBD
104	3rd Triennial (2018-2020)	PG&E	3.38 - Voltage Checks	TBD	TBD	TBD	TBD	TBD
105	3rd Triennial (2018-2020)	PG&E	3.39 - Optimized Restoration	TBD	TBD	TBD	TBD	TBD
106	3rd Triennial (2018-2020)	PG&E	3.40 - Advanced Reference Tool	TBD	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
100	3rd Triennial (2018-2020)	PG&E	3.34 - Wireless Security	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
101	3rd Triennial (2018-2020)	PG&E	3.35 - Advanced Security for IoT	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
102	3rd Triennial (2018-2020)	PG&E	3.36 - Cyber for ICS	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
103	3rd Triennial (2018-2020)	PG&E	3.37 - Augmented Reality	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
104	3rd Triennial (2018-2020)	PG&E	3.38 - Voltage Checks	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
105	3rd Triennial (2018-2020)	PG&E	3.39 - Optimized Restoration	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
106	3rd Triennial (2018-2020)	PG&E	3.40 - Advanced Reference Tool	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD

Row #	Investment Program Period	Program Administrator	Project Name	Project Type	Brief Description of the Project - Objective
	A	B	C	D	E1
For Report DOC	i. Investment Plan Period		Project Name		iii. Objective
107	3rd Triennial (2018-2020)	PG&E	3.41 - Drone Enablement	Cross-Cutting/Foundational	To develop and demonstrate a foundational utility-focused Drone enablement systems and initial use cases to form the foundation for future utility Drone operations. These devices have the potential to revolutionize monitoring, inspection, and real-time awareness of pipeline and powerline infrastructure in normal or outage conditions.
108	3rd Triennial (2018-2020)	PG&E	3.42 - Ridesharing Load Management	Renewables/DER Resource Integration	• Evaluate grid impacts from Electric Vehicle (EV) charging used for ridesharing applications, to assess the ability to manage the resulting load using active demand management.
109	3rd Triennial (2018-2020)	PG&E	3.43 - Momentary Outage Information	Grid Modernization and Optimization	To test and demonstrate the hypothesis that AMI momentary events ("blinks") and trap alarms correlate to and can be used to identify specific equipment failures and/or vegetation contact. The project will use the Agile methodology to develop analytical models that use AMI momentary events and trap alarms to identify issues with customer service drops, distribution equipment, and intermittent vegetation contact.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Scope
	A	*B*	*C*	*E2*
For Report DOC	i. Investment Plan Period		Project Name	iv. Scope
107	3rd Triennial (2018-2020)	PG&E	3.41 - Drone Enablement	This project would partner with an industry-leading drone solution vendor to develop and demonstrate automated and beyond visual line of sight (BVLOS) drone operations at a limited scale within PG&E's service territory. The first phase of the field demonstration will focus on flight automation within LOS. The second phase will extend to demonstrating automation BVLOS.
108	3rd Triennial (2018-2020)	PG&E	3.42 - Ridesharing Load Management	TBD
109	3rd Triennial (2018-2020)	PG&E	3.43 - Momentary Outage Information	• Leverage multiple sources of data, including but not limited to SmartMeter™, time of day, location and weather data, to proactively identify potential problems in the Electric Distribution system, specifically related to identifying locations with high incidences of momentary outages which may be caused by imminent failures of conductors, insulators, transformers and/or vegetation contact.

Row #	Investment Program Period	Program Administrator	Project Name	Brief Description of the Project - Deliverables	Brief Description of the Project - Schedule (2016)	Date of the Award	Was This Project Awarded in the Immediately Prior Calendar Year?	Assignment to Utility Value Chain	Encumbered Funding Amount ($)	Committed Funding Amount ($)
	A	*B*	*C*	*E3*	*E4*	*F*	*G*	*H*	*I*	*J*
For Report DOC	i. Investment Plan Period		Project Name	v. Deliverables	vii. Schedule			ii. Assignment to Value Chain	viii. EPIC Funds Encumbered	
107	3rd Triennial (2018-2020)	PG&E	3.41 - Drone Enablement	**Transmission & Substation Inspections:** Automated drone operation system for transmission tower and substation imagery data capture, demonstrated on 3-5 transmission towers and 1 substation. 1 instance of remote charging solution Data manually transferred from drone SD card to AWS and analyzed in Sherlock FAA approval for BVLOS inspection of transmission towers. **Distribution Alert Verification:** Automated drone operation system for investigation of distribution alerts, demonstrated at 1-2 distribution feeders, with drones residing at the associated substation(s) 1 instance of remote charging solution Limited integration with the distribution sensor alert systems Data manually transferred from drone SD card to AWS and analyzed in Sherlock FAA approval for BVLOS drone operation over distribution feeders.	2 Years	8/14/2020	No	Transmission, Distribution, Grid Operation/Market Design	$ 125,000	$ 2,902,328
108	3rd Triennial (2018-2020)	PG&E	3.42 - Ridesharing Load Management	TBD	TBD	N/A	N/A	Grid Operations/Market Design; Distribution; Demand Side Management	$ -	$ -
109	3rd Triennial (2018-2020)	PG&E	3.43 - Momentary Outage Information	Primary deliverables include: * Correlation of events to geographic locations, equipment classes, and vintages, to identify areas and assets with systemic issues and/or higher likelihood of failures. * Development of analytical models to predict & identify the equipment source of momentary events "meter blinks" and voltage sags/swells as well as momentary loss of voltage. * Evaluation of performance of models on historical failures of assets or time frames which have been excluded from model development processes. * Field verifications/inspections of assets identified to be responsible for smart meter anomalies to validate the models' performance.	1.75 years	12/16/2019	No	Grid Operations/Market Design; Distribution	$ -	$ 682,000

Row #	Investment Program Period	Program Administrator	Project Name	Funds Expended to Date: Contract/Grant Amount ($)	Funds Expended to Date: In House Expenditures ($)	Funds Expended to Date: Total Spent to Date ($)*	Administrative and Overhead Costs to Be Incurred for Each Project	Leveraged Funds	Partners	Match Funding	Match Funding Split
	A	B	C	K	L	M	N	O	P	Q	R
For Report DOC	i. Investment Plan Period		Project Name			ix. EPIC Funds Spent*			x. Partners (if applicable)	xi. Match Funding (if applicable)	xii. Match Funding Split (if applicable)
107	3rd Triennial (2018-2020)	PG&E	3.41 - Drone Enablement	$ 891.43	$ 152,654.91	$ 153,546.34	$ 298.43	N/A	N/A	N/A	N/A
108	3rd Triennial (2018-2020)	PG&E	3.42 - Ridesharing Load Management	$ -	$ (3)	$ (3)	$ (3)	TBD	TBD	TBD	TBD
109	3rd Triennial (2018-2020)	PG&E	3.43 - Momentary Outage Information	$ 423.63	$ 119,530.88	$ 119,954.51	$ -	N/A	N/A	N/A	N/A

Row #	Investment Program Period	Program Administrator	Project Name	Funding Mechanism	Intellectual Property	Identification of the Method Used to Grant Awards.	If Competitively Selected, Provide the Number of Bidders Passing the Initial Pass/Fail Screening for Project	If Competitively Selected, Provide the Name of Selected Bidder.
	A	B	C	S	T	U	V	W
For Report DOC	i. Investment Plan Period		Project Name	xiii. Funding Mechanism (if applicable)	xiv. Treatment of Intellectual Property (if applicable)			
107	3rd Triennial (2018-2020)	PG&E	3.41 - Drone Enablement	Pay for performance	TBD	Direct Award to Avineer LLC (>$75K PG&E program threshold for 2020): - This acquisition required a very specific set of expertise, including detailed aerospace engineering expertise, drone industry and technology expertise, and knowledge of FAA regulatory requirements and waiver processes. The selected vendor not only provided all of this expertise, they did so without also being a technology provider themselves. This was critical, as we needed a consultant that would be unbiased in helping PG&E prepare the RFP for the project's larger drone solution vendor partnership, and other vendors we'd engaged with provided both consulting and components of the technology solution that would later be solicited in the RFP they would help to administer.	N/A	N/A
108	3rd Triennial (2018-2020)	PG&E	3.42 - Ridesharing Load Management	TBD	TBD	TBD	TBD	TBD
109	3rd Triennial (2018-2020)	PG&E	3.43 - Momentary Outage Information	TBD	TBD	TBD	TBD	TBD

Row #	Investment Program Period	Program Administrator	Project Name	If Competitively Selected, Provide the Rank of the Selected Bidder in the Selection Process.	If Competitively Selected, Explain Why the Bidder Was Not the Highest Scoring Bidder, Explain Why a Lower Scoring Bidder Was Selected.	If Interagency or Sole Source Agreement, Specify Date of Notification to the Joint Legislative Budget Committee (JLBC) Was Notified and Date of JLBC Authorization.	Does Award Recipient Identify as California-Based Entity, Small Business, Businesses Owned by Women, Minorities, or Disabled Veterans? Information Requested for Technology Vendor Procurements Only (i.e., Not PMs, Consulting Services, Etc.)	How the Project Leads to Technological Advancement or Breakthroughs to Overcome Barriers to Achieving the State's Statutory Energy Goals	Applicable Metrics
	A	*B*	*C*	*X*	*Y*	*Z*	*AA*	*AB*	*AC*
For Report DOC	i. Investment Plan Period		Project Name						vi. Metrics
107	3rd Triennial (2018-2020)	PG&E	3.41 - Drone Enablement	N/A	N/A	Column applicable to CEC only		Column applicable to CEC only	•1.h. Customer bill savings (dollars saved) •3.a. Maintain / Reduce operations and maintenance costs •4.b. Criteria air pollution emission reductions. •5.d. Public safety improvement and hazard exposure reduction •5.e. Utility worker safety improvement and hazard exposure reduction
108	3rd Triennial (2018-2020)	PG&E	3.42 - Ridesharing Load Management	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	TBD
109	3rd Triennial (2018-2020)	PG&E	3.43 - Momentary Outage Information	TBD	TBD	Column applicable to CEC only		Column applicable to CEC only	3a - Maintain / Reduce operations and maintenance costs 5a - Outage number, frequency and duration reductions 5d - Public safety improvement and hazard exposure reduction 7b - Increased use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid (PU Code § 8360)

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

FINAL PROJECT REPORTS

Pacific Gas and Electric Company

EPIC Final Report

Program	***Electric Program Investment Charge (EPIC)***
Project	***EPIC 2.34 Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors***
Reference Name	***EPIC 2.34 RF Sensors***
Department	*Distribution Grid Operations*
Project Sponsor	Jeff Deal – Distribution Grid Operations
Project Business Lead	Neelofar Anjum
Contact Info	EPIC_Info@pge.com
Date	11-12-2020
Version Type	*Final*
Version	1.2

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Table of Acronyms

ADC	Analog to Digital Converter
AHPC	Asset Health and Performance Center
AMI	Advanced Metering Infrastructure (SmartMeter)
API	Application Programming Interface
ATS	Applied Technology Services
CPUC	The California Public Utilities Commission
CT	Current Transformer
CYME	CYME is a Power Engineering software that performs fault current magnitude calculation and location of circuit areas with a given magnitude
DRLM	Distribution Reliability Line Monitors
ECCVM	Event Classification through Current and Voltage Monitoring
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
FFT	Fast Fourier Transform
FPGA	Field Programmable Gate Array
GFRM	Grid Failure Risk Metric
GIS	Geographic Information System
GPS	Global Positioning System
HFTD	High Fire Threat District
IoT	Internet of Things
IPAC	Integrated Protection Auxiliary Cabinet
iPCGrid	Innovations in Protection and Control for Greater Reliability Infrastructure Development
LIDAR	Light Detection and Ranging
LPWAN	Low Power Wide Area Network
MV	Medium Voltage (1 - 35kV)
PD	Partial Discharge
PG&E	Pacific Gas & Electric
PHC	Proprietary Hardware Component
PSPS	Public Safety Power Shutoff
PT	Potential Transformer
RF	Radio Frequency
RFI	Request for Information
RMS	Root Mean Square
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
TAM	Texas A&M University
TD&D	Technology Development and Deployment
VPN	Virtual Private Network

1 Executive Summary

This report summarizes the project objectives, technical results and lessons learned for EPIC Project 2.34 Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors, also referred to as EPIC RF Sensor Project as listed in the EPIC Annual Report. The project was authorized in December 2017 and concluded in July 2020.

Many types of distribution faults and equipment failures have the potential to cause outages and even ignite wildfires. Insulators with partial discharge, or dielectric breakdown between conductors, can cause pole fires that can spread to vegetation or cause equipment arcing. Asset failures and conductor slap can rain sparks and molten metal to the ground, and most of these types of hazards have precursor signatures that can be detected by grid sensor technologies. In this project, PG&E sought to apply grid asset monitoring technology to locate developing hazards, issue targeted field patrols, and where appropriate, create corrective maintenance tags.

Through demonstration of the technologies evaluated in this project, PG&E was successful in detecting and locating multiple examples of conductor damage, vegetative encroachment, internal transformer discharge, fault-induced conductor slap, and arcing at a loose conductor clamp.

During 2018, PG&E demonstrated fixed-mounted prototype RF sensors for grid asset monitoring. The RF sensors collected both radiated and conducted RF emissions, and machine learning models were applied for prediction of the locations of deteriorated grid assets. Field verification was conducted using a directional ultrasonic acoustic detection tool. While the project was successful as a demonstration of fixed-mounted RF sensors, the supplier will need to continue development toward a commercial and scalable technology.

In 2019-2020, PG&E evaluated RF Network Monitoring and Event Classification through Current and Voltage Monitoring (ECCVM) sensor technologies for application in grid asset performance monitoring. The RF Network Monitoring technology, with sensors distributed over the circuit, can detect and locate partial discharge (PD) activity on grid assets, while the ECCVM waveform analysis technology logs classified disturbance events and waveforms for the feeder from the substation.

PG&E observed that RF Networking Monitoring and ECCVM are complementary and together deliver high value in grid asset condition monitoring for reduction of wildfire risks. Although this project has provided a good evaluation foundation for both technologies, more work is planned to develop operational processes and system integrations to support larger scale deployments for wildfire risk reduction.

The RF Network Monitoring technology was demonstrated on a 12 kV 3-Wire distribution feeder in the Napa Valley area. The technology was successful in detecting “hot spots” of partial discharge activity that were field investigated and confirmed to result from asset conditions including conductor damage, vegetative encroachment, crossarm degradation, insulator and clamp issues. The technology provides an accurate source location to within +/-30 Feet to tightly target the field inspection.

The ECCVM technology was deployed on the same feeder as the RF Network Monitoring Technology, as well as five other feeders in the same vicinity. During the field evaluation, the ECCVM technology logged more than 38,000 events across all six feeders. Most of these events were normal operating events (e.g. motor starts, load variations, capacitor switching, regulator steps) which demonstrates the

ECCVM technology's capabilities in detecting operational issues, while around 8% were abnormal events (e.g. faults, arcing, transients, unbalanced capacitor switching). Of the abnormal events, about a quarter were low-level series and shunt arcing events.

ECCVM technology by itself cannot provide the location of developing grid asset conditions. However, it was confirmed that the RF Network Monitoring technology and other distributed sensors, such as Advanced Metering Infrastructure (AMI) and current/fault monitoring Line Sensors can be used to identify event location. Of these options, RF sensors provided the most tightly defined event location, while the AMI and Line Sensors can identify branches or sections of the feeder as source locations when aligned by timestamps.

Although originally thought of as competing technologies, PG&E found that the RF Network Monitoring and ECCVM technologies are complementary due to strength of RF technology in locating events and strength of ECCVM in classifying the events. Other types of grid sensor information could be added to the analysis in an ensemble technology monitoring approach to enrich overall solution capabilities.

The RF Network Monitoring and ECCVM technologies were manually monitored and analyzed for grid asset risk during the field evaluations. Under continued technology deployment, manual monitoring processes could continue for several years, beyond which a more automated, immediately proactive, and scalable monitoring solution would be recommended, especially for combined application of information from multiple sensor technologies.

PG&E envisions a data integration and analytics platform that could consume all grid asset data and apply analytical models to the correlation, risk assessment, decision making, work order management and tracking of detected grid asset conditions.

Key Objectives

Evaluation of real-time grid asset monitoring technologies to detect and locate developing hazards on the grid for interventional maintenance to mitigate wildfire risk.

Key Accomplishments

The following summarize some of the key accomplishments of the project over its durations:

- Demonstrated stationary RF sensor grid asset health monitoring with prototypes and an analytical model for locating deteriorated grid assets.
- Successfully demonstrated both RF Network Monitoring and ECCVM technologies in a field deployment and compared the performance and value of each technology
- Confirmed RF Network Monitoring technology's ability to identify and locate conductor damage, vegetative encroachment, and arcing conditions
- Demonstrated ECCVM technology's ability to identify and classify various normal and abnormal grid events. ECCVM relies upon other grid sensor information to determine event source location and has been shown to add value in an ensemble approach to effective grid asset health monitoring.
- Developed an understanding of analyzing and interpreting the sensor technology data through weekly calls with respective technology suppliers.
- Confirmed that both RF Network Monitoring and ECCVM technologies can be effectively applied to wildfire risk mitigation.

- Determined that RF Network Monitoring and ECCVM each have gaps in event detection that the other technology can detect, and developed an understanding of the reasons why and possible resolutions.
- The ECCVM technology offers high resolution current/voltage waveform analytics that can detect <2 cycle duration arcing events. These brief duration arcing events are not reliably detected by the current implementation of RF Network Monitoring technology, or by Line Sensors or AMI, leaving a gap presently in the locating these short duration arcing events. The RF Network Monitoring product monitors for 1/25 of each second, and often missed detection of short duration arcing events in the sampling window. The technology vendor is evaluating the ability to develop continuous RF monitoring which would close the gap.

Key Takeaways

This project has confirmed that RF Network Monitoring and ECCVM technologies are effective and complementary in grid asset monitoring for wildfire risk reduction.   Further work is necessary to improve the technologies and integrate them into Operations, Distribution Management Systems and with other emerging technology applications such as the Rapid Earth Fault Current Limiter system.

The RF Network Monitoring sensors are distributed on the grid at approximately 3-mile spacing. Finding pole space for the sensors was an issue during the project, and total installation cost needs to be reduced for wide-scale deployment. PG&E continues to work on an improved design which would ideally use a low partial discharge (RF quiet) potential transformer mounted on the sensor pole as the power source. Some rural circuits may present challenges with wireless communication coverage for the sensors and PG&E continues to evaluate this issue. The RF Network Monitoring technology supplier is working toward a next generation sensor product that will have multiple feature improvements. PG&E plans to continue evaluation of this technology under expanded deployment and to refine strategies for deployment at scale.

Evaluation of ECCVM technology will continue to further develop techniques for investigation of short arcing events. PG&E is planning on staged expansion of ECCVM deployment on prioritized HFTD circuits, and continued effort to integrate the technology into operations.

Recommendations

This project has identified several areas that should have continued effort. The following summarizes these recommendations:

- Expand to larger scale RF Network Monitoring technology deployment to formalize operations integration and refine operational interfaces.
- Move Event Classification through Current and Voltage Monitoring (ECCVM) into production with a staged and prioritized deployment to higher risk circuits.
- Expand research into the technology gap on shunt-arcing.

Conclusion

Utility real-time health monitoring practices have been stagnant while available technologies have been unable to respond to the challenges presented by aging grid infrastructure and the increasing wildfire risks driven by climate-change. This project has demonstrated and evaluated the potential of recently commercialized technologies for the application of continuous grid asset health and performance monitoring. Just-in-time maintenance is an optimal strategy with lower cost and risk than periodic inspection-based maintenance that can miss rapidly developing grid asset hazards.

RF Network Monitoring Technology is effective in the detection and location of grid asset hazards that can be mitigated before materializing as faults and asset failures that can cause wildfire ignition. The technology is highly sensitive and able to detect low level partial discharge activity such as primary conductor damage and vegetative encroachment on secondary conductors. The technology can detect these conditions through accumulation of detections of energy dissipated in “hot spots” over extended durations (e.g. weeks). The RF Network Monitoring Technology presents moderate challenges and costs for widescale deployment but is worthy of continued investment and optimization given the potential benefits, including operational cost reductions and wildfire mitigation value. There may be some locations that cannot be cost effectively included in RF Network Monitoring strategies due to a lack of cellular network coverage.

The ECCVM technology detects and classifies normal operating events and abnormal events that can be predictive of developing hazards. The ECCVM technology is not able to detect the same low-level persistent conditions that RF monitoring can, but it is able to detect brief <2 cycle duration arcing events that the RF Network Monitoring Technology may not detect, or may not detect in a timely manner. ECCVM technology cannot determine the source location of detected events and relies upon distributed sensor technologies for this purpose. Asset hazard location identification has been demonstrated with RF Network Monitoring Technology, Line Sensors and AMI.

PG&E has concluded that effective grid asset health and performance monitoring is best delivered through combining sensor technologies in an ensemble approach, with each technology adding uniquely to the event classification, location and prioritization of detected hazards. The ensemble approach provides backup and needed validation between sensor technologies resulting in a resilient and robust vision into the performance of the distribution system. When there are areas that cannot be served by RF or Line Sensor components, AMI may be able to provide some of the necessary information for effective grid monitoring. PG&E’s Distribution and Grid Monitoring Roadmap and Implementation Plan proposes to expand deployment and operation of emerging technologies, such as those demonstrated in this project, that provide grid event data for real-time monitoring and analytics of asset health and performance. PG&E strives to become more predictive of developing hazards on the electric distribution system for implementation of proactive maintenance in order to reduce wildfire risk and improve public safety. This work focuses on Tier 2 and Tier 3 High Fire Threat District areas of PG&E’s service territory.

During the technology demonstration with limited deployment, the sensor data was manually analyzed and reacted upon. PG&E recognizes that the manual approach is not scalable from a resource allocation perspective or due to the need to address detected grid asset conditions in a timely manner. Wide-scale adoption of grid monitoring technologies would require a sensor data integration and analytics platform to provide automated analysis and response for asset hazards. PG&E has plans to investigate approaches to this problem, which can enable timely analysis and response to data from multiple grid sensor technologies that report asset health conditions.

2 Introduction

This report documents the EPIC 2.34 Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors project results and achievements, highlights key learnings from the project that have industry-wide value, and identifies future opportunities for PG&E to leverage this project.

The California Public Utilities Commission (CPUC) passed two decisions that established the basis for this demonstration program. The CPUC initially issued D. 11-12-035, *Decision Establishing Interim Research, Development and Demonstrations and Renewables Program Funding Level*[1], which established the Electric Program Investment Charge (EPIC) on December 15, 2011. Subsequently, on May 24, 2012, the CPUC issued D. 12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020*[2], which authorized funding in the areas of applied research and development, technology demonstration and deployment (TD&D), and market facilitation. In this later decision, CPUC defined TD&D as "the installation and operation of pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks associated with a given technology."[3]

The decision also required the EPIC Program Administrators[4] to submit Triennial Investment Plans to cover three-year funding cycles for 2012-2014, 2015-2017, and 2018-2020. On November 1, 2012, in A.12-11-003, PG&E filed its first triennial Electric Program Investment Charge (EPIC) Application with the CPUC, requesting $49,328,000 including funding for 26 Technology Demonstration and Deployment Projects. On November 14, 2013, in D.13-11-025, the CPUC approved PG&E's EPIC plan, including $49,328,000 for this program category. On May 1, 2014, PG&E filed its second triennial

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[1] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/156050.PDF

[2] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167664.PDF

[3] Decision 12-05-037 pg. 37

[4] Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and the California Energy Commission (CEC)

investment plan for the period of 2015-2017 in the EPIC 2 Application (A.14-05-003). CPUC approved this plan in D.15-04-020 on April 15, 2015, including $51,080,200 for 31 TD&D projects.[5]

On February 7, 2017, PG&E filed a Tier 3 Advice Letter 5015-E[6] to request CPUC approval of additional EPIC projects for its EPIC 2 triennial plan, which included EPIC 2.34 Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors. The CPUC granted approval of the project on August 10, 2017 through Resolution E-4863[7]. Through the annual reporting process, PG&E kept CPUC staff and stakeholder informed on the progress of the project. The following is PG&E's final report on this project.

3 Project Summary

This project demonstrated the application of grid sensor technologies for predictive risk identification and wildfire risk mitigation. The path of the project developed incrementally between 2017 and 2019, with each step providing additional discovery on the application of sensor technology in support of wildfire risk mitigation.

The initial effort focused on integrating RF monitoring into conductor-mounted energy harvesting Line Sensors that monitor load current and faults. Upon a Request for Information, no supplier responded with a direct path to integration of RF monitoring into Line Sensors, or even offered a fixed-mounted RF technology. The best proposal came from a supplier with mobile RF survey expertise, that proposed a demonstration of pole-mounted prototype sensors and the application of machine learning to identify and locate grid asset hazards. The prototype RF sensor, called a Distribution Reliability Line Monitor (DRLM), was developed and demonstrated in the field.

The supplier manufactured ten of the prototype sensors, called Distribution Reliability Line Monitors (DRLMs) and completed lab testing to confirm operation with two communication gateways to deliver the sensor data to a Microsoft Azure portal. The DRLMs measured both radiated and conducted RF emissions to assess the condition of the operating electrical equipment. Radiated RF emissions broadcast radially in all directions from the emission source. Conducted RF emissions couple onto the distribution line and travel in both directions on the continuous conductor. The conducted emissions provide a direction to the emission source, along the electric conductor path. Deployment of multiple DRLMs in the project study area was necessary to provide for geospatial analysis and triangulation to the RF emission source from the radiated and conducted RF emissions recorded by multiple DRLM units. The battery powered DRLMs recorded RF emissions for 30 seconds of each hour.

The devices were deployed on the San Francisco Peninsula in a 1 sqkm area around a known RF-active grid component, which would provide model training data. The machine learning model predicted

[5] In the EPIC 2 Plan Application (A.14-05-003), PG&E originally proposed 30 projects. Per CPUC D.15-04-020 to include an assessment of the use and impact of EV energy flow capabilities, Project 2.03 was split into two projects, resulting in a total of 31 projects.

[6] Tier 3 Advice Letter 5015-E: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5015-E.pdf

[7] Resolution E-4863: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M193/K790/193790420.PDF

locations with asset issues, which were confirmed in the field with the use of directional ultrasonic detection tools. The model predicted asset hazard location with 1-2 conductor spans of actual location. Conducted RF emissions alone provided the best model forecast accuracy, and inclusion of radiated RF emission data detracted from model forecast accuracy.

While the project was successful as a demonstration of fixed-mounted RF sensors, the supplier will need to continue development toward a commercial and scalable technology. The project is discussed in more detail in section 4.1 Technology Demonstration 1 – Prototype Fixed-Mounted RF Sensor.

During summer of 2018, PG&E benchmarking for wildfire risk mitigation discovered an early commercial pole-mounted RF Network Monitoring technology that had early success in detecting grid asset conditions in limited deployments outside of America. This technology was evaluated under EPIC 2.34 and is discussed in section 4.2 Technology Demonstration 2 – RF Network Monitoring System. The RF sensors are deployed at approximately 3-mile spacing on overhead distribution poles to cover mainline and significant branches of each feeder. The technology was evaluated on a 12kV, 3-wire feeder in the Napa Valley. The strategy to locate RF emissions used time-of-flight (proportional to distance) for the signal to reach two adjacent sensors and proved to be accurate within 30 Feet. The RF sensors in Technology 2 monitor RF for 40ms of each second, which proved valuable to monitoring and trending "hot spots".

Late in 2018, PG&E learned of a third sensor product "Event Classification through Current and Voltage Monitoring" (ECCVM) with application for grid asset health monitoring. PG&E determined that ECCVM would be useful for both confirmation of asset hazards identified in the RF Network Monitoring evaluation, and as a comparison technology to help PG&E in determining a strategy for effective for grid asset monitoring. This third technology demonstration is discussed in Section 4.3 Technology Demonstration 3 – ECCVM. The ECCVM technology classifies events well and detects even very brief <2 cycle arcing, but requires supplemental technologies to be able to determine event location. During the evaluation, there was success with using the RF Networking technology, AMI, and Line Sensor data to determine the location of ECCVM events.

In the evaluation of the RF Network Monitoring System and ECCVM technology, there were some events that both technologies detected, and these were long arcing events. RF Network Monitoring detected partial discharge hot spots caused by damaged conductors and vegetative contacts that the ECCVM technology did not detect. The ECCVM technology detected short series and shunt arcing events that the RF Network Monitoring technology did not detect. We attribute these findings to the fact that the RF Network Monitoring technology measures RF for 1/25th of each second, and may often miss brief arcing events in the sampling window. However, the RF Network Monitoring technology is very good at detecting persistent partial discharge patterns over many accumulated sampling periods. ECCVM technology, through advance signal processing, is able to detect less than 2 cycle duration arcing. A solution to this disparity in detection would be provided through continuous RF monitoring, which the technology supplier is evaluating for future products.

RF Network Monitoring and ECCVM are complementary and work well together. The ECCVM performs classification and captures waveforms of events which are useful in understanding the phenomena observed. The ECCVM can be used successfully with a variety of other sensor technologies to determine event location.

PG&E concludes that the best approach to grid asset condition monitoring is to apply an ensemble of sensor technologies that best fit the circumstances of each feeder. ECCVM is low cost sensor technology that covers the whole feeder with one substation installation. RF Network Monitoring technology is valuable for monitoring persistent partial discharge activity and can accurately locate asset issues. There may be areas unsuitable for either RF Sensors or Line Sensors, due to poor cellular coverage. For these locations, more advanced SmartMeter technology, able to stay energized and record voltage sags, could be a low-cost solution.

PG&E will continue evaluation of both RF Network Monitoring and ECCVM technologies as components of the long-term strategy for grid asset condition monitoring.

3.1 Issue Addressed

Some types of grid failures cannot be predicted in advance, such as vehicle collisions with assets, trees falling into assets, and many types of animal contact incidents. However, many types of grid asset hazards can be detected in the incipient stages, offering utilities the opportunity to intervene with corrective maintenance before the hazards materialize as faults and asset failures. Predictive maintenance is beneficial due to lower operating costs, reduced fault and collateral asset damage to the grid, safer working conditions during normal business hours, better reliability and reduced risks for the public and the environment.

Many types of faults and equipment failures have to potential to ignite wildfires. Insulators with partial discharge can cause pole fires that can spread to vegetation, equipment arcing. asset failures and conductor slap can rain sparks and molten metal to the ground, and most of these types of hazards have precursor signatures that can be detected by sensor technologies.

Arcing, sparking and partial discharge conditions emit Radio Frequency (RF) and utilities have for many years applied mobile RF survey technology to detect these incipient conditions. Mobile RF survey technology simultaneously records GPS coordinate and RF emission data as asset corridors are patrolled by vehicle or helicopter. Multiple patrol passes are necessary to eliminate spurious RF signals and determine locations with RF detection on multiple passes. The data is analyzed after the series of patrols are completed, and then field personnel return to the hot spots with a directional ultrasonic acoustic detection tool to identify specific components at risk.

Due to the repeated patrol requirement over long distances, mobile RF surveys are expensive to perform and provide only a snapshot of the grid asset health at the time of the patrols. The health and performance of aging grid infrastructure is dynamic and can change rapidly under operational stress and extreme weather patterns. For these reasons, PG&E sought to evaluate fixed-mounted RF sensors for continuous, real time grid asset health and performance monitoring.

At the inception of the EPIC 2.34 project in 2017, PG&E was planning to expand deployment of conductor-mounted energy harvesting Line Sensors which monitor load and fault current, and capture fault waveform patterns. The primary use cases for Line Sensors at the time were load switching and outage restoration. PG&E wanted to expand on the benefits of Line Sensor through the addition of RF monitoring technology and proposed EPIC 2.34 to explore this possibility.

After the wildfires of Fall 2017, the priority use case for continuous RF monitoring shifted to grid asset health and performance monitoring for wildfire risk mitigation.

3.2 Project Objectives

To accomplish the objectives for the EPIC 2.34 RF Sensors project, the following key items were performed:

- Deploy the RF network monitoring system on the PG&E network and assess its capabilities over several months
- Perform a technology review of the RF network monitoring system and understand its limitations and strengths relevant to PG&E's needs.
- Assess the information provided by the RF network monitoring system and work with local PG&E crews to gauge its accuracy and take action where appropriate.
- Provide key input for the RF network monitoring technology roadmap and determine how the technology may be applicable to PG&E's long-term objectives for preventive maintenance:
    - Assess the scalability of the solution architecture and develop roadmap options for operational deployment opportunities; and
    - Define predictive maintenance strategies for improved distribution network performance and fire safety.

To supplement the RF sensor technology the following key objectives were developed for the ECCVM technology:

- Deploy ECCVM monitoring on the same feeders as the RF sensors over the same project period.
- Deploy ECCVM monitoring on an additional 5 circuits that do not have RF sensing to capture conditions that RF might not capture, giving a further indication of potential value of RF technology, as well as demonstrate an alternative to RF technology.
    - Utilize other existing monitoring technology, such as line sensors and Advanced Metering Infrastructure (AMI), in an ensemble approach to identify incipient conditions.
- Assess the information provided by ECCVM in conjunction with the RF sensor information and other sensor information, to determine location of incipient and systemic field conditions.
- Evaluate how ECCVM can complement PG&E's long-term objectives for operations and preventative maintenance.

More detailed technology specific objectives are discussed under each technology in Section 4.

3.3 Scope of Work and Project Tasks

Per our commitment as documented in PG&E's 2017-2019 EPIC Annual Reports, the project Scope of Work is defined as:

- Assess technical feasibility of various sensor products and validate opportunity for business benefits;
- Develop solution designs, develop test plans, and conduct testing at ATS; and
- Conduct field demonstrations of various products and develop post-EPIC roadmaps for integrating capabilities in production.

Consistent with these high-level statements detailed tasks and milestones were defined for each of the sensor technologies. These are included, by technology, in Section 4 of this report.

3.3.1 Tasks and Milestones

This project had multiple technology streams which added to the complexity of task scheduling and definition of milestones. However, the overall project structure followed the major tasks and milestones listed below:

<u>Task 1: Benchmarking and Planning</u> – Initial efforts required significant review of literatures, assessment of different supplier technologies and benchmarking these technologies. An RFI was issued to broadly assess available technological options. Once key suppliers were selected, contracts were developed and executed per program requirements.

Milestone 1.1 – RFI for sensing technologies

Milestone 1.2 – Execution of contracts with key suppliers

<u>Task 2: Engineering Design and Constructability Review</u> – Sensor technologies were reviewed by internal engineering groups as needed. Each technology went through a formal constructability review. Complete material lists and construction schedules were developed. Testing of devices was conducted as needed to ensure field installations went smoothly.

Milestone 2.1 – Testing of devices

Milestone 2.2 – Develop schedule for procurement and construction

<u>Task 3: Construction and Commissioning</u> – Key hardware was collected prior to field installation. Final construction was done by internal resources with assistance from suppliers as needed. Once installed the sensor technologies followed supplier and corporate commissioning process.

Milestone 3.1 – Receive key hardware

Milestone 3.2 – Constructed/install sensor technology

Milestone 3.3 – Commission sensor technology

<u>Task 4: Demonstration and Operation</u> – Once each sensor technology was operation assigned team members conducted daily review of event activities. Periodic team reviews of the collective data for the sensors was conducted to identify system issues and direct field patrols or corrective action. Periodic meetings were also held to keep key stakeholders informed of activities and monitor progress.

Milestone 4.1 – Periodic meetings for review of recorded events

Milestone 4.2 – Field visits for key events

<u>Task 5: Project Closeout</u> – Completion of the project required collective compiling of sensor data. Final reporting was done first within each technology stream and then collected for full project results. Presentations on the results were made internally to key stakeholders.

Milestone 5.1 – Complete final report

Milestone 5.2 – Complete final presentations

4 Project Activities, Results, and Findings

This section describes the activities, results and findings from field evaluation of three grid asset monitoring technologies.

RF Sensor 1 is a pre-commercial prototype fixed-mounted RF sensor that was evaluated to demonstrate that fixed-RF sensors can be used to locate grid asset showing deterioration. In this project, the battery-operated prototype RF sensors recorded hourly measurements and applied machine-learning to assess asset health on distribution poles in project study area.

RF Network Monitoring System is an early commercial fixed-mounted RF sensor that monitors the distribution assets between each pair of sensors that are mounted up to 3 miles apart on distribution poles. PG&E learned about the availability of this technology halfway through the evaluation of RF Sensor 1 prototype technology. Each distributed RF sensor evaluates measurements for approximately 40 mS of each second, and reports the data to an application portal. The application portal is preloaded with the distribution circuit GIS with distribution pole locations representing conductor paths. To determine RF detections that arise from the monitored path between two sensors, RF data from individual sensors are matched to RF detections of the other sensor in pair, and RF source locations are determined by time-of-flight (proportional to distance) for the matched RF detections to reach each sensor in the pair.

Event classification through current and voltage monitoring (ECCVM) technology is a substation mounted sensor system that monitors three-phase voltages and currents at the circuit level.   The technology has undergone years of development to produce a rich library of event signatures and patterns, allowing waveform capture and classification of grid disturbances.

4.1 Technology Demonstration 1 – Prototype Fixed-Mounted RF Sensor

A prototype RF sensor called a Distribution Reliability Line Monitor (DRLM) was developed and demonstrated in the project. The DRLMs measured both radiated and conducted RF emissions to assess the condition of the operating electrical equipment.   Radiated RF emissions broadcast radially in all directions from the emission source. Conducted RF emissions couple onto the distribution line and travel in both directions on the continuous conductor. The conducted emissions provide a direction to the emission source, along the electric conductor path. Deployment of multiple DRLMs in the project study area was necessary to provide for geospatial analysis and triangulation to the RF emission source from the radiated and conducted RF emissions recorded by multiple DRLM units.

4.1.1 Technology Objectives

To accomplish the objectives of the project, the following key items were developed:

- Evaluate the effectiveness of fixed-mounted RF sensors in monitoring and locating grid asset conditions.
- Develop prototype RF Sensors to record both radiated and conducted RF emissions and evaluate their effectiveness in monitoring and locating grid asset issues.
- Compare the value of radiated and conducted RF emissions in determining source location.

- Design a data communication network to collect hourly data from sensors during field trial evaluation.
- Determine the value of environmental variable data in grid asset condition assessment
- Apply machine learning analysis of sensor data and make predictions about deteriorated assets and their location.
- Field verify predicted distribution asset failures and their location.

4.1.2 Tasks and Milestones

Project delivery was set up through the following tasks and milestones:

- Kick-off Meeting
- Knowledge transfer to PG&E
- System Design Presentation
- Circuit analysis to determine sensor and communication component layout
- Design and Develop Field Trial Components
- Test Field Trial Components
- Deliver Field Trial Equipment with Installation and Commissioning Instructions
- Provide Access to Application Portal
- Field Trial Report
- Technology Roadmap Workshop
- Technology Roadmap Presentation
- Final Report

4.1.3 Technical Development and Methods

DRLM Prototype RF Sensor

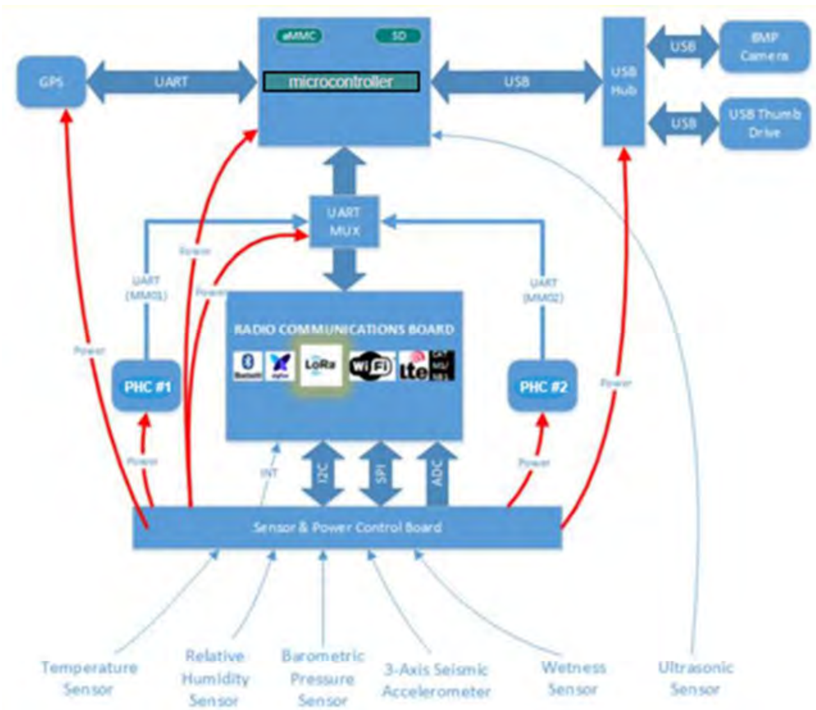
The DRLM RF sensor prototypes employed the use of the supplier's proprietary hardware component ("PHC") to process RF emissions through Fast Fourier Transform (FFT) and other techniques used to analyze the RF signal and discriminate grid asset failure patterns from other RF emissions. The analytical techniques resulted in a proprietary "Grid Failure Risk Metric"(GFRM) indicating the magnitude and persistence of RF emissions and the severity of asset risk.

The PHC provided for Edge Computing analysis of grid failure signature pattern and reduced the data volume transmitted to the Azure analytical platform which focused on machine learning algorithms and geolocation predictions of deteriorated equipment.

A vertically oriented antenna was connected to one of the PHC components to detect radiated RF emissions. A horizontally oriented antenna was connected to the second PHC component to detect conducted RF emissions emanating from conductors.

Figure 1 shows the DRLM block diagram of components.

Figure 1 DRLM Block Diagram



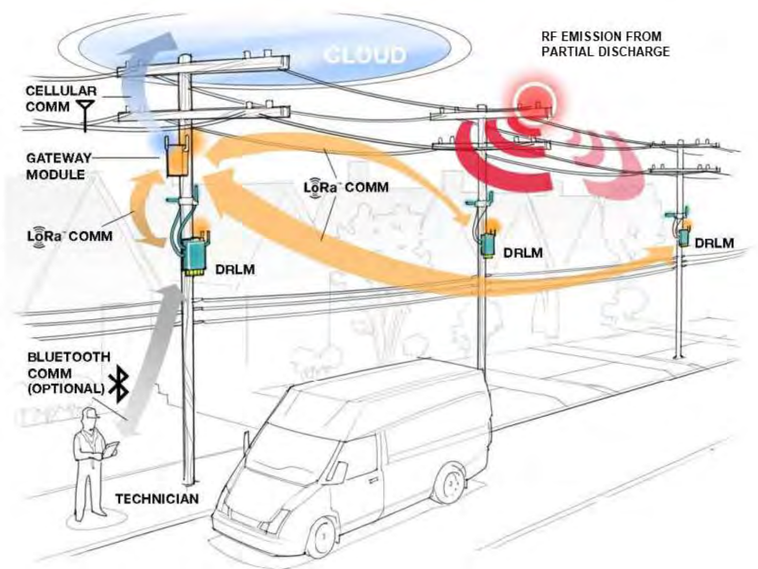
LoRaWAN Spoke-and-Hub Communication

The DRLMs were designed to collect data regularly on an hourly schedule. The collected data was transferred to a cloud Microsoft Azure Web Portal via two deployed LoRaWAN gateway Hub units.

LoRaWAN is a Low Power Wide Area Network (LPWAN) specification intended for wireless battery-operated Internet of Things (IoT) in a regional, national or global network. LoRaWAN targets key requirements of IoT such as secure bi-directional communication, mobility and localization services.

The DRLMs were equipped with peer-to-peer LoRaWAN Spoke networking capability to form a linear mesh data communication network to the LoRaWAN gateways. This allowed the DRLMs to transfer data through other DRLMs to the gateway and reduce the number of required network gateways deployed for the evaluation project, as well as decrease the likelihood of communication issues caused by inability of the DRLMs to reach a gateway directly. Figure 2 illustrates the communication network for the field demonstration. The DRLMs were not installed on every pole, the illustration is for concept only.

Figure 2. Illustration of the installed DRLM and Network Components



DRLM Power Source

Lithium cell battery banks were used to power the DRLMs. A battery pack was selected to supply the DRLMs for more than the duration of the field evaluation period. Not needing to connect the DRLMs to pole secondary power greatly simplified the requirements, planning/design scope and lead time for deployment.

The main processor remained constantly powered. The sensors, CPU, PHCs, and GPS assemblies were powered on as needed.

The system was designed to power up once per hour, record sensor measurements, and then go back to sleep. The total time required for each measurement sequence, including startup, acquisition, processing, and shutdown was approximately 30 seconds. To extend battery life, individual circuits were powered up only as long as needed and then restored to their sleep state.

Data Storage

Two data storage facilities were designed in the DRLM. A non-volatile, removable SD memory card was used to record all data recorded by the DRLM. Additionally, all data was backed up onto a memory stick.

DRLM Lab Testing

Prior to delivery and field installation, the DRLM sensors were tested in a laboratory environment. A High Voltage Laboratory contracted to create radiated and conducted RF emissions by energizing a deteriorated insulator at line voltage. The sensor was operated to confirm that all measurements were being captured and that the Data Network could receive the data from the sensor.

The DRLM system of partial discharge emission detection, discrimination and analysis, and data transport was successfully tested. The DRLM Dual PHC detection was demonstrated to perform well both to discriminate and measure partial discharge from a deteriorated equipment sample both as radiated and conducted emissions. The system also demonstrated the rejection of RF emissions that were not related to the deteriorated equipment sample.

There was expected attenuation of sensitivity as the antennae were moved away from the source, but there was no interruption of operation or analysis in this result. The attenuation effect was be used in the Geospatial Vector Analysis to recognize near field vs. far field emissions. The folded dipole antenna design was more sensitive (can hear further) than the tested monopole antenna for radiated emissions and will be used in the field deployment.

The LoRaWAN network demonstrated proper operation in an electrically noisy environment and passed all data without error or any need for repeated messages.

Grid Analysis and Deployment Plan

A goal of the field trial was to plan the deployment around a pre-existing and known RF-active distribution grid component. The RF-active component with confirmed location would provide training data for the machine-learning analytical model. It was expected that additional incipient asset failure conditions would develop and manifest of the duration of the active field trial. The targeted field trial area was the San Francisco Bay Peninsula area.

PG&E provided the supplier GIS asset location data for the selected distribution feeders in the target area. The supplier performed mobile RF surveys in the area to identify locations with RF-active grid components. The DRLM deployment was then designed to surround the RF-active grid component with the 10 DRLM sensors covering an area of approximately 1 km^2.

DRLM Delivery and Installation

The ten DRLM sensors and two LoRaWAN Gateways were delivered to PG&E and installations were completed by 8/21/2018. Following installation, the entire network was tested and found to be functioning properly.

Figure 3 shows the DRLM sensor and gateway during installation, and mounted to a pole.

Figure 3. DRLM Sensor Installation

Figure 4 shows the locations of the 10 DRLM sensors and two Gateways. The Orange callouts indicate DRLM locations, Green callouts are the Gateway locations, and the original RF-Active Distribution Grid component is noted by the yellow circle. DRLM unit A4 was placed on the pole with pre-identified defective grid component to provide training for the analytical model.

Figure 4. DRLM and Gateway Locations, showing original RF-Active Grid Component

4.1.4 Analytical Approach

The supplier's data scientists developed a model for the evaluation of DRLM sensor data and the forecast of deteriorated equipment location within the study area. The model was based upon scientific formulae for radiated and conducted RF emission detections and their decay rates over distance from source.

Distribution component failure RF analysis (e.g. processing of RF file to remove noise and discriminate information relevant to asset health monitoring) was completed at the DRLM unit through proprietary processing to avoid large RF file transmission. A Digital Twin cloud-based network allowed the Artificial Intelligence Network (AIN) to evaluate a variety of sensor/detector scenarios. Sensors could be removed from the analysis and the resultant change in the AIN output could be evaluated.

Modeling was performed using a Bayesian Hierarchical Model. Radiated and conductive measurements were used to infer a latent Grid Failure Risk Metric value at each pole on each day between the start and end of data collection.

4.1.5 Challenges

The following challenges were encountered during the deployment of this RF sensor technology:

1. Location of RF emission source is a significant issue in the evolution from mobile RF survey technology to fixed-mounted RF sensors that provide continuous monitoring. In mobile RF survey technology, the asset corridor is patrolled while simultaneously recording RF emissions and GPS coordinates, such that strong persistent RF emissions can easily be associated to asset location. With fixed-mounted RF sensors, remote RF source locations must be inferred from multiple stationary RF sensors. This problem is approached by the machine learning component of project.
2. DRLM A9 stopped reporting new data on 9/20/2018 at 4:30PM. At the end of the field trial, the USB drives were retrieved, and it was found that the DRLM recorded data to end, but had not transmitting the data to gateway, possibly due to a defective antenna. The recovered data was included in the analysis and results.
3. Azure, the Microsoft platform on which the DRLM data was collected, was down for 36 hours between 9/4/2018 and 9/5/2018. This time period appears as a gap in all data collected.

4.1.6 Results and Observations

Analytical Model Performance

The DRLM sensors collected hourly data samples from August 21 through October 29, 2019, except for the 36 hours when the Azure platform was down. The sensors were able to detect both radiated and conducted emissions from a known deteriorated equipment location that was selected for the project. This known location provided a benchmark for the AIN network and supplied initial study data. As the project progressed, RF emission data from other deteriorated devices in the project area was sensed, evaluated and transmitted to the AIN for use in the grid resiliency forecast algorithms. The DRLM preprocessed data called Grid Failure Risk Metric (GFRM) along with the data from the other detectors allowed the AIN Machine Learning Algorithms to create forecasts of potential deteriorated equipment locations.

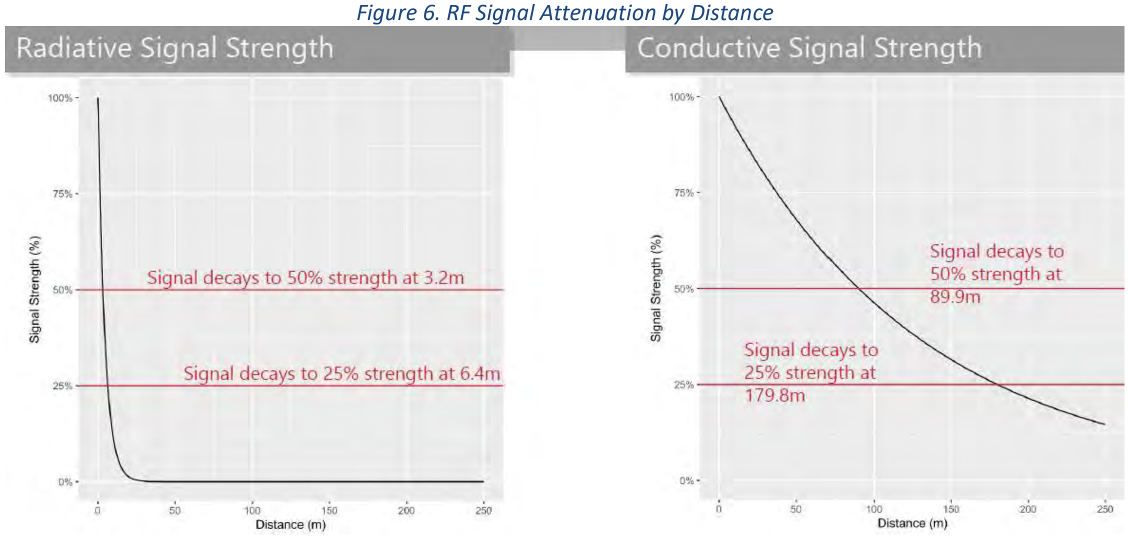
The final inferred deteriorated equipment locations are shown in Figure 5, where distribution poles are represented by rectangles shaded with predicted relative Grid Failure Risk Metric. The lightest colored rectangles indicate poles with highest Risk Metric. The DRLM sensor poles are indicated by rectangles with a yellow border. At the end of the field trial on 10/22/2018, engineers verified ground-truth defective equipment poles with commercial directional ultrasonic acoustic measurement tools, and located five asset issues indicated by the blue circles. The model forecast degraded equipment locations within 0 to 2 conductor spans from field verified locations.

Figure 5. Machine-Learning Model Accuracy

Radiated and Conducted RF Emission Measurements

Conducted RF Emissions travel 30x as far as radiated emissions. Figure 6 shows the signal attenuation by distance.

Figure 6. RF Signal Attenuation by Distance



The analytical model was formally assessed with a Receiver Operating Characteristic (ROC) Curve. The Area Under the Curve (AUC) metric gives a general measure of accuracy. Comparing the model accuracy with inclusion of both radiated and conducted RF measurements, with radiated RF measurements alone, and with conducted measurements alone, the conducted RF alone provided the best accuracy. In contrast, radiated RF measurements alone indicate performance with the worse than random chance (<50%) of prediction accuracy. The Model Accuracy Comparison is summarized in Table 1.

Table 1. Model Accuracy Comparison

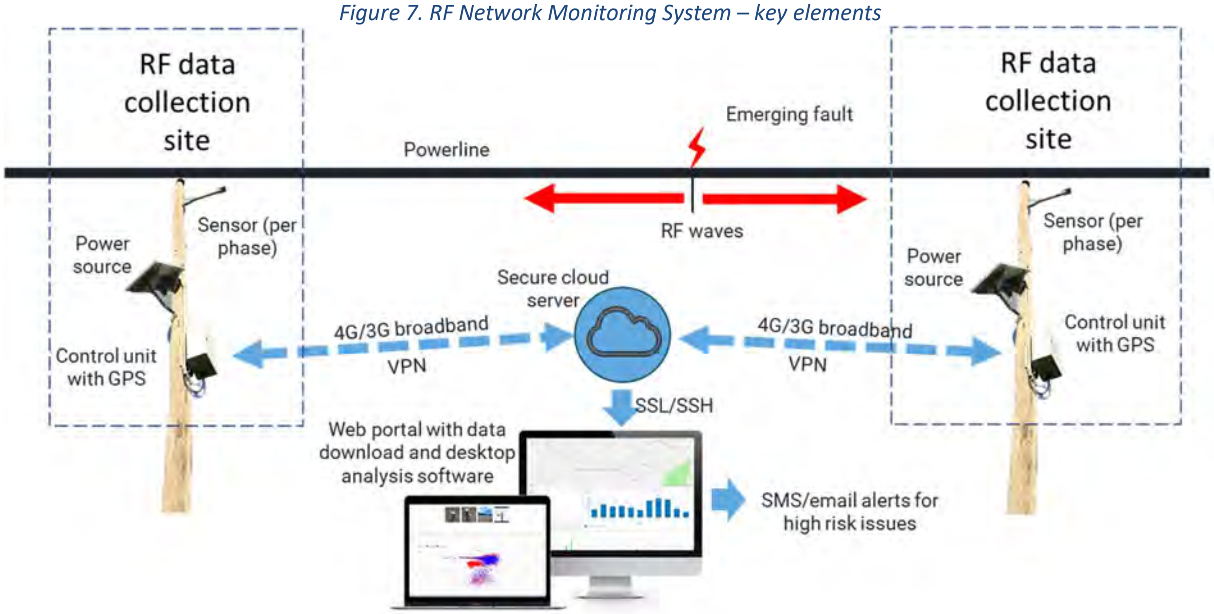
RF Data Included in Analysis	Model Accuracy (AUC)
Radiated RF Only	42.7%
Conducted RF Only	91.3%
Radiated and Conducted RF	81.6%

While the project was successful as a demonstration of fixed-mounted RF sensors, the supplier will need to continue development toward a commercial and scalable technology. The supplier indicated forward strategies to offer a more compact pole-mounted version of the RF sensor as well as continued pursuit of integration into a conductor-mounted Line Sensor product.

4.2 Technology Demonstration 2 – RF Network Monitoring System

The RF network monitoring system is illustrated schematically in Figure 7. The tangible elements of the system are a set of pole-mounted RF data collection units spread across the network at (nominal) three-mile spacing. The more complex and powerful elements of the system are a set of 'big data' processes and algorithms running on secure cloud-based IT infrastructure accessed by utility teams from their desktops via encrypted secure browser sessions.

Figure 7. RF Network Monitoring System – key elements



The RF network monitoring technology deployed in the trial was based on architecture in which geographically distributed set of smart sensors performing edge-computing (RF data collection units installed on poles up to three miles apart along monitored powerline paths) deliver data via encrypted and authenticated data communication links to a secure cloud-based storage and data processing platform. Results can be explored remotely using a secure web-based data-visualization portal. Alternatively, data can be downloaded for local desktop analysis.

Each RF data collection unit monitored signals on powerline primary conductors using wide-band RF coupling devices (sensors) located outside safe approach distance limits. RF data collection units performed initial signal pre-processing and sent a digest of signal data to the secure cloud server to enable 'big data' analysis of data from multiple locations.

Items installed on the pole at each selected RF data collection site included RF-coupling sensors, a control unit with GPS and data communication antennas and solar system battery, and the solar panel. An ADC-FPGA combination performed on-site high-speed signal processing. Each unit also contained a Linux-based set of processes to manage and monitor dataflow and overall unit health.

4.2.1 System Concepts

The RF network monitoring technology deployed for the trial was designed to realize a specific set of concepts: continuous monitoring; incipient fault detection and location; and risk classification.

- Continuous monitoring of network condition: Experience of powerline-caused fires around the world has demonstrated the inherent limitations of routine inspections at set intervals, often years apart. These limitations were confirmed in the trial project by incidents that developed material risk of a fault within hours or days of initial detection. All incipient faults detected in the trial proved to be intermittent in activity and continuous monitoring proved essential to understand the development of an asset defect to the point of failure. Point-in-time detection of intermittently active threats is necessarily limited to the chance the issue is active when the inspection or test occurs. Hence, the desirability of continuous monitoring.

- Detection of incipient faults: The hypothesis underlying RF network monitoring is that high-frequency signals are emitted in the early stage of development of many asset-failure faults. Asset-failure faults have historically been prominent in extreme fire-risk conditions and have caused catastrophic fires. Examples include tree branch-touch, wires down (both due to conductor failure and failure of fittings such as clamps), flashover due to partial discharge or micro-arcing within or on the surface of assets. The trial confirmed these problems generate RF signals in early stages of their development and these signals can be detected at a distance of some miles by suitable monitoring equipment. Continuous monitoring allowed progressive development of incipient faults to be tracked over time so response decisions could be taken remotely with confidence well before the fault occurred.

- Location of incipient faults: Rural powerlines can be more than fifty miles long, so automated accurate location of any identified problem is a high priority for network operators. The fault location concept used in the RF network monitoring system deployed for the trial was 'time-of-flight', i.e. signal sources were located using the time of arrival of signals at multiple RF data collection units operating on a common clock derived from precision time synchronization via the GPS satellite network. This technique is enabled by GIS asset data on the conductor path between adjacent sensors, and the fact that 'time-of-flight' is proportional to distance. Experience in the trial confirmed location accuracy to be thirty feet or better in many cases.

- Classification of risk: Whenever an incipient fault is detected, the type of fault is important information for network operators. Efficient deployment of responder resources relies on the ability to distinguish signals that indicate significant risk such as mid-span vegetation touches or broken strands or high-energy in-tank transformer partial discharge, from signals that indicate no (in the extreme) risk such as signals from raindrop impacts or farm equipment. Time-frequency analysis of detected signals provided signature recognition capability as an integral feature of the RF network monitoring system, though other factors were also important in fault-type identification such as signal energy, the local environment at the location (vegetation present or not), frequency of occurrence, signal waveform, intermittency, time-of-day and seasonal variation, weather conditions, metering data, etc.

4.2.2 Technology Objectives

PG&E's 2019 EPIC Annual Report records the project objective as: 'Demonstrate distribution sensor products that provide indicators of imminent asset failure and real time monitoring of PG&E rights-of-way'.

This goal was reflected in four specific project objectives set out in the Contract's Statement of Work:

1. Deploy the RF network monitoring system on the PG&E network and assess its capabilities over a six-month period.
2. Perform a technology review of the RF network monitoring system and understand its limitations and strengths relevant to PG&E's needs.
3. Assess the information provided by the RF network monitoring system and work with local PG&E crews to gauge its accuracy and act where appropriate.
4. Understand the RF network monitoring technology roadmap and determine how the technology may be applicable to PG&E's long-term objectives for preventive maintenance:
    a. Assess the scalability of the solution architecture and develop road-map options for mass deployment opportunities; and
    b. Define predictive maintenance strategies for improved distribution network performance and fire safety.

To accomplish these objectives, the following key items were developed for the project:

- RF data collection units adapted to suit PG&E networks; and
- US-located secure cloud data processing infrastructure.

4.2.3 Tasks and Milestones

The Statement of Work incorporated into the RF network monitoring system procurement contract details nine milestones for the project:

1. Execute contract and place order.
2. Hold project kick-off meeting.
3. Select sites for installation of RF data collection units.
4. Hold knowledge transfer workshop.
5. Deliver, install and commission RF data collection units.
6. Train PG&E staff in use of RF network monitoring system web portal.
7. Field investigate to verify grid conditions identified by the RF sensor system.
8. Deliver preliminary field trial report(s).
9. Develop future technology roadmap.
10. Deliver final project report.

4.2.4 Technical Development and Methods

At the time of contract execution and order placement, it was intended that between 30 and 50 data collection units would be deployed in the trial to give coverage of about 75-125 route-miles of network. As the project plans were further developed, it became clear that the availability of field crews to perform equipment installations would be the limiting resource and the trial scope was trimmed to the minimum contract quantity of 30 RF data collection units.

PG&E selected HFTD circuits in the Napa Valley area for the Trial:

- Substation A Circuit 1101, a 12kV three-wire circuit: 19 RF data collection units covering 19 inter-sensor paths with a total length of 46 route-miles (Figure 8 shows the deployment concept for this circuit, Sensor A is the substation); and
- Substation B Circuit 2104 (part), a 21kV four-wire circuit: x RF data collection units covering nine inter-sensor paths with a total estimated length of 23 route-miles.

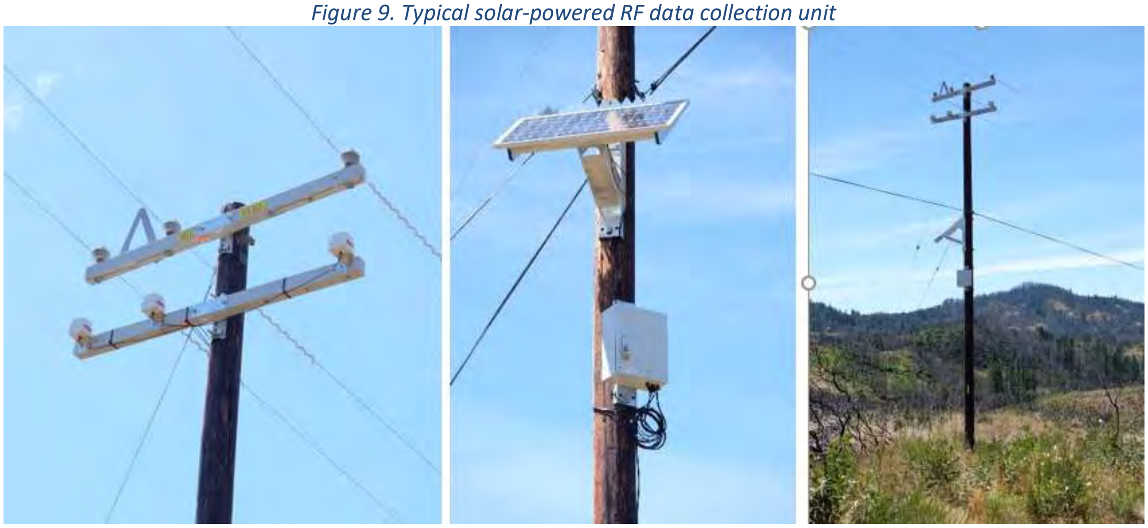
Using PG&E’s network GIS data, the supplier developed concept plans showing suggested locations of RF data collection units to give effective coverage of the selected circuits. Each suggested RF data collection site was audited by PG&E to verify cellular data service coverage, pole mechanical design, pole ‘real estate’, and construction access. In some cases, PG&E moved the planned location to accommodate constraints in these site qualifications.

Figure 8. Feeder concept plan showing suggested RF data collection sites

4.2.5 System Installation

Installation of the 19 RF data collection units on a Napa Valley Area Circuit 1101 commenced mid-June 2019 and continued at a pace determined by construction resource availability through September 2019. Original plans to use AC-powered sensors with a potential transformer on the adjacent pole were not feasible due to the long conductor spans in the area. Solar power was used for the majoritiy of the installations.

Figure 9. Typical solar-powered RF data collection unit



4.2.6 System Commissioning

As each RF data collection unit was installed and switched on, it immediately commenced VPN dataflow to the secure cloud server. The only exceptions were sites where cellular data service signal strength was zero or intermittent (often despite an earlier PG&E audit visit which showed good signal strength).

Each pair of installed RF data collection units defined a monitored network path displayed on the system's web portal. Latitude and longitude data for each pole along the path was entered into the web portal to allow the path to be portrayed on a map so detected risks could be clearly located on the monitored network, e.g. by pole number(s).

The map-based presentation of network monitoring results allowed drill-down (zoom) into problem locations to check for example, the proximity of vegetation to the powerline near an identified risk.

The 19 monitored paths, shown in Table 2, on Circuit 1101 were commissioned between mid-June 2019 and late September 2019, except for Path P-Q which was commissioned in March 2020. The site of RF data collection unit Q showed zero cellular data service signal strength during earlier attempts at commissioning.

For tap lines and branches without sensors, the system locates RF detections on those branches at the intersection of the branch with the monitored paths of the circuit.

Table 2. Monitored Network Paths on Circuit 1101

Path	Length (Miles)	Poles	Path	Length (Miles)	Poles
A-B	1.93	47	H-I	2.15	42
B-C	1.85	53	H-J	2.66	52
B-F	2.92	79	J-K	1.66	29
B-G	3.40	80	L-M	2.67	58
B-M	3.05	76	M-N	2.69	63
C-D	2.22	41	N-O	2.87	48
D-E	3.22	81	N-S	1.63	33
F-G	3.20	72	O-P	1.45	24
G-H	2.17	41	P-Q	1.01	16
G-R	3.21	48			
Total 19 Monitored Paths:				**45.96**	**983**

4.2.7 Challenges

The installation and commissioning phase of the project produced some valuable insights:

1. Costs: The installation of RF data collection units was the most significant component of the project's total cost. Efforts to optimize overall system cost in any future rollout would be best focused on the reduction of installation cost and level effort to perform the Estimating, pole qualification and loading analysis, and installation.

2. Construction resource availability: The installation phase was extended over many months by field crew resource constraints due to other higher priority work, mostly emergency, compliance and public safety power shutdown related. This reduced the period of experience of RF network monitoring system operation in the trial. Use of a dedicated specialized installation team might facilitate faster installation to mitigate risks, achieve earlier system commissioning and potentially reduce installation costs.
3. GIS data: The GIS data used to populate the web portal (pole latitude and longitude) was found to have errors ranging up to 500 feet at some locations. If not addressed, this would have compromised accurate location of detected network risks. For the trial, an extra process step was incorporated in the commissioning process to determine correct (±10 feet) pole location data using Google Earth images wherever possible and enter this data into the web portal to replace PG&E's GIS data. Where a pole could not be accurately located on Google Earth images, such as in forests, a best estimate of the pole location was derived from the nearest accurately determined locations. Some poles and tap-lines were found to be missing from the GIS data. In some cases, this may have been because the assets were privately owned, though the issue was not investigated in depth to confirm this.
4. Cellular data service coverage: In rural locations, cellular data service coverage was found to be intermittent and variable over time. A particular cellular data service might have had strong signal at a location during installation, only to have no signal at all some months later (and vice versa). Post-fire reconstruction and reconfiguration of cell networks may have been the cause. However, this issue was observed widely across the trial area. It was not feasible to restrict units to a single preferred cellular data service. All available cellular data services were considered in a 'best signal strength' on-site selection decision. Verizon required its certified modem hardware to be used; SIMs from all other cellular data service providers fitted the US-standard modem provided in the RF data collection unit. Even this approach did not prevent continuing problems, with inability to connect occurring at some sites multiple times each hour. Ability to connect was not always reflected in low signal strength and investigations are continuing into root causes to see if further design changes can improve dataflow continuity.
5. Solar coverage: Insolation was inadequate in many locations due to trees located to the South of the installed unit. Some sites with adequate solar in Summer had very little solar capability during other seasons. The preferred option to overcome this challenge in future rollouts is to move AC-powered RF data collection units supplied if necessary, by a micro-transformer (or a customer supply transformer if policy is changed) mounted on the same pole.
6. Correct phase identification: For RF network monitoring to be fully effective, it is important the individual RF-coupling sensors at each RF data collection site are pointed at the correct phases of the electricity network. This requires installation crews to use specialized phase identification equipment at each site, which could not always connect to cellular data network for reference signal acquisition.

The above listed challenges were successfully managed, and the RF network monitoring system operated in the later stages of the trial with good levels of availability.

4.2.8 Results and Observations

The predictive risk identification capability of the RF network monitoring system was proven in the trial. The system successfully identified and located a range of common threats to network operation before these developed into faults that could potentially cause interruptions to supply or create safety hazards such as fires or facility damage.

First results followed immediately upon commissioning as pre-existing incipient fault conditions were revealed at locations on Path O-P, the first Circuit 1101 path to be commissioned. New emergent risks continued to be identified throughout the duration of the trial. Not all of the identified threats were high-risk, though all were detected with high signal-to-noise ratio and accurately located by the RF network monitoring system.

Fully resolved case studies are listed in Table 3 and documented in more detail in the Appendix.

Table 3. Summary of case studies of network issues revealed by RF network monitoring

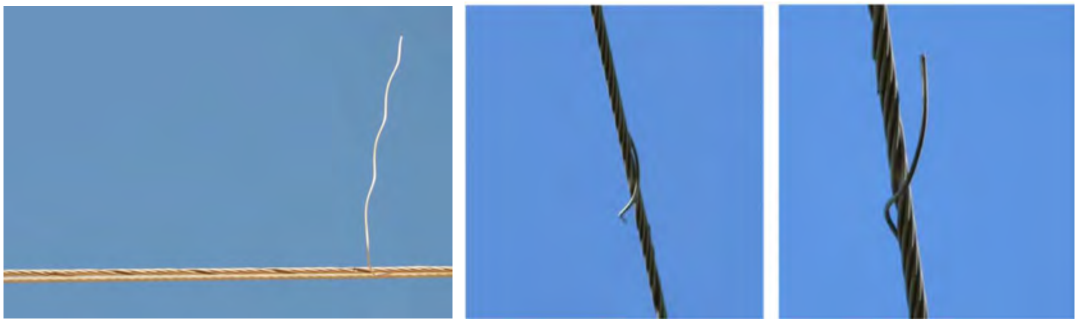
Case	Path	Month	Issue	Inspected	Resolution
1	O-P	June 2019	Vegetation on bare secondary wires (multiple)	Y	Cleared vegetation from the secondary. Detection remained on customer premise wiring.
2	O-P	July 2019	Secondary crossarm fail, insulator pulled out	Y	Cleared by reconstruction.
3	N-S	July 2019	Primary crossarm failure (on tap-line)	Y	To be repaired
4	N-S	July 2019	Covered secondary wiring in tree (on tap-line)	Y	To be repaired
5	D-E	Aug/Sep 2019	Primary conductor broken strands (multiple)	Y	Repaired after inspection
6	O-P	Sep/Oct 2019	Vegetation on secondary (on tap-line)	N	Cleared by reconstruction
7	D-E	October 2019	Primary conductor slap damage (multiple)	Y	Damaged conductor (multiple) to be repaired/replaced
8	A	January 2020	Gunshot primary conductor (Circuit 1102)	Y	750 feet beyond Circuit 1101 monitored path
9	A	January 2020	Transformer internal discharge (Circuit 1102)	Y	2,300 feet beyond Circuit 1101 monitored path
10	E	February 2020	Primary conductor arcing at loose clamp	Y	1,500 feet beyond Unit E, repaired

<u>Key Results</u>

Conductor Damage

Following commissioning of RF network monitoring of Sensor Path D-E in August 2019, the RF network monitoring system detected multiple instances of conductor damage on a high-altitude section of powerline exposed to extreme wind speeds and temperatures. The damage included: broken conductor strands; residual damage from conductor slap; and conductor bird-caging. The RF network monitoring system also identified gunshot damage on a conductor near feeder substation. Figure 10 shows examples of conductor damage.

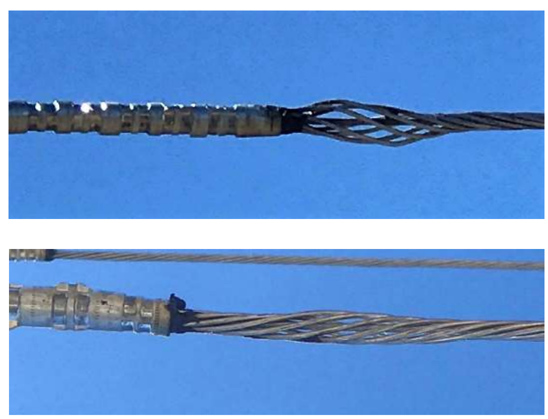
Figure 10. Examples of conductor damage found by the RF network monitoring system



Broken strands

Conductor slap damage (molten droplets, broken strands)

Gunshot damage



Bird-caging

Vegetative Encroachment

Immediately upon commissioning of Path O-P on the 25th June 2019, the RF network monitoring system identified a problem, which on-site inspection proved to be vegetation on bare secondary conductors as shown in Figure 11 below. Also shown is a covered secondary service line run through a tree from a tap-line transformer 1,000 feet from monitored Path N-S which was also detected by the RF network monitoring system and located to the tap-pole. One of the ten pressure points on the service cable in the tree appeared to have insulation worn away from rubbing against the tree branch.

Other similar instances were detected and located during the course of the trial, but they were not confirmed by inspection prior to their disappearance coincident with passage of a fire through the area. Figure 11 shows examples of vegetative encroachment detected by the technology.

Figure 11. Examples of vegetation on secondary conductors

Damaged Secondary Crossarm and Cable

A second issue detected and located two days after commissioning of Path O-P was investigated by inspection and confirmed to be a failed wooden crossarm (split with strain insulator pin pulled out) which had caused the secondary supply service line to wrap around the transformer tank and apply full strain to the transformer low-voltage terminals. Since reconstruction and the fitting of a service cable anchor bracket, the issue has not reappeared.

Primary Crossarm Failure

An incipient fault was detected and located to a tap-pole on Sensor Path N-S. Inspection of the tap-line confirmed a failed crossarm 1,500 feet from the monitored path with suspected tracking from a phase conductor to the crossarm. Crossarm failure had allowed an insulator to 'sit down'. Buildup of dirt under the insulator skirt greatly reduced the surface path between the high-voltage conductor and the crossarm. It was assessed as low-risk and has been listed for repair as other priorities allow.

Transformer Internal Discharge

High-energy signals received at RF data collection unit Sensor A showed an emerging transformer defect beyond the end of monitored network Path A-B on Circuit 1102 which is on the same bus as monitored Circuit 1101. A patrol located a very noisy solid-dielectric voltage transformer 2,300 feet away on a pole-mounted capacitor bank. It was connected to the two phases identified by the RF network monitoring system. This transformer type is known for high internal discharge but no other transformers on the trial network exhibited internal discharge energy. The condition is being monitored.

Arcing Conductor Clamp

RF data collection Sensor E started receiving intermittent bursts of high-energy signal on Phase A from beyond the end of monitored path D-E. Intermittent signal bursts continued before the customer at the end of the line 1,000 feet beyond Unit E called in to report arcing at the top of the pole supplying their load. The signal did not recur after the loose clamp was repaired. The load current involved was about two amperes.

The Technical Appendix for evaluation of the RF network monitoring technology can made available upon request (EPIC_info@pge.com).

<u>Key Technical Observations</u>

The system installed for the trial project continues to operate and be monitored. The following findings are based on experience through April 2020.

Good system performance as a predictive risk identifier: The RF network monitoring system performed successfully in the trial to an extent sufficient to deliver material benefits to wildfire risk mitigation reliability. It predictively identified a variety of network risks, many of which were of types known to start fires. They included conductor damage, vegetation encroachment (both primary and secondary), crossarm failures and a loose conductor clamp. All these conditions were found well in advance of their development into network faults. Site inspections confirmed evidence of the presence of the network defects identified by the system.

Good system accuracy in location of risk: The level of risk location accuracy demonstrated by the RF network monitoring system was sufficient for network operational purposes. In many cases, the system located the incipient fault to an accuracy of five or ten feet. In other cases, especially those where the defect was some distance away from the monitored path on a tap-line or secondary service line, accuracy was within 50 to 100 feet on monitored path lengths that ranged up to a little over three miles (16,500 feet). Performance in the trial was consistent with the supplier's specification of a nominal plus or minus thirty feet accuracy.

Good system risk-detection sensitivity and signal-to-noise ratio: The detection sensitivity demonstrated by the RF network monitoring system in the trial was sufficient to detect situations that could pose short-term risk to the network from deteriorated, damaged or compromised network assets. The system exhibited extreme sensitivity and recorded random noise down to the level of one tenth of a picojoule of collected energy, well below the level required to detect and locate impacts of individual raindrops on primary conductors. In detecting defects, it achieved signal to noise ratios of many orders of magnitude when the defect produced high-energy signals, e.g. internal transformer defects. High signal-to-noise ratios (up to a million to one) were also achieved for the lowest-energy defects when data was accumulated over a period of time, e.g. one month. Sensitivity and noise discrimination were sufficient to achieve reliable predictive risk identification.

Adequate system continuous monitoring for risk: The RF network monitoring system produced a signal record every second as designed. All risks it detected showed very intermittent activity, confirming the potential limitations of 'point in time' asset inspection and test methods. Interruptions to system dataflow were caused by loss of cellular data service coverage and by loss of power due to low insolation. Firmware patches rolled out to RF data collection units over the secure data communications connection during the trial improved system resilience against temporary loss of cellular data service and the supplier is developing a firmware update that will automatically retrieve 'stranded' data recorded during periods of lost connection.

Good system provision of data to identify network risk type: The RF network monitoring system provided data to ascertain the most likely fault-type to guide decisions on field crew attendance priority. It was demonstrated this data could be correlated with data from other sources to create further insights. The system provided risk data including the location of the detected issue (including Pole number, so users could check GIS to ascertain the assets located there, or check Google Earth to ascertain the location of nearby trees or infrastructure), the pattern of occurrence (intermittent activity bursts could be correlated with weather, metering data, field work, likely customer activity, etc.), the phases involved (indicating a primary or secondary problem), signal signature (which could distinguish transformer discharge, conductor damage, loose clamp arcing, etc.).

4.2.9 RF Networking Technology Roadmap

Workshops of PG&E technical staff and supplier experts generated insights into possible technology pathways for larger-scale rollout of RF network monitoring on PG&E networks. Discussions converged to three key issues: lower installation cost, support for fault location, and data integration.

Lower cost installation options

The trial project demonstrated the biggest cost in any larger-scale rollout would be in installing the RF data collection units on poles. In the trial, this cost far outweighed the cost of the units themselves – a disparity that could be expected to increase with scale. The recommendation is to use a larger-scale trial to optimize the design and installation process to reduce this cost before embarking on full-scale commitment.

Three factors were identified for further attention in cost optimization investigations: sensor mounting, power supply, and correct phasing of sensors.

- Mounting of RF coupling sensors

The networks in the trial had a diversity of pole-top designs. The RF coupling sensors had to be mounted with a consistent spacing between each sensor and the primary conductor it monitored. The pragmatic solution adopted for the trial was to change the pole-top to flat construction (all the primary conductors at the same height) before mounting the three sensors underneath on a second crossarm. Instead of this uniform approach, a small set (perhaps only three) of standard sensor mounting arrangements selected to suit the most common pole designs on PG&E networks may offer cost reduction opportunities.

- Power supply to the RF data collection unit

A second factor in the installation cost was the use of solar power. Originally, secondary AC power was planned to be supplied by a transformer on an adjacent pole, but long conductor spans prohibited this option. Mounting an internally fused, 'PD-quiet' micro-transformer on the crossarm holding the sensors may offer cost reduction opportunities, reliable power supply and deserves further investigation.

- Auto-phasing of RF data collection units

Operation of the RF network monitoring system can be impaired if the phasing of the primary conductors allocated to particular RF coupling sensors is not consistent, i.e. RF coupling sensors labelled Red phase must always be pointed at the Red phase conductor. This requirement added some time and effort to the installation task. The phasing tool was not able to connect to the cellular network at installation locations to obtain a reference signal. Experience indicated it was challenging to consistently get it right. All installed sensors were visited and checked, and it was found that only eight of 19 sites had all sensors correctly pointed at the right phase. Errors were easily remedied during the site visit by swapping cables inside the control unit. However, this experience illustrated the challenge of ensuring correct phasing and further, ensuring it stayed correct when networks were rebuilt.

In response, the supplier has committed to investigate system design concepts whereby the RF network monitoring system itself automatically allocates the whole cohort of sensors installed on a network consistently to appropriate primary conductors. This would remove the phase-check task from the installation process. The auto-phasing should be repeated at regular intervals to check and adjust for changes due to network reconstruction. Site visits to check and remedy phasing issues would be eliminated.

Fault location using RF network monitoring

During the course of the trial, a number of network faults occurred - fuse candling, tree fall, etc. The RF network monitoring system was not designed for fault location. However, system records for the time of occurrence of a small number of faults were retrospectively investigated in depth to see if RF monitoring might add value in this key operational task. The results were encouraging enough to prompt the supplier to commit to exploration of design changes to enhance the fault location capability that was apparent. Changes to provide fault location capability would likely require significant changes to the system's architecture. The supplier's investigations into this potential opportunity are continuing.

Continuous RF Network Monitoring

The supplier is investigating the potential to advance the current sampling window of 1/25th of each Second to continuous monitoring that would more reliably detect infrequent <3 cycle duration arcing events.

Integration for enhanced network operations

PG&E is committed to the enrichment of network monitoring data to support enhanced network operations. It has made investments in trials and installation of smart line sensors and substation-based network monitoring systems. The RF network monitoring trial demonstrated the rich data available from this technology. It prompted consideration of the potential benefits of integrating this data with that from other sensors and systems and of presenting it on existing field operations information delivery platforms.

A workshop was held with PG&E and supplier experts focused on IT and data networks to consider options that may become available if wider rollout of RF network monitoring goes ahead. Three options were considered: the software-as-a-service approach used in the trial; a new message-based application programming interface; and, hosting of the system on PG&E's IT infrastructure. Integration opportunities for data networks and collection of weather data were also explored.

- Software as a service

The standard baseline RF network monitoring system provides capability for download of all system data via secure browser session from the system's cloud-based IT infrastructure. This capability was used extensively by both PG&E and supplier teams during the trial. It is simple, easy to use and has few cyber-security threat exposures. However, it is unlikely to be efficient as rollout scale increases. All parties in the workshop confirmed this model would likely be sufficient to meet PG&E needs for the next few years in all likely rollout scenarios, after which it would need to be supplemented by a fully automated capability.

- Message-based Application Programming Interface

A message-based API would be a natural next step. This would simply automate the data download process to allow PG&E network operations support systems to automatically reach into the RF network monitoring system's cloud IT infrastructure to retrieve the data they require. The API itself would not involve major cost and any associated cyber-security issues would likely be manageable. IT changes on the PG&E side to enable its systems to initiate data requests and to integrate and present the retrieved data would likely constitute the majority of the work in implementing this option. This was seen as the natural next step in evolution of integration as rollout scale increases.

- PG&E hosting

The option of moving all the RF network monitoring system's data and algorithms onto PG&E's internal IT infrastructure was also explored. However, this option would involve multiple major challenges as PG&E would be required to license and operate software from both the supplier and the cloud infrastructure provider. It was seen as requiring major long-term IT investment and would have substantial cyber-security issues, both of which would require very careful consideration.

- Use of PG&E data network

The workshop on integration also assessed the option of using PG&E's FAN data network to link RF data collection units to the secure cloud IT infrastructure. There appeared to be no technical barriers that would prevent this. However, it was confirmed that extending FAN coverage for this purpose alone would not be economically justified.

- Collection of weather data

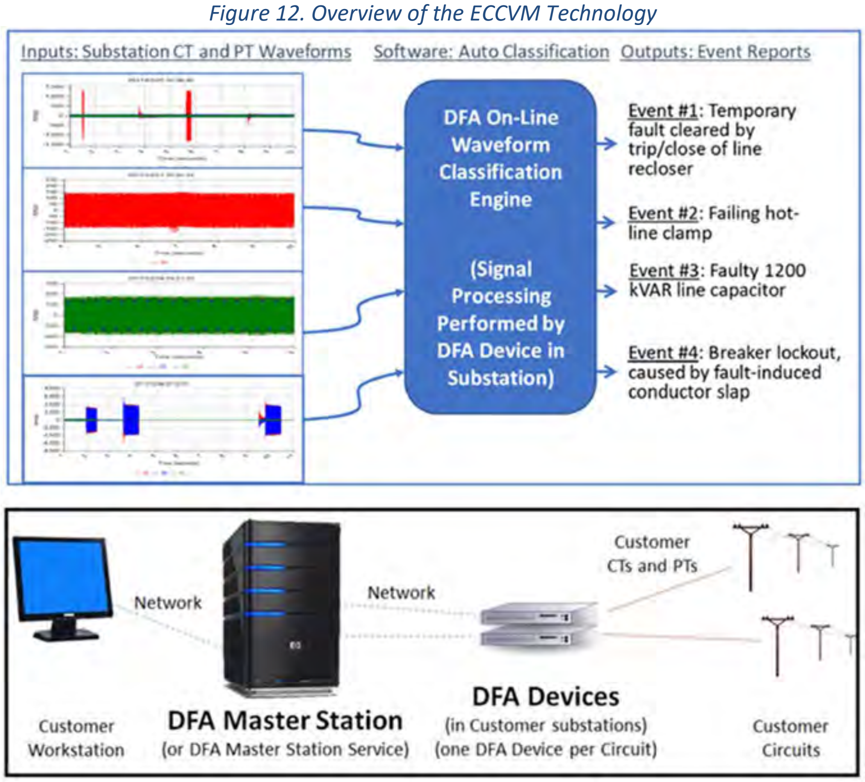
Local weather data is becoming more important in utilities, especially to indicate wind-related risk at a more granular level to minimize the impact of Public Safety Power Shutoffs. The standard RF network monitoring product includes an optional integrated weather station which shares power supply and data communications with the RF network monitoring system. The device has no moving parts and uses ultrasonics to measure wind speed and direction. For comparative evaluation, one of these devices was installed at RF data collection Unit E approximately 200 feet from an existing ‘propeller and vane’ weather station.

4.3 Technology Demonstration 3 – ECCVM

Event classification through current and voltage monitoring (ECCVM) technology is a sensor technology that monitors three-phase voltages and currents at the circuit level. The sensor is in the substation and connects directly to the circuit breaker Current Transformers (CTs) and the bus voltage Potential Transformers (PTs). The sensors continuously monitor voltage and current waveforms, in high fidelity, and detect electrical anomalies using sophisticated digital signal processing, pattern matching, and other techniques to report ongoing and developing circuit conditions. Figure 12 is a diagram that shows the conceptual structure of the ECCVM technology.

The ECCVM technology was developed over several decades by Texas A&M Engineering and the Electric Power Research Institute, Inc (EPRI). The initial effort was focused on improvement of system reliability and was built on early high-impedance fault detection work. Texas A&M hypothesized that failing equipment would causing arcing well in advance of ultimate failure and the key to anticipating failure through electric signal monitoring was detection of this arcing.

Figure 12. Overview of the ECCVM Technology



The ECCVM algorithm can report 29 different classification of events that it captures. Several of these are related to normal operating events such as motor starts, capacitor switching, and regulator operation. ECCVM classifies 26 different abnormal grid events which are summarized into the broad categories of overcurrent, shunt arcing, series arcing, and capacitor problems. All the grid events are capture within the ECCVM interface under the waveform tab. The abnormal events are captured both in the active grid event tab but also under the grid reports.

4.3.1 Technology Objectives

RF sensor technology is geographically located along a distribution circuit. Limitations to access, both physical and communications, can inhibit deployment. The ECCVM sensor technology, which is located at the substation to sense voltage and current waveforms, was used to compensate for these limitations.

The technology was also used on distribution feeders that do not have RF technology deployed both to capture conditions that RF might capture, giving an indication of potential value of RF technology, as well as demonstrating an alternative to RF technology.

The ECCVM technology is being demonstrated within the EPIC 2.34 project even though the primary objective of the EPIC project is to demonstrate RF sensors. The ECCVM technology is also being demonstrated by Southern California Edison under their 2019 Wildfire Mitigation Plan clearly defining the ECCVM technology as a commercial product and hence not eligible by itself under the EPIC mandate. PG&E still felt the technology needed to be demonstrated at a smaller level for its system since there were several other technologies that it was considering. The EPIC 2.34 seemed a good fit because ECCVM could help validate the RF technology as well as provide a comparison at a reasonable scale.

4.3.2 Tasks and Milestones

To align with the overall EPIC project structure, the scope of work was spread over four main tasks. This permitted periodic review and project offramps if needed.

Task 1: Benchmarking and Planning – ATS's technical team did a thorough review of the ECCVM technology. The results of this work and formal process effort were needed to harden the projects execution plan. Specific tasks performed under this phase included:

> Task 1.1 – Historical Field Performance Review and Benchmarking: Detailed benchmarking with current ECCVM utility users was conducted. This did not include any "in-plant" visits.
>
> Task 1.2 – Literature Review: A literature review of related technical papers and documents was also conducted.
>
> Task 1.3 – Feeder Screening: Initial screening of substation and feeders within wildfire areas was conducted in coordination with the PMO's office and the business leaders.
>
> Task 1.4 – Contracting: Project coordination to finalize contacts and purchase agreements was also performed during this phase.

Task 2: Engineering Design and Constructability Review – Installation of the ECCVM devices in the field required full engineering and construction by PG&E's substation department and some initial laboratory testing to reduce the risk and burden on field physical forces. Task performed under this phase include:

Task 2.1 – Substation Pilot Process: Before any work related to new technology can be introduced into a PG&E substation it has to go through a project review process. This engages all components of the substation design and construction teams in PG&E and insures buy-in from these key members. Evaluation of work methods and constructability is also addressed under this task.

Task 2.2 – Detailed Design: After the project has been reviewed and approved by the substation team, the substation design group developed the detailed design. This includes a procured material lists and schedule.

Task 2.3- Material Procurement: Equipment needed for completing the installation was ordered or procured from company stock. The longest procurement equipment item was the installation cabinet as it required hand wiring by the substation tech group within their shop. However, since similar cabinets are used for other substation applications the component supply chains were already in place and all components were acquired well ahead of schedule.

Task 2.4 – IT/Telecom Survey: Communications requirements were evaluated both by ATS Grid Technologies and Substation Telecom. Substation Telecom conducted site surveys of the proposed substation locations to determine the best carrier options. Once the evaluations were completed cell modems and related carrier cards were procured.

Task 3: Construction and Commissioning: Most of the construction was done by the substation group with support from ATS and the TAM teams. Under this phase the following tasks were performed:

Task 3.1 – Field Construction: Field construction work performed by substation construction included installation of the ECCVM cabinets, installation of the ECCVM units into the cabinet, and wiring and validation of the completed construction. The construction process followed all standard PG&E safety and construction practices.

Task 3.2 – ECCVM Device Configuration: Prior to sending the ECCVM units into the field they were put through a series of communications and performance test just to make sure there were no problems with the units in the field. All this testing was done at ATS's communication lab by the ATS team. Any firmware or performance issues were addressed prior to deployment.

Task 3.3 – Field Commissioning: Once the installations were completed, commissioning and functional testing was performed by substation personnel in coordination with both ATS and ECCVM team members. Communication data rates and actual voltage and current measurements were verified. The portal interface was exercised to insure access to all data by team members.

Task 3.4 – Training: A full training session not only on how to use the ECCVM portal but also how to begin to interpret the ECCVM data was given by the TAM team to both the operational engineering component at ATS and the distribution grid operations Asset Health and Performance Center (AHPC). Training covered how the sequence of events are recorded by ECCVM and examples of key types of events and the associated data.

Task 4: Demonstration & Operation – The core of this project was to evaluate the performance of the ECCVM system in relation to the key objectives. Operation of the ECCVM devices was led by ATS with help and coordination of PG&E's substation/telecom (support for any potential field problems with the devices), AHPC (coordination with the RF sensor monitoring) and TAM. The following tasks were performed and coordinated through this phase:

> Task 4.1 – ECCVM Monitoring: Daily review of ECCVM detect events was performed. Key events, specifically those that indicated incipient conditions or systemic issues, were investigated across companion data sources. These events were logs and events files create to collect related data. Weekly review meetings were held with TAM and the RF sensor teams. The detailed evaluation methodology can be found in Section 4 of this report.
>
> Task 4.2 – Analysis with RF: Specific to project goals, additional investigation was conducted for events occurring on the feeder with RF sensing. These investigations were in two directions: events detected by ECCVM were validated with RF and events detected with RF were validated with ECCVM.
>
> Task 4.3- Analysis with Other Data Sources: As data was collected Data and statistical analysis was performed to gain better understanding of the ECCVM event data and to correlate the results with other data sources. This work was primarily performed in Jupyter Notebooks.
>
> Task 4.4 – ECCVM Technology Transfer: Once the project is completed a determination will be made, with key stakeholders on whether the ECCVM technology is to be handed off or to be decommissioned. If deemed necessary, the physical decommissioning of the devices will be performed.

Task 4.5- Final Reporting: Full documentation of the results and findings of this demonstration project will be collected in two primary reports: an ATS technical report and an EPIC final report. The EPIC final report will be created collaboratively with the RF sensor team. A final report from the supplier will also be reviewed. Presentations, both intermittent and final project will also be prepared under this report.

4.3.3 Technical Development and Methods

The installation of the ECCVM sensor is relatively simple when compared to other substation sensor packages because it can piggyback on the same CTs and PTs that a standard feeder breaker relay use. As such, the ECCVM unit needs to be located near, and preferable on the same device stack, as the distribution circuit breaker relays. Its installation requirements are like what a relay would require. The ECCVM device requires phase CT connections and line-to-ground PT connections. This was added as a criterion in the substation selection process to help limit the amount of work required within the substation.

The complete substation design went through the substation pilot project review (TD-3340P-04) and the complete detailed design was done by PG&E's substation engineering group. It should be noted that the substation team's timely responses and diligence was the key to the successful installation of the ECCVM devices.

PG&E uses what is called the Integrated Protection Auxiliary Cabinet (IPAC) to house the relays and test switches for a typical distribution substation breaker. This self-contained cabinet is located at the breaker in a substation. Ideally, the IPAC cabinet would have additional space for a new circuit device such as the ECCVM unit, and in some versions of this cabinet there is the space, however, for the majority of the project's installations the existing IPAC cabinets at the breaker did not have enough room for the ECCVM devices. An additional cabinet had to be added to house the ECCVM unit, its power supply, test switches, and the cell modem on the rear side of the steel pillar that supported the existing IPACs. A conduit between the IPAC and the auxiliary cabinet was used to complete the wiring. A small antenna was located on the top of the cabinet for the cell modem.

4.3.4 Challenges

ECCVM Workflow:

Prior to final commissioning of the ECCVM devices, the ECCVM supplier team developed a process for documenting findings and investigation of critical events. As monitoring progressed modifications were made to further streamline the process while still capturing the relevant data.

Monitoring of the ECCVM devices and investigation was conducted by ATS technical personnel with input from the ECCVM supplier team. The ECCVM portal was reviewed by ATS personnel every workday. The portal was not reviewed for weekend and holidays however since all data that is capture events that occurred during these periods could be investigated the following workday.

Initially, within the portal all events that were displayed on the Grid Event page were reviewed and logged into the event log. Also, events identified by the RF sensor team were also investigated for relevant ECCVM data. After a couple of months of review and working with the data from the ECCVM portal it was determined that not all the events identified on the Grid Event page were of significance. One-off overcurrent events were no longer logged. All arcing and recurrent overcurrent events were continued to be logged.

ECCVM Operational Performance

On 8/16/20 t of the 21-kV feeder ECCVM units began to experience data dropout. This was first noticed by the supplier. After three days of conducting remote diagnosis on the unit, ECCVM supplier recommended replacement of the unit. The unit was successfully swapped out by substation personnel on 8/30/20 and was back operating the same day. A replacement unit had also been received from ECCVM supplier and the failed unit was shipped back.

4.3.5 Results and Observations

Considering the limited number of feeders that had ECCVM deployed and the short period that data was collected, it is impressive the amount and type of data that was collected by the ECCVM sensor technology. Because of this it will not be possible to list and detail every event recorded. The approach for the documenting the results involves two components: an overview will be given on the ECCVM data; and a more detailed presentation for several key results that highlight the capability and performance of ECCVM technology.

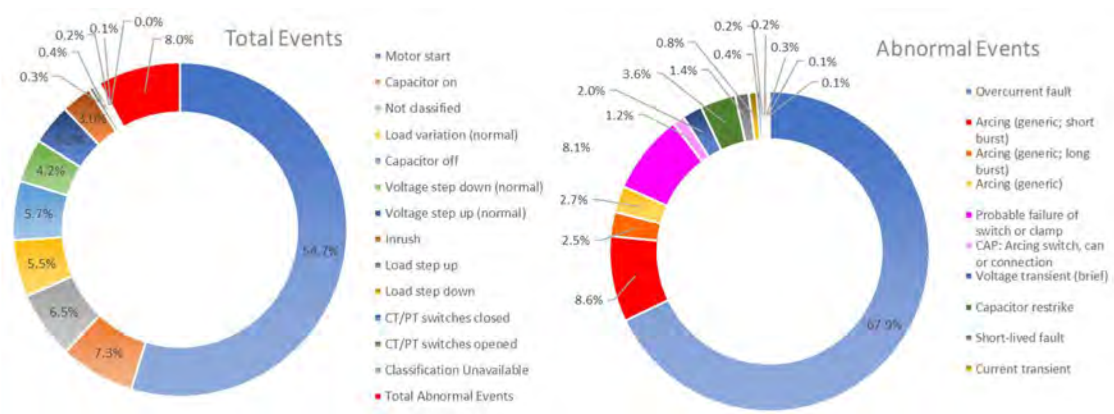
Overview

At the end of May 2020, the ECCVM system had collected over 38,000 events from the sensors deployed on the six project feeders. Most of these events can be classified as normal operating events (motor starts, load variations, capacitor switching, regulator steps, etc.) with motors starts being the most common normal operating event (approximately 50% of all events captured). This is expected from a device that monitors voltage and current waveforms. Motors are very common on the feeders located in the Napa Valley and motor starts would happen multiple times each day. Figure 13 shows a chart of the percentages by different types of events captured to the end of May for ECCVM.

The abnormal events (faults, arcing, transients, unbalanced capacitor switching) represented over 8% of the total number events in the same period. This seems reasonable since it can be assumed that the distribution systems should behave normally most of the time. Of the abnormal events the majority (68.7%) are overcurrent faults, however, 21.4% events are low energy arcing. Figure 13 shows a chart of the percentage of different types of abnormal events capture in this time frame.

Figure 13. ECCVM Events Captured by ECCM to the end of May 2020

a) Total Events *b) Abnormal Event Only*



Key Results

Series-arcing

Series-arcing is an arcing event that creates low-amplitude voltage/currents and results intermittent changes of the source impedance, a direct interruption of the load current. Series-arcing events can indicate an incipient failure and, since they impact the load current, can be collaborated from sag voltage alarms. ECCVM, using its localized digital signal process algorithm, is unique in its ability to identify these types of events. Sag alarms alone can't identify series-arcing as the cause.

ECCVM defines two classifications of series-arcing events: "Probable failure of switch or clamp" and "CAP: Arcing switch, can or connection". The "CAP: Arcing switch, can or connection" classification is only associated with capacitors and is generally identifiable by the additional change in reactive power. "Probable failure of switch or clamp" classification covers all other types of series-arcing events.

Series-arcing events generally come in clusters of time. These clusters can come and go in flare ups as the failing of the equipment progress. ECCVM supplier has seen series-arcing events cause unidentified operation of protective equipment. Both RF and infrared signatures are also effective at identifying possible series-arcing events, however, caution needs to be considered for the RF sensors piloted on these circuits as was discussed in the previous section. The series-arcing events captured during this project had long durations increasing the opportunity of RF sensor capture.

There were 5 specific case examples capture in this project. Three of them were on the EFD-monitored Circuit 1101 so there was opportunity of RF sensors matching. Two of the events were candling fuses. In both cases the RF sensors captured the location of the series-arcing source. In the remaining case, however, the RF sensors did not capture the location. Using AMI data ("Sag" and "Last Gasp"), the approximate location of the series-arcing was determined. Unfortunately, because of the time lag to obtain the AMI information no patrol was conducted so the cause was never determined.

Two series-arcing events occurred one of the 21-kV circuits, which did not have RF sensors, and in both cases AMI data was successfully used to determine the approximate location of series arcing. In one case, the series arcing began 10 days before final failure with AMI data showing a consistent location. A field patrol was not conducted because of time-lag in getting AMI data. In the other case, the series-arcing began only hours before final failure. The patrol of the line in this case did not identify the cause.

Shunt-arcing

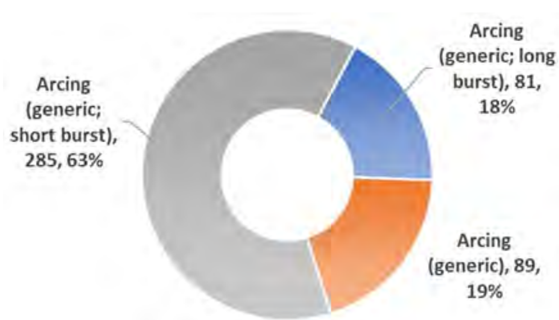
Shunt-arcing is not a faulted event; they are low current events that typically last for only a few cycles. Shunt-arcing does not trigger magnitude/duration sensing such as protective relays or fault analyzers. The signal preprocessing on ECCVM sensor looks for specific characteristics of the abnormal component of the current and voltage signal.

The technical difference between shunt-arcing and a high-impedance fault is the nature of what these two technical terms are defining, and a brief description will help with the subtleties. A shunt-arc is an ionization of air as a result of electrical potential energy. A high-impedance fault is fault in which its impedance limits the fault current. It is not necessary for arcing to occur for there to be a high-impedance fault. When ECCVM identifies a shunt-arcing event it is looking for characteristics of the ionization of air from an electric field.

ECCVM defines three types of arcing events:

1. Arcing: generic – 2 to 3 cycles
2. Arcing: short burst – less than 2 cycles
3. Arcing: long burst – more than 3 cycles

Figure 14. ECCVM Recorded Shunt-Arcing Events by Type



There has been a total of 429 shunt arcing events captured by the ECCVM sensors for this project since its inception until the end of April 2020. Figure 15 shows the breakdown by shunt-arcing type for the recorded events, with short burst being the most common. Figure 15 shows the number of shunt-arcing events for each of the six feeders with ECCVM installed. The first feeder is monitored with the RF sensors. The other feeders have no other sensor package that has the potential for capturing shunt-arcing events.

Figure 15. ECCVM Recorded Shunt-Arcing Events by Feeder

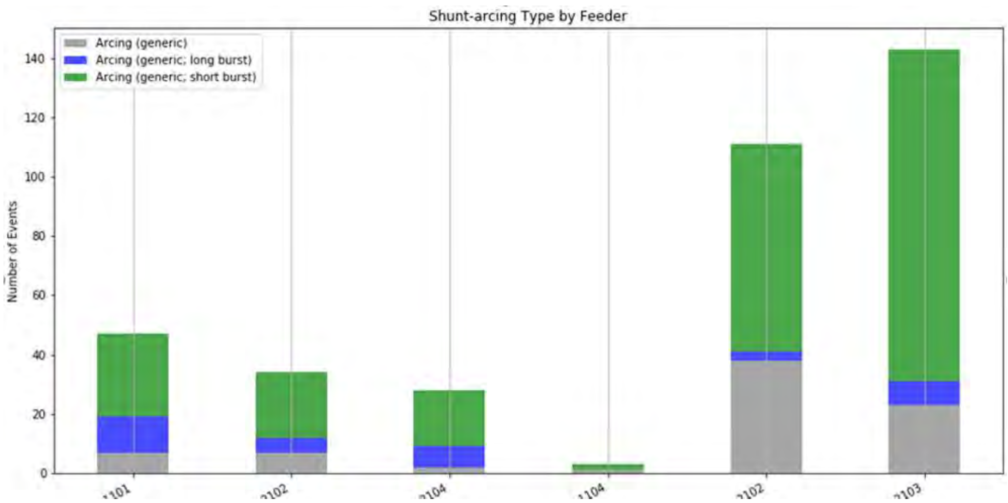
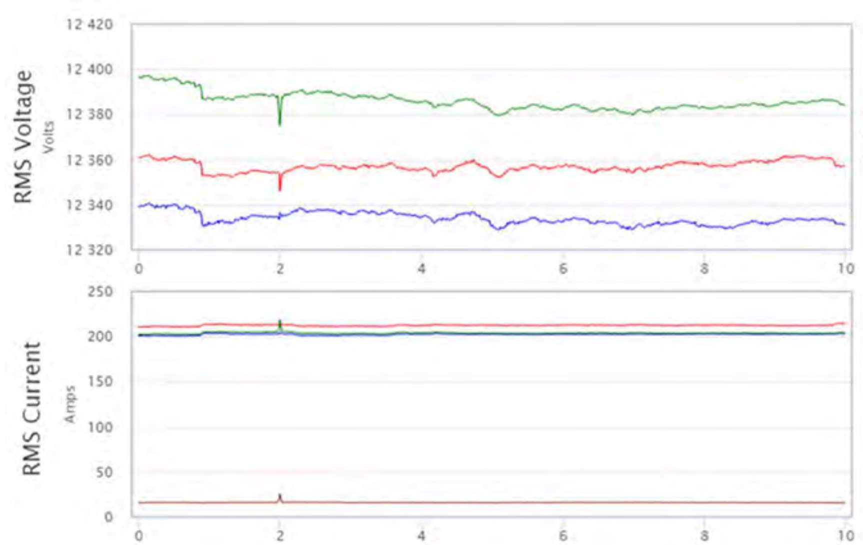


Figure 16 shows the typical RMS current and voltage as result of a shunt-arcing event. Note the small magnitude change in current and voltage. Validation of these events being shunt-arcing comes from two sources: ECCVM supplier research and field verification. ECCVM supplier has conducted years of research on the nature and characteristics of shunt-arcing. They have collected data from both laboratory testing and field studies through the ECCVM product. One 21kV series-arcing event migrated into shunt-arcing (see case studies above) and had shunt-arcing just prior to the final failure, thus providing field validation of shunt arcing for this project. On the EFD monitored feeder, a series-arcing event also had shunt arcing for the "candled" fuse in the case study above.

Figure 16. ECCVM RMS Voltage/Current for Shunt-Arcing Event



Specific causes of shunt-arcing have been difficult to come by other than immediate predecessors for a catastrophic failure, however, there have been 2 representative cases that begin to point to the value of identifying shunt-arcing and highlighting the existing technology gap in locating.

The first case, which occurred on the EFD monitored circuit, were a clustering of shunt arcing events around a momentary outage. A recloser on the circuit opened and reclosed for a fault of approximately 763A. The fault started on phases BC and then migrated to all three phases. Prior to the fault there were two shunt-arcing events, one 12 hours before, and the other 2 hours before. Both occurred on phases BC. Since it was a momentary outage no patrol was conducted after the initial event alarm. RF sensors did not capture data related to either the momentary outage or the shunt-arcing events.

Line sensors also capture the momentary fault and that data, in combination with a CYME model fault location analysis, narrowed the potential problem area. This data allowed operations to conduct a field patrol of the area. The field patrol located “a newly fallen tree”. “The tree crossed the road and appears to have possibly hit the primary wires.”

The second case, which also occurred on the EFD monitored circuit, were a clustering of shunt-arcing events within a five-minute period. There were other “Non classified” events that were captured in this same timeframe, their RMS readings looked like the shunt-arcing events. The ILIS report for that day identified burned conductor as a result of a third-party structure fire. The report located the fire near a section of line that was between the B-F RF sensor pair. The processed data from the sensor pair did not show any correlating data, however, examining the raw data from each of the sensors showed that the B sensor had signal problems but sensor F did capture some signal that correlated with the later “Not Classified” ECCVM events.

Fault-induced Conductor Slap

The ECCVM technology directly identified a fault-induced conductor slap on a 21kV 4-Wire circuit.

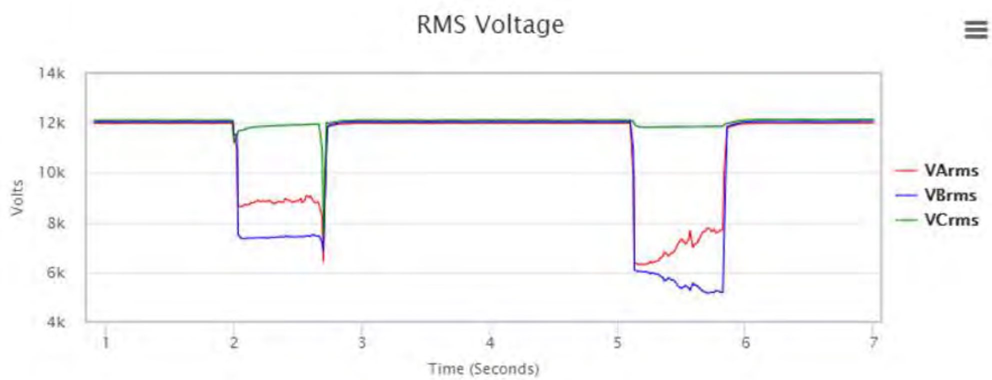
Figure 17 shows the RMS voltage and current for this event. The second reclose has significantly larger fault current. For the second reclose the current ramps down as would be expected for the resulting Jacobs-ladder as the conductors separate. ECCVM also identified a breaker trip that occurred eleven seconds before the first recloser operation.

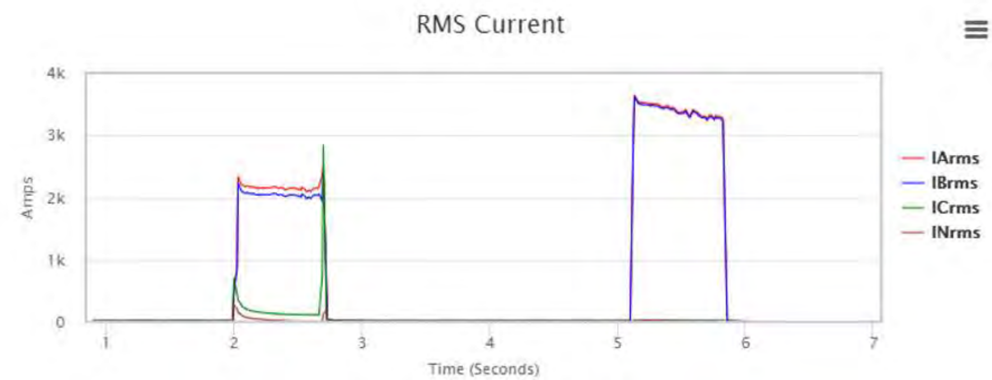
SCADA logs validated the operation of both the recloser and circuit breaker, however, the timestamps for these logs do not have enough detailed to see their time-series proximity. The outage report incorrectly identifies this as a “miscoordination”. The outage report for this event identified the cause as a branch falling on the line.

Line sensors on the circuit captured some of the faults around the ECCVM identified event, however, only one waveform captured both the fault and the conductor slap but even this was a residual of the breaker trip from eleven seconds earlier.

A patrol was performed based upon CYME “Fault Location” analysis but did not identify the location of the conductor slap.

Figure 17. ECCVM Recorded Fault Induced Conductor Slap





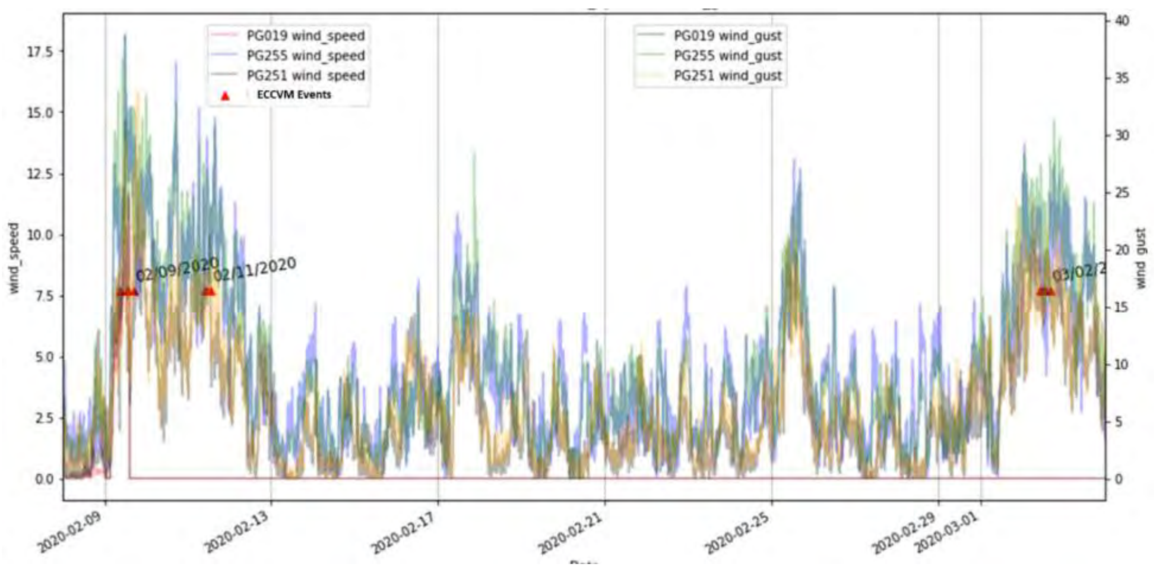
Recurrent faults

ECCVM can identify recurrent faults; faults that have the same magnitude of fault current, occur on the same phases, and last for the same duration. These types of faults are systemic and involve some type of construction or operational deficiency.

An example of this was a recurrent fault that occurred on a 21kV circuit over a 22-day period, which clustered around three specific days. Line sensors also identified these faults but, at the time, did not classify them as recurrent. Based upon the data from ECCVM the settings for recurrent faults were adjusted so that the line sensor portal now identifies these faults as recurrent.

Examining nearby weather stations for wind conductions for these events there was a correlation with wind speed/wind gust. Figure 18 shows the wind speed/wind gusts timeseries with the ECCVM recurrent faults. These faults seem to always cluster around peaks in wind speed.

Figure 18. Wind Speed/Wind Gust Timeseries Data for Weather Stations with ECCVM Events



A CYME fault location model was run and, along with line sensors data, a location for a patrol was identified. Operations completed the field patrol and located a section of circuit in which there appeared to have been phase conductors slapping together, probably caused by wind. A spacer was added to this circuit and no additional faults have recurred.

Cable Failure

Cable failures can have precursors that can be detected by ECCVM sensors. The ECCVM sensor deployment for this project was primarily driven by wildfire concerns so the distribution feeders targeted by this technology tend to have a relatively small quantity of underground circuit. There was one cable failure that illustrative of how ECCVM would be able to help in identify incipient cable failure.

ECCVM began reporting a series of “Current Transients” and “Load Variations” that were of very short duration, typically under a single cycle. These events were occurring on average 30 seconds apart but ranging from a few seconds to minutes. A total of 52 events occurred over a two-hour period.

Line sensors identified these events as “line disturbances” but gave a “Insufficient Waveform” for classification, the events were too short for classification. This data did provide information on where on the circuit they were occurring.

These events were occurring just before a Public Safety Power Shutoff (PSPS) event. A PSPS is when PG&E intentionally de-energizes a circuit because fire risk it too high. These events are identified 48 hours in advance, require notification of local customers and agencies, and mobilization of large amounts of physical forces to implements and ensure public safety. The identification of the ECCVM events were given to distribution operations with the suggested area to patrol and the project team’s suspect of an incipient cable failure but because of the PSPS operation could not be acted upon.

The circuit was de-energized for the PSPS. After weather conditions improved a complete visual inspection was made of the circuit. The circuit was re-energized which was recorded by ECCVM. No additional incipient events occurred. Later that day ECCVM recorded a multi-phase fault of short duration. Line sensors also detected the fault. Field inspections by operations located a failed elbow on the sections of circuit that was identified for patrol.

Operational Visibility

Although this project was primarily focused on detection of incipient failure modes, the ECCVM technology provides improved monitoring resolution that can be leveraged for better operational visibility of the system. Details of specific case examples during this project can be found in the ATS final report. Here are some highlights of ECCVM demonstration of operational visibility:

1. Capacitor Operations: ECCVM is the only sensor package that has a significant amount classification capability specific to shunt capacitors on the distribution system. This is significant to PG&E's operations as over 10% of all 10,000 shunt capacitors on its distribution fail in some manner each year. Annual inspections of all these capacitors requires significant company resources. The capability to monitor and validate performance beyond these annual inspections can help improve system performance. In this project ECCVM captured an unbalance capacitor switching event that was later determined to be a blown fuse on a capacitor bank.
2. Substation Voltage Regulator Monitoring: ECCVM captures and reports incremental voltage steps. Since these are correlated with current, they are identified as voltage regulation. These types of events are considered normal operation but can be used to validate substation regulation. For example, during this project ECCVM capture a voltage step changes that occurred within seconds of each other without any significant change in current. These quick succession voltage steps indicate improper settings on the controller, specifically a change in delay timer settings. Operating engineering was notified of this discovery.
3. Non-downstream Event Detection: Since ECCVM's classification algorithm considers both voltage and current simultaneously it can determine whether a classified event is occurring downstream on the feeder being monitored or not downstream such as on a neighboring feeder or transmission system. During this project ECCVM detected simultaneous overcurrent fault events on all the monitored feeders at the exact same time. The event was caused by a regional transmission fault.
4. Line Sensor Validation: Although one of this project's primary objectives is to validate the RF sensors the ECCVM technology was also used to validate and calibrate the line sensors already extensively deployed on PG&E's circuits. ECCVM's classification of recurrent faults was used to identify the mis-calibration of the recurrent detection tolerance of line sensors. A second example of line sensor validation was for a more troubling discovery of incorrect RMS current during the first cycle of the line sensor capture waveforms. The information has been given to the line sensor manufacture for correction.
5. Hidden Load Detection: ECCVM has higher resolution of measurement then is currently used on most PG&E SCADA devices. This feature enables a more finessed analysis of performance of the distribution system under dynamic conditions. An example is the ability to identify a circuits response to renewable generation sources tripping off after a low voltage condition caused by a fault. This is often referred to in the utility industry as the "hidden load" problem

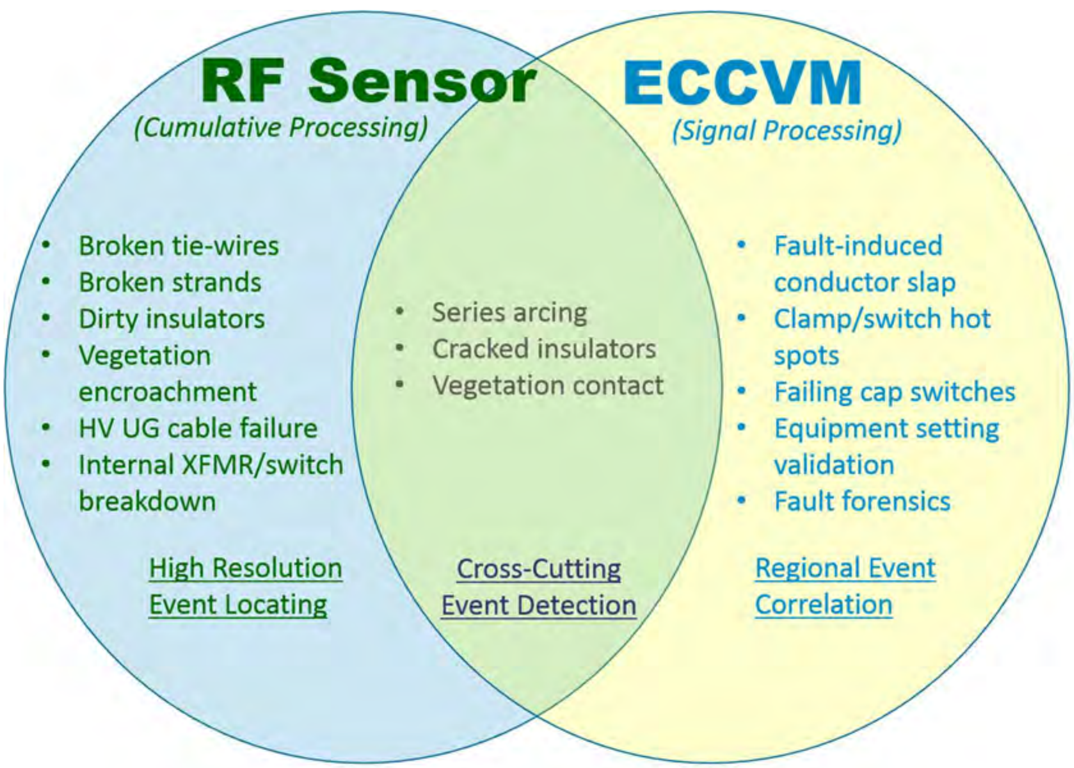
of renewables. During this project ECCVM was able to clearly identify the load increase following a fault.

4.4 Comparison of Technologies

The RF Sensor and the ECCVM technology were both successfully deployed on the 12kV 3-Wire circuit which enabled a side-to-side comparison between the two technologies.

RF sensors utilize a cumulative detection strategy where RF sampling occurs for 1/25th of each second, and "hot spots" are identified as accumulated RF detections at the same location of the circuit. This enable the sensors to identify "hot spots" of partial discharge on the circuit. Arcing that is the result of a single event, or an infrequent period event, can be problematic for RF sensors to detect because the RF sampling window may miss these brief events. ECCVM, in contrast, does continuous monitoring of the waveform with triggering based upon a complex of processed signals so a single arcing event or infrequent events will be detected. Figure 19 shows a Venn diagram of the types of events that will be seen by RF sensors only, ECCVM sensors only, and by both sensors.

Figure 19. RF Sensors and ECCVM Complementary Technologies

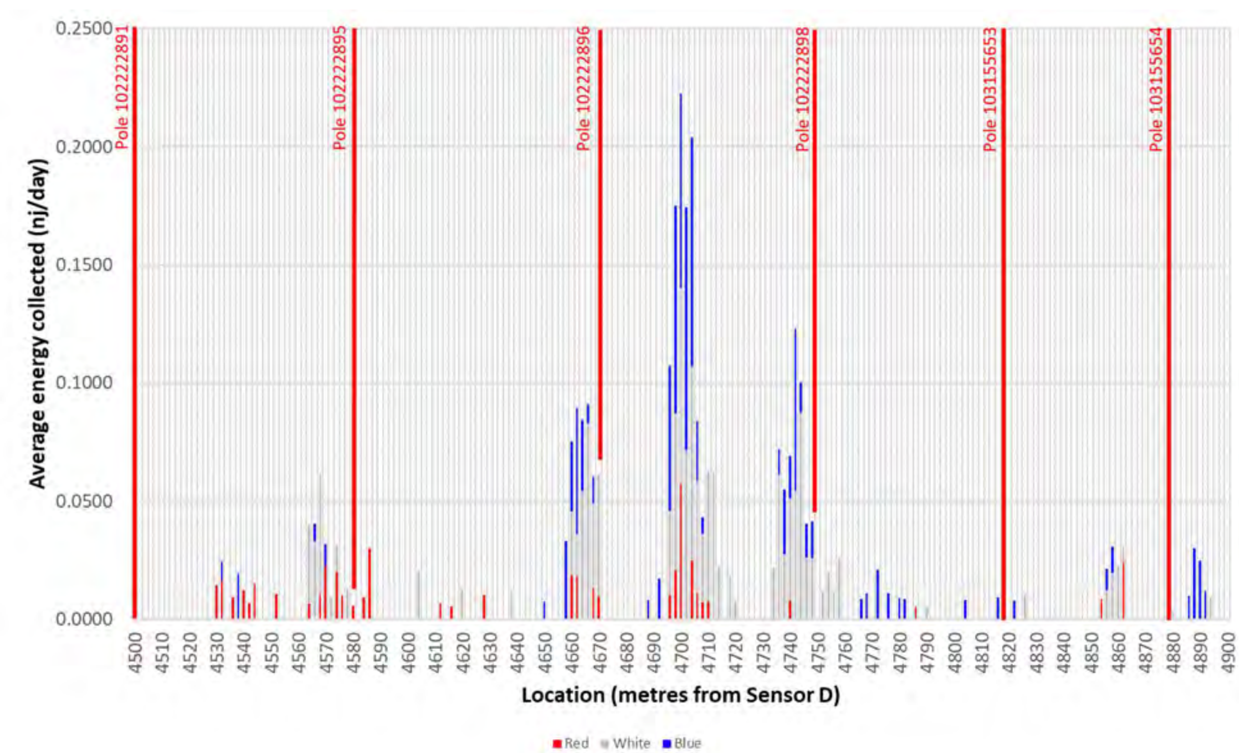


4.4.1 Events detected by only one technology

Events Detected by RF Sensor, but not by ECCVM

The RF sensor technology demonstrated 10 case studies as identified in Section 4.2.8. Of these 10 cases only the conductor arcing event (case 10 in Table 3) was also seen by the ECCVM technology. Of the remaining cases in the table the "damaged conductor as a result of conductor slap" is the only case where ECCVM should have captured data. For that matter, both line sensors and protective equipment should have also detected this type of event. A conductor slaps is a metal-on-metal condition which would have produced a large fault current and resulted in a strong voltage and current signal. The reason ECCVM would not have capture this event is that the conductor slap could have occurred outside of the project monitoring timeframe, such as before the monitoring began. The RF sensors detect RF conducted signal which occurs as a result of the conductor's damage and not just a result of the conductor slap event. Figure 20 shows the D-E RF Sensors pair cumulative energy near the damaged conductor form conductor slap.

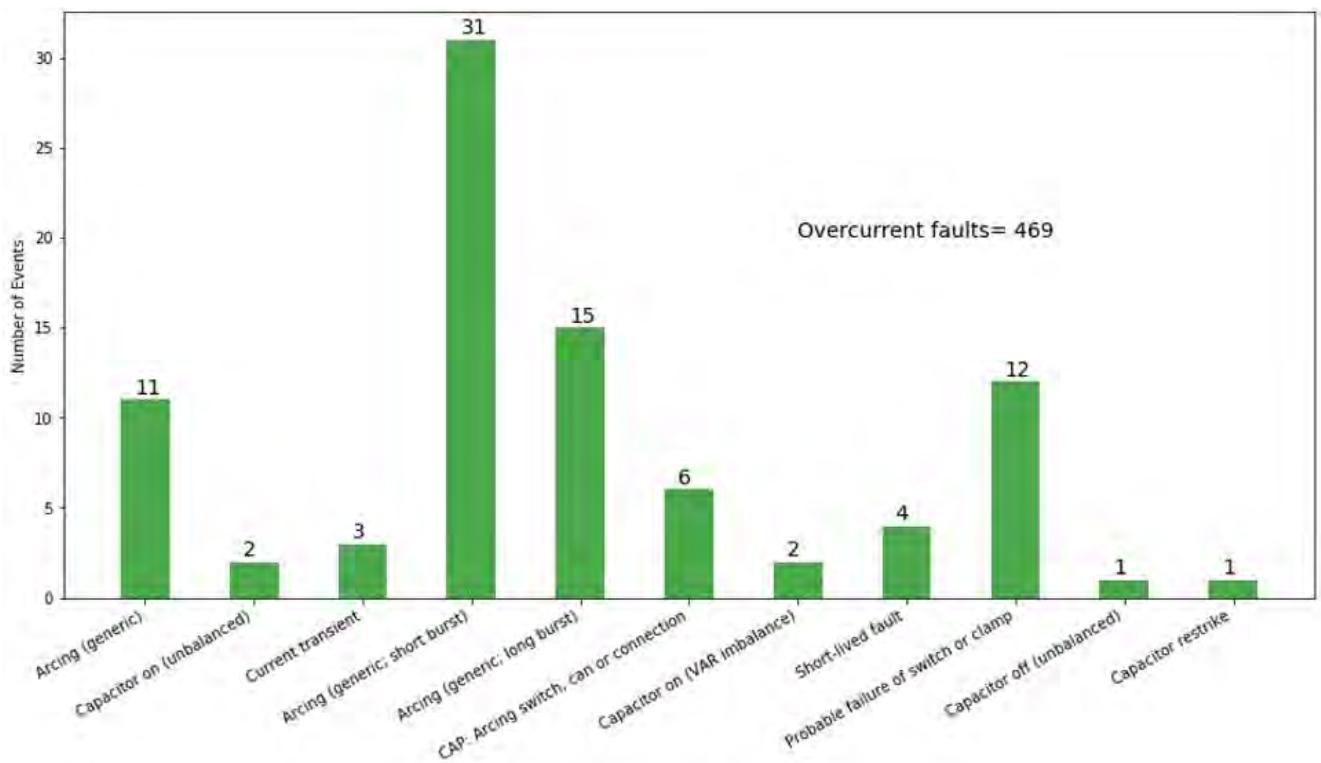
Figure 20. Data from Path D-E Daily Energy (13.71 days, 2-meter segments)



Events Detected by ECCVM, but not by RF Sensor

Figure 21 shows the different types of abnormal event that were capture by ECCVM on the EFD monitored circuit. This figure does not include overcurrent fault, there were 469 overcurrent faults on the circuit during the project. Of these events the RF sensors capture majority of the 12 "Probable failure of switch or clamps" and only one part of a shunt arcing event. This is in part because of the difference in monitoring strategies of the two sensor packages.

Figure 21. ECCVM Captured Abnormal Events on the circuit



4.4.2 Events detected by multiple technologies

The series-arcing events ("probable failure of switch or clamps") were discussed earlier in Section 4.3.5. For two of the ECCVM capture series-arcing events the RF sensors also captured the same events (see Section 4.2.8), with the matching timestamp. Correlation of the two sensors' data can be seen in Figure 22 and Figure 23. Series-arcing events have a relatively long duration for acing events, typically seconds in length. This allows the RF sensors to capture these events with their periodic sampling strategy.

There were some operational problems with RF sensor in proximity to the third event and that may have contributed to the RF sensors not capturing data for that event.

The RF sensor data and the ECCVM event timestamp are shown in Figure 23 for the one shunt-arcing event that was captured by both devices. Most of the shunt-arcing events captured by ECCVM are very short duration, one to two cycles and RF sensors, using a periodic sampling strategy, can't detect this type of shunt-arcing reliably. As Figure 23 shows, the RF sensor only captured data toward the end of the event, just before failure.

For the events detected by both types of sensors none of the alarming was done via the RF sensor's portal. All alarm notifications were done using the ECCVM "Grid Monitoring" portal.

Figure 22. Timeline of Sensor K Maximum Voltage and ECCVM Events

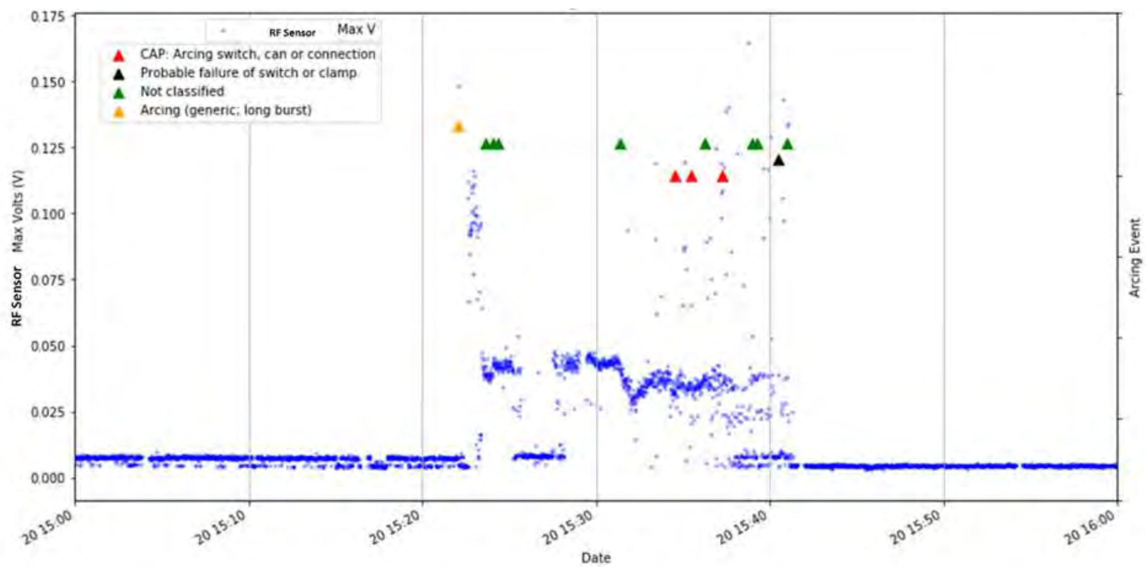


Figure 23. RF Sensor Pair D-E Energy for 3/15 to 3/22

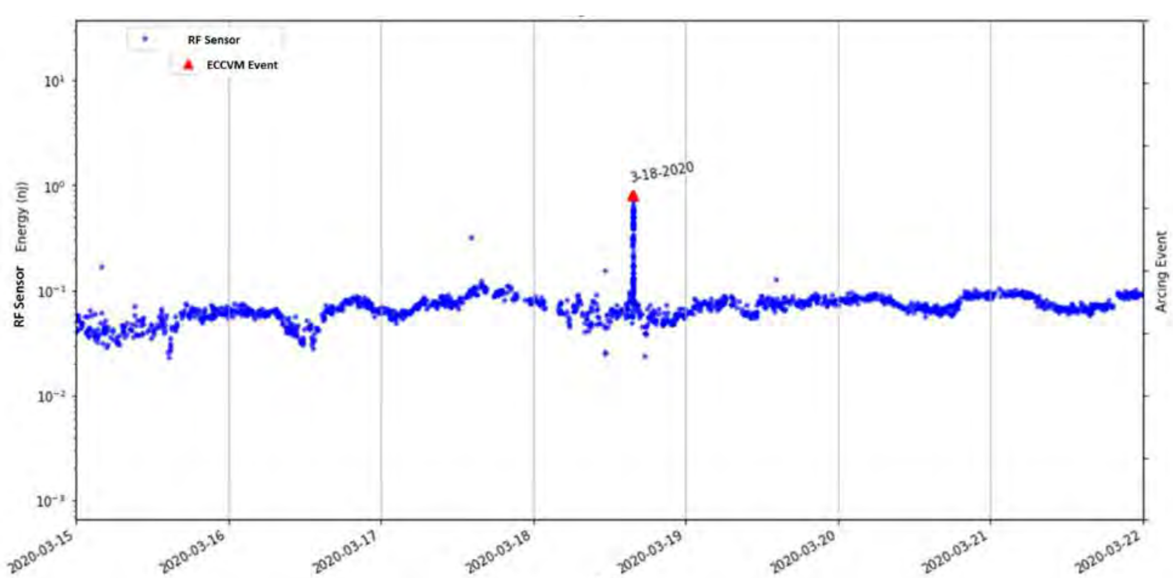
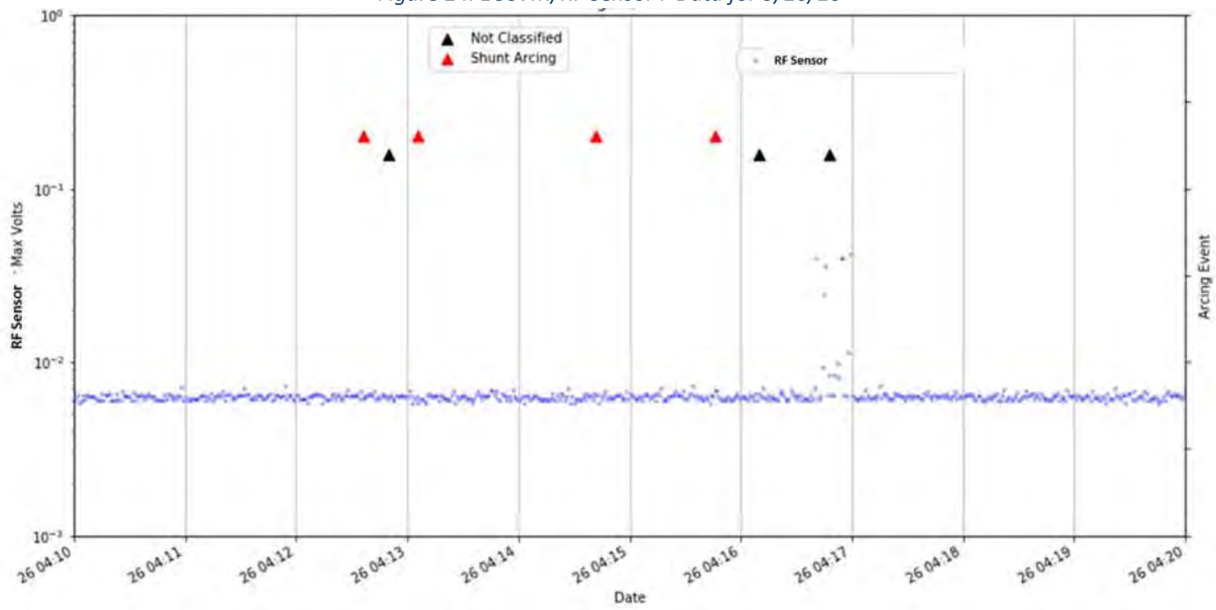


Figure 24. ECCVM/RF Sensor F Data for 5/26/20



5 Value proposition

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity customers of PG&E, San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). EPIC 2.34 RF Sensors project has successfully demonstrated the field deployment of RF sensors to capture incipient system conditions. It has used ECCVM technology to validate the performance of the RF sensors and provided a comparison of the RF and ECCVM sensor technology in side-by-side field deployment. It also showed that sensors can work in an ensemble approach, building on the strengths of each technology, to monitor the grid for developing hazards.

5.1 Primary Principles

The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting increased safety, greater reliability, and lower costs. This EPIC project contributes to these primary principles in the following ways:

- **Increase safety**

RF network monitoring offers to reduce the rate of occurrence of many classes of network faults that are known wildfire risks in California and globally. The technology predicts powerline fire risks ranging from vegetation encroachment to conductor (and conductor clamp) failure. Its predictive identification of risks allows them to be addressed proactively before they materialize.

The ECCMV technology provides identification and classification of abnormal series and shunt arcing that the RF networking monitor technology not detect or elevate. The project demonstrated that the ensemble sensor technology approach provides backup and needed validation between sensor technologies resulting in a resilient and robust vision into the performance and risks of the distribution system.

- **Greater Reliability**

RF network monitoring system offers to reduce the number of network faults caused by deteriorated, damaged and compromised electricity network assets. The risks predictively identified in the trial were all known to be common causes of faults on PG&E's electricity distribution and transmission networks - faults that can and do regularly lead to interruptions to customer supply. Early warning of these risks can prevent the associated supply interruptions, thereby increasing supply reliability. Additional reliability that will result from identification of systemic fault conditions as has been demonstrated with the ECCVM on fault inducted and wind induced conductor slap.

- **Lower Costs**

Cost saving from RF Network monitoring and ECCVM technology will result from the difference between repair to damaged equipment under normal schedule operating conditions instead of emergency conditions. If hazardous asset conditions are allowed develop to faults and asset failure, there is additional damage to asset infrastructure through the wear and tear of faults, as well as collateral damage to equipment near the fault. Additional operational performance savings, such as reduction in system losses, would be achieved through the validation of correct operations of field equipment as was demonstrated with ECCVM's ability to detect asymmetrical capacitor operations and voltage overshoot from regulator control settings.

5.2 Secondary Principles

EPIC also has a set of complementary secondary principles. This EPIC project contributes to the following secondary principles:

- Societal Benefits

Improved reliability support from both the RF and ECCVM technology achieves a lower cost of service through a reduction in losses and, lessening the overall cost of electric service to all customers, and is extended to society through shared economic interests in efficiency improvements.

- Greenhouse Gas Emission Reduction

ECCVM was able to identify the system condition where PV based distributed generation would trip-off after a fault induced voltage sag, called a "hidden load" event. These conditions have been suspected to occur for some time and the new Rule 21 requirements for smart inverters included features that mitigate the tripping of inverters under fault conditions. The enhanced monitoring fidelity of ECCVM will provide a method to validate this feature. Reducing or eliminating the "hidden load" effect will help with DER deployment on PG&E's system which will help reduce greenhouse gas emissions.

5.3 Accomplishments and Recommendations

5.3.1 Accomplishments

The project achieved much in its short period of operation. The accomplishments are summarized by technology stream. Overall project accomplishments are summarized in their own section.

Technology 1. Prototype RF Sensor Accomplishments

Demonstrated the use of RF Monitoring for Grid Condition Assessment: Evaluated ten prototype sensors and a machine-learning model to assess grid conditions in 1 Km^2 area. Supplier has miniatured hardware components for fitting and integration into a conductor-mounted line sensor. Further development work is needed to define grid deployment strategy, data processing and visualization.

Technology 2. RF Network Monitoring Technology Accomplishment.

Installed RF network monitoring systems on one circuit: Nineteen RF data collection units were installed on poles on three-wire 12kV circuit. Secure cloud IT infrastructure used by RF network monitoring systems in other countries was replicated to a US-located data center in accordance with cyber-security requirements.

Successfully used RF network monitoring to detect real risks: Used the RF network monitoring systems to predictively identify the locations of multiple examples of conductor damage, vegetation encroachment, plus single instances of internal transformer discharge, and arcing at a loose conductor clamp. All of the detected risks are known powerline wildfire risks, and all were identified early and accurately located to within a few tens of feet. Some of the conductor damage was repaired as a priority following identification. Multiple instances of vegetation encroachment were observed.

Trained PG&E team in interpretation and analysis of results: Introduced PG&E team members to RF network monitoring concepts, the functions and operating envelope of the RF data collection units, the web portal data visualizations and the desktop analysis tools.

Successfully managed a range of challenges: Challenges overcome in operating RF network monitoring included challenges with pole space for the sensors, problematic cellular data service availability, poor solar insolation. Acted to ensure RF network monitoring continued throughout the trial. Developed forward management strategies for each of these challenges.

Gained deep appreciation of the value of RF network monitoring for PG&E: The trial revealed the results and data available to utilities from RF network monitoring and provided data needed to assess its tactical and strategic business value.

Developed forward technology adoption scenarios: In collaboration with the Supplier, identified the challenges of wider adoption and developed strategies to manage them to obtain maximum value from RF network monitoring.

Technology 3. ECCVM Technology Accomplishments

Installed ECCVM on six circuits: ECCVM devices were successfully installed on 6 circuits in the Napa Valley. Installation required full substation project design and review, IT security review, and commissioning. The successful installation of the devices provided consistent resource and financial estimates for scaling of the technology.

Successfully used ECCVM to detect incipient, recurrent fault, and operational events: The ECCVM technology captured over 32, 000 events on the 6 monitored circuits for the duration of the project. Most of these events were related to routine operations, but the devices did provide new visibility into operations issues including capacitor asymmetric switching, voltage regulator settings validations, hidden load issues, and non-project sensor tuning. The ECCVM technology was able to provide detailed forensic fault information, such as fault-inducted conductor slap, that identified systemic problems. ECCVM captured incipient conductor clamp arcing and vegetation contact through series and shunt arc detection.

Demonstrated an ensemble approach of the use of sensors to locate and identify events: ECCVM's locating at a substation limited the technologies capabilities to locate on the distribution feeder the exact area of issue. However, using the ECCVM as a compass of "when" and "what" is occurring on the feeder with other sensor packages, such as AMI, locations could be narrowed for operational patrolling. An example of this is when ECCVM's series-arcing was used with AMI to locate a failed jumper connector and fuse candling.

Successfully share operational experience on ECCVM both internally and externally: The project team has conducted internal presentations on ECCVM to operational and engineering departments within PG&E. The project team has also participated in a bi-weekly phone call with technical leads from SCE.

Overall Project Accomplishments

Compared RF and ECCVM technologies in a field deployment: The field deployment of both RF sensing and ECCVM sensing on the same feeder provided a side-by-side comparison of the two technologies. This comparison demonstrated the capabilities of both technologies and contrasted their detection strategies. The comparison also identified technology gaps in the detection of certain types of shunt-arcing events with RF sensing able to detect very low energy shunt-arcing and ECCVM detecting short single event shunt-arcing. RF sensing demonstrated its ability to locate the source of incipient events and ECCVM demonstrated its ability to capture high resolution time characteristics of events.

5.3.2 Recommendations

The successful performance of RF network monitoring and the demonstration of ECCVM technology in the current project leads to the following recommendations:

Expand RF Sensor 2 to Larger-scale Trial: Carry out a larger-scale trial of RF network monitoring to better define the challenges of wider adoption and identify strategies to address these challenges so maximum safety and reliability benefits can be delivered to Californian communities. A first step will be to extend the current deployment and testing to refine monitoring and operating techniques. Further expansion will be scheduled to match resources and technology refinement availability. Investigate the feasibility and benefits of RF Technology integration with the Distribution Management System for fault location, root cause analysis and preventative maintenance enhancement, as well as integration with Rapid Earth Fault Current Limiting technology to identify faulted protection zone.

Move ECCVM into a Production Footing: ECCVM is a very cost-effective technology that enables a significant improvement in data resolution and operator situational visibility into PG&E's electric distribution system. This capability should be moved into a staged production path and exercised as part of a risk assessment activity.

Integration opportunities: In conjunction with larger-scale RF deployment and production footing for ECCVM, explore and assess the potential benefits of integration this network monitoring data with data from other network monitoring technologies and relevant non-network data sources. Develop operational interface and combined data analytics tools for expanded operational usage.

Expand Shunt-arcing Research: ECCVM detection of shunt-arcing has not been seen before with PG&E's existing monitoring technology and the projects companion RF sensors were not able to detect these types of low energy arcing. RF sensors are great at detection of lower-energy partial-discharge events through a cumulative strategy, but the shunt-arcing instantaneous events of greater energy are missed by this strategy. Unfortunately, ECCVM by itself has been unable to help further identify direct causes of these arcing events as it cannot paint the location. Related system faults around shunt-arcing events has been able to provide circumstantial evidence of potential causes but the goal of identifying the cause while still a shunt-arcing event (no fault) has not been achieved. This area needs further research to better understand the shunt-arcing events and close the technology gap in shunt-arcing event locating.

5.4 Key Accomplishments

The following summarize some of the key accomplishments of the project over its durations:

- Demonstrated stationary RF sensor grid health monitoring with prototypes and an analytical model for locating deteriorated grid assets.
- Successfully demonstrated both RF Network Monitoring and ECCVM technologies in a field deployment.
- Demonstrated RF sensing technology's ability to identify and locate conductor damage, vegetative encroachment, and arcing component incipient events in the field.
- Demonstrated ECCVM technology's ability to identify series-arcing events related to conductor clamp failure. Using AMI data with ECCVM, locate the series-arcing events.
- Identified technology gap of shunt-arc detection where current RF sensing technology often misses in the sampling window the ECCVM-detected shunt-arcing such that the source asset cannot be located.

5.5 Key Recommendations

The project's work identifies several areas that should have continued effort. The following summarizes these recommendations:

- Carry out a larger-scale trial of RF network monitoring to better define the challenges of wider adoption and identify strategies to address these challenges so maximum safety and reliability benefits can be delivered to Californian communities.
- In conjunction with a larger-scale trial, explore and assess the potential benefits of integration of RF network monitoring data with data from other network monitoring technologies and relevant non-network data sources.
- Move ECCVM into production with a staged approach to match ongoing technology monitoring and system risk assessment activities.
- Expand research into the technology gap on shunt-arcing.

5.6 Technology transfer plan

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within PG&E, and across the other IOUs, the CEC and the industry. In order to facilitate this knowledge sharing, PG&E will share the results of this project in industry workshops and through public reports published on the PG&E website. Specifically, below is information sharing forums where the results and lessons learned from this EPIC project were presented or plan to be presented:

5.6.1 IOU's technology transfer plans/ Information Sharing Forums Held

- SDG&E Visit to PG&E, San Ramon, CA - February 14, 2020
- California Utility Wildfire Risk Reduction Meeting, Conference Call - February 18, 2020
- PG&E/SCE DFA Demonstration Check-In, Conference Call/February 28, 2020 and June 12, 2020
- PG&E/Duke Energy Discussion of RF Monitoring, Conference Call/May 20, 2020
- PacifiCorp & PG&E Discussion of Asset Health Monitoring, Conference Call/June 12, 2020
- PG&E has participated in multiple information-sharing meetings with SCE and other utility companies in California and elsewhere related to ECCVM-detected events and response, Multiple dates since 1/1/2020 and continuing

5.6.2 Information Sharing Forums Planned

- Texas A&M Conference for Protective Relay Engineers, College Station, Texas, April 2021
- CIGRE Grid of the Future Conference, Providence, Rhode Island, November 2020
- iPCGrid (Innovations in Protection and Control for Greater Reliability Infrastructure Development) Workshop, California, April 2021

5.7 Data Access

Upon request, PG&E will provide access to data collected that is consistent with the CPUC's data access requirements for EPIC data and results.

6 Metrics

The following metrics were identified for this project and included in PG&E's EPIC Annual Report as potential metrics to measure project benefits at full scale.[8] Given the proof of concept nature of this EPIC project, these metrics are forward looking.

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[8] 2015 PG&E EPIC Annual Report. Feb 29, 2016.
http://www.pge.com/includes/docs/pdfs/about/environment/epic/EPICAnnualReportAttachmentA.pdf

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area)	Reference
3. Economic benefits	
a. Maintain / Reduce operations and maintenance costs	3.1, 5.1, 5.2
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
d. Public safety improvement and hazard exposure reduction	3.1, 5.1

7 Conclusion

Utility operational practices have been stagnant while available technologies have been unable to respond to the challenges presented by aging grid infrastructure and the increasing risks of climate-change driven stresses and environmental sensitivities, which in California is predominantly the risk of wildfire ignition. This project has demonstrated and evaluated the potential of recently commercialized technologies for the application of continuous grid asset health and performance monitoring. Just-in-time maintenance is an optimal strategy with lower cost than time-based maintenance and lower risk than periodic inspection-based maintenance that can miss rapidly developing grid asset hazards.

RF network monitoring technology sensors can successfully detect and accurately locate incipient failure conditions for corrective maintenance and wildfire risk mitigation. The technology is highly sensitive and able to detect low level partial discharge activity such as primary conductor damage and vegetative encroachment on secondary conductors. There are additional use cases PG&E plans to explore, including integration with the Distribution Management System for fault location, and potentially integration with Rapid Earth Fault Current Limiting (REFCL) to identify faulted protection zone. Distributed sensors technologies present some deployment challenges such as finding pole space and adequate cellular coverage, streamlining the estimating and installation processes that PG&E will continue to evaluate and optimize. The product supplier is planning several promising technology advancements that PG&E plans to demonstrate through expanded deployment.

The ECCVM technology effectively detects and classifies normal operating events and abnormal events that can be predictive of developing hazards. The ECCVM technology is not able to detect the same low-level persistent conditions that RF monitoring can, but it is able to detect brief <2 cycle duration arcing events that the RF Network Monitoring Technology may not detect, or may not detect in a timely manner. ECCVM technology cannot determine the source location of detected events and relies upon distributed sensor technologies, including RF Network Monitoring Technology, Line Sensors, and AMI, for this purpose. The ECCVM technology was shown to be successful at detecting shunt-arcing events that RF sensors, as currently designed, do not reliably detect, therefore presenting a challenge for the location of shunt arcing source. Through circumstantial data these shunt-arcing events have been validated to be real, and potentially hazardous, events. The RF technology supplier has plans to progress to continuous RF monitoring and if successful, this may close the gap and allow the RF technology to provide the source location of shunt arcing events.

The project has been able to demonstrate incipient conditions can be identified and located with the combining of sensor data into an ensemble approach, with each technology adding uniquely to the event classification, location and prioritization of detected hazards. The ensemble approach provides backup and needed validation between sensor technologies resulting in a resilient and robust vision into the performance of the distribution system. When there are areas that cannot be served by RF or Line Sensor components, AMI may be able to provide some of the necessary information for effective grid monitoring. PG&E's Distribution and Grid Monitoring Roadmap and Implementation Plan proposes to expand deployment and operation of emerging technologies, such as those demonstrated in this project, that provide grid event data for real-time monitoring and analytics of asset health and performance. PG&E strives to become more predictive of developing hazards on the electric distribution system for implementation of proactive maintenance in order to reduce wildfire risk and improve public safety. This work focuses on Tier 2 and Tier 3 High Fire Threat District areas of PG&E's service territory.

During the technology evaluations with limited deployments, the sensor data was manually analyzed and reacted upon. PG&E recognizes that the manual approach is not scalable for either resource allocation or rapid response to detected grid asset conditions. Clearly wide-scale adoption of grid monitoring technologies would require a sensor data integration and analytics platform to provide automated analysis and response for asset hazards. PG&E has plans to investigate approaches to this problem, which can enable timely analysis and response to data from multiple grid sensor technologies that report asset health conditions.

Pacific Gas and Electric Company

EPIC Final Report

Program	***Electric Program Investment Charge (EPIC)***
Project	***Dynamic Rate Design Tool***
Reference Name	***EPIC 2.36***
Department	*Regulatory Affairs*
Project Sponsor	Megan Lawson
Project Business Lead	Deb Ghosh
Contact Info	EPIC_Info@pge.com
Date	August 14, 2020
Version Type	*Final*
Version	Version 1.3

Table of Contents

Table of Acronyms /Glossary

Bill Determinant	A bill determinant is a function of a customer's delivered or received loads.
Customer	For purposes of this tool, a customer is the basic entity for which rates are calculated. For the forecast data, a customer is a profile of attributes, such as baseline territory, heating code, etc. that represents the average entity with those attributes. For each profile, there is an associated interval load shape for the year and a count of the entities represented by that profile. For the historical data, a customer could be a meter (service point id), person (service agreement id), plot of land (premise id) or some combination.
Customer Group	A set of customers grouped together by common attributes. For example, grouping all low-income customers together to form a low-income customer group.
Customer Tree	A hierarchical grouping of customer groups that stores the relationships between groups of customers.
EPIC	Electric Program Investment Charge
Evaluation Metrics	An evaluation metric is a quantitative measure of the rate design. The principal evaluation metrics are: • Bill Impacts: A comparison of customers' bills under two different rate schedules or scenarios. • Bill Volatility: A measure of how much a customers' bills vary. • Energy Burden = The ratio of a customer's annual bill to annual income. • Subsidy = The difference between a customer's annual revenue and annual cost of service.
Rate Component	A dollar per kWh, kW, customer-month or some combination of the three. A rate component is multiplied by a bill determinant with the same units to get the revenue.
Rate Schedule	A rate schedule is set of formulas comprised of individual bill determinants and rate components that specify how customers' monthly bills and annual bill are calculated.
Rate Design	A rate design is a system of equations that specify how the rates and the revenues from customers and rate schedules are related.

Customer Profile	A group of customers that are assumed to be homogenous. The lowest level at which hourly loads are forecasted and the lowest customer-unit at which calculations are done for the forecast data.
Good or Service	A good or service or function that PG&E performs for the customer such as generation or distribution. Each good or service has a revenue requirement.
Customer ID	A positive integer that identifies a particular customer profile
Tag	A tag is a label that is used to identify a customer group or customer tree as having some particular attribute.

1 Executive Summary

This report summarizes the project objectives, technical results and lessons learned for Electric Program Investment Charge (EPIC) Project 2.36 *Dynamic Rate Design Tool* as listed in the EPIC annual report.

1.1 Objectives

The key objectives of EPIC 2.36 were to:

- Demonstrate a more dynamic rate design tool[1] approach for modeling customer bill impacts from changes to rates and new rate scenarios;
- Leverage advanced approaches, such as distributed computing or parallel processing, that can be applied to the rate design process;
- Explore a faster and easier process to experiment with new bill determinants and analyze impacts of different scenarios under consideration, such as impacts of Distributed Energy Resource (DER) adoption.

The vision for this project was to design an experimental rate design tool for scenario analysis. As the penetration of technologies, such as DERs, continues to grow, the Company identified an opportunity to develop a rate scenario engine that could provide analysis without the time constraint of its "production" rate models. In order to perform quick analysis of multiple scenarios that utilize "big data," the Company would demonstrate that such a rate engine could be built on a distributed computing platform. Although the envisioned tool is not a replacement for existing production quality rate models which are built on hundreds of mandated policies and rate design principles, it was intended as a dynamic rate design and evaluation product that can provide directional information for making policy decisions.

1.2 Issues Addressed

Current rate design and evaluation tools were built on technologies from decades ago. PG&E's rate design models are in Microsoft Excel spreadsheets, upstream (to rate design) bill determinant models and downstream rate evaluation models are in SAS whereas customer demographics, billing and hourly usage data are stored in Teradata database. It requires significant back and forth coordination among the proceeding witnesses, rate analysts, and data analytics team to prepare all inputs and outputs for rate design. The current labor intensive and time-consuming processes limit the ability of PG&E to experiment with new and novel rate designs using these tools and processes. While PG&E's existing rate design models remain necessary for formal proposals in regulatory proceedings at the California Public Utilities Commission (CPUC or Commission) or at the Federal Energy Regulatory

[1] Note that the term "dynamic rate design tool" as used here, refers to the flexibility of the tool itself and is not a reference to dynamic pricing structures, i.e., rates structures where price signals are sent to customers.

Commission (FERC), those models are not nimble for exploratory or scenario-based rate design work for new technologies, such as DERs.

1.3 Key Accomplishments

The following has been accomplished through this project:

- PG&E built a distributed computing platform leveraging Amazon Web Services (AWS), which have been deployed in production at the conclusion of this project.
- PG&E extracted residential customers' characteristics and hourly usage data for one year and created a database, utilizing big data technologies, that enables the processing of billions of rows of information in a few hours, compared to a number of days using PG&E's current process
- PG&E built a high-level rate design framework that can enable a faster and easier experimental rate design process.
- PG&E built high level building blocks for experimental rate design so users can dynamically segment customers, create bill determinants, design new rate structures and evaluate their bill impacts.
- PG&E built application programming interfaces (API) for users to interact with the above building blocks to design and evaluate rates at a high level.

These key accomplishments are foundational for the future development of a more fully functional rate design and evaluation product. At this stage, the tool can design high level experimental tiered, time-of-use, and tiered time-of-use rates as well as rates with a maximum demand charge. It is important to note that the milestones that PG&E achieved in support of building the dynamic rate design tool (e.g., creating the distributed computing platforms, database, and design framework) are not only proof of concept, but can be leveraged to significantly improve other production-grade tools for rate and bill analysis that are built on existing technology.

1.4 Challenges and Lessons Learned

Rate design and, in general, pricing models are industry-specific, and the rate design requirements of a California electric utility are overwhelmingly complicated. To develop a faster, easier and more flexible pricing model that is capable of handling millions of customers' hourly usage (approximately 1.5 terabytes of data), expert data engineering and data science skillsets are required. Finding experienced resources that could pair data science and newly taught utility pricing concepts proved to be the most challenging aspect of this project.

Creating experimental bill determinants iteratively, rapidly and on-demand using terabytes of hourly usage data as well as calculating monthly bills for over 4 million customers, which was required to solve rates, proved to be quite a challenge even for a distributed computing environment and required extensive research and development on database design and parallel processing capabilities. The team addressed that by implementing an innovative approach to sort and partition customers' hourly usage data before storing them in the distributed computing platform.

1.5 Conclusion

The key features of a Dynamic Rate Design Tool were successfully demonstrated, laying the groundwork to enable PG&E to improve rate design and evaluation capabilities in the future.

Rate design for regulatory proceedings and implementation in tariffs is based on numerous niche policies, rules, and principles which are often conflicting and constantly evolving. While this tool cannot be a replacement for PG&E's operational rate design models used in rate cases, PG&E concluded that big data technologies can provide a one-stop solution to build experimental rate design and evaluation models, back-end customer database as well as front-end user interface. This provides a consistent and cohesive approach for designing, developing and deploying complex yet flexible applications that are also easy to maintain in the future.

PG&E demonstrated five distinct rate designs in this project. This demonstrates that a fully functional product using this framework can potentially model hundreds of illustrative rate design scenarios in a limited amount of time and effectively assess impacts to utility customers.
However, such a fully functional product requires improving usability through development of a custom graphical user interface for input and output and integration with utilities' existing customer information and analytics systems.

2 Introduction

This report documents the EPIC 2.36 *Dynamic Rate Design Tool* project achievements, highlights key learnings from the project that have industry value, and identifies future opportunities for utilities to leverage this project.

The California Public Utilities Commission (CPUC) passed two decisions that established the basis for this demonstration program. The CPUC initially issued D. 11-12-035, *Decision Establishing Interim Research, Development and Demonstrations and Renewables Program Funding Level*[2], which established the Electric Program Investment Charge (EPIC) on December 15, 2011. Subsequently, on May 24, 2012, the CPUC issued D. 12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020*[3], which authorized funding in the areas of applied research and development, technology demonstration and deployment (TD&D), and market facilitation. In this later decision, CPUC defined TD&D as "the installation and operation of pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks associated with a given technology."[4]

The decision also required the EPIC Program Administrators[5] to submit Triennial Investment Plans to cover three-year funding cycles for 2012-2014, 2015-2017, and 2018-2020. On November 1, 2012, in A.12-11-003, PG&E filed its first triennial Electric Program Investment Charge (EPIC) Application with the CPUC, requesting $49,328,000 including funding for 26 Technology Demonstration and Deployment Projects. On November 14, 2013, in D.13-11-025, the CPUC approved PG&E's EPIC plan, including $49,328,000 for this program category. On May 1, 2014, PG&E filed its second triennial investment plan for the period of 2015-2017 in the EPIC 2 Application (A.14-05-003). CPUC approved this plan in D.15-04-020 on April 15, 2015, including $51,080,200 for 31 TD&D projects.[6]
Pursuant to PG&E's approved 2015-2017 EPIC triennial plan, PG&E initiated, planned and implemented the following project: 2.36 Dynamic Rate Design Tool. Through the annual reporting process, PG&E has kept CPUC staff and stakeholders informed on the progress of this project. The following is PG&E's final report on this project.

[2] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/156050.PDF
[3] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167664.PDF
[4] Decision 12-05-037 pg. 37
[5] Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and the California Energy Commission (CEC)
[6] In the EPIC 2 Plan Application (A.14-05-003), PG&E originally proposed 30 projects. Per CPUC D.15-04-020 to include an assessment of the use and impact of EV energy flow capabilities, Project 2.03 was split into two projects, resulting in a total of 31 projects.

3 Project Summary

The EPIC 2.36 *Dynamic Rate Design Tool* project demonstrated essential supporting structures that enable flexible rate design and a faster and easier process to evaluate potentially hundreds of such scenarios leveraging big data technologies.

3.1 Project Objectives

The key objectives of EPIC 2.36 were to:

- Demonstrate a more dynamic rate design tool approach for modeling customer bill impacts from changes to rates and new rate scenarios;
- Leverage advanced approaches, such as distributed computing or parallel processing, that can be applied to the rate design process;
- Explore a faster and easier process to experiment with new bill determinants and analyze impacts of different scenarios under consideration, such as impacts of Distributed Energy Resource (DER) adoption.

3.2 Issues Addressed

Current rate design tools were built decades ago when utilities were the sole providers of electricity and DER technology was not prevalent. PG&E's rate design models are in Microsoft Excel spreadsheets, upstream (to rate design) bill determinant models and downstream rate evaluation models are in SAS whereas customer demographics, billing and hourly usage data are stored in Teradata database. It requires significant back and forth coordination among the proceeding witnesses, rate analysts, and data analytics team to prepare all inputs and outputs for rate design. The current labor intensive and time-consuming processes limit the ability of PG&E to experiment with new and novel rate designs using these tools and processes. While PG&E's existing rate design models remain necessary for formal proposals in regulatory proceedings at the California Public Utilities Commission (CPUC or Commission) or at the Federal Energy Regulatory Commission (FERC), those models are not nimble for exploratory or scenario-based rate design work for new technologies, such as DERs.

DERs and other drivers such as EV charging, electrification, regionalization, new service offerings etc. are changing the utility landscape and creating gaps in the current rate design process. For utilities and regulators to address the continued growth expected in technology penetration, there is a need for new capabilities to effectively model the interaction between technology adoption and rates, and to ultimately encourage adoption.

In line with PG&E's strategy to create more equitable, cost-based rate structures that minimize cross-subsidies within revenue classes, a modern rate design tool can strengthen policy decisions by designing and evaluating various experimental rate scenarios. Such a modern rate design tool requires rethinking from the ground up, including:

- an ability to analyze customer data prior to designing rates;
- an ability to dynamically create customer segments based on their characteristics so that experimental rates can be designed either by keeping the same revenue requirement or by changing it to meet certain policy requirements;
- an ability to dynamically create bill determinants using advanced metering infrastructure (AMI) interval meter data for both usage and demand charges for various time-of-use periods;
- a flexible rate design framework so any rate structure can be implemented using the aforementioned bill determinant;
- an ability to calculate customers' bills in a reasonable amount of time; and
- an ability to generate rates in a reasonable time and to evaluate rates using various metrics such as bill impact, bill volatility and energy burden.

It is expected that a modern rate design tool will enable a faster and easier exploratory rate design process for the users as well as make it more cost effective to maintain. Finally, it is required that such a tool be able to process, in a reasonable amount of time, high volumes of customers' (AMI) interval meter data, which is typically over a terabyte (one thousand gigabytes).

3.3 Scope of Work and Project Tasks

To accomplish the above objectives, the project team completed the following tasks:

1. Designed, created and tested a database using big data technologies to store customers' characteristic and hourly usage data spanning one year.
2. Designed, developed and tested a Customer Segmentation module to dynamically crate customer groups based on their characteristics.
3. Designed, developed and tested a Bill Determinant Module to calculate bill determinants using customers' hourly usage data.
4. Designed, developed and tested a Rate Schedule Module to build rate schedules in order to calculate bills for customers in a segment and calculate corresponding revenue.
5. Designed, developed and tested a Rate Design Module to create formula for rate design and solve rates.
6. Designed, developed and tested a Rate Evaluation Module to calculate customers' bill impact, bill volatility and energy burden.
7. Designed and developed an extensible code base so that others can extend the code to incorporate their models.
8. Designed, developed and tested the ability for users to load and save the results of rate design calculations.

4 Project Activities, Results, and Findings

4.1 Technical Development and Methods

The rate design tool framework has a three-tier architecture. The first tier consists of a back-end database hosted on an Amazon Web Services (AWS) cluster. The second tier comprises of the actual rate design and evaluation building blocks, written in Python, Pandas and PySpark, as well as application programming interfaces (APIs), which enable interactions with the building blocks. For the third tier, Jupyter notebook, a web based graphical user interface has been provided to demonstrate the functionalities.

4.1.1 High Level System Overview

The new rate design tool leverages the latest big data technologies to provide computing power and storage to optimize process runtime. The system consists of three tiers which are hosted and based on an AWS cloud distributed storage and computing platform, namely:

1) The data storage in AWS Spark MapR File System:

The AWS cluster with Spark MapR is a clustered file system that supports both very large-scale and high-performance uses. The data stored in MapR is automatically distributed and has native support for parallel processing of the Spark application. The data, which was previously recorded in spreadsheets and SAS, is now stored and partitioned to streamline the data input and output process and support the new rate design tool. The following data is stored in AWS Spark MapR:

- Customer Classification Information
- Customer Historic (AMI) Interval Load Data
- Customer Forecast Interval Load Data

2) The Rate Design Tool in AWS Spark Cluster:

Apache Spark is an open-source distributed general-purpose cluster-computing framework. Spark provides an interface for programming entire clusters with implicit data parallelism and fault tolerance. Spark's core functionality is the implementation of the so-called Map Reduction process which significantly reduces the process runtime. The new rate design tool which is implanted in AWS Spark Cluster has the following modules:

- Customer Group Module
- Bill Determinant Module
- Rate Schedule Module
- Bill Calculation Module
- Rate Evaluation Module

The rate design tool developed through this project consists of basic building blocks necessary to design rates. The user interacts with the tool by creating and combining the building blocks to create a rate design. The number and types of building blocks are such that the user can create any rate design consisting of energy charges, demand charges, customer charges or other charges that are a function of customers' hourly load or demographic information. For rate design, the building blocks include customer groups, bill determinants, rate components, marginal costs, and revenue requirements. The user is presented with a large set of pre-existing building blocks. The user then combines the rate components and bill determinants to build rate schedules. The user can then apply the rate schedules to different customer groups, such as low-income customers or customers with DERs. To solve for the rates, the user specifies equations at the rate level or revenue level. After the rates are calculated, the tool can then calculate the evaluation metrics of the rate design such as bill impact or energy burden.

3) User Interface (UI) in Jupyter Notebook:

The Jupyter Notebook server is deployed in AWS Spark Cluster to provide an interface to the user. The user interacts with the tool by creating and combining the building blocks to create a rate design. It uses rate design APIs described below to invoke each rate design module and return the result in the same interface. For more advanced users, the interface also provides flexible data querying and debugging capabilities. Note the Jupyter Notebook UI is generally used by experienced programmers and is not itself a user-friendly interface.

The high-level system overview of the rate design tool is shown below:

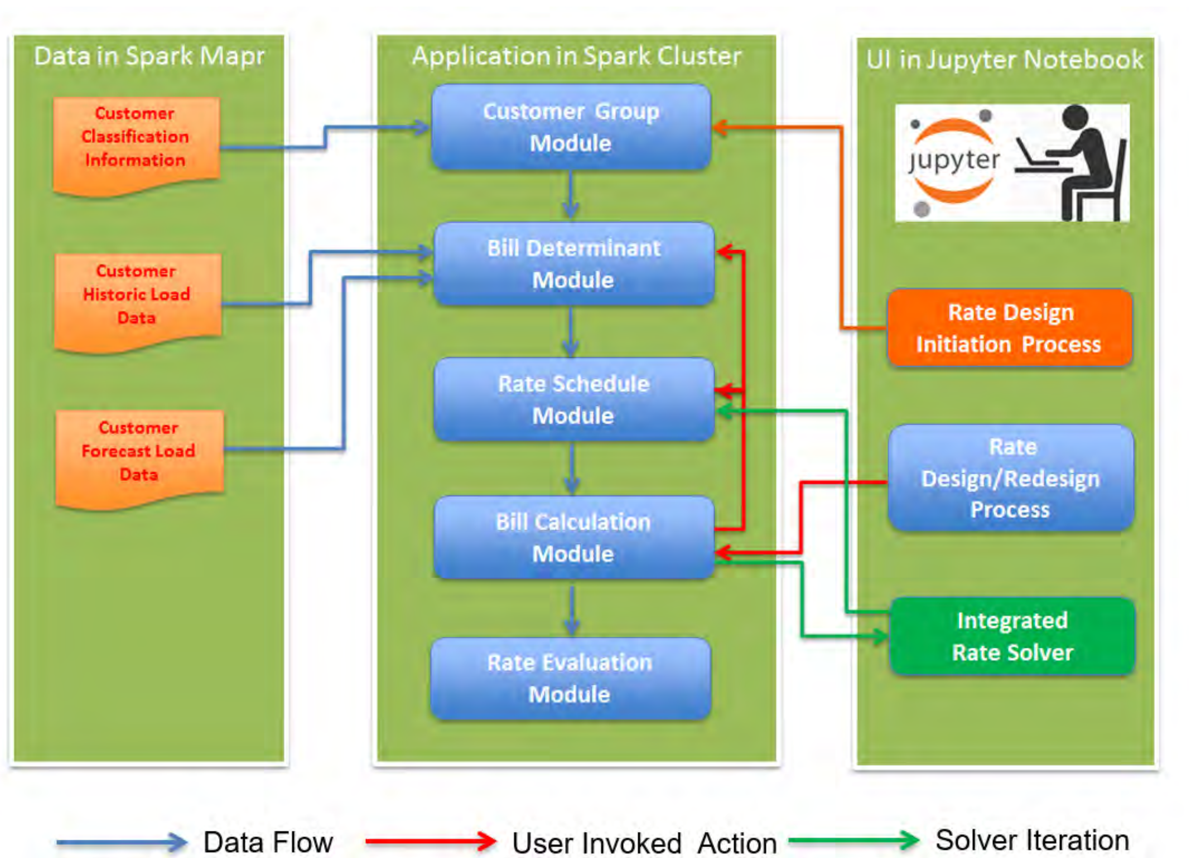


Fig. 1. High Level System View

4.1.2 New Rate Design Process

Users can create any rate design for residential customers based on their hourly load and demographic information. The framework is outlined in the steps below:

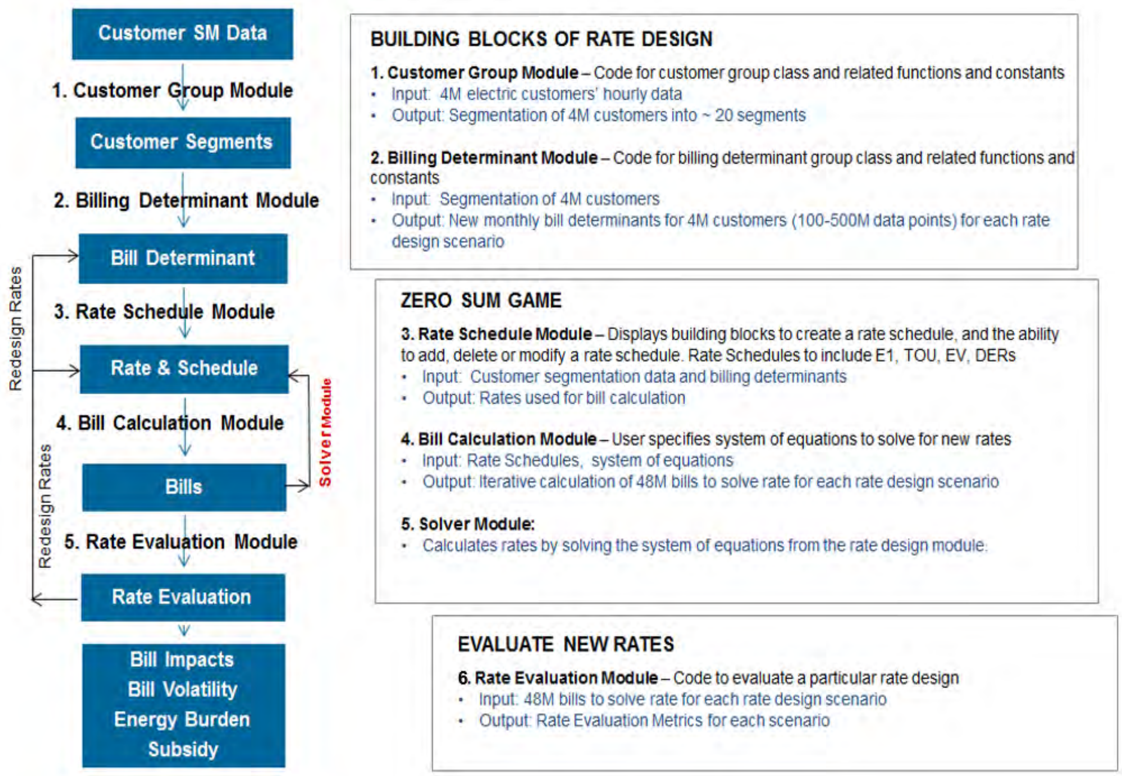


Fig. 2. New Rate Design Process

- Step 1 (Create Customer Groups and Bill Determinants): If customer group, rate component, and bill determinant objects for a rate schedule do not exist, the user must first create them. To facilitate creation of these basic building blocks, the tool will come pre-loaded with libraries that contain the most commonly used customer groups, rate components, and bill determinants. The user can then use these pre-loaded objects as templates for new building blocks or use them directly to create a rate schedule. A user will have the ability to save any user-defined objects to the corresponding libraries.

- Step 2 (Create Rate Schedule and Calculate Bills): If there are not any existing rate schedules or if the user wishes to add another rate schedule to the library of existing rate schedules, the user begins by creating a new rate schedule. To create a new rate schedule, the user selects bill determinants from the bill determinants library and rate components from the rate components library. Lastly, the user selects the customer groups that apply to the rate schedule. The new rate schedule is then saved to the rate schedule library. In addition, the rate schedule library will come pre-loaded with common rate schedules, such as E1 for residential customers, to facilitate the building of rate schedules.

- Step 3 (Create a Rate Design): The next step is to specify the mathematical formulas that relate the unknown rate components and recover revenue from customer groups. The tool will require the user to input the same number of equations as the number of unknown rate components. Inputs into this step are the rate schedules for which the user wants to calculate the rates and revenue.

  Example Rate Design:

  Suppose the user has created two rates schedules: E1A and EL1A. E1A applies to non-CARE customer groups, while EL1A applies only to the CARE customer group. E1A has two energy rate components $r_1$and r_2 and a customer charge component c. EL1A has two energy rate components $r_1'$and r_2'. Since there are five rate components, the user must enter five equations:

  $$
  \begin{aligned}
  &(1)\quad r_2 = 1.25r_1\\
  &(2)\quad c = 10\\
  &(3)\quad r_2' = 1.1r_1'\\
  &(4)\quad EL1A\_CARE\_rev = 0.65\, E1A\_CARE\_rev\\
  &(5)\quad E1A\_nonCARE\_rev + EL1A\_CARE\_rev = RRQ
  \end{aligned}
  $$

  Note that equation (4) is the Public Utility Code Statute 739.1 that states that “the average effective CARE discount shall not be less than 30 percent or more than 35 percent of the revenues that would have been produced for the same billed usage by non-CARE customers.”

- Step 4 (Solve for Rates): In this step, the tool takes all the information from steps 1 and 3 and solves for the rates. In the process of solving for the rates, the tool will make use of the cached bill determinants for each customer group and rate schedule combination. The tool will then take the rate design equations and call the appropriate numerical solver to solve the system of equations. It is expected that the majority of rate designs will be a linear system of equations, although a nonlinear system of equations is possible, for example if the user specifies a monthly or annual minimum bill.

- Step 5 (Calculate Rate Evaluation Metrics): In this step, the tool calculates bill impact, bill volatility and energy burden metrics. The inputs for this step are the bills calculated from step 4 and customer demographic information. The tool will also generate charts to visually display the results.

4.1.3 Rate Design Modules

The following modules of the rate design tool were developed using Python programming language and leveraged the distributed parallel processing capability using PySpark library.

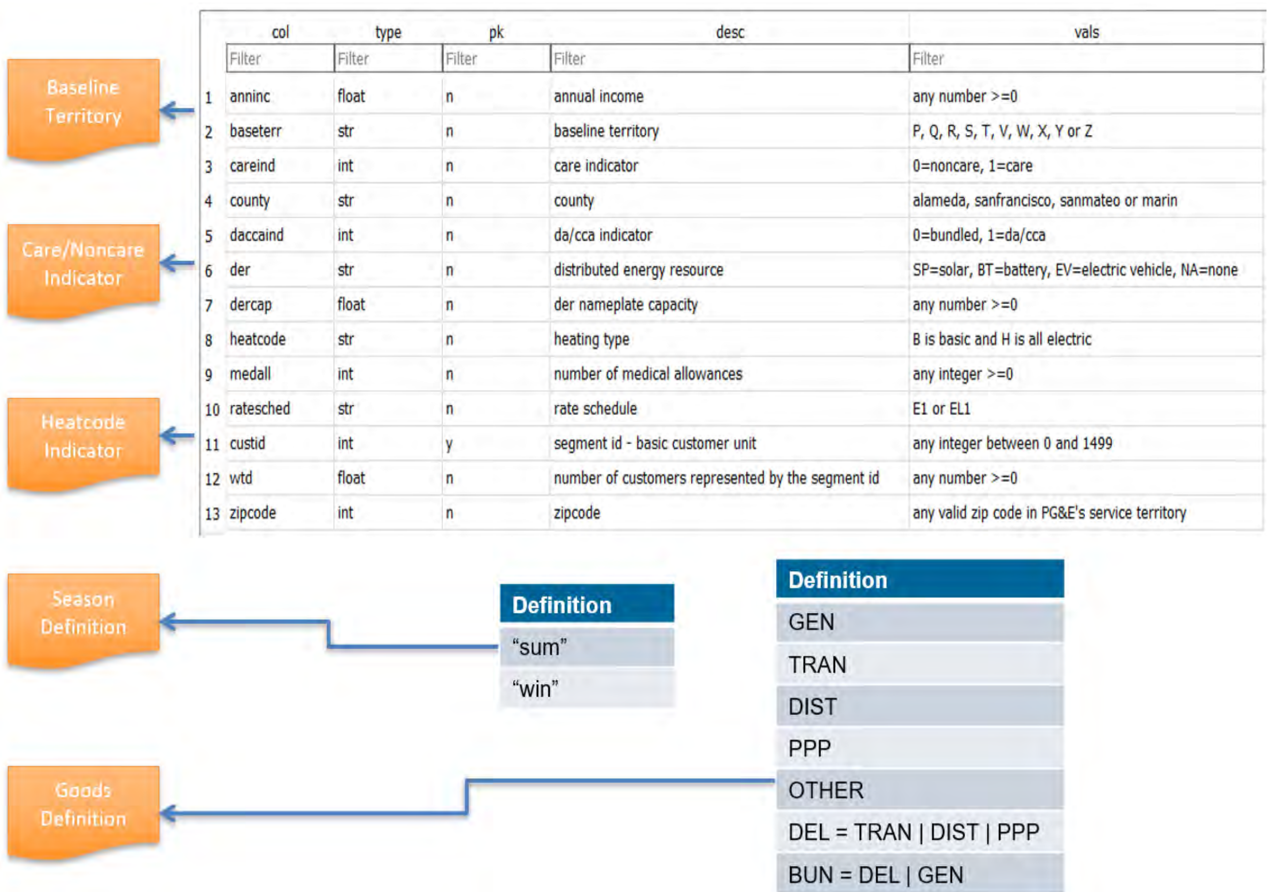
Customer Group Module:

This module enables users to create custom customer groups based on the following customer demographic information:

- Baseline Territory
- Low income (i.e. CARE/Non-CARE) Indicator
- Heating-code Indicator
- Season
- Goods and Service

The customer group information is stored in Spark Map-R cluster and customer demographic data is stored in parquet format which is optimized for distributed parallel processing.

Below is an illustration of Customer Group and Customer Demographic information:



	col	type	pk	desc	vals
	Filter	Filter	Filter	Filter	Filter
1	anninc	float	n	annual income	any number >=0
2	baseterr	str	n	baseline territory	P, Q, R, S, T, V, W, X, Y or Z
3	careind	int	n	care indicator	0=noncare, 1=care
4	county	str	n	county	alameda, sanfrancisco, sanmateo or marin
5	daccaind	int	n	da/cca indicator	0=bundled, 1=da/cca
6	der	str	n	distributed energy resource	SP=solar, BT=battery, EV=electric vehicle, NA=none
7	dercap	float	n	der nameplate capacity	any number >=0
8	heatcode	str	n	heating type	B is basic and H is all electric
9	medall	int	n	number of medical allowances	any integer >=0
10	ratesched	str	n	rate schedule	E1 or EL1
11	custid	int	y	segment id - basic customer unit	any integer between 0 and 1499
12	wtd	float	n	number of customers represented by the segment id	any number >=0
13	zipcode	int	n	zipcode	any valid zip code in PG&E's service territory

Fig. 3. Customer Group, Season and Rate Component Information

Bill Determinant Module:

This module performs the customer level usage aggregation calculation based on the customer group information and intended rate design specification. The process includes the following sub-processes:

- Customer load import based on selected user group
- Customer load aggregation based on rate (Tiered or TOU) specification
- Customer monthly usage calculation

Below is the diagram of the Bill Determinant Module:

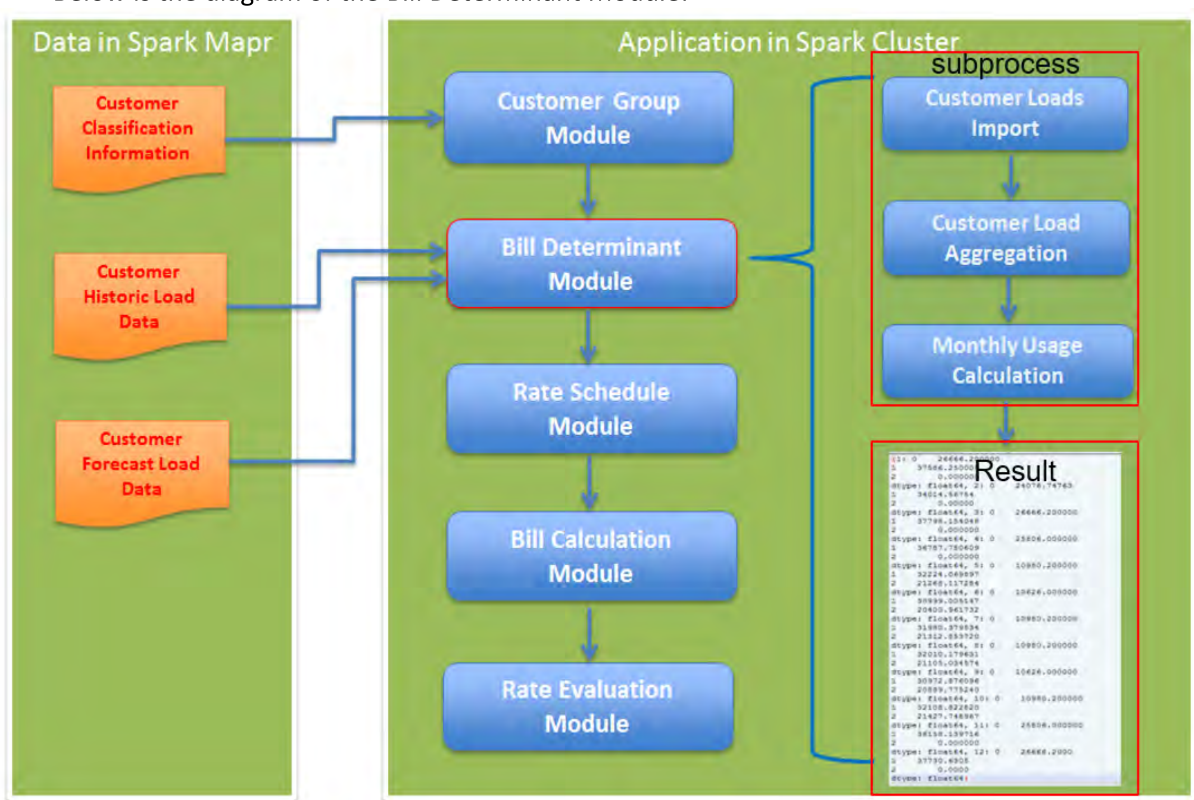


Fig. 4. Bill Determinant Module Diagram

Rate Schedule Module:

This module performs the runtime rate schedule formulation design. The rate designer will use this module to add, modify and delete rate schedules for intended rate design scenarios. The module has been implemented for the following rate schedules:

- E1 (tiered rate)
- E TOU B (time-of-use rate)
- E TOU A (tiered time-of-use rate)
- EVA (special TOU rate for Electric Vehicle customer)
- DER (special rate with a demand charge for potentially DER customers)

Below is the diagram of the Rate Schedule Module:

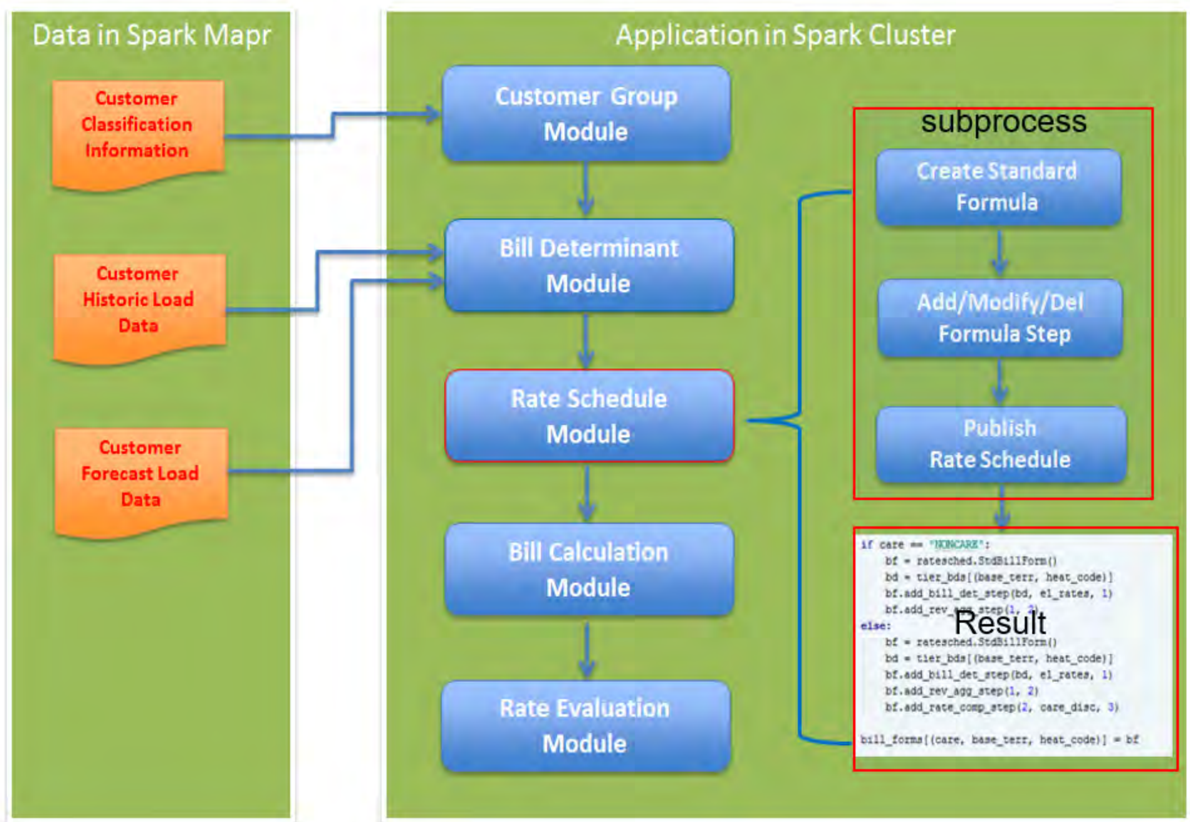


Fig. 5. Rate Schedule Module Diagram

Bill Calculation Module:
This module uses the specific rate schedules formulated in the Rate Schedule Module and corresponding bill determinants from the Bill Determinants Module to calculate customer monthly bills and total revenue.

Below is the diagram of the Bill Calculation Module:

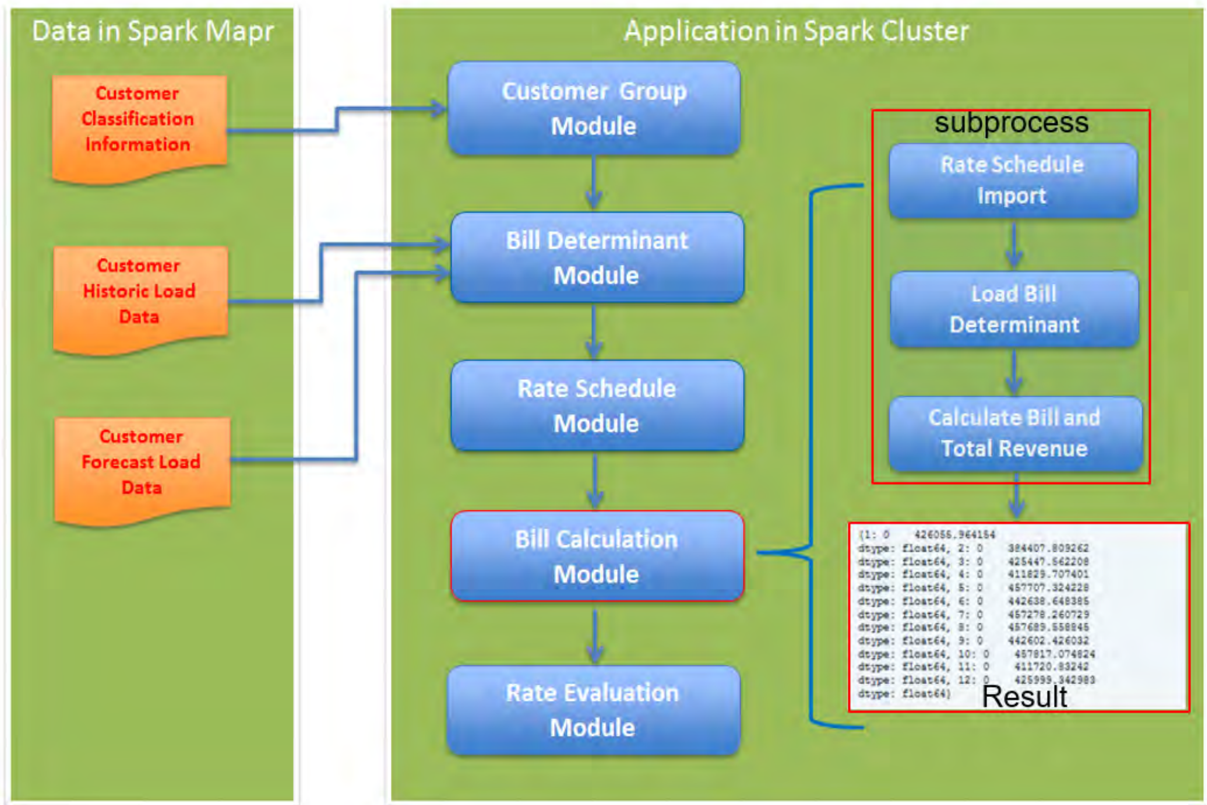


Fig. 6. Bill Calculation Module Diagram

Rate Evaluation Module:
This module will evaluate the rate design based on the following metrics:

Customer Bill Impacts Analysis
Customer Bill Volatility Analysis
Customer Energy Burden Analysis
Customer Energy Subsidy Analysis

Below is the diagram of the Rate Evaluation Module:

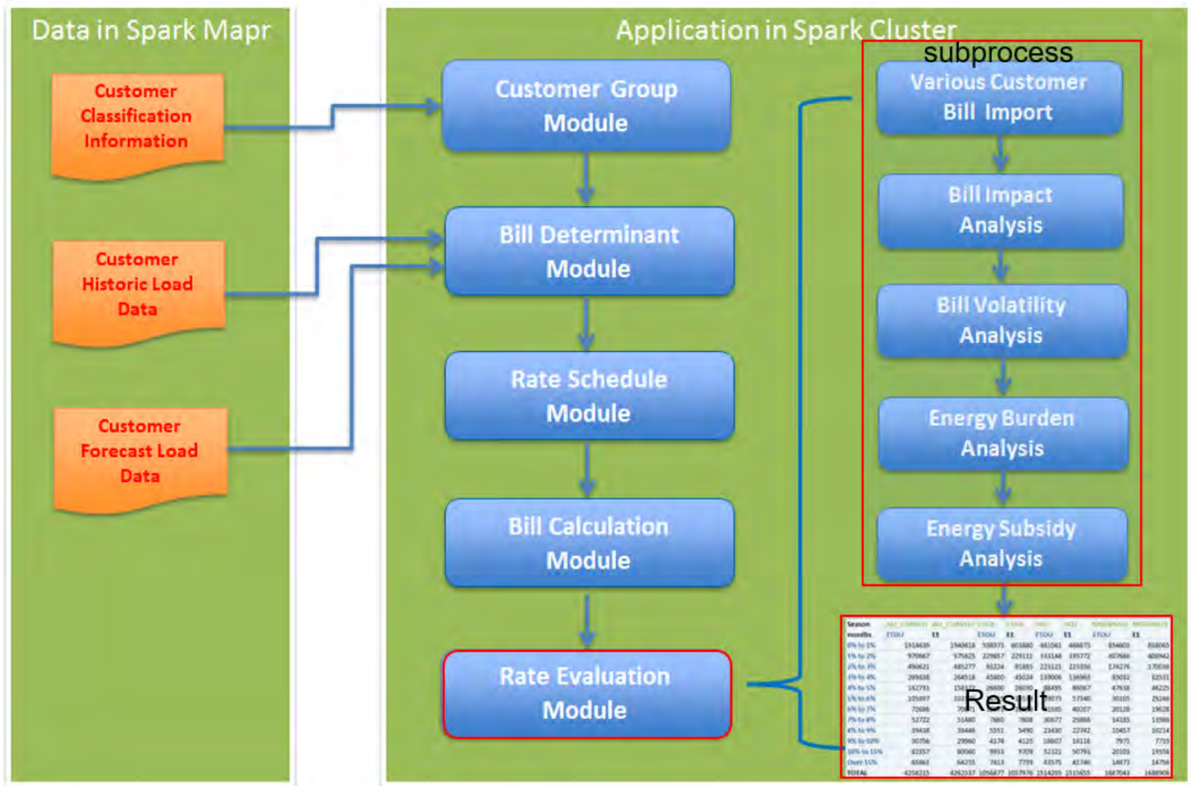


Fig. 7. Bill Calculation Module Diagram

Rate Solver:

The solver is the linear optimization engine which will solve the rates based on the sets of constraint equations (such as revenue neutral constrains, fixed discount, etc.) and specific rate schedule. It will use the revenue requirement of the rate schedule as the objective function to be "revenue neutral" and iterates the calculation to find the best solution for the constraints.

Below is the diagram of the Integrated Rate Solver:

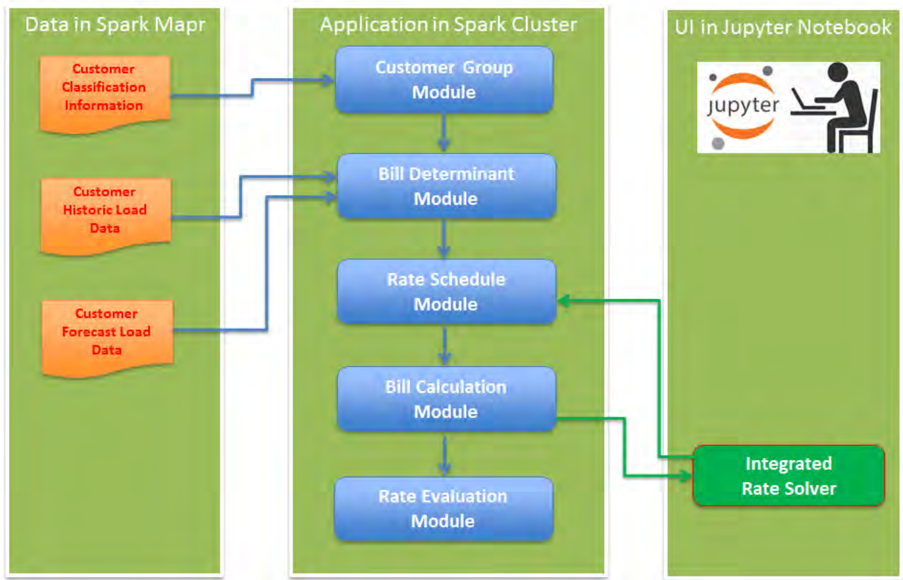


Fig. 8. Integrated Rate Solver Module Diagram

The Solver Module is implemented directly on the Jupyter notebook to allow the rate design the maximum flexibility to perform various rate scenarios.

The Solver Module is using the Python library and can be specified in the Jupyter Notebook.

Below is an example of the DER solver implementation:

f1: RRQ Objective Function
f2-f5: Other Rate Constraints
root = solv.find_root: Python liner equation solver function to find the solution for f1-f5 equations

```
def f1(tier1, tier2, tier3, tier4, tier5, usage, mc, custmth,maxdemand):

    rev_diff = (total_rev(usage, custmth, maxdemand, tier1, tier2, tier3, tier4, tier5) / RRQ) - 1
    print(rev_diff, RRQ, tier1, tier2, tier3, tier4, tier5)

    return rev_diff

def f2(tier1, tier2, tier3, tier4, tier5, usage, mc, custmth, maxdemand):

    return tier1 - mc["sum-on"] - tier2 + mc["sum-part"]

def f3(tier1, tier2, tier3, tier4,  tier5, usage, mc, custmth, maxdemand):

    return tier1 - mc["sum-on"] - tier3 + mc["sum-off"]

def f4(tier1, tier2, tier3, tier4, tier5, usage, mc, custmth, maxdemand):

    return tier1 - mc["sum-on"] - tier4 + mc["win-on"]

def f5(tier1, tier2, tier3, tier4, tier5, usage, mc, custmth, maxdemand):
    return tier4 - mc["win-on"] - tier5 + mc["win-off"]

root = solv.find_root([f1,f2,f3,f4,f5], usage=Usage, mc = MC, custmth = CusMonth, maxdemand = MaxDemand)
```

Fig. 9. Solver Module Template for DER Rate

4.2 Results and Observations

4.2.1 System Architecture

The tool leveraged the Integrated Data Analytics (IDA) platform comprised of an AWS cluster along with a Hadoop filesystem and associated tools.

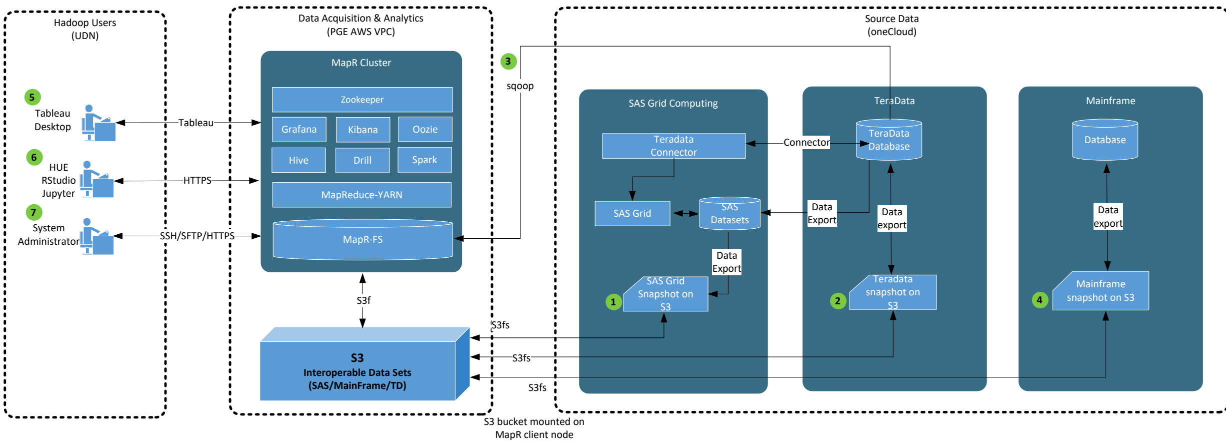


Fig. 10. System Architecture

4.3.2 Rate Design APIs

The following APIs were developed using Python programming language and leveraged the distributed parallel processing capability using PySpark library. The API implemented each of the modules described in section 4.1.3.

Customer Group Module:

This module provides a set of API functions to create a custom Customer Group in the tree structure. This API is used by Jupyter Notebook to build the Customer Group, Season and Rate Component Information (see Fig. 3) to review the Customer Group Module function.

Customer.CustTree is the top-level tree structure for all PG&E customers, which is the first step in rate design. In the example below, the residential customer tree called “res_cls” is created for rate design:

API Name	Customer.CustTree
Description	Creates the customer tree with the tag structure
Example	`customer.CustTree("res_cls", "Residential Class")`

Table 1. Customer.CustTree API

After the customer tree is created, the user can assign customers to the customer tree based on the following customer demographic information:

- Baseline Territory
- Low income (i.e. CARE/Non-CARE) Indicator
- Heating-code Indicator
- Season
- Goods and Service

API Name	**Customer.Partition_all**
Description	Partition the Customer Tree
Example	`customer.partition_all(partitions, tag_map)`
Input	`partitions = [("careind", []), ("baseterr", []), ("heatcode", [])]`

Input	`tag_map = tag.TagTblMapping("FORE_CUST")`
	`tag_map.add_mapping("careind", (0, "NONCARE"))`
	`tag_map.add_mapping("careind", (1, "CARE"))`
	`tag_map.add_mapping("baseterr", ("P", "P"))`
	`tag_map.add_mapping("baseterr", ("Q", "Q"))`
	`tag_map.add_mapping("baseterr", ("R", "R"))`
	`tag_map.add_mapping("baseterr", ("S", "S"))`
	`tag_map.add_mapping("baseterr", ("T", "T"))`
	`tag_map.add_mapping("baseterr", ("V", "V"))`
	`tag_map.add_mapping("baseterr", ("W", "W"))`
	`tag_map.add_mapping("baseterr", ("X", "X"))`
	`tag_map.add_mapping("baseterr", ("Y", "Y"))`
	`tag_map.add_mapping("baseterr", ("Z", "Z"))`
	`tag_map.add_mapping("heatcode", ("B", "B"))`
	`tag_map.add_mapping("heatcode", ("H", "H"))`

Table 2. Customer.Partition-all APIs

The example customer tree structure is shown below:

```
Node noncare: CustTree(name=noncare, desc=noncare customers)
        Node pbn_grp: ForeCustGrp(name=pbn_grp, desc=base terr p, heat code b, noncare)
        Node phn_grp: ForeCustGrp(name=phn_grp, desc=base terr p, heat code h, noncare)
        Node qbn_grp: ForeCustGrp(name=qbn_grp, desc=base terr q, heat code b, noncare)
        Node qhn_grp: ForeCustGrp(name=qhn_grp, desc=base terr q, heat code h, noncare)
        Node rbn_grp: ForeCustGrp(name=rbn_grp, desc=base terr r, heat code b, noncare)
        Node rhn_grp: ForeCustGrp(name=rhn_grp, desc=base terr r, heat code h, noncare)
        Node sbn_grp: ForeCustGrp(name=sbn_grp, desc=base terr s, heat code b, noncare)
        Node shn_grp: ForeCustGrp(name=shn_grp, desc=base terr s, heat code h, noncare)
        Node tbn_grp: ForeCustGrp(name=tbn_grp, desc=base terr t, heat code b, noncare)
        Node thn_grp: ForeCustGrp(name=thn_grp, desc=base terr t, heat code h, noncare)
        Node vbn_grp: ForeCustGrp(name=vbn_grp, desc=base terr v, heat code b, noncare)
        Node vhn_grp: ForeCustGrp(name=vhn_grp, desc=base terr v, heat code h, noncare)
        Node wbn_grp: ForeCustGrp(name=wbn_grp, desc=base terr w, heat code b, noncare)
        Node whn_grp: ForeCustGrp(name=whn_grp, desc=base terr w, heat code h, noncare)
        Node xbn_grp: ForeCustGrp(name=xbn_grp, desc=base terr x, heat code b, noncare)
        Node xhn_grp: ForeCustGrp(name=xhn_grp, desc=base terr x, heat code h, noncare)
        Node ybn_grp: ForeCustGrp(name=ybn_grp, desc=base terr y, heat code b, noncare)
        Node yhn_grp: ForeCustGrp(name=yhn_grp, desc=base terr y, heat code h, noncare)
        Node zbn_grp: ForeCustGrp(name=zbn_grp, desc=base terr z, heat code b, noncare)
        Node zhn_grp: ForeCustGrp(name=zhn_grp, desc=base terr z, heat code h, noncare)
```

Bill Determinant Module:

This module performs the customer level usage aggregation calculation based on the customer group information and intended rate design specification.

The user will first create the Bill Determinant Object for specific rate specification such as Tier or TOU (see Fig. 4. Bill Determinant Module Diagram).

The API to create E1 Tiered Bill Determinant object is shown below:

API Name	**Billdet.TireDB**
Description	Create Bill Determinant Object for Tier
Example	`tier_bd = billdet.TierBD()`

Table 3. Billdet.TireDB API

The API to define the Tier boundaries for each month depending on the number of days in the month is shown below:

<table>
<tr><th>API Name</th><th>Billdet.add_tiers</th></tr>
<tr><td>Description</td><td>Add Tier to Bill Determinant Object</td></tr>
<tr><td>Example</td><td><pre>tier_bd.add_tiers([1, 3, 12], [bqw * 31, bqw *
31 * 4], tier_names)
tier_bd.add_tiers(2, [bqw * 28, bqw * 28 * 4],
tier_names)
tier_bd.add_tiers([4, 11], [bqw * 30, bqw * 30
* 4], tier_names)
tier_bd.add_tiers([5, 7, 8, 10], [bqs * 31,
bqs * 31 * 4], tier_names)
tier_bd.add_tiers([6, 9], [bqs * 30, bqs * 30
* 4], tier_names)</pre></td></tr>
<tr><td>Input</td><td><pre>bqw = bqs_e1[(base_terr, heat_code, "win")]
bqs = bqs_e1[(base_terr, heat_code, "sum")]
base_terr_tags = ["P", "Q", "R", "S", "T",
"V", "W", "X", "Y", "Z"]
heat_code_tags = ["B", "H"]</pre></td></tr>
<tr><td>Baseline Input</td><td><pre>bqs_e1 = dict()
bqs_e1[('P', 'B', 'sum')] = 13.8
bqs_e1[('Q', 'B', 'sum')] = 7
bqs_e1[('R', 'B', 'sum')] = 15.6
bqs_e1[('S', 'B', 'sum')] = 13.8
bqs_e1[('T', 'B', 'sum')] = 7
bqs_e1[('V', 'B', 'sum')] = 8.7
bqs_e1[('W', 'B', 'sum')] = 16.8
bqs_e1[('X', 'B', 'sum')] = 10.1
bqs_e1[('Y', 'B', 'sum')] = 10.6
bqs_e1[('Z', 'B', 'sum')] = 6.2
bqs_e1[('P', 'B', 'win')] = 12.3
bqs_e1[('Q', 'B', 'win')] = 12.3
bqs_e1[('R', 'B', 'win')] = 11
bqs_e1[('S', 'B', 'win')] = 11.2
bqs_e1[('T', 'B', 'win')] = 8.5
bqs_e1[('V', 'B', 'win')] = 10.6
bqs_e1[('W', 'B', 'win')] = 10.1
bqs_e1[('X', 'B', 'win')] = 10.9</pre></td></tr>
</table>

	`bqs_e1[('Y', 'B', 'win')] = 12.6`
	`bqs_e1[('Z', 'B', 'win')] = 9`
	`bqs_e1[('P', 'H', 'sum')] = 16.4`
	`bqs_e1[('Q', 'H', 'sum')] = 8.3`
	`bqs_e1[('R', 'H', 'sum')] = 18.8`
	`bqs_e1[('S', 'H', 'sum')] = 16.4`
	`bqs_e1[('T', 'H', 'sum')] = 8.3`
	`bqs_e1[('V', 'H', 'sum')] = 13.6`
	`bqs_e1[('W', 'H', 'sum')] = 20.8`
	`bqs_e1[('X', 'H', 'sum')] = 9.3`
	`bqs_e1[('Y', 'H', 'sum')] = 13`
	`bqs_e1[('Z', 'H', 'sum')] = 7.7`
	`bqs_e1[('P', 'H', 'win')] = 29.6`
	`bqs_e1[('Q', 'H', 'win')] = 29.6`
	`bqs_e1[('R', 'H', 'win')] = 29.8`
	`bqs_e1[('S', 'H', 'win')] = 27.1`
	`bqs_e1[('T', 'H', 'win')] = 14.9`
	`bqs_e1[('V', 'H', 'win')] = 26.6`
	`bqs_e1[('W', 'H', 'win')] = 20.6`
	`bqs_e1[('X', 'H', 'win')] = 16.7`
	`bqs_e1[('Y', 'H', 'win')] = 27.1`
	`bqs_e1[('Z', 'H', 'win')] = 18.7`

Table 4. Billdet.add_tier API

Rate Schedule Module:

This module performs the run-time rate schedule formulation design. The rate designer will use this module to add, modify and delete rate schedules for intended rate design scenarios (see Fig. 5. Rate Schedule Module Diagram).

The user first defines the Standard Bill Calculation format using the following API:

API Name	Ratesched.StdBillForm
Description	Create standard Rate Schedule Formula
Example	`bf = ratesched.StdBillForm()`

Table 5. Ratesched.StdBillForm API

For the E1 Rate, the user will use bill determinant boundary and the E1 tier rate for the calculation step as step 1:

API Name	Ratesched.add_bill_det_step
Description	Add Bill Determinant Step to Formula
Example	`bf.add_bill_det_step(bd, e1_rates, 1)`
BD Input	`bd = tier_bds[(base_terr, heat_code)]`

Rate Input	`# E1 Total Rates`
	`mths = list(range(1, 13))`
	`rates = {"TIER1": 0.21169, "TIER2": 0.27993,`
	`"TIER3": 0.43343}`
	`e1_rates = ratesched.RateComp("E1", rates,`
	`mths)`

Table 6. Ratesched.add_bill_det_step API

Next, the user will add the revenue aggregation step to the bill calculation as step 2:

API Name	Ratesched.add_rev_agg_step
Description	Add Revenue Aggregation Step to Formula
Example	`bf.add_rev_agg_step(1, 2)`

Table 7. Ratesched.add_rev_agg_step API

Finally, the user will add the revenue discount for CARE group customers as step 3:

API Name	Ratesched.add_rate_comp_step
Description	Add CARE Discount Step to Formula
Example	`bf.add_rate_comp_step(2, care_disc, 3)`

Discount Input	`# EL1 Percentage Discount`
	`rates = {"TOT_": 0.65}`
	`care_disc = ratesched.RateComp("DISC", rates, mths)`

Table 8. Ratesched.add_rate_comp_step API

The rate schedule example is shown below:

```
# Single Rate Schedule
bill_forms = dict()
for care, base_terr, heat_code in itertools.product(care_tags, base_terr_tags, heat_code_tags):
    if care == "NONCARE":
        bf = ratesched.StdBillForm()
        bd = tier_bds[(base_terr, heat_code)]
        bf.add_bill_det_step(bd, el_rates, 1)
        bf.add_rev_agg_step(1, 2)
    else:
        bf = ratesched.StdBillForm()
        bd = tier_bds[(base_terr, heat_code)]
        bf.add_bill_det_step(bd, el_rates, 1)
        bf.add_rev_agg_step(1, 2)
        bf.add_rate_comp_step(2, care_disc, 3)

    bill_forms[(care, base_terr, heat_code)] = bf
```

Bill Calculation Module:

This module uses the specific rate schedules formulated in the Rate Schedule module and corresponding customer bill determinants to calculate customer monthly bills and total revenue (see Fig. 6. Bill Calculation Module Diagram).

The example below uses the bill formula defined for "P", "B" and "NONCARE" to calculate the Bill.

API Name	Ratesched.calc_rev

Description	Calculate Revenue for specific group
Example	`rev = bill_forms[("NONCARE", "P", "B")].calc_rev(cust_npb)`
Customer Group Input	`cust_npb = res_cls.find_by_tags({"NONCARE", "P", "B"})[0]`

Table 9. Ratesched.calc_rev API

The example of bill calculation result is shown below:

```
{1: 0    426055.964154
dtype: float64, 2: 0    384407.809262
dtype: float64, 3: 0    425447.562208
dtype: float64, 4: 0    411829.707401
dtype: float64, 5: 0    457707.324228
dtype: float64, 6: 0    442638.648385
dtype: float64, 7: 0    457278.260729
dtype: float64, 8: 0    457689.558845
dtype: float64, 9: 0    442602.426032
dtype: float64, 10: 0    457817.074824
dtype: float64, 11: 0    411720.83242
dtype: float64, 12: 0    425999.342983
dtype: float64}
```

Rate Evaluation Module:

This module will generate corresponding rate evaluation report for bill impact, energy burden, and bill volatility based on two different bill calculation results (see Fig. 7. Rate Evaluation Module Diagram)..

API Name	rateeval.ratecls
Description	Calculate the bill impacts, energy burden, bill volatility for any particular group
Initialization	`rate_eval = determinator.rateeval.ratecls.RateEval("E1_ETOU_BILL_IMPACTS")`
Input	`rate_eval.add_rate("E1","/projects/rd/data/bill_forecast/bill_1.csv")` `rate_eval.add_rate("ETOU","/projects/rd/data/bill_forecast/bill_2.csv")`
Output	`rate_eval.add_output_path("/projects/rd/j3na/output/")`

Execution	`rate_eval.calc_bill_impacts('HIST')`
	`rate_eval.calc_bill_volatility('HIST')`
	`rate_eval.calc_energy_burden('HIST')`

Table 10. rateeval.ratecls API

The example of rate evaluation results is shown below:

Season	ALL_CLIMATE	ALL_CLIMATE	COOL	COOL	HOT	HOT	MODERATE	MODERATE
months	ETOU	E1	ETOU	E1	ETOU	E1	ETOU	E1
0% to 1%	1914639	1940618	598973	603880	461061	468673	854605	868065
1% to 2%	970667	975825	229857	229111	333144	339772	407666	406942
2% to 3%	490621	485277	93224	91885	223121	223356	174276	170036
3% to 4%	269838	264518	45800	45024	139006	136963	85032	82531
4% to 5%	162733	158322	26600	26030	88495	86067	47638	46225
5% to 6%	105897	103125	16719	16539	59073	57340	30105	29246
6% to 7%	72686	70671	10973	10836	41585	40207	20128	19628
7% to 8%	52722	51480	7660	7608	30877	29886	14185	13986
8% to 9%	39438	38446	5551	5490	23430	22742	10457	10214
9% to 10%	30756	29960	4174	4125	18607	18116	7975	7719
10% to 15%	82357	80060	9933	9709	52321	50793	20103	19558
Over 15%	65861	64235	7413	7739	43575	41740	14873	14756
TOTAL	4258215	4262537	1056877	1057976	1514295	1515655	1687043	1688906

Integrated Rate Solver:

The solver is the linear optimization engine which will solve the rate based on the sets of constraint equations and specific rate schedules. It will use E1 RRQ as an objective function to be revenue neutral and iterates the RRQ calculation to find the best solution for the constraints.

The first step is to define the formula for calculating the total revenue. The example of DER Rate is shown below:

API Name	Total Revenue
Description	Formula to Calculate Total Revenue

DER Rate Example	def total_rev(usage,custmonth, maxdemand, rate_sum_on,rate_sum_part,rate_sum_off,rate_win_on,rate_win_off):
	    tou_rev = usage["sum-on"]*rate_sum_on + usage["sum-part"]*rate_sum_part + usage["sum-off"]*rate_sum_off + \
	                usage["win-on"]*rate_win_on + usage["win-off"]*rate_win_off + \
	                custmonth*4.0 + maxdemand*8.4

Input	Usage: DER TOU Aggregated Usage Custmonth: Total Customer Bill Month Maxdemand: Total Customer Max Demand

Table 11. Total Revenue API

The solver is invoked by calling the solv.find_root function. It will iterate until a solution is found:

API Name	Solver.find_root
Description	Function to solve the targeted rate
DER Rate Example	root = solv.find_root([f1,f2,f3,f4,f5], usage=Usage, mc = MC, custmth = CusMonth, maxdemand = MaxDemand)

Input	Usage: DER TOU Aggregated Usage Custmonth: Total Customer Bill Month Maxdemand: Total Customer Max Demand MC: Marginal Cost MC = {"sum-on": 0.15807,"sum-part": 0.08605, "sum-off": 0.03544, "win-on": 0.04716, "win-off": 0.02652}

Table 12. Root Solver API

The constraint functions are defined to meet various design considerations. For DER Rate, the different rates for specific time period (Winter-On, Winter-Off, Summer-On, Summer-Off) and corresponding marginal generation cost should be the same. An example is shown below:

API Name	**f1,f2,f3,f4,f5**
Description	Solver Constrains Function

DER Rate Example	`def f1(tier1, tier2, tier3, tier4, tier5, usage, mc, custmth,maxdemand):`
	
	`    rev_diff = (total_rev(usage, custmth, maxdemand, tier1, tier2, tier3, tier4, tier5) / RRQ) - 1`
	`    print(rev_diff, RRQ, tier1, tier2, tier3, tier4, tier5)`
	
	`    return rev_diff`
	
	`def f2(tier1, tier2, tier3, tier4, tier5, usage, mc, custmth, maxdemand):`
	
	`    return tier1 - mc["sum-on"] - tier2 + mc["sum-part"]`
	
	`def f3(tier1, tier2, tier3, tier4,  tier5, usage, mc, custmth, maxdemand):`
	
	`    return tier1 - mc["sum-on"] - tier3 + mc["sum-off"]`
	
	`def f4(tier1, tier2, tier3, tier4, tier5, usage, mc, custmth, maxdemand):`
	
	`    return tier1 - mc["sum-on"] - tier4 + mc["win-on"]`
	
	`def f5(tier1, tier2, tier3, tier4, tier5, usage, mc, custmth, maxdemand):`
	`    return tier4 - mc["win-on"] - tier5 + mc["win-off"]`

Input	RRQ: E1 Rate Total Revenue

Table 13. Constraints Function Definition API

The example of the solver execution process is shown below:

```
(('E1', {'TIER1': 0.21169, 'TIER2': 0.27993, 'TIER3': 0.43343}), ('DISC', {'TOT_': 0.65}))
{'DER': {'Fixed': 4.0, 'Demand': 8.4, 'Sum-On': 0.26813, 'Sum-Part': 0.19611, 'Sum-Off': 0.14550000000000002, 'Win-On': 0.15722, 'Win-Off': 0.13658}}
Total Revenue: 4162990005.59758
0.16703988556196192 4162792094 0.2 0.2 0.2 0.2 0.2
0.16703988556196192 4162792094 0.2 0.2 0.2 0.2 0.2
0.16703988556196192 4162792094 0.2 0.2 0.2 0.2 0.2
0.16703988698920336 4162792094 0.20000000298023224 0.2 0.2 0.2 0.2
0.16703988671558956 4162792094 0.2 0.20000000298023224 0.2 0.2 0.2
0.16703988772652845 4162792094 0.2 0.2 0.20000000298023224 0.2 0.2
0.1670398871373191 4162792094 0.2 0.2 0.2 0.20000000298023224 0.2
0.16703989194896374 4162792094 0.2 0.2 0.2 0.2 0.20000000298023224
1.5159495880823215e-10 4162792094 0.2681188506516547 0.19609885038320216 0.14548885019455493 0.15720885023824083 0.13656885016130577
0.0 4162792094 0.2681188502161708 0.19609885021617085 0.14548885021617086 0.15720885021617084 0.13656885021617085
Rates: [0.2681188502161708, 0.19609885021617085, 0.14548885021617086, 0.15720885021617084, 0.13656885021617085]
```

Fig. 11. System Performance Analysis Result

5 Value proposition

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity customers of PG&E, San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). The Rate Design Tool as demonstrated in this project enables flexible rate design and faster and more efficient processes to experiment and evaluate potentially hundreds of scenarios. The specific benefits are outlined below.

- Potential to design experimental rates such as for DER customers.
- Explicit and rigorous evaluations of multiple rate design scenarios so that they can be quantitatively compared.
- Significant efficiency in running multiple rate design scenarios and evaluating rates using Advanced Metering Infrastructure (AMI) interval meter data.
- Seamless integration of customer data and rate design framework eliminates dependencies on data engineers.
- Reduces potential errors, such as from copying and pasting large amounts of customer data and/or bill determinants, since the tool relies on a single framework for all rate design and evaluation steps.
- A seamless one stop technology solution eliminates back and forth interactions among multiple resources and/or teams.
- Reduces internal labor hours as the data intensive processes leverage big data technologies.

Furthermore, the infrastructure required to develop the Rate Design Tool, i.e., the distributed computing platform, may be leveraged to advance existing, production grade rate design models and analytical tools.

EPIC 2.36 demonstrated the potential for the following cost benefits:

- Metric 1: Reduction in time to complete the process of designing, optimizing, and analyzing the impact of an exploratory rate design.

- Metric 2: Increased number of rate design scenarios that can be analyzed and evaluated.

- Metric 3: Overall reduction in internal labor cost as a direct result of the tool.

Additional Metrics:

- Number of proactively addressed data requests as a result of tools capabilities.
- The number and types of hypothetical rate designs a user can create.
- Reduction in time required to respond to data requests.

5.1 Primary Principles

The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability and lower costs. This EPIC project contributes to these primary principles in the following ways:

- **Greater reliability:** Reduces errors in the rate design and evaluation processes by eliminating manual transfer of inputs and outputs.
- **Lower costs:** Enables employees to run analyses faster. The tool enables employees to be more efficient and focus more on innovative rate design and evaluation.

5.2 Secondary Principles

EPIC also has a set of complementary secondary principles. This project contributes to the following secondary principle:

- Efficient use of ratepayer funds: Enables experimental rate designs and potentially evaluate hundreds of scenarios in a short amount of time.

5.3 Key Accomplishments

The following has been accomplished through this project:

- PG&E built a distributed computing platform leveraging Amazon Web Services (AWS), which have been deployed in production at the conclusion of this project.
- PG&E extracted residential customers' characteristics and hourly usage data for one year and created a database, utilizing big data technologies, that enables the processing of billions of rows of information in a few hours.
- PG&E built a high-level rate design framework that can enable a faster and easier experimental rate design process.
- PG&E built high level building blocks for rate design so users can dynamically segment customers, create bill determinants, design new rate structures and evaluate their bill impacts.
- PG&E built application programming interfaces (API) for users to interact with the above building blocks to design and evaluate rates at a high level.

These key accomplishments are foundational for the future development of a more fully functional rate design and evaluation product. At this stage, the tool can design high level experimental tiered, time-of-use, and tiered time-of-use rates as well as rates with a maximum demand charge. It is important to note that the milestones that PG&E achieved in support of building the dynamic rate design tool (e.g., creating the distributed computing platforms, database, and design framework) are not only proof of concept, but can be leveraged to significantly improve other production-grade tools for rate and bill analysis that are built on existing technology.

5.4 Key Recommendations

The project aligns well with PG&E's strategy to create more equitable, cost-based rate structures that minimize cross-subsidies within revenue classes. A fully functional production quality tool can strengthen policy decisions by designing various experimental rate scenarios and evaluating bill impact, bill volatility and energy burden for such proposals.

The tool enables rate analysts to create their own rate designs from a list of most commonly used billing determinants (tiered, time-of-use, monthly demand, fixed charge etc.) as well as user-defined billing determinants based on customer hourly usage and demographic information.

The Rate Design Tool demonstrated through this project provides access to the rate design APIs described in section 4.3.2 via Jupyter notebook. The Jupyter notebook is a web-based rapid application development tool that is generally used by experienced programmers. In order for rate analysts, who are generally non-programmers, to use this tool as currently built they have to learn how to use Jupyter notebook but most importantly they have to learn Python to use the rate design APIs. Therefore, a broader adoption of the tool will rely greatly on improving usability through the development of a user-friendly graphical user interface (GUI), which can be used by any rate analyst. The interface must include user authentication capability to enable customer data privacy.

For the purpose of this demonstration, the project created a back-end customer demographic and hourly usage databases in AWS clusters and loaded the data from PG&E's customer data and analytics systems. An automated interface to periodically refresh the databases will greatly improve efficiency and applicability of the tool.

5.5 Technology transfer plan

5.5.1 Production Deployment

As part of this EPIC project, PG&E leveraged big data technologies in an AWS platform to analyze over four million customers characteristics and hourly usage data spanning one year, which is over 40 billion rows (over one terabyte) of information. PG&E has deployed the AWS platform and corresponding technologies for use to support regulatory proceedings.

PG&E has also deployed customer database and customers' hourly usage database in the AWS platform at the conclusion of the project to support regulatory proceedings.

PG&E has installed the rate design and rate evaluation tool as built in this project for high level experimental rate design. It requires an IT programmer to run and produce results given a clear set of requirements for rate design and evaluation.

5.5.2 IOU's technology transfer plans

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within PG&E, and across the other CA IOUs, the CEC and the industry. In order to facilitate this knowledge sharing, PG&E shared some of the analysis and demonstrated the product as follows. PG&E will publish a public report in its website as required in EPIC program. Specifically, below are information sharing forums where the results and lessons learned from this EPIC project have been presented to date:

Information Sharing Forums Held

- Rutgers Center for Research in Regulated Industries 31st Annual Western Conference
  - Rutgers University New Jersey 6/28/18
- Market Credit and Risk
  - PG&E San Francisco 8/30/18
- PG&E Data Users Community of Practice
  - PG&E San Francisco 9/18/18
- IT Electric and Gas Planning Strategy
  - PG&E San Francisco 10/5/18
- Energy Policy & Planning
  - PG&E San Francisco 10/10/18
- Demo for PG&E Electric Rates Team
  - PG&E Electric Rates Team 12/6/2018

5.5.3 Adaptability to other Utilities and Industry

For utilities and regulators to be prepared for expected substantial growth in DER and other technology penetration, there is a need for the capability to effectively model the interaction between technology adoption and rates. This tool may help improve that understanding, especially in relation to en masse bill impact assessment automation, enabled rate schedule experimentation, and technology adoption scenario impact modeling with additional investment as concluded later in this document.

5.6 Data Access

Upon request, PG&E will submit data from user acceptance testing that is consistent with the CPUC's data access requirements for EPIC data and results.

6 Metrics

The following metrics were identified for this project and included in PG&E's EPIC Annual Report as potential metrics to measure project benefits at full scale.[7] Given the proof of concept nature of this EPIC project, these metrics are forward looking.

[7] PG&E EPIC 2018 Annual Report. Submitted Feb 28, 2018.
https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/2018-EPIC-Annual-Report.pdf

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area)	Reference
3. Economic benefits	
Time to complete the process of designing, optimizing, and analyzing the impact of a hypothetical rate design	1.3

7 Conclusion

This report documented the achievements, highlights, and key learnings of EPIC 2.36 – *Dynamic Rate Design Tool.* The key components of a Dynamic Rate Design Tool were successfully demonstrated, laying the groundwork to enable PG&E to improve rate design capabilities in the future.

Rate design for regulatory proceedings and implementation in tariffs is based on numerous niche policies, rules, and principles which are often conflicting and constantly evolving. While this tool cannot be a replacement for PG&E's operational rate design models used in rate cases, PG&E concluded that big data technologies can provide a one-stop solution to build experimental rate design and evaluation models, back-end customer databases, as well as front-end user interfaces. This provides a consistent and cohesive approach for designing, developing, and deploying complex yet flexible applications that are also easy to maintain in the future.

PG&E demonstrated five distinct rate designs in this project. This demonstrates that a fully functional product using this framework can potentially model hundreds of rate design scenarios in a limited amount of time and effectively assess impacts to utility customers.

PG&E concluded that development of a fully functional, flexible and robust product will require significant multi-year investment. In addition to the rate design and evaluation functions, the product needs to improve its usability through the development of a custom graphical user interface for input and output and integration with utilities' existing customer information and analytics systems.

8 Appendix A – Technical Information Data Dictionary

The following is a data dictionary for the various modules of the Rate Design Tool.

Revenue Requirement Inputs – This table contains the revenue requirements or the amount of money to be collected for each good or service. These are the amounts that the calculated rates must tie to in total. The revenue requirements are for calculating unbundled rates and total rates.

Field Name	Description
COMPONENT	The good or service that is provided. The tariffs list: Generation = GEN Distribution = DIST Transmission = TRAN Public Purpose Programs = PPP Other = OTHER = {Transmission Rate Adjustment = TRA, Reliability Services = RS, Nuclear Decommissioning = ND, Competition Transition = CTC, Energy Cost Recovery Amount = ECRA, DWR Bond = DWR, New System Generation Charge = NSGC} In addition, the following is needed: AB32, the dollar amount of the care discount from the RCBG model and the total RRQ, which is the sum of the RRQs for the above goods and services. Total RRQ = ALL
RRQ	The amount of money to collect in total for a particular good or service

Customer-Level Hourly Loads Database – This database contains the hourly loads for the year. Each row is a group of customers assumed to be homogenous. Each row could represent a single customer (sa_id, sp_id, prem_id, etc.) or a grouping of customers by certain characteristics, such as baseline territory, county, income status, etc.

The database's interface needs to support fast, efficient, and repeated access to the data.

Field Name	Description
SEGMENTID	An integer that identifies a group of customers assumed to be homogenous. SEGMENTID and ENERDIR form the primary key.
ENERDIR	Energy direction(D = delivered, R = received)
H1-H8760	Hourly loads for the year (1 to 8,760)

Dates Database – This table contains each hour of the year, day of the week, holiday, etc. in order to calculate TOU bill determinants. Its primary purpose is to help the user define bill determinants by being able to enter higher level identifiers, such as day of the week rather than each individual hour that comprises the formula for a bill determinant.

Field Name	Description	Use
INTERVAL	Integer between 1 and 8760 that identifies a particular hour of the year	This is the primary key
DATE	MM/DD/YYYY	
DAY	Day of the week Sun, Mon,…, Sat	
MTH	Month of the year Jan, Feb, …, Dec	
HOLIND	If date is a holiday (1) or not (0)	
HOLNAME	Name of the holiday	
SEASON	Spring, Summer, Fall or Winter	

Customer-Level Characteristics Database – This database contains the customer-level characteristics and socio-economic information. The primary purpose of this database from a rate design perspective is to define customer groups. A customer group can be defined in two ways, either as an array of segment IDs or as dictionary of customer fields and values.

Field Name	Description
SEGMENTID	This field is the primary key to identify an observation (homogeneous group of customers) and to join with other tables. This field can be used to define custom customer groups that can't be defined from other fields.
WEIGHT	The number of customers represented by a segment id. This field is needed to scale to population totals
RATESCHED	The current rate schedule
DACCAIND	DA/CCA indicator. 1 = DA/CCA, 0 = Bundled
COUNTY	County customer is located in
CITY	City customer is located in
ZIPCODE	Zip code customer is located in
MEDALL	The number of medical allowances customer has
CAREIND	1 if the customer is in the CARE program, 0 otherwise
ANNINC	Customer's annual income

BASETERR	Baseline territory a customer is located in	
BQ	A customer's current baseline quantity	Define kWh, kW or custmth bill determinants
HEATCODE	H for all-electric, B for basic	Define kWh, kW or custmth bill determinants and customer groups
DER	Type of DER technology (solar, battery, electric vehicle, etc.)	Define customer groups
DERCAP	Capacity size of installed DER technology	Define customer groups
CZ	CEC climate zone designation	Define customer groups
FERAIND	1 if customer in FERA program, 0 otherwise	Define customer groups

Customer-Level Cost Database – This database contains the customer-level loads and marginal cost revenue to determine cost of service.

Field Name	Description	Use
SEGMENTID	This field will be the primary key to identify an observation (homogeneous group of customers) and join with other tables	
DIVISION	Distribution division planning area	
GENPCAF	generation pcaf based on net interval loads	
MGCC	marginal cost for generation capacity	
GENMCR	Generation marginal cost revenue = GENPCAG x MGCC	
ENRMCR	energy marginal cost revenue	
DISTPCAF	distribution pcaf based on delivered loads	
MDCCPRI	primary mdcc	
DISTPRIMCR	primary distribution marginal cost revenue	
DISTPRIMCR	customer load coincident with max final line transformer load. THIS IS AN ANNUAL NUMBER. Divide by 12 to get monthly number	
DISTFLT	new business on primary mdcc	
MDCCNB	secondary mdcc	
MDCCSEC	secondary distribution marginal cost revenue	
DISTSECMCR	marginal customer access costs (RCS + TSM) based on rental method. This is a monthly number	
MCAC	customer marginal cost revenue	
MCACMCR	annual marginal cost revenue	
TRANPCAF	transmission pcaf based on net loads?	
MTCC	Marginal transmission cost of capacity	
MTCCMCR	Transmission marginal cost revenue	
ANNMCR	distribution pcaf based on delivered loads	

Marginal Cost Database – This database contains all of the marginal costs to determine cost of service.

Field Name	Description	Use/Purpose
ID	Integer Identifier for a particular set of marginal costs	
NAME	Abbreviated name of the marginal cost	
VOLTAGE	The voltage for the marginal cost	
TOU	Time period for marginal energy cost	Could replace this with hour instead of more aggregated TOU period
DIVISION	Division for marginal distribution costs	
CLASS	Customer class for marginal customer access costs	
UNIT	Unit of the marginal cost, e.g. marginal energy costs are $/MWh	
VALUE	Dollar amount of the marginal cost	