PACIFIC GAS AND ELECTRIC COMPANY
SMART GRID ANNUAL REPORT – 2020

SMART GRID TECHNOLOGIES

ORDER INSTITUTING RULEMAKING 08-12-009

CALIFORNIA PUBLIC UTILITIES COMMISSION

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CPUC Reporting Requirements and

Pacific Gas and Electric Company's Smart Grid Deployment Plan and Project Updates

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

a) A summary of PG&E's deployment of Smart Grid technologies during the reporting period (July 2019 through end of June 2020) and its progress on its Smart Grid Deployment Plan.[1] Added focus is given this year to grid wildfire protection and safety-related investments which support the development of the Smart Grid to cope with the accumulating impacts of climate change[2].

b) The costs and benefits of Smart Grid deployment to PG&E's customers during the past year, including a monetary estimate of the health and environmental benefits that may arise from the Smart Grid where possible[3].

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

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

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1 Unless otherwise specified, PG&E has provided cost and benefits for all projects for the period beginning July 1, 2019 through June 30, 2020.

2 To help meet the climate-driven challenge of increasing wildfires and extreme weather events, PG&E announced a comprehensive Community Wildfire Safety Program (CWSP) in 2018.

3 For information on project costs and benefits in former years, please reference past Smart Grid Deployment Plan Updates on California Public Utilities Commission's (CPUC or Commission) California Smart Grid website at: www.cpuc.gov/General.aspx?id=4693.

Consistent with PG&E's Smart Grid Deployment Plan, PG&E's SGAR provides information on the status of its PG&E's Smart Grid investments, including Smart Grid Baseline Projects, Smart Grid-Related Customer programs, and proposed Smart Grid Roadmap Projects.[4]

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

CHAPTER 1

SMART GRID ANNUAL REPORT

EXECUTIVE SUMMARY

1 Smart Grid Annual Report Executive Summary

Throughout the reporting period of July 2019 to June 2020, PG&E continued to build capabilities to deliver on its vision of modernizing its grid. This vision integrates new energy devices, monitoring and control, and other situational awareness technologies to enable greater grid safety, resiliency, and energy diversity for our customers. PG&E plays a critical role in delivering an integrated grid that will help define tomorrow's energy landscape for California.

California has experienced dramatic and rapidly evolving environmental changes[5] in recent years, resulting in record drought, unprecedented tree mortality, record rainfall, record heat waves, and extremely strong wind events. The climate change underlying these changes has altered the operating risks of the electric grid.[6] In the CPUC's 2018 Fire-Threat Map, more than 50 percent of PG&E's territory is now identified as having an elevated or extreme wildfire risk. PG&E continues to take all efforts necessary to maximize the safety of its electric facilities, including with respect to the risk for catastrophic wildfires. PG&E is providing regular updates on efforts to reduce the wildfire risk via PG&E's Wildfire Mitigation Plan Report[7] and ongoing regulatory and public communications.

Grid modernization through Smart Grid and supporting technologies play a key role in PG&E's strategies to mitigate risks brought on by the changing climate. PG&E is taking advantage of technological advancements to reduce system risks as part of its development of an integrated grid. These investments play a key role in increasing the flexibility of the grid to allow for greater resiliency. For example, PG&E is implementing technology demonstration projects and pilot programs to evaluate alternative technologies that may harden and modernize the electrical system and improve operational capabilities. This includes a demonstration project on

5 From 2010 to 2018, according to the U.S. Forest Service, over 147 million trees have died in California. Bark beetle infestations and drought have contributed to this. Moreover, as air temperatures rise, forests and land are drying out, increasing fire risks and creating weather conditions that readily facilitate the rapid expansion of fires.

6 PG&E's Initial Response to OII and Order to Show Cause (I.19-06-015) filed June 27, 2019

7 PG&E's 2020 Wildfire Mitigation Plan Report (R.18-10-007) describes the enhanced, accelerated, and new programs that PG&E is and will continue to implement to prevent wildfires in 2019 and beyond, submitted in February 2019 pursuant to the requirements of SB 901.

Rapid Earth Fault Current Limiter (REFCL), a technology that moves the neutral line to the faulted phase during a fault, significantly reducing the risk of ignition.

Microgrids (MG) have the potential to enhance the resiliency of the grid. PG&E is exploring the use of remote grid configurations as an advanced solution for wildfire risk mitigation. This includes testing the use of MG operations for their potential to reduce customer impact during proactive grid operations deployed for reducing wildfire risk or other natural disaster response scenarios. PG&E is actively engaging in new demonstration and pilot projects to help unlock new value streams provided by Distributed Energy Resources (DERs).

An integrated grid enables our customers to have greater flexibility and choice in how they use and obtain value from their energy supply. PG&E customers are leading the adoption of DERs and clean technologies, including solar, storage, and electric vehicles (EV). However, the widespread adoption of DER and clean technologies also introduces new challenges in operating the grid, such as those related to two-way power flow, voltage and power quality issues as well as supply intermittency. Smart Grid and technology advancements help PG&E to manage and optimize this additional complexity, through advanced grid communication, analysis [monitoring] and control capabilities. This is critical to realizing the requirements set forth in CA's Senate Bill (SB) 100 (2018), which increases CA's renewable portfolio standard (RPS) to 60 percent by 2030 and requires all the state's electricity to come from carbon-free resources by 2045.[8]

PG&E's Grid Modernization Vision

PG&E's vision for modernizing its grid through Smart Grid and supporting technologies furthers developments towards a secure, resilient, reliable and affordable platform that strengthens the grid while enabling continued gains for clean-energy technologies.[9] PG&E's Smart Grid and

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8 CPUC, RPS Program, https://www.cpuc.ca.gov/rps/.

9 Adapted from PG&E's 2020 General Rate Case (GRC) application, Chapter 19, Attachment A: Grid Modernization Plan – 10 Year Vision technology upgrades are foundational to achieving its grid modernization vision, which focuses on developing the following capabilities:

1. Seamless integration of critical grid data visualization, analysis, and control systems to optimize grid operational efficiency and stability in Real-Time (RT)
2. Enhanced situational awareness and operational flexibility to mitigate more dynamic and extreme weather events while minimizing disruption to customers
3. Enhanced grid communications and cybersecurity infrastructure necessary to securely accommodate the growth in web-enabled grid-tied devices
4. Reliable integration of geographically dispersed DER generation and storage options to provide customers with clean energy choices and to enable grid configurations designed to provide enhanced resiliency.

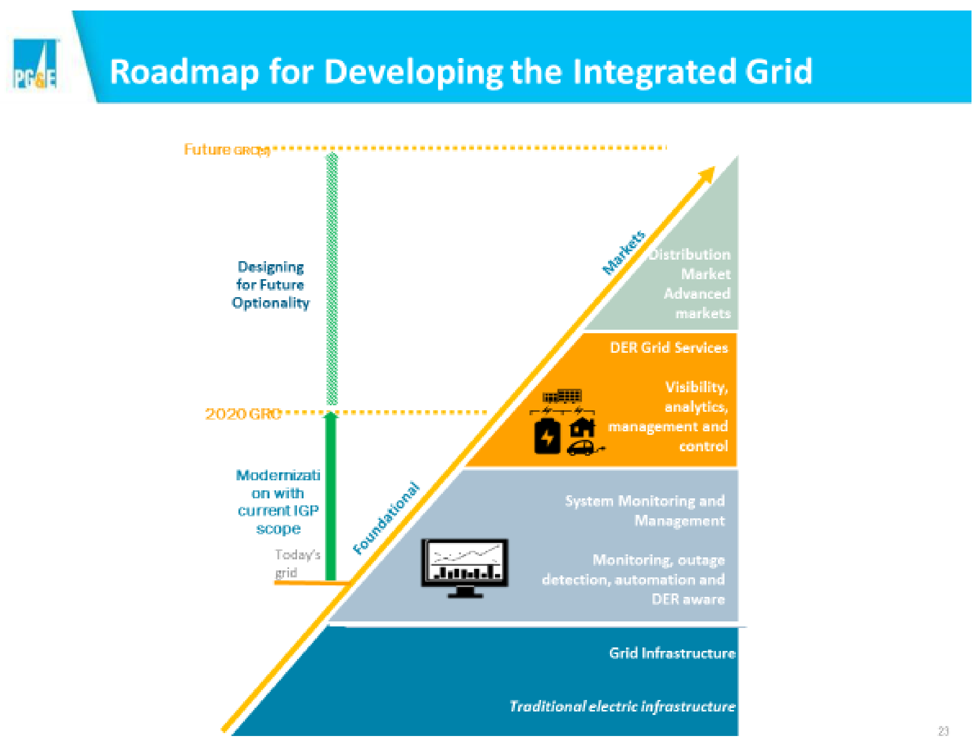

Figure: PG&E's Grid Modernization Plan – Integrated Grid Capabilities

PG&E's grid modernization vision is, in part, enabled by the **Electric Program Investment Charge (EPIC)**. Through EPIC, PG&E has been able to cost-effectively develop and demonstrate innovative technologies that advance a broad array of objectives including grid safety, resiliency, reliability, and the integration of a wide range of DERs such as clean, renewable energy. EPIC demonstrations aid in identifying key requirements, implementation challenges, and benefit-cost details to inform future deployment. PG&E's EPIC projects also support the creation of new and valuable Intellectual Property (IP), which can lead to improved products and services that help improve the operations of the electricity grid by reducing operating expenses and/or potentially generate alternative forms of incremental revenue that can reduce customer costs.

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 advancement of the grid. Innovation is further required to enable increased customer choice and empower Disadvantaged Communities. PG&E is excited to embark on new technology demonstrations contained within that plan which build on past projects, meet emerging grid needs and California policy objectives, and ensure that customers and the state can maximize the benefits of this program.

Smart Grid & Technology - Focus Areas:

i. **Wildfire Safety & Grid Resilience:** PG&E details its efforts to reduce the wildfire risk via PG&E's annual Wildfire Mitigation Plan, including a section on new or emerging technologies. Technology plays a significant role in wildfire risk mitigation and associated potential impact on public safety. Select wildfire mitigation capabilities progressed through smart grid and technology investments include:

    a. **Situational Awareness & Forecasting**: PG&E is deploying a powerful set of complementary tools to better assess and more accurately locate, often in near real time, environmental events that pose a danger to the grid so that critical issues may be dealt with as quickly as possible to avoid the risk of catastrophic wildfires. In addition, PG&E is exploring the use of situational awareness technologies and analytics that provide insights on grid conditions. Select examples include: (i) Incorporating new data sets to further PG&E's Wildfire Spread Modelling capabilities; (ii) Promoting situational awareness through PG&E's industry-leading fire detection system and sharing automated email fire alerts with California Department of Forestry and Fire Protection (CAL FIRE) and numerous county and local fire departments; and (iii) installing sensor technology on PG&E assets to monitor system health.

b. **Grid Design & System Hardening**: Smart grid and technology investments can enable innovative system hardening techniques to mitigate the risk of fire ignition and potential impacts on public safety. Select examples include (i) demonstrating the ability to rapidly reduce the flow of current when faults are detected to minimize ignition risk; (ii) exploring the use of MG configurations and underlying technologies to support wildfire risk mitigation; (iii) system automation including Supervisory Control and Data Acquisition (SCADA)-enabled recloser device and sectionalizing device implementation to allow greater operational flexibility

c. **Asset Management (AM) and Inspections**: Smart grid and technology investments can enable automated and improved methods to identify asset or system issues so that high risk items can be addressed prior to failure. Select examples include (i) the development of predictive maintenance tools that can identify the onset of equipment failure so that correct action can be taken before actual failure occurs; and (ii) the use of machine learning and data analytics to accelerate accurate inspections to ensure system safety.

d. **Data Governance & Enablement** Smart grid and technology investments unlock new data streams that can be leveraged to inform risk-based decision-making. PG&E aims to integrate certain data from different data sources into a single environment, enabling data driven approaches to wildfire mitigation initiatives and efforts.

Successful wildfire-mitigation-focused technology implementation relies on smart grid technology investments, including grid communication tools and control networks, which enable greater exchange of information required to provide real or near-real time operational visibility across the grid for enhanced decision-making. These foundational items can also increase the flexibility of the grid, providing additional capabilities to advance system resiliency.

ii. **DER Integration & Enablement**: PG&E continues to make significant strides in the deployment of emerging grid technologies (e.g., solar, grid-tied storage and EV charging infrastructure) and the deployment of technologies to facilitate integration and optimization of DER resources. PG&E offers a wide array of incentives to encourage customer adoption of cost-effective energy efficiency (EE) measures, is developing new Smart Grid and technology solutions to encourage the adoption of DERs and is exploring the potential for demand management programs. Some examples of new and emerging Smart Grid and related technologies that seek to optimize DERs for our customers include (i) the development of an Advanced Distribution Energy Resources Management System (ADERMS) and (ii) a demonstration project in collaboration with the California Energy Commission (CEC) and Schatz Energy Research Center to develop a multi-customer MG for enhanced reliability and resilience.

iii. **Customer Service**: PG&E provides customers with the tools necessary to understand and manage their energy use and costs through programs such as Home Energy Reports (HER) and Stream My Data. PG&E also offers innovative programs that help customers participate in EE. One example is the introduction of financing programs that reduce the up-front cost of large, comprehensive EE projects that would not have been financially feasible otherwise. Another example is the Residential Pay-for-Performance (P4P) pilot which uses the Normalized Meter Energy Consumption (NMEC) approach to estimate customer EE savings directly from Advanced Metering Infrastructure (AMI)-meter readings. PG&E uses market feedback to understand the roadblocks to customer adoption of EE and uses advertising and marketing campaigns to promote engagement with these tools and participation in programs.

iv. **Security**: The increase in internet-connected Smart Grid and technology devices will be accompanied by a corresponding increase in cyber-security threats. In December of

2019, the five-year California Energy Systems for the 21st Century (CES-21) program was concluded. CES-21 was primarily a cybersecurity Research and Development (R&D) partnership among the California investor-owned utilities (IOU) and national labs that began to build the foundation of next generation of industrial control systems cybersecurity and automated threat response capabilities.

1.1 Conclusion

PG&E's Smart Grid vision is for a safer, more resilient grid that gives our customers maximum flexibility and maximum choice in how they use energy. Smart Grid and related technologies play a key role in achieving this vision. The energy landscape in PG&E service territory is evolving in complexity – a result of climate induced challenges of heightened wildfire threat and increased DER penetration. Smart grid technologies will have a profound impact on how the grid operates, enabling new operational processes, providing visibility into RT system conditions, and increasing grid operating flexibility. This in turn unlocks new capabilities for proactive grid management and opportunities for continuous improvement. PG&E continues to progress these capabilities through a strategic approach to Smart Grid and technology investments, as highlighted throughout the report.

1.2 Epilogue

This year represents the last annual SGAR update pursuant to D.10-06-047 and the Smart Grid Deployment Plan D.13-07-024. Substantial progress towards realizing the vision for the Smart Grid has been made in the 10 years since PG&E first submitted its 2011 Smart Grid Deployment Plan, as highlighted by select examples provided below:

1. Smart Grid digital information and control technologies provide a foundation for new grid devices and capabilities to enhance operational outcomes:

    a) SCADA technologies have been deployed to most areas of the electric transmission (ET) and distribution grids. SCADA-enabled reclosing and sectionalizing devices have been implemented at scale to allow greater operational flexibility and resiliency. Currently, 97 percent of distribution substations are equipped with SCADA and nearly 10,000 automated devices (switchers and reclosers) have been installed throughout the distribution system. Nearly 650 additional SCADA commissioned distribution sectionalizers have been installed in Tier 2 and Tier 3 High Fire Threat Districts (HFTD) since 2019 to minimize the impact of Public Safety Power Shutoff (PSPS) events in addition to 23 SCADA transmission sectionalizing devices.

    b) Smart Grid Fault Location, Isolation, and Service Restoration (FLISR) technology has so far been installed on 967 of PG&E's distribution circuits serving 2,187,704 customers. To date it has helped PG&E reduce customer power interruptions by over one million avoided outage hours over the last five years.

    c) Line sensors are one of a number of next generation fault identification technologies that monitor and communicate grid disturbances in real time and is being enabled to support preventative maintenance to reduce asset failure risk. To date PG&E has installed approximately 987 current-measuring line sensors as well as 25 Early Fault Detection (EFD) line sensors across more than 350 locations. Since 2019, all line sensors installations (180) have been in HFTD's, which includes all installed EFD line sensors.

d) Development of the next generation of integrated monitoring and control Advanced Distribution Management System (ADMS) is underway, which will further improve the reliability, security, and efficiency of the electric grid.

2. More than 99 percent of customers now have two-way communicating Smart Meters enabling customers to monitor and adjust energy use and providing PG&E with data to drive insights on grid operating conditions:

   a) Smart Meter technology is the basis for customers being able to monitor and adjust their energy use, including through programs such as StreamMyData which enables real time energy monitoring via a smart phone app.

   b) PG&E has enabled Single-Phase SmartMeters™ to send RT alarms to the Distribution Management System (DMS) under partial voltage conditions (25-75 percent of nominal voltage). Energized or de-energized wires down will create a low voltage condition on transformers through the mechanism of transformer back feed from the inactive phase to the fault. This enhanced situational awareness can help detect and locate downed distribution lines more quickly to enable faster response.

   c) PG&E is leveraging automated Smart Meter technologies to improve customer service. These solutions, which include the ability to automatically identify "nested outages"[10], have allowed us to realize improved distribution grid reliability, reduced outage restoration times, and provide more accurate outage information to our customers. They also can provide data to target maintenance programs in the best interest of the customer.

3. There has been substantial deployment and integration of cost-effective DERs and renewable generation:

[10] A nested outage occurs when a circuit has more than one electrical break occurring in series.

a) PG&E's electricity supply mix has increased from 14.4% eligible renewable energy in 2009 to 29.7%[11] in 2019, driven by the adoption of solar and other renewable energy sources. This has occurred without disrupting grid stability.

b) The expansion in grid-tied solar includes 465,000 customer solar systems – more than 4,400 megawatts (MW) – that were connected to PG&E's electric grid by 2019.

c) Battery storage to further integrate clean energy from renewable generation while ensuring future grid reliability has been growing rapidly in recent years. Earlier this year, PG&E in partnership with Tesla obtained approval for a one gigawatt (GW) battery storage facility at Moss Landing, which will be one of the largest of its kind in the world. Approval for an additional five battery storage projects totaling 423 MW was requested from the CPUC in May.

4. **EV Expansions:** In 2010, there were 195 customers enrolled in time-variant EV tariffs. Today that number has grown to over 63,000, mirroring the growing adoption of EVs in PG&E's service area and which reached 292,145 registrations as of June 2020. A pilot program is also underway to provide make-ready infrastructure for Level 2 EV charging stations with a target to reach 4,500 charging ports by 2021. PG&E had installed 2,192 ports as of March 31, 2020.

5. **Energy Efficiency:** PG&E's gross electric energy savings from innovative EE programs have generally exceeded 1,200 gigawatt-hour (GWh) per year between 2011 and 2019, roughly equivalent to the annual energy use of 148,000[12] homes.

6. **Data Driven Insights**: Images captured via drone and helicopter are being captured and fed into Sherlock, a web application that allows inspectors to view photographs of assets along with associated data. The markups from Sherlock feed into computer vision models, which are being trained to classify photos, identify asset components, and

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[11] https://www.pgecorp.com/corp_responsibility/reports/2020/bu07_renewable_energy.html

[12] Average Pacific states annual residential household electricity use in 2015 was estimated to be 8,088 kilowatt-hour (kWh): https://www.eia.gov/consumption/residential/data/2015/c&e/pdf/ce2.5.pdf

search for potential issues in an automated fashion. Models within the inspection flow are currently being used to flag select images (e.g. overview, right of way, asset tag), saving time for inspectors and allowing them to focus inspection efforts on potential ignition risks.

While the annual reporting of Smart Grid deployments pursuant to D.10-06-047 is coming to an end progress towards California's vision of a modernized Smart Grid is not. Meeting California's 100 percent clean energy electricity and state-wide carbon neutrality goals by 2045 will continue to drive Smart Grid technology change. Two examples that illustrate how PG&E will continue to develop and implement the technologies necessary to realize these goals are Distributed Energy Resource Management Systems (DERMS) and data analytics.

The increasing penetration of renewables into the grid will bring about significant operational challenges in terms of distribution power flow patterns and regulation and necessitate major changes to the protection, distribution, automation, as well as voltage and volt-ampere reactive management. Increased renewable generation also implies limited dispatchability and intermittencies, which will require ancillary services. PG&E is developing a DERMS system which will provide the advanced monitoring and control capabilities to enable integration of the increasing adoptions of solar, battery storage, EVs, MGs, etc. while maintaining grid reliability and resiliency.

Second, the two-way communication channels and data layers being added to the transmission and distribution (T&D) grids through widespread installation of smart meters and myriad sensors is driving huge growth in RT and near RT data collection. While harnessing such data offers new opportunities to operate the grid safely and efficiently, deriving full value from these data streams requires advanced data analytics capabilities. PG&E has embarked on developing these capabilities in a number of key areas, including in the current use of advanced meteorological forecasting to predict wildfire related outages. Additional use cases being worked on include data mining for predictive maintenance and grid health monitoring as well as complex network analysis to aid fault detection. Future advanced analytics capabilities will include transient network stability analysis in areas with high renewables penetration and advanced security protection.

PG&E looks forward to continuing the leading role in the development of California's Smart Grid and in supporting the realization of California's ambitious green energy goals while ensuring safe, reliable, and affordable energy for our customers.

CHAPTER 2

SELECT SMART GRID AND TECHNOLOGY

FURTHERING GRID MODERNIZATION

2 Select Smart Grid and Technology Furthering Grid Modernization

Chapter 2 details example Smart Grid and technology projects, demonstrations, pilots, and regulatory proceedings taking place over the reporting period that contribute to the achievement of our vision. Project updates are organized under the following categories:

- **Wildfire Mitigation & Grid Resilience**
- **DER integration & Enablement**
- **Customer Service**
- **Security**

2.1 Wildfire Mitigation & Grid Resilience

During the July 1, 2019 to June 30, 2020 reporting period, PG&E made substantial progress on several fronts to enhance wildfire safety and grid resilience through the utilization of Smart Grid and technology solutions across a variety of programs, including EPIC and the CWSP. Technology-dependent focus areas include but are not limited to: (i) Situational Awareness & Forecasting; (ii) Grid Design & System Hardening; and (iii) AM and Inspections. Additional details on PG&E's work to enhance grid resiliency and wildfire safety are described in its Updated 2020 Wildfire Mitigation Plan[13].

2.1.1 Situational Awareness & Forecasting

PG&E is deploying multiple complementary tools to better assess and more accurately locate, often in near real time, environmental events and grid issues that increase wildfire risk so that critical issues may be dealt with as quickly as possible to avoid the risk of catastrophic wildfires. In addition, PG&E is exploring the use of situational awareness technologies and analytics that provide insights on grid conditions. Select examples include:

[13] PG&E's Updated 2020 Wildfire Mitigation Plan February 28, 2020, R.18-10-007.

- **Satellite Fire Detection**: Uses remote sensing data from six geostationary (GOES-16 and GOES-17) and polar orbiting satellites (MODIS, VIIRS) to detect fires. PG&E is actively sharing automated email fire alerts with CAL FIRE through the California National Guard and with numerous county and local fire departments. PG&E is sharing these data with Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) through the Technosylva wildfire analyst application. PG&E also developed a public facing webpage where these detections are available: https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/fire-detection-satellite-map.page

- **SmartMeter Partial Voltage Detection**: Energized or de-energized wires down will create a low voltage condition on transformers through the mechanism of transformer back feed from the inactive phase to the fault. PG&E has determined that with a firmware change, SmartMeters can detect this partial voltage condition (25-75 percent of nominal voltage) and send RT alarms to the DMS. This enhanced situational awareness can help detect and locate downed distribution lines more quickly to enable faster response.

- **Predictive risk identification with radio frequency added to line sensors:** Distribution Fault Anticipation (DFA) technology captures primary distribution disturbance current and voltage waveforms. It then conducts digital signal processing locally, communicating results to a waveform classification engine which then identifies both normal and abnormal events on the distribution system. The DFA technology is installed within the substation and uses existing substation bus potential transformers and circuit breaker current transformers. DFA technology is being evaluated on six distribution feeders covering 718 line miles. These installations are part of PG&E's EPIC 2.34 and have a primary objective of validating the performance of the EFD sensors in capturing disturbance and arcing events.

2.1.2 Grid Design and System Hardening

PG&E is reducing the risk of fire ignition through the adoption of grid design and system hardening practices that leverage Smart Grid and supporting technologies. Select examples include:

- **PSPS Mitigation**: PG&E's PSPS program proactively de-energizes power lines to prevent wildfires if gusty winds and dry conditions, combined with a heightened fire risk, are forecasted. PG&E recognizes the burden that PSPS places upon affected customers and communities and is committed to minimizing the number of PSPS events and their scope (number of customers affected) and duration, while working to keep our customers and communities safe during times of severe weather and high wildfire risk. Smart grid and technology investments can help to reduce the scope, duration and frequency of PSPS events. Select investments include:
    - **Distribution Segmentation**: PG&E is targeting various distribution lines where additional switching devices coupled with targeted system hardening can be utilized to further sectionalize distribution feeders to minimize the number of customers impacted by PSPS outages.
    - **Transmission Line Sectionalizing**: PG&E plans to enhance transmission segmentation strategies including installation of additional SCADA-controlled switches. PG&E has identified various transmission lines where additional switching devices will be utilized to further sectionalize transmission lines to be able to minimize the number of customers impacted by PSPS outages.
    - **Microgrids**: MGs can reduce the number of customers deenergized during PSPS events, as well as provide additional impact mitigation by energizing shared community resources that support the surrounding population. Developments in this space are subject to the MG and Resilience Strategies Rulemaking (R.19-09-009).

- **EPIC 3.15: Proactive Wires Down Detection:** The EPIC 3.15, Proactive Wires Down Mitigation demonstration project, seeks the ability to automatically and rapidly reduce the flow of current and risk of ignition in single phase to ground faults through the use of REFCL. The REFCL Technology has been shown by the Victoria State Government (Australia) to directly reduce the risk of wildfires for single line to ground faults. REFCL works by moving the neutral line to the faulted phase during a fault, which significantly reduces the energy available for the fault. This significantly lowers the energy for single line to ground faults by reducing the potential for arcing and fire ignitions, as well as better detection of high impedance faults / wire on ground. REFCL technology is only feasible for three-wire uni-grounded circuits, which are the majority of PG&E's distribution circuits within high fire threat areas. Successful implementation of REFCL technology has the potential to more reliably detect high impedance ground faults and energized wire down events and minimize this risk to public safety.
- **EPIC 3.11: Multi-Use Microgrid:** The EPIC 3.11, Multi-use MG demonstration project, seeks to enable a multi-customer MG within the Arcata-Eureka Airport business community and will incorporate four PG&E and Redwood Coast Energy Authority (RCEA) customers. The project will design and develop control specifications and provide SCADA integration to maintain visibility and operational control of the MG in grid-connected and islanded modes. This project will test capabilities to integrate third party controlled MGs into PG&E's distribution system. The findings of this project will help support MG growth to support resiliency (e.g., remote grid configurations) and enhanced customer choice.
- **SCADA-enabled automation**: PG&E has installed SCADA-enabled reclosers in place of manual devices to allow system operators to remotely prevent a line from automatically reenergizing ("reclosing") after a fault. This assures that if any potential fire or other risk event causes a line to drop out of service, that line will remain out of service and not contribute to a fire until PG&E personnel can verify that it is safe to put the line back in operation. In 2019, PG&E completed SCADA-enabling of all line reclosers serving HFTD areas. PG&E will continue upgrading devices with SCADA capability in targeted portions of the HFTD areas to help minimize the impact of PSPS events on customers in low-risk

areas adjacent to the HFTD areas. These upgrades will include adding or replacing existing manually operated fuses and switches at strategic locations with new SCADA-enabled Fusesavers™, switches, or reclosers. By isolating the lines closer to the border of the HFTD, fewer customers will be impacted and fewer lines will be de-energized. These improvements will also expedite restoration by reducing the amount of lines requiring a patrol.

2.1.3 AM and Inspections

Smart grid and technology investments can enable automated and improved methods to identify asset or system issues so that high risk items can be addressed prior to failure. Select examples include:

- **Enhanced Asset Inspections - Drone/AI (Sherlock & Waldo):** Sherlock is a web application that allows inspectors to view and inspect photographs of assets along with associated data. It also allows for pre-inspection review of data coming in from drone pilots, helicopter photographers, and other means of data capture, to ensure that only quality-assured data is viewed by inspectors, and further by others such as engineers, estimators and investigators who need the photos for their work. In addition, inspectors can file corrective requests within the Sherlock application itself by marking up photographs and selecting the appropriate failure and severity rating of identified issues. The corrective requests identified by inspectors inside Sherlock feed Waldo, a computer vision API (Application Programming Interface), where computer vision models are trained to identify issues using Artificial Intelligence (AI), in an automated fashion. Waldo's predictions can then be surfaced in Sherlock to be confirmed as correct or incorrect by inspectors, creating a positive feedback loop which then improves the models further. Other applications (e.g., mobile applications) can send/receive data and images to/from Waldo to train/retrain models, and/or to receive predictions to help automate their processes.

- **EPIC 3.20: Maintenance Analytics**: The EPIC 3.20, Maintenance Analytics, demonstration project aims to reduce unanticipated distribution asset failures through the development of predictive maintenance capabilities. The project will monitor for signs of failure onset through use of existing data sources including SmartMeter™ connectivity data, geolocational asset data, and weather data. The objective is to develop an analytical model in conjunction with existing PG&E data sets to predictively identify electric distribution equipment issues so that corrective action can be taken before failure occurs.

- **Probability of Asset Failure (PAF)**: The 2020 PAF project uses data science methods to predict the likelihood of corrective maintenance tags on different ET asset classes (insulators, conductors, switches, steel and non-steel structures). The work supplements engineering judgment used to inform asset strategy and project nomination decisions. The 2020 PAF project delivers enhancements to the asset health models delivered in 2019 via the System Tool for Asset Risk (STAR) for T-line project (see 'appendix: closed projects' for details). Each update of the asset health models delivers learnings of what additional data improve the quality of the models, allowing the models to mature in accuracy of predictions.

2.1.4 Data Governance & Enablement

Smart grid and technology investments unlock new data streams that can be leveraged to inform risk-based decision-making. PG&E aims to integrate certain data from different data sources into a single environment, enabling data driven approaches to wildfire mitigation initiatives and efforts. PG&E's vision for data analytics is focused on a practical data integration approach (utilizing data pipelines from data sources/systems into an integrated data platform) as opposed to a data consolidation approach (eliminating existing data sources/systems and building a single data system for all PG&E data). The long-term objective is to enable advanced data analytics that allow for predictive models to identify at risk assets to further enable proactive AM practices to mitigate the risk of asset failure and enhance customer safety.

2.2 DER Integration & Enablement

DERs and clean technology growth continues in PG&E's service territory, with EV sales, solar installations, and grid battery storage adoption rates growing at unprecedented rates. DER milestones achieved in PG&E service territory over the current reporting period include:

- The number of EVs sold in PG&E service territory reached 292,145 by the end of June this year, a roughly 24 percent increase over the previous year.
- PG&E's EV Charge Network Program will install up to 7,500 EV level 2 charging ports focused on workplaces and multi-unit dwellings. As of March 31, 2020, 200 sites representing 4,932 ports had signed agreements with PG&E.[14]
- Over 420,000 solar roof-top photovoltaic (PV) systems have been installed by the end of the current SGAR reporting period, an increase of about 14 percent over the previous reporting period.
- PG&E has already contracted for greater than 600 MW in utility owned and third-party contracted grid-tied battery storage, in excess of the CPUC mandated goal of 580 MW by 2020.

2.2.1 Managing the Effects of DER on the Distribution System

Balancing loads between three phases on the distribution grid becomes challenging with higher DER penetration. Considerations include the effects of DERs' output, location and characteristics on the distribution grid to mitigate issues such as phase imbalance and voltage regulation problems. PG&E is investing in Smart Grid technologies to establish more sophisticated engineering and operational tools to detect and predict grid issues. One key development includes the testing of an ADERMS through EPIC 3.03. This project seeks to design, procure, and deploy a prototype enterprise DER Management System. This includes development of a cost-effective non-SCADA solution for providing advanced situational awareness and control capabilities. These will enable operators to manage DERs, dispatch DER

14 https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/EV-Charge-Network_2020_Q1_Report.pdf

Registration data requests and monitor Smart Inverter (SI)-based DERs through a head-end platform, and provide an interface to dispatch DERs as a remote grid and Non-Wires Alternative (NWA) solutions.

DERs can provide new products and services for customers, including enhanced resiliency through MG configurations. PG&E is actively assessing and testing MG capabilities and how these may provide greater benefit for our customers. For instance, EPIC 3.11, Multi-use MG, seeks to enable a multi-customer MG within the Arcata-Eureka Airport business community and will incorporate four PG&E and RCEA customers. The project will design and develop control specifications and provide SCADA integration to maintain visibility and operational control of the MG in grid-connected and islanded modes and will help satisfy the community's demand for enhanced resilience of their power supply.

The following projects have proven successful in addressing DER integration and enablement and are currently being scaled-up. The multi-year ADMS deployment is an earlier Phase 2 EPIC demonstration project[15]:

- Multi-year ADMS deployment integrating several mission critical distribution control center applications that are currently spread across multiple platforms. This technology will enable the visibility, control, forecasting and analysis required from a more dynamic grid.
- T&D SCADA deployments which will achieve close to 100 percent visibility and control of all critical transmission substation and distribution substation breakers over the next few years.
- Expansion of the FLISR system to approximately 30 percent of PG&E's distribution circuits.
- Continued development of the transmission Energy Management System's (EMS) capabilities, including improved integration of additional synchrophasor PMUs.

15 For more information, reference EPIC closeout reports: https://www.pge.com/en_US/about-pge/environment/what-we-are-doing/electric-program-investment-charge/closeout-reports.page.

2.2.2 Distribution Resources Planning

Distribution Resources Plan (DRP) Overview

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

Refreshed Data Portal Reflects Increased DER Integration Capacity

Since 2016, PG&E and California's other investor owned utilities have provided contractors and developers with online access to maps designed to help them find potential project sites for DERs, such as solar and energy storage. PG&E has refreshed the maps reflecting an increase in the posted DER integration capacity of our electric distribution system. The maps are accessible at PG&E's Distributed Resource Planning Data Portal, and show hosting capacity, grid needs and other information about PG&E's electric distribution grid.

Distribution Investment Deferral Framework

The Distribution Deferral Opportunity Report (DDOR) and Grid Needs Assessment (GNA) reports identify locations where DERs may be a feasible and cost-effective option to defer traditional "wires" solutions on PG&E's distribution grid. On August 17th of 2020, PG&E published its third annual GNA and DDOR reports. The GNA identified capacity, voltage support, reliability and resiliency needs on PG&E's distribution system and the DDOR identified and assessed planned "wires" investments as potential candidate deferral opportunities for DERs. The 2020 reports identified 29 candidate deferral opportunities and recommends 8 candidate deferrals (30 MW) for NWA solicitation.

2.3 Customer Service

Over the past year, PG&E has continued to make progress providing customers with a robust suite of solutions that empower customers to eliminate unnecessary energy use, reduce their carbon footprint, and save money[16]. PG&E considers its customers to be the primary driver of its Smart Grid and technology investments. Therefore, without engaged and empowered customers, many of the benefits that Smart Grid and technology systems can offer will be difficult to realize.

PG&E administers a diverse portfolio of EE programs that include strategies to help customers upgrade to more energy efficient equipment, audit their energy use and understand opportunities for savings, and undertake comprehensive retrofits. PG&E's Codes & Standards (C&S) program has been particularly effective in achieving energy savings. Highlights from PG&E's work for the current 2019/2020 reporting cycle include:

- **We expanded our EE financing program**, which provides commercial customers and government agencies with loans for EE upgrades with no out-of-pocket costs and zero interest. The program affords project developers and customers flexibility in how they implement their projects. It also allows customers to get measures tailored to their needs and drive the process and timeline themselves. In 2019, the program funded 668 loans worth a total of $59 million. Most loans went to small and medium businesses, and public organizations.
- **Increased financial incentives for energy-efficient and resilient construction practices in homes rebuilt after wildfires.** As part of our broader efforts, PG&E is encouraging customers to build high-performing homes that will result in lower energy bills.
- **Meter-based savings programs** use actual meter energy use to estimate EE savings. Data analytics has provided a powerful tool in identifying and targeting customers with high savings potential. The continuous feedback and P4P nature of meter-based programs helps ensure that the expected savings are realized. PG&E launched its first

16 PG&E's 2019 Energy Efficiency Annual Report: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M337/K862/337862483.PDF

residential NMEC program, the Residential P4P pilot program, in 2018. P4P employs energy meter data to understand the impacts of customers targeting deeper energy savings. During the current reporting cycle, this program served 2,206 homes, an increase of 21 percent over the previous period. In 2019 PG&E launched NMEC programs to serve the commercial and public sectors and is on track to launch several more in 2020 and 2021. These programs also help achieve PG&E's goals of establishing on-going relationships with its customers in a joint pursuit of energy savings. Additional EE products which help further these efforts are HERs[17]; Business Energy Checkup and Home Energy Checkups[18] and Industrial Strategic Energy Management programs[19].

- **Moving forward on predominantly third-party implemented EE portfolio by 2023.** In January, 2018, the CPUC issued D.18-01-004, which formalized the third-party solicitation process for EE programs. In June, 2020, PG&E signed eight new statewide third-party contracts for EE resource programs. To help ensure programs goals will be attained, the contracts include performance payments for energy savings, cost effectiveness goals, as well as other key performance metrics

- **Supported California's goal for all newly constructed residential buildings to be zero net energy (ZNE) by 2020.** To do so, PG&E experts advocated for strong state and federal appliance standards and conducted research to support California's 2022 Energy Code rulemaking cycle. Further, the 2019 update to California's Energy Code, which applies to all new construction, additions, and alteration projects permitted on or after January 1, 2020, is expected to result in savings from the measures of approximately 603 GWh/year, 3.2 million therms and 30 million gallons of water for each year's construction following the effective date.

  Additional C&S program highlights for the 2019/2020 reporting cycle include:

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[17] HERs are comparative energy usage reports for residential customers.

[18] Business Energy Checkup and Home Energy Checkups are online assessment tools that help customers understand their energy usage and offer tips on how to save energy.

[19] Industrial Strategic Energy Management programs involve industrial facility employees tracking down energy savings opportunities and provide planning resources for future energy needs.

i. PG&E leads Appliance Standards Advocacy for new or updated sections of California's Title 20 Appliance Efficiency Regulations (Title 20) and Department of Energy (DOE) appliance standards, and related ENERGY STAR® activities. In 2019, PG&E led the IOU's support to revise the commercial Variable Refrigerant Flow (VRF) test procedure and efficiency standard which will ensure VRF energy savings are accurately reflected in their equipment ratings. PG&E collaborated with DOE to demonstrate that equipment ratings, based on the new test procedure, could double the savings consumers would realize in their facilities. This effort is opening opportunities to collaborate on other test procedures.

ii. Through the Energy Code Ace platform, the Compliance Improvement program offered training, tools, and resources to support compliance with California's existing EE regulations. In 2019, PG&E delivered more than 101 classes, across eight modalities and dozens of roles. PG&E reached more than 2,660 students and achieved a 98 percent satisfaction rate and an 18 percent knowledge swing, on average.

iii. PG&E also provided support to jurisdictions interested in adopting local reach codes, including those that contain pro-electrification policies, that go beyond the state's current Energy Code and help achieve local greenhouse gas (GHG) emission reduction goals. By June 2020, approximately 30 jurisdictions had adopted reach codes. PG&E submitted letters of support to more than 25 cities who requested a public statement as part of their city council approvals process.

PG&E's EE programs in 2019 resulted in annual electric and demand savings of 1,253 GWh and 253 MW, respectively.[20]

[20] Annual energy savings refer to the first-year impacts associated with installed customer energy efficiency projects and codes and standards interventions. Savings are calculated on a net basis, which excludes savings that would have been achieved in the absence of energy efficiency programs. Savings shown comprise 539 GWh and 96 MW from installed projects and 714 GWH and 157 MW from codes and standards programs. Data are as filed with the CPUC in PG&E's Energy Efficiency Program Portfolio Reports and available on the CPUC's CEDARS website: https://cedars.sound-data.com/upload/confirmed-dashboard/PGE/2019/.

2.4 Security

The increase in internet-connected Smart Grid and technology devices will be accompanied by a corresponding increase in cyber-security threats. PG&E is collaborating with other California IOUs and national labs to understand the threats that could result from integrating grid communications and controls required for the functioning of the grid with the goal of developing the next generation cybersecurity and automated threat response capabilities that can be applied to industrial control systems such as the electric grid. Significant progress was made in the previous year in terms of leveraging modeling & simulation capabilities to understand the potential effects and mitigations of the malware and tactics employed in the December 2016 Ukrainian power system event. With the installation of PG&E equipment at INL, all three IOUs now also have substation instances at the Physical Test Bed, to allow for high-resolution assessments of specific threats. Over the past year, significant progress was also made across the various sub-components of the Automated Response Research Package, including the continued development of Indicator and Remediation Language use cases and continued enhancement of vulnerability scoring capabilities.

CHAPTER 3

SUMMARY OF BENEFITS

FOR SELECTED PROJECTS

3 Summary of Benefits for Selected Projects

3.1 Summary of Benefits for Selected Projects

This year, PG&E's Smart Grid benefits continued to grow, adding an estimated $202.6 million of incremental savings from July 2019 through end of June 2020 for select projects (shown below).

Table 3-1: PG&E's Smart Grid Estimated Project Benefits – July 2019 to June 30, 2020[21]

Category	Annual Savings
Direct Customer Savings (Bill Forecast Alerts (BFA), Demand Response (DR))	$372 Thousand (est.[22])
Avoided Costs (Operational, Capital, Environmental[23])	$3.2 Million
Customer Reliability Benefit[24]	$199 million[25]
Total Benefits	**$202.6 million**
Reliability	81.1 million customer minutes avoided[26]

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

22 Saving based on 2018/2019 customer participation data. Comparable data is not available for the current reporting period. However, PG&E does not anticipate that customer participation changed substantially over the reporting period.

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

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

25 Customer Reliability Benefit for FLISR since inception is $1,320 million, with 472 million customer minutes avoided.

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

- Avoided Customer Sustained outages over reporting period: 824,258 (CESO)
- Actual recorded outage minutes over reporting period: 719,792,704
- 5-year average recorded outage minutes: 147,390,767 (CMI)
- 5-year average avoided outage minutes: 78,079,958 (CMI)

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

- PG&E's SmartMeter Outage Information Improvement ($0.7 million)
- PG&E's BFAs (formerly: Energy Alerts) ($0.372 million est.)
- PG&E's FLISR project ($199 million)
- PG&E's Modular Protection and Automation Control (MPAC) project ($2.6 million)

3.2 Benefits Descriptions

3.2.1 Direct Customer Savings (BFAs/Automated Demand Response (AutoDR))

BFA estimate what a customer's bill will be (gas and electric) and alerts them when the forecasted amount exceeds their custom-set threshold. Because forecasts are predictions, estimates may differ from the customer's actual charges for each statement period. PG&E's current BFA replaced the former Tier Alerts in March 2016 in anticipation of E1 tier collapse and new Time-of-Use (TOU) rates coming on-line. Additionally, gas usage was added to the forecast for a more complete customer experience. Many customers have been receiving alerts (both Tier and then the BFA) for eight years. Early savings results from the programs were a result of initial awareness of household costs associated with energy usage and initial meaningful adjustments made to control this. PG&E's *2018 Program Year SmartMeter Program Enabled Demand Response and Energy Conservation Annual Report* concluded $372,000 in annual customer savings for BFA participants, dually enrolled High Usage Alert (HUA) and BFA customers, for a combined savings of 9,521 megawatt-hours (MWh)[27]. While comparable participant savings data is not included for the 2019/2090 reporting cycle to calculate actual customer savings benefits, overall program participation levels are believed to have been similar. The program continues to serve customers by providing them with a transparent billing alert and helps customers to manage energy cost with consumption patterns. We are therefore using 2018/2019 direct customer savings as an estimate for the current reporting cycle savings.

[27] https://www.pge.com/pge_global/common/pdfs/safety/how-the-system-works/electric-systems/smart-grid/AnnualReport2019.pdf

Automated DR benefits result from load reductions for customers who adopt control technologies and participate in a DR program. No direct customer savings are calculated for AutoDR for the 2019/2020 reporting cycle. More information on the benefits calculation for this project can be found in the 'Automated Demand Response (AutoDR) Program' program box in the *Emerging Customer Side Technology Projects* section of this report.

3.2.2 Avoided Costs (SmartMeter Outage Information Improvement/MPAC)

Avoided cost benefits represent the total avoided costs associated with SmartMeter Outage Information Improvement and MPAC. SmartMeter Outage Information Improvement project delivers reliability and operational benefits through leveraging SmartMeter data to better understand and resolve customer outages. The program reduced an estimated 8,174 "truck rolls," saving over $600,000 over the reporting period. MPAC helps improve reliability of the transmission system by replacing aging infrastructure and modernizing facilities. Over the past year, the MPAC Installation Program has avoided $2.6 million in capital costs over traditional upgrade methods and has avoided a cumulative total of $72.4 million[28].

3.2.3 Reliability Benefits (FLISR)

Reliability benefits come primarily from PG&E's FLISR project. FLISR limits the impact of outages by quickly opening and closing automated switches. What may have been a one- to two-hour outage can be reduced to less than five minutes. For the purposes of this report, the benefits are estimated using a Value-of-Service reliability model that was developed in-house using the Freeman & Sullivan analysis incorporating various tax law changes[29]. FLISR procedures have been updated to account for fire index disabling, under which select FLISR circuits may be disabled on extreme fire condition days.

28 MPAC benefit totals reflect updated calculations for 2020 Smart Grid Annual Report.

29 FLISR reliability benefits are calculated from actual CMI and CESO savings (tracked per every event) that are applied to the Value of Service calculator.

3.2.4 Smart Grid's Role in Furthering Environmental Sustainability

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

Smart Grid and technology enable numerous environmental benefits. Over 465,000 customers have installed roof top solar and generate their own power in PG&E service territory. 292,145 customers have decided to replace their traditional vehicles with EVs fueled by the Smart Grid. Smart Grid technologies, including sensing technologies, two-way digital communication, controls and automation, all provide foundations for which new DERs can be connected and controlled via the grid. Given the intermittency and flexibility of DERs like solar and EVs, PG&E's ability to communicate with such assets and in some cases, determine whether it generates or uses energy, enables GHG reductions while building a more resilient grid.

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

CHAPTER 4

PG&E'S SMART GRID DEPLOYMENT

PROJECT UPDATES

Introduction

Chapter 4 provides detailed updates on the Smart Grid and technology projects and programs over the reporting period of July 1, 2018 to June 30, 2019.

4 Summary Updates for Selected Projects

4.1 Community Wildfire Safety Program – Select Technologies

PG&E continues to make substantial progress toward its CWSP goals. Below are select technology projects enabling new capabilities to help mitigate the risk of wildfires and protect customers and communities.

PSPS Risk Modeling	Approximate Cost Over Reporting Period: N/A
Summary and Background: Recognizing that wildfire risk cannot be completely eliminated through vegetation management, system inspection, and system hardening, PG&E has developed, and continues to refine, a proactive de-energization program that was initially developed in advance of the 2018 wildfire season and deployed in October 2018. The program was significantly enhanced for the 2019 wildfire season and is being further enhanced for the 2020 wildfire season. PG&E implemented its PSPS program in 2018 to proactively de-energize lines that traverse Tier 3 HFTD areas with extreme fire risk. In developing the PSPS program, PG&E performed extensive benchmarking with SDG&E (the domestic utility with the longest history of proactively shutting power off to avoid wildfire events) in a variety of areas, including meteorology, operational processes, emergency response, restoration, communications and customer support. PG&E is focused on maturing this program to most effectively eliminate potential ignitions during extreme weather conditions. In 2020, lines considered for potential PSPS events include all distribution and transmission lines at all voltages (500 kilovolt (kV) and below) that traverse Tier 2 or Tier 3 HFTD areas. In comparison, lines considered for potential PSPS events in 2018 included all distribution lines and transmissions lines at 70 kV or below that crossed Tier 3 HFTD areas. This expansion of the PSPS program increases the targeted distribution lines from approximately 7,000 circuit miles to over 25,000 circuit miles, and the targeted transmission lines from approximately 370 circuit miles to approximately 5,500 circuit miles. As PG&E expanded the PSPS program to include higher-voltage lines within HFTD areas in 2019, PG&E also developed a risk-based process, or Operability Assessments (OA), to assess the wildfire risk of individual transmission lines and structures. Through these OAs, initially applied to transmission lines in 2019, PG&E has applied a risk-informed methodology to evaluate the potential risks and impacts from de-energization. This risk-informed methodology guides PSPS decisions, allowing PG&E to de-energize specific, targeted transmission lines to reduce wildfire risk and minimize impacts to customers. OA also facilitates compliance with federal reliability and operational requirements (e.g., NERC Reliability	

Standards, and California Independent System Operator (CAISO) Corporation Tariff requirements) and limits wide-area grid reliability risk while still reducing wildfire risk.

OA Methodology Detail: A fundamental aspect of managing the operation and maintenance of transmission infrastructure is assessing the condition (health) of the components and structures and evaluating the increased risk of failure associated with known degradation mechanisms or aging in general. Key to understanding the OA tool is the concept of fragility. In short, fragility refers to the increasing probability of failure for increasing applied load. In the context of the OA tool, fragility is the conditional probability that an asset (tower, pole, conductor, anchor, etc.) will fail at a given wind speed.

While wind speed is the intensity measure used to define fragility, the OA tool considers many damage mechanisms such as corrosion, fatigue, wear and decay that can lower the capacity of the asset to resist wind loads. The OA tool is based on assigning a fragility curve to each asset to reflect its current health relative to a newly designed and constructed, but otherwise identical, asset. This is done by first presuming a fragility associated with a new, healthy asset, and then adjusting both the strength and uncertainty to reflect the observed condition, age, environment, and historical performance of the circuit in whole. Specifically, the median strength is adjusted based on ground and drone inspection results, test and treat inspection findings (for wood poles only), and structural engineering analysis of the towers/poles, insulators, guys, foundations, anchors and conductors. The uncertainty is adjusted based on the asset age versus a notional design life, the aggressiveness of the asset environment with respect to corrosion and windiness, and the past performance of the circuit.

For OA, the fragility can be used to predict the risk that an asset (or set of assets) will underperform at a forecast wind speed. Alternately, if a risk tolerance is defined, the corresponding wind speed at which that tolerance is exceeded can be determined directly from the fragility as described earlier. The risk tolerance is an input to the OA tool, and is a function of many concerns outside the scope of the OA tool. The OA tool also includes a mechanism for continuous improvement of wind-based asset strength estimation. Past and on-going component failures and survivals of assets in windy conditions are incorporated into the model using Bayesian updating methodologies. Further, PG&E is undertaking a testing program to better define fragility curves for specific components. In 2020, OA has been migrated to run in PG&E's cloud-based Asset Data Foundation (ADF). ADF is PG&E's first-of-its kind unified T&D Asset data set where attributes are defined, sources are known, and data pipelines are established and governed. By linking multiple utility systems of record into one data warehouse using the Amazon Web Services cloud platform, ADF's mission is to operationalize electric asset intelligence at lower cost and greater repeatability with more trustworthy analytical results for wildfire risk reduction.

Funding Source: Fire Risk Mitigation Memorandum Account (FRMMA) / Wildfire Plan Memorandum Account (WPMA) per PG&E's Amended 2019 Wildfire Safety Report (WSP)

Status: Active

Benefits Description: Proactively de-energizes high fire risk power lines to prevent wildfires during extreme weather conditions.

Benefit Category: PG&E Community Wildfire and Safety Program - Smart Utility

Dx Risk Model	Approximate Cost Over Reporting Period: N/A

Description: Dx risk model project objectives are to develop models that 1. Provide situational awareness of risk, 2. Enable risk-informed decision making and 3. Enable PG&E to develop line-of-sight on risk reductions from wildfire risk mitigation initiatives. Meeting these three objectives will raise the modeling maturity from relative risk models at the circuit level with system level risk reduction and Risk Spend Efficiency (RSE) capabilities, as represented in the CPUC maturity survey, to automated quantitative risk models that include risk reduction and RSE evaluations all at the asset level.

Funding Source: PG&E expense

Status: The Dx modeling effort recently delivered a Distribution Enhanced Vegetation Management (EVM) model to VM and is in the process of developing a System Hardening equipment failure model for use by Distribution Asset Strategy in determining the System Hardening workplan.

Benefits Description: Benefit Category: PG&E Community Wildfire and Safety Program - Smart Utility

Probabilistic Risk Assessment (PRA) Model	Approximate Cost Over Reporting Period: N/A

Description: As part of PG&E's response to SB 901, PG&E itemized efforts to develop and operationalize methods and capabilities for proactive wildfire risk management and response planning. Under a collaborative R&D agreement, PG&E and the UCLA B. John Garrick Institute for the Risk Sciences have been working together to develop an integrated wildfire PRA model. This model will include developing a web-based software platform to support risk informed decisions during normal and abnormal conditions to prevent and mitigate safety, reliability, financial, and environmental impact of wildfires.

Currently, Diablo Canyon utilizes a PRA model to manage risk. First, the PRA model is used to inform AM plans by determining risk reduction for different mitigation options. Second, the model is used to assess the risk inherit with different operational decisions. Finally, the model output provides a common measure with the Nuclear Regulatory Commission for determining acceptable risk and reporting on plant performance.

Project Objective: The Electric PRA Model Project will explore the applicability of this model as an analytical and decision tool for Electric Operations.

Model Structure: The proposed framework is designed for use in three different modes:

(1) **Offline Mode** for long-term risk management and decisions such as AM strategies and prioritization of risk mitigation options;

(2) **Online Mode 1** for continuous risk monitoring and decision support based on real time or near real time information (e.g., meteorological condition) to alarm operators of the changing risk levels and provide input in decision making regarding actions such as proactive PSPS;

(3) **Online Mode 2,** for decision support during an active fire situation, dynamic updating of risks associated with fire propagation and supporting decisions on PSPS, and evacuation.

The structure of the model begins at a high level with an event tree. The event tree details the key events or decisions related to a risk. At each of these events the model provides probabilistic information on the outcome, in this case a Catastrophic Wildfire.

Funding Source: This model is being developed with the Garrick Institute for Risk at University of California Los Angeles (UCLA) which is funded with a Pledge of funding to UCLA. Under this funding approach there is not a formal Contract Work Authorization (CWA) issued. For the HFRA review this is a statement of work with a CWA / contract and is treated differently.

Status: The PRA model recently completed the major milestone – a North Bay division pilot which was reviewed by leadership with the approval to proceed toward developing a model for the whole PG&E electric system. Next step is to the develop the schedule for this next phase.

Benefits Description: Benefit Category: PG&E Community Wildfire and Safety Program - Smart Utility

Temporary MG – Preinstalled Interconnection Hub (PIH)	Approximate Cost Over Reporting Period: $13.7 Million

Description: PG&E is continually working to analyze our systems, refine our procedures and further assess how we can minimize the impacts of a PSPS. One of the ways we are working to do this is through establishing new "Temporary Microgrids" (the 2019 Angwin pilot was referred to as a "Resilience Zone").

Temporary MGs are being developed across PG&E's service area in 2020 as a part of the company's comprehensive actions to reduce wildfire risks across our system and minimize the impact of public safety outages on our customers and communities. PG&E's specific objective with the development of Temporary MGs is to provide electricity to resources such as medical facilities and pharmacies, police and fire stations, gas stations, banks, markets and other shared community services when weather conditions make it unsafe to operate the grid.

A Temporary MG is a designated area where PG&E can safely provide electricity to central community resources by rapidly isolating it from the wider grid and re-energizing it using temporary mobile generation during a public safety outage. Though each Temporary MG will vary in scale and scope, the following equipment will be found at each site:

1. Isolation devices used to disconnect the circuit from the wider grid during a public safety outage
2. A pre-installed interconnection hub (PIH) that enables PG&E to rapidly connect temporary generation and energize the isolated circuit (thereby forming an energized "island")

Weather conditions and other operational considerations prevent PG&E from guaranteeing electricity to all customers potentially served by a Temporary MG during all PSPS conditions or scenarios.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP, CWSP, MWC 49M

Status: Pilot project was operational in 2019. Summary status on Temporary MG development is as follows:

Design Completed – 10

Construction in Progress – 3

Construction Completed - 4

Benefits Description: Reduce public safety impact and increase community normalcy during PSPS events.

Benefit Category: PG&E Community Wildfire and Safety Program - Smart Utility

PGE.com Portal Enhancements	Approximate Cost Over Reporting Period: $0.58 Million

Description: Enhancements were made to PG&E's website by creating a web portal to support the PSPS program. The main focus of the work was sharing maps of de-energization areas and creating interstitials to encourage customers to provide notification information. This work has been transitioned into PG&E's Emergency Web implementation, which expands on prior work and builds additional resiliency as an outcome.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: Complete

Benefit Description: Public safety

Benefit Category: PG&E CWSP - Smart Utility

Weather Station Deployment / Hi-Definition Camera Deployment	Approximate Cost Over Reporting Period: $8.5 Million

Description: PG&E is rapidly increasing its situational awareness—its knowledge of local weather and environmental conditions—to obtain real time information on a more granular level. This type of information is critical for both wildfire prevention and PSPS events and is accessible to respective fire response agencies. From 01 July 2019 through 30 June 2020, PG&E installed 298 weather stations and 154 HD cameras to continue to improve its RT knowledge of localized conditions that affect wildfire risk. By 2022, PG&E plans to install a total of 1,300 weather stations and 600 HD cameras across its service territory. PG&E will grant fire agencies access to control the cameras, consistent with an approach taken by SDG&E.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: Active.

Benefits Description: Provides real time information on temperature, humidity and wind speed that is used for fire modeling and decision-making processes during a possible PSPS event.

Benefit Category: System reliability and operational efficiency. CWSP - Smart Utility.

Wildfire Spread Models	Approximate Cost Over Reporting Period: $6M

Description: In late 2019, PG&E partnered with Technosylva, an external expert in the fire modeling field to test and deploy cloud-based wildfire spread model capabilities to better understand the technology and to test integration into current decision support frameworks. In 2020, several enhancements are being made to the inputs and underlying fuel model maps to improve the fire spread outputs. Over 70 million virtual fires are simulated by the technology each day every 200m along PG&E's overhead assets in the CPUC HFTD. Fire simulations are driven by weather and fuel model inputs from PG&E's high resolution PG&E Operational Mesoscale Modeling System (POMMS) weather model. Fire simulation outputs are available every 3 hours across a 3-day forecast horizon. In Q3 2020 and beyond, PG&E plans to continue to work with Technosylva to enhance the inputs and outputs of the model framework.

Funding Source: Wildfire Mitigation Balancing Account (WMBA)

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: Active

Benefit Description: Enhanced understanding of fire spread risk based on forecast information. Added ability to rapidly simulate new fires for enhanced awareness and potential impacts.

Benefit Category: CWSP – Smart Utility.

POMMS Enhanced Fire-Risk Modelling	Approximate Cost Over Reporting Period: $3.5 Million

Description: POMMS is a high-resolution weather forecasting model that generates important fire weather parameters including wind speed, temperature, relative humidity, and precipitation at a 3-kilometer (km) resolution. Outputs from POMMS are used as inputs to the National Fire Danger Rating System (NFDRS), the Nelson Dead Fuel Moisture (DFM) model, and a proprietary Live Fuel Moisture (LFM) model to derive key fire danger indicators such as 1hr, 10hr, 100hr, 1000hr DFM, LFM, and NFDRS outputs such as the Energy Release Component, Burning Index, Spread Component and Ignition Component.

In late 2018 to 2019, PG&E successfully completed one of the largest known high resolution climatological datasets in the utility industry: a 30-yr, hourly, 3 km spatial resolution dataset consisting of weather, dead and live fuel moistures, NFDRS outputs, and fire weather derivative products such as the Fosberg Fire Weather Index. The quantity of data generated at the near-surface was near 80 billion datapoints. With this robust weather and fire parameter dataset, PG&E Meteorology sought to develop outage and fire potential models in 2019 utilizing best-practices deployed in the utility industry, fire science and data science communities.

PG&E is enhancing its weather model capabilities by creating a new 2km version of its weather model as well as reconstructing a new 30-year climatology based on the 2 km model configuration. PG&E has partnered with external numerical weather prediction vendors to help execute this project. Enhancing this data through POMMS can drive improved results in downstream models such as the Outage Producing Wind Model, the Fire Potential Index, and fire spread simulations.

Funding Source: WMBA

Status: Active

Benefit Description: Enhanced model accuracy and granularity. Benefits downstream models such as FPI and OPW, which are main inputs for PSPS

Benefit Category: CWSP – Smart Utility

DMS/ Outage Management Tool (OMT) / Integrated Logging Information System (ILIS) Enhancements	Approximate Cost Over Reporting Period: NA

Description: Enhancements to PG&E's DMS, OMT, and ILIS to manage PSPS events. The focus is on management of Estimated Time of Restoration (ETOR), providing operational views of outages to support patrol and restoration, inclusion of OMT capability to document presence of hazard(s) at outage location, creation of new customer coding for pandemic responses (i.e., PR1 code) and telecommunication customers (i.e., TT1 & TT2), improved PSPS alignment between ILIS, DMS, and OMT when creating new outages, and notification of customers for All-Clear, ETORs and final restoration.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: In-Flight

Benefit Description: Public Safety

Benefit Category: PG&E Community Wildfire and Safety Program - Smart Utility

Enhanced Vegetation Management – Information Technology (IT) Field Tool	Approximate Cost Over Reporting Period: $4.6 Million

Description: The EVM* program was implemented by PG&E's Vegetation Management organization as an additional precautionary measure intended to help further reduce wildfire risks by reducing vegetation above and adjacent to overhead primary voltage power lines in the HFTD.

The EVM work includes the following:

1. Meeting state standards for minimum clearances around the power lines
2. Addressing overhanging limbs and branches directly above and around the lines
3. Removing hazardous vegetation such as dead or dying trees that pose a potential risk to the lines
4. Trimming vegetation around lower voltage secondary lines to prevent damage, when needed
5. Evaluating the condition of trees that may need to be addressed if they are tall enough to strike the lines

Vegetative fuels under power lines may also be considered for treatment, the scope for that effort is captured separately as the "Fuel Reduction" program. To enable this program, mobile-application-based solutions were rapidly developed and deployed using the ESRI ArcGIS Online Software as a Service platform. These solutions expedited the performance of pre-inspection and tree work activities in the field via work management enablement on hand-held smart phones and devices. *From August 2018 through 12/10/2018 the program was called Accelerated Wildfire Risk Reduction. Beginning 12/11/18 the program was renamed to EVM to reflect changes in the program's scope of work. <u>Funding Source</u>: FRMMA / WPMA per PG&E's Amended 2019 WSP <u>Status</u>: Mobile applications were developed and deployed in September 2018 and have been maintained and enhanced since that time to meet the requirements of the program. Additionally, end user support of over 2,500 field users is ongoing with major application enhancements planned quarterly to improve functionality and maintain alignment with business processes. <u>Benefits Description</u>: These solutions expedited the performance of pre-inspection and tree work activities in the field via work management enablement on hand-held smart phones and devices. <u>Benefit Category</u>: PG&E Community Wildfire and Safety Program - Smart Utility

Enhanced Asset Inspections – Drone/AI (Sherlock & Waldo)	**Approximate Cost Over Reporting Period:** **$5.8 Million**
<u>Description</u>: PG&E developed an enhanced inspection program as part of the CWSP, known as the Wildfire Safety Inspection Program (WSIP). The WSIP implemented enhanced inspections to be completed on an accelerated schedule for PG&E to inspect its electric facilities in Tier 2 and Tier 3 HFTD areas and address any high priority repairs identified before the 2019 fire season. Under WSIP, the accelerated inspections focus on conditions that could lead to potential fire ignitions, identified through a Failure Modes and Effects Analysis (FMEA), and supplement PG&E's baseline inspection and maintenance procedures. Through the FMEA, PG&E has identified single points of failure of electric system components that could lead to fire ignition. The identification of these failure points will aid in the development of inspection methods that can most appropriately identify the condition of such components, which are designed in accordance with CPUC General Orders (GO) 95, 165, and 174 requirements. Under the program, PG&E has and will continue to perform detailed ground inspections and climbing inspections (for transmission towers) that focus on failure points capable of visual inspection as well as secondary inspections using drones for all transmission assets and for distribution assets that are on or near those transmission towers. Sherlock is a web application that allows inspectors to view photographs of assets along with associated data and enables tracking the remote inspections within Sherlock in near RT. It also allows for remote access of data new drone/helicopter images taken by the vendors, as well as quality assurance review of the data coming in from drone pilots to ensure that only corrected data is viewed by inspectors. This helps to reduce the time from flight to inspection. In addition, inspectors can	

mark-up issues within the inspection profile of the application, which generates the necessary documentation from the application itself, ensuring auditability and data quality.

The markups from Sherlock feed Waldo, a computer vision API, where computer vision models are trained to identify components as well as problems in an automated fashion. Other applications can send/receive data to/from Waldo to train/retrain models, and/or to receive predictions. Models within the inspection flow are currently being used to flag particular images (e.g. overview, right of way, asset tag) for inspectors so as to free up time that could otherwise be used to find potential ignition risks. This will allow for measurement of how introducing automation may affect inspector behaviour. These models can also be used to identify particular components or issues in images that are in the inspection queue, or to enable searching images by components visible in them, rather than by asset identifiers.

Future features include the ability to write correctives directly into source systems, enabling full imagery QA, adding the inspection questionnaire, and enabling tracking from flight through to inspection, all within a single interface.

Funding Source: FRMMA / WPMA per PG&E's Amended 2019 WSP

Status: In Development

Benefits Description: PG&E Community Wildfire and Safety Program - Smart Utility, System Reliability and Operational Efficiency.

Benefit Category: Community Wildfire and Safety Program - Smart Utility. System Reliability and Operational Efficiency.

4.2 Customer Engagement and Empowerment Projects

Over the reporting period, PG&E continued to make steady progress on several projects to provide customers with the tools necessary to manage their energy usage and costs. Continuing to leverage SmartMeter™ capabilities and providing energy use data access to customers is vital to the company's efforts to help customers understand their energy use and manage their energy bills.

Progress continues to be made on pilot programs exploring the use of DR as a behind-the-meter DER that can be integrated into the wholesale energy market but can also address local distribution needs. DR programs can be used to both mitigate excessive demand and as a way to support the future grid in times of excess generation by storing this energy for later use. Existing technologies such as storage, EVs and smart devices can be used for this purpose. PG&E is undergoing efforts to enhance customer access to EV infrastructure and programs. By supporting adoption of EVs, PG&E can extend efforts to reduce GHG emissions across the state.

As PG&E considers its customers to be the primary driver of its Smart Grid and technology investments, without an engaged and empowered customer population, many benefits offered by a Smart Grid would be difficult to realize.

4.2.1 DR Projects

Supply Side II DR Pilot (SSP II)	Approximate Cost Over Reporting Period: $0.47 Million
Description: The Supply Side II DR Pilot (SSP II) continues the work started in previous DR pilots to enable participation of customer behind-the-meter DERs as DR in the wholesale energy market using the Proxy Demand Resource (PDR) whole sale product. In addition, the SSP II in 2017 was expanded to start investigating the ability of wholesale DR to also provide distribution services, specifically investigating how to operationalize the interactions between wholesale market availability and distribution services availability and starting to develop a method for dispatching available DR resources based on distribution operational needs. Funding Source: Funding for this pilot in 2017 was approved by the CPUC in D.16-06-029, and the CPUC subsequently approved 3 additional years of funding (2018-2020) in D.17-12-003. Status: Participants have been bidding into the wholesale energy market. Between April 2015 and June 2020, pilot participants have submitted over 16,650 bids and received over 2,400 awards in the wholesale day-ahead energy market. While the pilot is open to residential aggregators, and several have gone through various stages of the enrollment process, to date none have completed the process and all participants are commercial customers or aggregators. In 2017, the SSP II started investigating the operational feasibility of utilizing DR resources that are integrated in the wholesale energy market to also address local distribution needs. As part of this work, the SSP II was used in conjunction with PG&E's EPIC 2.02 (DERMS) project to test if an aggregation of behind-the-meter DERs could respond to both wholesale and distribution instructions with no negative impact to the safety and reliability of the grid. While work with EPIC 2.02 ended in 2018, the SSP II is continuing to investigate this issue. PG&E submitted AL 5799-E back in April 2020, proposing to close the SSP II by December 31, 2020. Benefits Description: The SSP II is a gateway for more DR resources to be integrated into the CAISO wholesale market. PG&E has structured the pilot as a bridge between the retail and wholesale market as well as an avenue for third-party DR providers to participate in the CAISO wholesale market. This step is vital to have a self-sustaining third-party DR market in California. Learnings from the pilot were integrated into PG&E's proposed enhancements to its Capacity Bidding Program (CBP) included in its 2018-2022 DR Application, and future results from the SSP II, in addition to inputs from the Distributed Resource Plan and Integrated DERs proceedings, may be used to inform a proposal for distribution service offerings in future DR programs. The SSP II also provides a pathway for new technologies. Technologies behind the customer meter, such as storage, EVs, and or Smart devices, can play a vital role as grid-responsive assets.	

DR programs will act as avenues for participants to provide demand reduction based on the needs of the CAISO and distribution systems. Results of the SSP II will help PG&E and the Commission assess the benefits of DR as a gateway to grid benefits and provide an in-depth understanding of the benefits of behind-the-meter technologies.

Benefit Category: Smart Market – PG&E is continuing to evaluate the value streams of enabling DR resources in a changing operations environment and to provide services to facilitate the reliable and cost-effective integration of renewable resources. PG&E is pursuing discovery of the necessary program attributes that T&D system operators will need in the future.

Excess Supply DR Pilot (XSP)	**Approximate Cost Over Reporting Period:** **$0.36 Million**

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

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

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

Status: The XSP was initiated in 2016 and was approved by the CPUC to continue through at least 2020. During this timeframe, there were twenty-seven non-residential customers fully enrolled with several other participants that have completed part of the enrollment process. In addition, Q4 2019 commence the enrollment of customers that are part of PG&E's Electric Vehicle Charge Network (EVCN) into XSP. PG&E's EVCN program offers EV chargers and installation to customers located in PG&E's service territory. Of the twenty-seven non-residential XSP participants, 16 are part of EVCN. To date, larger commercial customers, and 3rd parties aggregating commercial customers, have generally been more interested in participating in the XSP than small commercial and residential customers.

Since there is currently not a mechanism or model in the wholesale market to register or bid this type of load increase/shift DR resource, the XSP is operated out of market but is designed in a manner to potentially enable market integration in the future. In addition, XSP events were dispatched based on administrative decisions to test the overall construct of response to excess supply conditions, not based directly on actual grid conditions. This enabled broader testing of participants by allowing more flexibility in when test events were called without having to wait for actual excess supply market conditions. However, starting in 2018 the XSP began using day-ahead oversupply forecasts from PG&E's Short-Term Electric Supply group as a way of triggering dispatches, and these oversupply forecasts use day-ahead wholesale market prices as an input.

An additional enhancement to the XSP in 2018 was the introduction of bi-directionality where a participant could provide non-overlapping load increase and load decrease bids. However, even if a participant chose to provide bids in both directions, load increase and load decrease dispatches were treated independently, and energy neutrality was not required.

The XSP has been successful in gaining learnings in a number of its key objectives and, in doing so, has directly and indirectly addressed multiple barriers to renewable integration challenges. In addition, these learnings have helped inform ongoing proceedings at the CPUC and CAISO. The XSP is also being looked at and utilized by other groups. For example, site hosts in PG&E's EVCN program can meet the EVCN's load management plan requirement by participating in the XSP. Including EVCN participants in the XSP enables the pilot to incorporate a technology (EVs) and customer classes (smaller commercial and multi-unit residential) that have been absent from the program.

In 2019, the XSP was also recognized by the Peak Load Management Alliance (PLMA) as one of three recipients of its 2019 Program Pacesetter award. More information about the PLMA awards can be found at https://www.peakload.org/awards, and a webinar about the pilot can be viewed at https://www.peakload.org/dialogue--pg-e-excess-supply-dr . The XSP was also featured in an article in Energy Central and can be found at https://www.energycentral.com/c/em/pges-excess-supply-demand-re. PG&E submitted AL 5799-E back in April 2020, proposing to close the XSP by December 31, 2020.

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

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

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

Benefit Category: Smart Market – PG&E is continuing to evaluate the value streams of enabling DR resources in a changing operations environment and to provide services to facilitate the reliable and cost-effective integration of renewable resources through improved alignment of supply and demand. PG&E is pursuing discovery of the necessary program attributes that T&D system operators will need in the future.

AC Cycling	Approximate Cost Over Reporting Period: $2.5 Million*

Description: Under its direct installation program, SmartAC™, PG&E has deployed direct load control devices on or near central air conditioners since 2007. Currently, there are 92,000 active participants on the program who either have legacy 1-way paging devices or the new technology which leverages PG&E's investment in the AMI network by communicating through SmartMeters. In order to improve the reliability of this resource, PG&E conducted extensive testing beginning in 2014 and began deployment of the bidirectional (2-way) technology by Tantalus (formerly Energate) in 2017. communicates through Smart Meters. This technology communicates with PG&E's SmartMeters via a Zigbee Smart Energy 1.1b standard protocol module. Residential SmartMeters at PG&E incorporated this auxiliary communication module since initial deployment to promote Home Area Network and Smart Grid automation. PG&E has integrated the 2-way device head-end control system, Itron's (formerly Silver Spring Networks) Home and Business Area Network (HAN) Communication Manager, with its DR management system, TRC's (formerly Lockheed Martin Energy) SEEload product, to have a single system of dispatch to support CAISO market integration of its SmartAC program in 2018 and provide a graphically based dashboard of enrollment and dispatchable status.

Funding Source: *PG&E's SmartAC program is authorized through 2023 under D.17-12-003 which provides a balancing account mechanism. Includes marketing, administrative, and device costs

Upcoming Plans (Subject to Change): PG&E has currently deployed nearly 15,000 2-way load control switches. Deployment plans do not entail mass replacement of legacy 1-way technology but rather if existing devices are malfunctioning, they will be replaced. The SmartAC program is currently in a mode of not recruiting any new customers. The SmartAC program technology maybe leveraged for localized purposes such as support during Public Safety Power Shut-off events and/or to alleviate substation constraints.

Benefits Description: Because 2-way switches are associated with healthy SmartMeter devices, the reliability rate of this resource will improve over 1-way paging devices. By installing 2-way direct load control devices, PG&E has near RT visibility into an individual premise and the air conditioner's actual response to a load control event signal. This facilitates early detection of device malfunction in either under- or over-performance circumstances and lost load can be recaptured quicker. Currently, PG&E uses SmartMeter data to determine an estimate of the number of non-performing devices in its maintenance program. With a disconnect alarm on a 2-way switch, unnecessary truck rolls can be avoided to sites.

Benefit Category: Smart Utility – The 2-way technology provides greater visibility into device behavior, which will be used in more accurate forecasting of load reduction during events, increase the load reduction value per customer, and provide efficiencies in program management operations. Further, DR is a DER and as such can provide load balancing benefits for grid operators.

4.2.2 EV Integration Projects

PG&E continued to make significant progress is in enablement of EV adoption with its EV Charge Network Program. This is the 3rd year of a three-year pilot whose purpose is to increase access to charging for EVs within PG&E service territory by installing approximately 4,500 EV level 2 charging ports focused on workplaces and multi-unit dwellings. As of June 30, 2020, 198 sites representing 4,898 ports had signed agreements with PG&E.[30]

The EV Charge Program positions PG&E at the nexus of customer service and emerging infrastructure needs. Public charging infrastructure is needed for California to meets its goal of 5 million zero emission vehicles on the road by 2030. PG&E's dedicated end-to-end deployment of infrastructure will help meet the state's goals. Furthermore, a customized customer-facing web portal and tools, marketing collateral, application process, and community partnerships will foster a level of customer service and public EV education formerly absent.

The program will scale to completion in 2021 and construction times have been setback due to COVID-19. For further project information, see the EVCN Quarterly Reports: https://www.pge.com/en_US/business/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/resources.page.

EV Infrastructure	Approximate Cost Over Reporting Period: $35 Million
Description: PG&E's EV Charge Network Program is a three-year pilot which enables the deployment of service connection and supply infrastructure (make-ready infrastructure) to support approximately 4,500 EV Level 2 charging ports. The program focuses on serving two key market segments, workplaces and multi-unit dwellings. Charging ports may be owned by either Site Hosts or PG&E, with PG&E able to own charging ports in multi-unit dwellings and workplaces located in disadvantaged communities. PG&E also administers rebates and participation payments for the EV chargers contingent upon the Site Hosts' attributes, physical location, and ownership model selected. The total program cost will not exceed $130 million. Funding Source: This project was funded through the PG&E EV Balancing Account.	

30 https://www.pge.com/en_US/large-business/solar-and-vehicles/clean-vehicles/ev-charge-network/program-participants/resources.page .

Status: In 2019, PG&E fully subscribed the program. As of June 30, 2019, PG&E had received 819 applications for the program, totaling more than 15,000 charging ports. At the close of Q1 2020, 198 sites had been approved and moved into final design and pre-construction phases, including 119 sites that have completed construction, installation, and activation of chargers. PG&E has installed 2,192 ports as of March 31, 2020. The program will scale to complete construction in 2021. For further project information, see EVCN Quarterly Reports: https://www.pge.com/en_US/business/solar-and-vehicles/your-options/clean-vehicles/charging-stations/program-participants/resources.page. Upcoming Plans (Subject to Change): See program status for details of upcoming plans. Benefits Description: The EV Charge Network Program positions PG&E at the nexus of customer service and emerging infrastructure needs. Public charging infrastructure is needed for California to meets its goal of 5 million zero emission vehicles on the road by 2030. PG&E's dedicated end-to-end deployment of infrastructure will help meet the state's goals. Furthermore, a customized customer-facing web portal and tools, marketing collateral, application process, and community partnerships will foster a level of customer service and public EV education formerly absent. PG&E is also mindful of potential grid benefits that EV charger deployment may drive, such as load shaping through DR communications and the establishment of load management guidelines. This charging and pricing data will help inform strategy for rapid EV growth across the state. Benefit Category: Smart Utility

EV Rates	Approximate Cost Over Reporting Period: $0.1 Million
Description: PG&E's EV rates provide customers with a TOU, non-tiered electric rate schedule that allows drivers to recharge their EVs at a fraction of the cost of gasoline. The rate is structured to offer low-cost, off-peak rates from 12:00AM to 3:00PM allowing customers to access low cost fuelling overnight and during the day. This helps PG&E integrate new EV charging load by shifting demand overnight when there is ample capacity on the utility grid and higher renewable energy during the day. The EV rates also remove the tiered rate structure of PG&E's default residential rates, which can cause EV charging to be as costly as, or more expensive than, gasoline for higher-usage customers. PG&E offers two residential EV rates to customers: Home Charging EV2-A[31] allows customers to meter their home usage and EV charging together; EV-B involves installation of a second utility meter to bill only vehicle charging on the EV rate. Since the introduction of	

31 The EV-A rate was closed to new enrollments on 7/1/2019 upon the launch of the EV2-A rate. The majority of customers enrolled in the EV-A rate were transitioned to the EV2-A rate in November 2019 with the exception of grandfathered NEM customers. The remaining customers on the rate will continue to be transitioned to EV2-A as part of annual transition based on grandfathering expiration dates taking place through 2025.

residential EV rates in 2013, PG&E has enrolled over 63,000 residential customers on an EV rate, representing 22 percent of the total registered EVs in PG&E's service territory to date.[32]

In May of 2020, PG&E introduced the Business EV rate, a new TOU rate option for commercial customers with EV charging capabilities. The rate is designed to lower the cost of charging for commercial customers and allow greater adoption of EVs. Customers can choose between the BEV-1, intended for low usage with charging installations up to 100 kW, or the BEV-2 for charging installations of 100 kW or more.

Funding Source: GRC

Status: On July 1, 2019, PG&E opened the Home Charging EV2-A rate plan, which replaces the EV-A rate. The Home Charging EV2-A rate plan is also available to battery storage customers. PG&E continues outreach activities to EV drivers to increase awareness of EV rates and other options for customers to reduce fuel costs. This includes a partnership with the Center for Sustainable Energy, the administrator of the State's Clean Vehicle Rebate Project, to reach new EV drivers. PG&E also supports several EV ride-and-drive events each year to connect with customers interested in transitioning to an EV. However, due to the COVID-19 pandemic, these have been paused for the time being and PG&E continues to explore ways to further customer outreach through digital platforms.

Benefits Description: The current off-peak price for electricity on the EV rate $0.15/kWh, equivalent to approximately $1.36/gallon of gasoline. This low off-peak price allows EV drivers to realize significant fuel cost savings compared to gasoline, which is currently trending just below $3.00 per gallon in California.[33]

Benefit Category: Engaged Customer – this program increases customer awareness and engagement in managing their energy use. With one EV accounting for roughly half of the annual consumption of a typical home, shifting charging behavior away from peak periods can allow PG&E E to avoid upgrades to local distribution infrastructure, as well as costs for expensive peak-hour energy procurement. In addition, the extension of the off-peak period to 3PM is designed to help support the integration of renewable energy, by reducing the morning and evening ramp period and thereby alleviating stress on the grid.

32 Percentage of registered EVs in PG&E territory is derived from Electric Power Research Institute (EPRI) Data. The cumulative number of customers on PG&E's rate, 63,285, is 21.7 percent of total EV sales in PG&E territory, 292,145 as of June 2020.

33 https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMM_EPM0_PTE_SCA_DPG&f=M.

4.2.3 SmartMeter-Enabled Customer Tool Projects

Energy Diagnostics and Management (ED&M)	Approximate Cost Over Reporting Period: $3.96 Million[34]
Description: The ED&M Project is the implementation of a comprehensive strategy for customer self-service demand-side management. With the release of ED&M Platform, the customer can use Your Account portal to understand their energy bills, how they use and generate energy, rate options, and savings opportunities. In addition to launching new versions of existing online tools, the current HER Program has been scaled to 1.8 million residential customers and expanded email HERs to 650,000 existing HER recipients to complement the mail and driver deeper engagement in the online channel. Funding Source: This project was funded through the EE and DR Balancing Accounts and GRC. Approximate costs listed reflect total budget allocated to project over the duration of the reporting period. Status: The project was launched in May 2015 and development completed in March 2017 on the base product. PG&E continues to release functionality on the web portal and new HER modules. Notable updates during this reporting period include: web and HER features to better support EV and solar customers (including new rates), new web functionality to support residential customers transitioning and enrolling in new TOU rates, dozens of new commercial and AG rate changes, and many new paper and electronic HER features, including providing easier ways for customers to complete the Home Energy Checkup. PG&E also increase its overall HER recipients by 300,000 customers during this timeframe. Upcoming Plans (Subject to Change): There are several planned rate changes for Non-Residential customers towards the end of 2020 to support Business EV rates, NEMs, peak day pricing (PDP), and new storage rates. Non-Residential customers will also have access to improve Rate Analysis tools which will allow them to better and more quickly understand the rate options on their accounts. Residential tools will continue to support new or updated residential rates. As households continue to increase electricity consumption due to electrification, the HER/BER program, with its proven ability to deliver electric savings, should continue to provide information on ways for customers to achieve electric savings. Benefits Description: This project provides residential and small and medium non-residential customers with actionable information and personalized recommendations on how they can save energy find the best rate for them and explore Distributed Generation (DG) and EV options. Benefit Category: Engaged Consumer – the project increases customer awareness and engagement in managing their energy usage in an environmentally sustainable and economically efficient manner.	

[34] HERs during this time period cost approximately $10.1 million. These costs are also reported as part of the Energy Efficiency Annual Report.

BFAs (formerly: Energy Alerts)	Approximate Cost Over Reporting Period: NA

Description: The BFA feature allows customers to set personalized budget thresholds and are notified via email, text, or phone when they are projected to exceed that amount during their monthly billing cycle. Customers with a single premise, with a SmartMeter, on their account, and on a supported rate plan (HG1, HE1, HE6, HEVA, HEVB, HETOUA, HETOUB, HETOUC, G1, E1, E6, , EVA, EVB) are eligible. The following classes of customers are not supported: DA, and Net Energy Metering (NEM).

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

Status: In March of PY 2016 Energy Alerts transitioned into BFAs. BFA replaced the Tier Alerts with an alert that warns customers when they reach their user-specified dollar amount threshold. Customers are subsequently notified with an alert via their channel of choice (email, phone, or text message) when they meet their designated threshold amount up to one day prior to the end of their billing cycle. BFA is only available for residential customers who are SmartMeter read and billed.

Customers can enroll in Energy Alerts, or currently BFA, online via the Your Account web site. During the past few years, PG&E has marketed Energy Alerts and BFA in a similar manner as Customer Web Presentment (CWP) and often in parallel with CWP and Your Account communications. In December 2013, the Your Account homepage was redesigned, which made it easier for customers to connect to other often-used functions, such as analyzing usage, comparing rate plans, and signing up for Energy Alerts. From 2014 through 2018 enrollments continued to increase, most likely due to greater customer awareness of PG&E's digital services accessible through the Your Account website. In December 2017, BFA reactivated Marin Clean Power and Sonoma Clean Energy customers who had been enrolled in BFA prior to transitioning to their Community Choice Aggregators (CCA). Though CCA customers have been ineligible for new BFA enrollments due to rate modelling limitations, PG&E opened enrollment into BFA to new CCA customers in 2019.

In February 2017, PG&E added to its product offering the HUAs program. This program sends out an early warning notification when customers are projected to trigger a surcharge. The High Usage Surcharge (HUS) is incurred when customers exceed four times their Baseline Allowance. HUA is only available for residential customers with electric service through a SmartMeter and are on eligible tiered rate plans. Similar to BFA, customers can enroll in HUA online via the Your Account website. As part of the implementation of the HUS, PG&E sends letters to customers who are at risk of the surcharge or have incurred it. The HUA program is featured in these compliance letters, which has helped drive some of the enrollments into the program.

In 2018, a total of 117,201 customers enrolled in the HUA program with 1,022,319 HUAs sent. These counts also include d participants who were enrolled in other PG&E programs such as CWP, BFA, SmartRate™ and SmartAC. As with BFA, the analysis population excluded SmartAC and SmartRate customers, participants who received alerts on more than one media type, and those who did not receive an alert in 2018. The analysis population was also segmented into singly-enrolled HUA participants and participants dually-enrolled in BFA and HUA. As a result, the HUA analysis population consisted of 42,393 singly-enrolled participants and 74,808 dually-enrolled participants, for a total of 117,201 analyzed HUA participants in 2018. Singly enrolled HUA Customers saved $98,000 annually with 2,501 MWh is energy savings.

Since the BFA program has similar enrollment numbers along with no major programmatic changes, PG&E did not complete a detailed participant analysis as in previous years. Given the similarities between the years, PG&E has no reason to believe that interest in the programs have substantially changed in the past year.

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

Benefit Category: Engaged Customer.

Benefits Quantification Methodology: In previous years, this evaluation was conducted in four phases: data collection, ex post impact estimation, documentation and reporting, and regulatory support and consultation. The data analyzed singly- and dually-enrolled HUA and BFA customers, and calculated Energy Savings and Financial benefits (reported in thousands). During the 2018/2019 reporting period, dually-enrolled customers experienced a total of 5,417 MWh of energy savings and $212,000 in financial benefits; singly-enrolled HUA customers experienced 2,501 MWh of energy savings and $98,000 of financial benefits; and singly-enrolled BFA experienced 1,603 MWh of energy savings and $62,000 of financial benefits. To calculate financial benefits for conservation programs, PG&E used the following formula: Financial benefits = energy savings x avoided generation costs ($39.06/MWh in 2018). The cost figure comes from Appendix A of the Settlement agreement on marginal Cost and Revenue Allocation in Phase II of G&E's 2014 GRC (A.13-04-02). Detailed results, including seasonal usage, comparison group matching, and alert data is found in the SmartMeter Enabled Programs PY 2018 Report and Appendix. As mentioned above, benefits in 2018/2019 are expected to be comparable to previously reported savings. Therefore, no calculation of the benefits for the current 2018/2019 are being provided.

2018 Full Report: PY2018 Evaluation of BFAs and HUAs. CALMAC ID PGE0418 Opinion Dynamics. For further project information, see: OP10 compliance report, Progress on Residential Rate Reform (http://www.cpuc.ca.gov/General.aspx?id=12154).

Share My Data (Customer Data Access (CDA)) Project	Approximate Cost Over Reporting Period: $0.44 Million

Description: Under the CDA project, now known as "Share My Data," PG&E developed a platform that provides authorized and secure data to customer-authorized third parties. With the release of CDA Phase 1 functionality, customers could share electric energy usage data with third parties. With the release of the CDA Phase 2 functionality in December 2015, customers could also opt to share one or more categories of information, including usage (e.g., interval usage data for gas consumption), billing (e.g., rate schedules, billing history) and account (e.g., service address). In 2018, PG&E implemented an online authorization process which enables customers to authorize data release via an online platform. This authorization pathway supplements the paper-based form which had previously been the sole means for customers to authorize data release.

Funding Source: This project was funded by the CDA D.13-09-025 through December 2016. As of January 2017, operation and maintenance for this project is funded through GRC. The Click Through Project is funded by D.16-06-008 and covers both Share My Data related updates and specific changes to better support Electric Rule 24 process for DRP.

Status: On September 19, 2013, the CPUC approved PG&E's CDA Application (D.13-09-025). PG&E launched Phase 1 of the Share My Data project in March 2015 and Phase 2 in December 2015. On August 25, 2017, the CPUC approved PG&E's Advice Letter (AL) 4992-E in compliance with OP 10 of D.16-06-008 to deliver Click Through with Resolution (Res.) E-4868. PG&E launched Click Through Phase 1 to comply with Res. E-4868 on February 22, 2018 and Phase 2 on June 28, 2018, Expanded Data Set at the end of September, and Phase 3 on November 15, 2018. This project was to provide improvements to the Electric Rule 24 process for DRPs to obtain customer authorization to access the customer's data for direct participation in the CAISO's wholesale market. This also included simplifying the overall electronic authorization process via the Share My Data platform. In 2020 PG&E continues to maintain the SMD platform and awaits CPUC decision on further enhancements according to Resolution E-4868.

Upcoming Plans (Subject to Change): There are no upcoming projects related to Share My Data. PG&E submitted an application to the CPUC in compliance with Resolution E-4868, in which it outlines its estimate to implement an Alternative Authorization Solution, proposes its plan to accommodate quick response and to expand click-through to DERs, and a few other enhancements submitted by vendors through the CDA Committee. The Application is pending with the Commission. Other upcoming work includes regular platform O&M and enhancements.

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

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

Energy Data Access	Approximate Cost Over Reporting Period: $0.2 Million

Description: In Commission D.14-05-016 (Decision), the Commission adopted rules to provide access to energy usage and usage-related data to local governments, academic researchers, and state and federal agencies for specific use cases, while protecting the privacy of customers' personal data. The Decision ordered the utilities to create a Data Request and Release Program to facilitate this access and instructed the utilities to submit an updated data catalog in the SGAR.[35]

Funding Source: Through December 2016, PG&E was tracking the incremental costs associated with implementing this decision in a memorandum account and was seeking authorized recovery of such costs through its GRC proceeding. As of January 2017, operation and maintenance for this project is funded through GRC.

Status: In December 2014, PG&E implemented the Decision requirements, which includes the development of an Energy Data Request Program portal, creation of a Data Request and Release Process, publishing of a data request log (referred to as data catalog in the Decision), publishing of a quarterly energy consumption report by zip code and customer class, and the formation of a statewide Energy Data Access Committee (EDAC). An updated data request log (data catalog) is provided

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

below and summarizes the requests worked on during the period July 1, 2019 through June 30, 2020. The complete log can be viewed on PG&E's website at http://www.pge.com/energydatarequest. The EDAC was required to hold quarterly meetings through December 2016 and thereafter only met on an 'as needed' basis. Minutes from the meetings are posted on the CPUC's EDAC website: http://www.cpuc.ca.gov/General.aspx?id=10151. For further project information see: Quarterly Advice Letters (Latest filing: https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4273-G.pdf).

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

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

Table 4-1: PG&E ENERGY DATA REQUEST PROGRAM – DATA REQUEST LOG (7/1/2019 – 6/30/2020)

Organization	Requestor Type	Description	Status	Change Date
Energy Institute at Haas	Academic Researcher	Data on agricultural users' usage and billing plus associated information to help identify and analyze pump usage/billing. Also pump test data, where available, from PG&E Agricultural EE programs.	In Review	6/30/2020
University of California, Davis CWEE	Academic Researcher	Interval and identifying information for all customers on agricultural rate schedules in zip codes specified by UCD. Also matching PG&E pump test data where available.	Downloaded	6/22/2020
The Regents of the University of California	Academic Researcher	Detailed electric usage for Yuron, Delano, and Fresno.	Downloaded	6/11/2020
Energy Institute at Haas	Academic Researcher	Anonymized usage data for the PG&E service territory.	Approved - In Progress	6/10/2020
University of California, Davis CWEE	Academic Researcher	Interval and identifying information for all customers on agricultural rate schedules in zip codes specified by UCD. Also matching PG&E pump test data where available.	Downloaded	5/22/2020

Organization	Requestor Type	Description	Status	Change Date
Purdue University	Academic Researcher	Anonymized monthly usage and EE program participation data plus location data for all NEM and a sample of non-NEM customers in a list of zip codes provided by Purdue.	Downloaded	5/19/2020
Michigan State University	Academic Researcher	Anonymized interval usage and usage related data for Pay for Performance (P4P) program users and a random sample of non-P4P users.	Completed	5/18/2020
City of San Mateo	Local Government	Aggregate energy savings data for the commercial sector for 2015-2019.	Approved - In Progress	5/7/2020
City of West Sacramento	Local Government		Canceled / Withdrawn	5/6/2020
Ca Dep. of Community Services & Dev.	Community Services & Development	Average usage and billing amount per household, and total number of residential households, by county, for residential households in PG&E's service territory.	Downloaded	4/8/2020
City of Arcata	Local Government	Anonymized monthly residential gas usage	Downloaded	3/27/2020
University of California, Davis CWEE	Academic Researcher	TBD: need to refine both customer list and data field list.	Suspended	3/26/2020
City of Sunnyvale	Local Government	Total usage and number of billed days, split by commodity and residential vs. non-residential, for 2019.	Downloaded	3/5/2020
City of Richmond	Local Government	Non-residential usage for 2014-18, by year.	Canceled / Withdrawn	3/4/2020
Town of Los Altos Hills	Local Government	TBD	Canceled / Withdrawn	3/4/2020
Gazarian Real Estate Center, CSUF	Academic Researcher	Installation date (where available) and address for all Solar installations in Fresno County.	Downloaded	3/2/2020
University of California Berkeley	Academic Researcher	TBD	Canceled / Withdrawn	2/20/2020
County of Santa Barbara	Local Government	Aggregated energy usage data and customer counts, by sector, for City of Arcata in 2018	Downloaded	2/12/2020
Spring Creek Apartments	Community Services & Development		Canceled / Withdrawn	2/11/2020

Organization	Requestor Type	Description	Status	Change Date
UCLA	Academic Researcher	Anonymized monthly usage/billing and daily usage for customers with a disconnect and for a random sample of customers across 800 Zip codes.	Downloaded	1/16/2020
EES Consulting, Inc.	Local Government		Canceled / Withdrawn	1/14/2020
City of San Luis Obispo	Local Government	TBD	Canceled / Withdrawn	12/31/2019
County of Santa Barbara	Local Government	Data description never finalized.	Canceled / Withdrawn	12/31/2019
City of South San Francisco	Local Government	Aggregated monthly electric and gas consumption for 2006â€“ 2018, split by residential vs. non-residential.	Downloaded	10/8/2019
City of Benicia	Local Government	Gas usage by sector by month for 2015-16	Completed	8/8/2019
AMBAG Energy Watch	Local Government		Canceled / Withdrawn	7/31/2019
University of California, Santa Cruz	State or Federal Agency		Canceled / Withdrawn	7/31/2019
PESD; Stanford University	Academic Researcher	Billing and interval data for residential customers, plus street address, rate code, and CSI and EE program usage.	Completed	7/26/2019
County of Marin	Local Government	Yearly gas and electric usage for all the cities in Marin County, split into residential and non-residential sectors.	Completed	7/18/2019
PESD; Stanford University	Academic Researcher	Interval data from 1/1/2012 to 7/31/2018 for CSI customers and a randomly selected control group.	Canceled / Withdrawn	7/18/2019

Stream My Data – HAN	**Approximate Cost Over Reporting Period:** **$0.08 Million**

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

1. Monitor your RT Electricity Usage (kilowatt (kW))
2. See your RT Price ($/kWh)
3. Get an Estimated Costs to Date and Estimated Electric Bill This Month

4. Receive DR Event Alerts (SmartRate and PDP) event alerts)

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

Status: "Stream My Data", aka HAN, continues its service with usage available at all SmartMeter devices, and PRICE information available to A1, A10, A6, E1, E6, and EVA rates. Commercial energy management solution providers have continued to explore HAN on a small scale and PG&E continues to support their efforts. Stream My Data has been revised to enable access to electrical usage for residential solar (Net Energy Metering Standard) SmartMeters. Price information availability remains the same for the limited set of rate plans.

Upcoming Plans (Subject to Change): Stream My Data will continue operation with current feature set levels.

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

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

Building Benchmarking Portal (BBP)	**Approximate Cost Over Reporting Period:** **$0.33 Million**

Description: The BBP, created in compliance with Assembly Bill (AB) 802, is a web-based system for building owners, or their authorized agents, to request aggregate whole-building energy usage data uploaded into their Energy Star Portfolio Manager accounts. The BBP is a streamlined service for procuring building energy usage data to assist customers in their benchmarking endeavors.

Funding Source: This project is funded through a memo account (MA). PG&E filed a Tier 2 Advice Letter (AL 3707-G/4829-E) seeking to establish memorandum accounts for gas and electric service. These MAs are being used to record costs incurred to comply with AB 802 and will be submitted in PG&E's GRC 2020 Rate Case. Upon review and approval by the CPUC, PG&E will transfer the AB 802 MA balances to the appropriate balancing accounts, as directed by the Commission, for recovery in rates.

Status: During the reporting period, the BBP has received over 6,000 requests for building energy usage data. Most requests are likely driven by the Building Energy Benchmarking Program administered by the CEC as well as an increasing number of local municipalities within the PG&E service territory implementing additional benchmarking reporting requirements. The Benchmarking Program requires certain buildings to report their building's energy usage data to the CEC. 2019 is the first year that qualifying multi-family buildings are required to submit energy usage data to the CEC, in addition to qualifying commercial buildings which began in 2018. During 2020 BBP has transitioned from MA funding to GRC funding.

Upcoming Plans (Subject to Change): No major changes to the BBP are under review. However, the benchmarking team continues to evaluate updates and process improvements to enhance customer experience and increase the value of the BBP for users.

Benefits Description: The BBP streamlines the procurement of energy data for benchmarking. Additionally, tenant turnover is not nearly as impactful on the benchmarking process. As more building owners benchmark their facilities, it will yield greater visibility into building energy use, and opportunities for customers to improve the performance of their buildings.

Benefit Category: Engaged Customer – By simplifying the authorization process, and designing a more resilient portal, the BBP will allow building owners to more easily track and manage building energy consumption.

Time-Varying Pricing (TVP) Rates	Approximate Cost Over Reporting Period: $2.96 Million

Description: TVP products, such as PDP, TOU, and SmartRate take advantage of SmartMeter capabilities that are now largely available across PG&E's service territory. Charging customers different rates based on varying system conditions is intended to more closely align retail and wholesale electric prices for generation, as well as create economic incentives for customers to actively manage their energy costs by shifting electricity use from when it costs more to when it costs less. PDP provides between 10-15 MW of load reduction on the hottest days of summer, equaling the load of one Peaker power plant. The SmartMeter has enabled PG&E to cost-effectively offer all customers these types of rate programs which provide significant customer and societal benefits.

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

Status: PG&E continues to administer and offer TVP Rates to all PG&E bundled residential and nonresidential customer classes. Beginning in November 2012, SMB customers with 12 months of SmartMeter data began a mandatory transition to TOU rates and two years later, in 2014, began transitioning to PDP with an option to opt-out. Small Agricultural customers began transitioning to mandatory TOU rates annually starting in March 2013. CPUC D.15-07-001 mandates that PG&E's residential customers be defaulted to TOU rates, beginning in 2019. Eligible residential customers may also enroll in the SmartRate Program. Enrollment in SmartRate is at 65,000 residential customers as of July 2020 and provides an average of 10-15 MW of load reduction on event days.

Over 505,000 SMB Service Agreements have transitioned to TOU rates. 104,000 Service Agreements are active participants in the PDP Program as of July 2020. In November 2019, PG&E began to offer new non-residential TOU rate plans that shift peak periods to the evening hours on an optional basis. Beginning in March 2021, PG&E will begin to transition remaining eligible commercial, industrial, and agricultural customers to these new rate plans with 4-9pm peak period for commercial and industrial customers, and 5-8pm peak for agricultural customers. This shift is being implemented to better align with the cost of energy in the later hours of the day.

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

Benefit Category: Engaged Consumer and Smart Utility – the program increases customer awareness and engagement in managing their energy usage.

4.2.4 Emerging Customer-Side Technology Projects

AutoDR Program	Approximate Cost Over Reporting Period: $2.1 Million

Description: PG&E's AutoDR program offers residential, small, medium (SMB) and large commercial and industrial (LC&I) customers an incentive or rebate to install equipment that has the ability to automatically reduce a customer's energy use during DR events without any manual intervention. Specifically, the technology that is incentivized ranges from smart thermostats to complex EMS and agricultural pumps and is provided for customers who agree to participate in either PG&E or third-party eligible DR programs. AutoDR provides a communication infrastructure that links PG&E's designated third-party head-end control system to either a cloud-based platform or the actual control technologies. PG&E supports commercial customers to develop pre-programmed energy management and curtailment strategies to participate in DR event days.

Funding Source: PG&E's AutoDR program is authorized through 2023 under D.17-12-003 and further governed under D.18-11-029 which provide a balancing account mechanism.

Status: From 2017 through 2019, PG&E developed the infrastructure to provide residential rebates on smart thermostats for customers who participate in DR programs. PG&E conducted a project to identify other residential control technologies that could be eligible for rebates in the future. The conclusion of the project was that technologies that receive other types of rebates, i.e. EE, Self Generation Incentive Program (SGIP), the DR component was not substantiated enough to provide a rebate at PG&E. PG&E will continue to monitor for market readiness. The SMB and LC&I customers continue to be supported through a third-party program implementer.

Benefits Description: Customers receive many benefits from deploying automated technologies. Oftentimes, they are also able to take advantage of EE and AutoDR incentives to offset the cost of the technologies, which can greatly benefit businesses. In addition to the ongoing benefits of energy savings, customers benefit from the ease of participating in DR events without manual intervention. Through DR program participation, typically customers are also compensated to reduce load on DR event days which can provide longer-term benefits to customers. Compensation varies depending on which DR program the customer chooses to participate. Eligible programs range from SmartRate and PDP, which have direct enrollment with PG&E, to the third party/aggregator managed Demand Response Auction Mechanism, CBP and the Excess Supply Side Pilot. Customer compensation can be especially variable when working with an aggregator as the level is decided between the customer and the aggregator.

Benefit Category: Technology Adoption and Customer Engagement – AutoDR provides rebates and incentives to customers to promote adoption of control technologies that can help them save energy and reduce costs on an ongoing basis. Through participation in a DR program, customers can also provide value to the grid. An overview of associated benefits is provided below:

1. Cumulative kWh benefit from CBP and PDP: 165 MWh

   Explanation of lower value than 2019 report: While 19 CBP events were called in 2018, only 5 were called that included AutoDR customers in 2019. The average CBP event duration dropped from 1.63 hours to 1.2 hours. Those customers that were called in 2019 were smaller – the average kW load shed commitment for an SAID in 2018 events was 97 kW, while the average dropped to 79 kW in 2019.

2. GHG Benefit with the 2016 factor from PG&E of 294 lbs. of CO_2 per MWh: 48,382
3. Financial Benefit: N/A – the purpose of AutoDR incentives and rebates is to promote adoption of automated technology that utilizes a specific communication protocol (Open AutoDR). The benefit of adopting technology that utilizes an open standard versus not (e.g. proprietary smart thermostat or battery management system) ensures that assets will not be stranded should there be an ownership change. The financial aspect of this benefit is not quantifiable at this time.

Smart Thermostat Study	Approximate Cost Over Reporting Period: NA

Description: PG&E conducted an Emerging Technologies field assessment to evaluate gross energy savings and effectiveness of EE facilitating features in multiple smart thermostats—Nest, EcoBee3 and Radio Thermostat of America CT50 with EnergyHub service provider—with focus on learning/optimization software, occupancy sensing and geo-location. Behavioral messaging and DR were out of scope. Smart thermostats were professionally installed at no cost to 2,207 residential customers in the North Valley, Stockton and Fresno areas in 2015. Both billing data and manufacturer thermostat usage data was collected over the 24-month monitoring period and used for analysis.

Benefits Description: In December 2016, a report providing an analysis of the first year's results was posted to the Emerging Technologies Coordinating Council (ETCC) website (https://www.etcc-ca.com/reports/smart-thermostat-study). All three thermostats achieved annual electric savings ranging from 4-5 percent. One of the thermostats tested also achieved annual gas savings. The project's second year of monitoring concluded in the fall of 2017 and a report detailing an analysis of the second year's performance and the results of a survey of the study participants was posted to the ETCC site in March 2018 (https://www.etcc-ca.com/reports/smart-thermostat-study). The results indicate that savings persisted in the second year, although at a somewhat lower level. The consultant concluded that the lower level of savings was due in part to the extreme heat in the second year of the study, and that continuing the study for a second year led to sample attrition making the savings more difficult to detect. Based on the positive results from these studies, PG&E added smart thermostats to the EE portfolio in June 2017.

Status: During the current 2019/2020 reporting period, PG&E delivered 15,080 smart communicating thermostats (SCT) through three residential EE programs, which included a downstream rebate program, a low-income Energy Saving Assistance Program and a P4P program. An additional 5,151 SCTs were offered through one of two "direct install" programs that offer a comprehensive or mix of measures, including SCTs, installed by contractors targeting income - or energy-constrained customers (the Residential Energy Fitness Program) or multifamily customers (the Enhance Time Delay Program).

CPUC Impact Evaluation: The CPUC completed its first impact evaluation of the statewide SCT measure in April 2020. After making adjustments for several factors, the estimated, per-household annual cooling load savings is 89.8 kWh for PG&E. The estimated per-household annual heating load savings is 7.7 therms for PG&E. These PG&E savings estimates compare favorably to the statewide per-household estimates of 72.2 kWh and 2.1 therms, respectively. Electric and gas realization

rates for PG&E—that is, the ratios of savings claimed to evaluated savings—are 42% and 37%, respectively. Conducted by the firm DNV GL, this evaluation exclusively measured the impact of the retailer rebate programs on energy use at customer residences using billing analysis. Commenters to the evaluation voiced concern about differences between the participant customers and non-participant customers used as a basis for pre/post energy consumption comparisons. The evaluators acknowledge that the composition of the comparison group used as a basis for savings estimates is subject to limitations. In its second impact evaluation of SCTs that is now underway, DNV GL is undertaking additional analyses that investigate the use of comparison groups that are composed from future participants who self-select into smart thermostat acquisition. <u>Benefit Category</u>: Engaged customer. The latest generation of Smart Thermostat products offers customers easier and more convenient ways to manage their heating, ventilation and air conditioning with improved functionality and integration to other connected devices. Moreover, smart thermostat as the first connected system in line is a way to enable customers to have insight and control over their energy usage pattern.

4.3 Distribution Automation and Reliability Projects

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

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2019 through June 30, 2020 timeframe, unless otherwise noted.

ADMS	Approximate Cost Over Reporting Period: **$22.5 Million**
<u>Description</u>: This project is the first component of a multi-year effort to implement an ADMS, which will integrate several mission critical distribution control center applications that are currently spread across multiple platforms. The ADMS will become part of the core distribution operations technology tools that enable the visibility, control, forecasting, and analysis of a more dynamic grid. When fully deployed, the ADMS platform will bring the capabilities of today's Distribution Supervisory, Control and Data Acquisition (D-SCADA) software, DMS, and Outage Management System (OMS) into a single platform. These applications are described below.	

ADMS	Approximate Cost Over Reporting Period: $22.5 Million

D-SCADA: PG&Es D-SCADA system gathers, processes, and displays system-wide operating data to Distribution Operators at control centers. Operators use the system to remotely control and/or operate devices on the distribution network. The D-SCADA system consists of distributed IT network system and server hardware (the SCADA "platform") and a growing number of SCADA-enabled field devices which send and receive real time data over the network.

PG&E's SCADA platform is no longer adequate to support projected growth, evolving cybersecurity threats, or the need for increasing integration with other control center systems. RT-SCADA, the current application managing data exchange between field devices, processors/servers, and displays in the control center, is nearing the end of its useful life and does not have the functionality and cybersecurity features to address future grid conditions, including an increased number of field devices and increased DER penetration. Similarly, the current hardware supporting the SCADA system does not have sufficient processing or storage capacity to address the increasing complexity of the grid, or to support advanced control and analytic applications. A major part of the project is associated with replacing the hardware and software associated with PG&E's D-SCADA platform, migrating data from the existing D-SCADA database to the new ADMS-SCADA database, and programming and testing to ensure that field devices communicate accurately with the ADMS-SCADA application.[36]

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

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

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

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

Status: PGE began the Analyze/Design phase of the first release the ADMS project (ADMS SCADA) in May 2019. We have completed 70% of the workshops and design of the solution and are tracking to a September 2020 completion date . We have already begun some of the software build activities for new functionality required by PGE (for example, the PGE protocol and new fire mitigation functionality). Additionally, we have begun the Substation Build portion of the Network Model build workstream.

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

ADMS	Approximate Cost Over Reporting Period: $22.5 Million

Upcoming Plans (Subject to Change): PG&E expects to complete the Release 1 Design phase in September 2020, and continue the software and network model build workstreams. We anticipate the software version to be released to PGE early Q2 2020. We anticipate beginning the feeder import of the Network Model build workstream in July 2020, continuing thru September 2021.

Benefits Description: ADMS delivers the following benefits:

- Safety – Increases ability to manage future cyber security vulnerabilities which are challenges of the existing D-SCADA application.
- Situational Awareness
  - ADMS can estimate the behind the meter load served by DERs, showing operators, the total load consumed as well as output. This load estimation, coupled with some RT telemetry of DERs, can provide operators with estimates that provide actionable information to perform restoration in the event of an outage on a circuit with a high penetration of DERs.
  - ADMS can provide improved filtering and prioritization of alarms for operators, making the operator more efficient when evaluating and addressing grid issues. This is especially important when storms create well above average outage and alarm volume, and operators can be inundated with alarms.
  - ADMS will promote greater awareness of RT grid status by enabling sharing of information contained in the ADMS with wider audiences across utilities. In addition, PG&E looks to "mobilize" ADMS features and allow for more PG&E personnel to have access.
- Training – ADMS has a training simulator that can effectively train existing and new operators. The simulator allows the creation of real-life complex training scenarios that includes SCADA related events and operations, switching management, outage management events (e.g., customer calls, SmartMeter outage notifications, hazards, damage, etc.).
- Operational Efficiency
  - ADMS enables switching submittal, planning, and execution to be a process contained within one application, driving substantial efficiency. ADMS provides the ability for efficient scheduling with "conflict checking" as well as fast development of switch logs, with fully embedded intelligence to verify the switch log's impact, in both real time and study mode.
  - Better load forecasting driving better grid operations: ADMS has a load forecasting engine that develops "operational time horizon" (i.e., 24 hr., 7 day) load forecasts.
  - FLISR expansion and maintenance: FLISR is an advanced application that is part of the ADMS platform. ADMS FLISR will know the topology and capacity of the grid, and the forecasted load. Therefore, ADMS FLISR requires less time to configure than PG&E's existing FLISR, which as a standalone application must manually be configured.

ADMS	Approximate Cost Over Reporting Period: $22.5 Million

- Reduce utility line losses: ADMS's optimal power flow capabilities can control SCADA-enabled capacitors to minimizing line losses while maintaining power factor and voltage compliance. Reducing line losses lowers GHG emissions and reduces PG&E's energy procurement costs.
- Drive Conservation Voltage Reduction (CVR): ADMS's optimal power flow capabilities can control SCADA-enabled substation transformer load tap changers, line voltage regulators, and capacitors to drive CVR. CVR is a physical effect which reduces the energy consumed by customers' devices. This lowers GHG emissions and reduces PG&E's energy procurement costs.

Benefit Category: Smart Utility

Distribution Substation SCADA Program	Approximate Cost Over Reporting Period: $23.1 Million

Description: The Distribution SCADA Program focuses on increasing SCADA penetration and improving reliability for PG&E customers. This program aided in the consolidation of PG&E's Distribution Control Centers, which was completed in 2016. PG&E's goal is to achieve close to 100 percent visibility and control of all critical distribution substation breakers over the next few years, adding or replacing SCADA for approximately 530 substations and approximately 3,400 breakers.

Funding Source: GRC

Status: This project is in progress. This project started in March 2011 and is expected to achieve 99 percent penetration by December 2022. The remaining 1% are projects that are being aligned with other planned major capital projects to take advantage of execution efficiencies. This project has upgraded or replaced SCADA in 517 substations and 2230 breakers between 2011 through June 2020.

Upcoming Plans (Subject to Change): SCADA Installation program is planned to achieve close to 100 percent visibility and control by 2022 and will transition to focus on proactively executing SCADA replacement program to proactive replace aging assets.

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

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

Smart Grid FLISR	Approximate Cost Over Reporting Period: $4.29Million
Description: This project continues the installation of FLISR systems work that was funded in the Cornerstone D.10-06-048. Smart Grid FLISR will expand the implementation of the FLISR system to approximately 30% of the distribution circuits in PG&E system to improve customer service reliability. Funding Source: This project is funded in PG&E's 2020 GRC. Status: This project has been approved. The Smart Grid FLISR project began in 2014 and is expected to continue through 2022. Upcoming Plans (Subject to Change): The Smart Grid FLISR project is expected to continue through 2022with lower rate of expansion during the 2020 GRC (8 circuits per year). Benefit Description: When installed, FLISR can reduce the impact of outages by quickly opening and closing automated switches to reduce what may have been a one- to two-hour outage to less than five minutes. Benefit Category: Smart Utility – the Smart Grid FLISR project improves customer service reliability, installs SCADA devices that provide RT load and voltage data which supports distribution operations and DER/distribution resource integration.	

4.4 Transmission Automation and Reliability Projects

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

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2019 through June 30, 2020 time period, unless otherwise noted.

Transmission Substation SCADA Program	Approximate Cost Over Reporting Period: $2.2 Million
Description: Under the Transmission Substation SCADA Program, PG&E is in the process of installing new SCADA on the transmission system to provide PG&E's Electric Operations and the CAISO with full visibility into the transmission system,	

significantly improving efficiency and operational flexibility. PG&E's current goal is to achieve close to 100 percent visibility and control of all transmission substations over the next few years, adding or replacing SCADA for approximately 460 substations and approximately 2,080 breakers.

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

Status: This project is currently in progress. The project started in July 2010 and is expected to achieve 98.2% penetration by December 2022. The remaining 1.8 % are projects that are being aligned with other planned major capital projects to take advantage of execution efficiencies. PG&E has added or replaced SCADA at 440 substations and 2,010 breakers from 2011 through June 2020.

Upcoming Plans (Subject to Change): SCADA Installation program is planned to achieve close to 100 percent visibility and control by 2022 and will transition to focus on proactively executing SCADA replacement program to proactive replace aging assets.

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

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

Modular Protection Automation and Control (MPAC) Installation Program	**Approximate Cost Over Reporting Period:** **$34.0 Million**

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

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

Status: This project is currently in progress. This is an ongoing program which doesn't have a defined end date. The project began in 2005. PG&E has installed and completed 124 MPAC buildings.

Upcoming Plans (Subject to Change): The MPAC program will continue focusing on deploying pre-engineered, fabricated, and standardized control buildings in transmission substations to support other capital projects in an integrated manner, such as capacity expansion projects, bus conversions, deficiency and aging asset replacement, control room condition improvements, reliability, and control center consolidation efforts.

Benefits Description: The program will help improve reliability of the transmission system by replacing aging infrastructure and modernizing facilities. Over the past year, the MPAC Installation Program has avoided $ 2.6 million in capital costs over traditional upgrade methods and has avoided a cumulative total of $ 72.4 million.[37]

[37] MPAC benefit totals reflect updated calculations for 2019 Smart Grid Annual Report.

<u>Benefit Category</u>: The program is a Smart Utility project designed to improve reliability of the transmission system by replacing aging infrastructure and modernizing facilities.

EMS	Approximate Cost Over Reporting Period: $4.5 Million

<u>Description</u>: The EMS is utilized by Transmission System Operations (TSO) to monitor and control the transmission system. The system is comprised of several modules which provide different functionality to Operations personnel. PG&E has recently completed upgrades to their hardware and software platform for the existing EMS and is continuing development work on new modules to increase EMS capabilities for System Operator, Dispatchers and Engineering to better analyze, monitor and control the transmission system and meet NERC compliance requirements.

<u>Funding Source</u>: This project is funded primarily under PG&E's TO cases.

<u>Status</u>: Active. EMS went live with new system on 12/2018, however development work continues to further enhance the system's functionality. Development is currently underway. Implementation and Testing for the new software modules will occur by the end of 2019, with further enhancements getting implemented in 2020.

<u>Current Plans</u>:

- Development of an integrated tool to manually or automatically generate System Restoration and Outage Plans based on RT or study conditions
- Implement Outage scheduler modules to interface with external software for automatic import of scheduled outage information into EMS

<u>Benefit Description</u>: Benefits include:

- Improves the ability to perform timely Operational planning analysis to maintain system reliability prior to or during system events, including PSPS.
- Better demonstrate NERC compliance.
- Minimizes 3rd party applications and interfaces to streamline EMS environment architecture, therefore more reliable and easier to maintain.
- Better integration of operational information for more efficient RT monitoring and analysis.

<u>Benefit Category</u>: System Reliability and Operational Efficiency

Synchrophasor Project Realization	Approximate Cost Over Reporting Period: $0.7 Million

Description: Synchrophasor Applications Upgrade project will build on the previous Synchrophasor infrastructure projects, to provide additional functionality to the EMS and integration into RT operations. Data flow into control centers has been enhanced and several use cases for TSO have been implemented. Examples include, post event analysis, phase angle delta monitoring, oscillation detection and monitoring, and model validation. Upcoming enhancements include streaming the data to the Utility Data Network (UDN) (corporate network) and building an application environment on the UDN for enterprise-wide use. Applications on the UDN will include PI, GE PhasorPoint, GE PhasorAnalytics, and others.

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

Status: Active. Communication protocol and transport layer enhancements continuing to support data availability and data quality. Installed PMUs on several 500 kilovolt buses for enhanced state estimation. Established connections to the new CAISO RC West WISP Synchrophasor network. Working with CAISO, Bonneville Power Administration, SCE, and SDG&E to improve Synchrophasor data sharing capability.

Upcoming Plans:

a) Establish data stream to the UDN corporate network to enable PI data archival and other enterprise applications

b) Establish a PMU/PDC lifecycle program to replace aging PMUs and PDCs

c) Install PMUs on all PG&E tie-lines at the request of the CAISO

d) Continue to enhance the synchrophasor system architecture and archives to improve data reliability

Benefit Description: Synchrophasor technology provides high resolution grid measurement and more accurate and synchronized measurements in RT. Benefits include:

1. Improvements in PG&E' system models (the basis for the EMS used by Operators) – Accurate model allows identifying true system constraints (voltage, system instability, thermal), improving transmission system performance, and evaluating true limits due to better results for on-line EMS applications supporting state estimation
2. More accurate Control Center understanding of the state of the Grid (Situational Awareness)
3. Faster operator alerts and improved visibility of the fast, dynamic grid conditions
4. Prompt identification of un-damped grid oscillations to prevent outages
5. Quick identification of the location of a grid disturbance for faster response
6. Compliance with NERC PRC, MOD, and TOP standards.
7. Compliance with CPUC Rule 21 frequency reporting requirements for SI programs

Benefit Category: System Reliability and Operational Efficiency

4.5 AM and Operational Efficiency Projects

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

The following sections provide an update on completed, in-progress or planned projects during the July 1, 2019 through June 30, 2020 time period, unless otherwise noted.

Network SCADA Monitoring Project	**Approximate Cost Over Reporting Period:** **2019 $7.7 Million** **2020 $8.5 Million**
Description: The project is installing new monitoring and control systems on the downtown San Francisco and Oakland secondary network systems including full remote control on network protectors (including remote setting of relays), and primary switches. The monitoring itself includes voltages, currents, temperature, oil level, and chamber pressures. For vaults, the monitoring system includes SCADA battery, water detection and may include others such as DG monitoring depending on future needs and feasibility. RT data collected from the equipment is used for triggering of alarms, and for equipment condition assessment as part of the Condition-Based Maintenance (CBM) system for O&M activities. The data is also used for AM decisions on maintenance and replacement of network equipment. The new SCADA system has remote operating capabilities that include network protector open/close and station transfer trip of the network protectors for feeder clearances. Funding Source: This project is funded by PG&E's 2014 and 2017 GRC filings and currently filed in the 2020 GRC. Status: This project is currently in progress. PG&E has a total of 12 network groups. Six network groups are complete (Z-34-1, Z-34-2, Z-1, Y-4, Y-3, Y-2) with two additional network groups (Y-1 and J-1) in progress. These completed network groups have been added to the PI Historian system which is the data accumulator for all the SCADA information. This data in turn is coupled with the CBM system described above which allows PG&E to transition from time based to condition-based replacement and maintenance. This results in a safer system while at the same time generating savings through deferring work until the condition of the equipment warrants. Upcoming Plans (Subject to Change): Continue with this project with installation of approximately one network group per year. Planned overall completion by 2024. Benefit Description: The new control features included as part of this project will improve personnel safety and overall system operability. Benefit Category: Smart Utility – This project provides information for PG&E to better manage its assets and make informed maintenance, repair and upgrade decisions.	

Pole Loading Assessments (PLA)	Approximate Cost Over Reporting Period: **$12 Million**

Description: Develop a scalable program to evaluate structural integrity across all Distribution poles (approx. 2.3 Million) over a 5-year period. Geo-correct pole locations using available LiDAR from Vegetation Management efforts. Objectives of this project include a greater understanding of failure modes, common repository of data gathered, and effectively updating the workflow and asset systems (GIS, SAP) to align with new data strategies. Wind loading segmentation will be performed to identify the wind loading of each asset on a support structure and integrate findings into the appropriate systems.

Funding Source: This is Electric Line of Business funded.

Status: In 2019, the PLA program was initiated to increase the presence of pole loading calculations with "desktop verified" or better status in the Pole Loading Database (PLDB) by 10% annually, as desktop verifications are completed. T1 deployment is planned to follow T2/T3 areas. Desktop validation of 100% of poles in T2 / T3 HFTD Areas is scheduled by 2024. Baseline pole loading calculations, Models & Pole Characteristics, performed using EDGIS information (small class, multiple circuits, treatment) help identify the priority assets for desktop verifications. Estimating resources provide quality assurance check on desktop previews performed by contractors.

Benefits Description:

1. Meet 100% of compliance requirement; comply with CPUC GO 95 Rule 44.1, 44.2
2. Accurate and timely mapping of poles into Electric Distribution GIS
3. Improved business and compliance tracking, reporting and document retention due to data integration
4. Integration with enterprise systems, ensuring data synchronization
5. System model to indicate wood poles that need additional attention
6. Starting point automated individual pole modeling

Benefit Category: System Reliability and Operational Efficiency

STAR for Transmission Line	Approximate Cost Over Reporting Period: **$3.4 Million**

Description: The STAR platform, which was completed in 2020, enables risk scoring and asset health evaluations to be applied at an individual-asset basis for major Electric assets across the whole PG&E territory. It enables consistent and automatic compilation of this information so that AM can focus on improving asset replacement, maintenance and inspection strategies and asset health, failure, and risk model sophistication. STAR also enables the ability to analyze likelihood of asset failure, and in the event of an asset failure, what is the consequence from a public safety and reliability standpoint.

During the current reporting period, STAR for T-line provided asset health intelligence and the foundational data model for the improved version of the OA model used for PSPS in 2020. Asset data from multiple systems of record were combined into a single data product using production data pipelines. Use of production data pipelines ensured that asset intelligence derived from the data product was based on fresh data sourced from the appropriate system of record, and not from stale, one-time data extractions. This project provided immediate value in 2019 by delivering asset intelligence, as well as providing continued learnings on how to cost effectively scale the building and maintenance of the foundational data model needed for scalable, auditable, and repeatable value-add asset intelligence.

Funding Source: WSIP / IT Book of Work (mixed)

Status: Completed

Benefits Description: 05 - ETD Wildfire: The STAR platform will enable understanding of where asset failures may result in severe impacts due to wildfire ignition. The platform will enable risk-based management for vegetation and overhead conductors as done for poles previously. 03 - Records and Information Management: STAR will help Electric AM maintain consistent and accurate records of asset health and risk scoring for T&D assets.

Benefit Category: System Reliability and Operational Efficiency

4.6 Smart Grid Foundational and Cross-Cutting Technology Projects

Foundational and cross-cutting projects are necessary building blocks for the development of the Smart Grid, such as grid communications, control and monitoring systems, and data management and analytics. An integrated approach in the design and development of these grid technologies will help ensure that the Smart Grid will deliver the greatest possible benefits to all stakeholder, including customers, and help ensure that the electric distribution grid will be able to accommodate high penetrations of DERs while maintaining or enhancing grid stability, resilience, and efficiency. Two foundational technology areas we report progress on in this report are integrated telecommunication systems and DERMS.

PG&E's grid modernization vision, enabled by Smart Grid investments, are largely informed by the work done through the **EPIC**. Phase 3 of the PG&E's EPIC program (2018-2020) kicked off in February 2019.

Advanced technology testing and standards certification in a realistic demonstration environment are essential before a new manufacturer's technology or product can be deployed onto the electric grid. This enables the risks associated with new technologies to be mitigated and controlled, and helps the IOUs maximize technology performance and interoperability prior to deployment.

Smart Grid foundational and cross-cutting technology development are driven by several state and federal laws and regulatory orders including SB 17, Energy Independence and Security Act, CPUC D.10-06-047, AB 32 and Executive Order S-305, SB 078 and SB X1-2.

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

Integrated Grid Communications Systems

Integrated grid telecommunications systems are a key foundational technology to achieve the grid reliability, flexibility, resiliency and security required to realize the full potential of the Smart Grid. These systems enable sensors, metering, maintenance, and grid asset control networks to allow the exchange of information required to provide real or near-real time operational visibility across the grid. In the mid- to long-term, integrated and cross cutting systems would enable information exchange with the IOU, service partners and customers using secure networks, and to enable new markets for ancillary energy services. Data management and analytics projects will improve the IOU's ability to utilize vast new streams of data from T&D automation and SmartMeter devices for improved operations, planning, AM, and enhanced services for customers.

EPIC Projects

The EPIC projects undertaken by PG&E in the area of Technology Demonstration and Deployment produce electricity ratepayer benefits in the form of increased reliability, improved safety, and/or reduced electricity costs. Projects fall into one of the following four subject areas: (i) Renewables and DERs; (ii) Grid Modernization and Optimization; (iii) Customer Service and Enablement; and (iv) Cross-Cutting/Foundational.

Following Smart Grid related projects were underway in PG&E's EPIC Program during the report cycle:

- EPIC 2.34 - *Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors* is demonstrating the use of RF sensor technology that could allow PG&E to more effectively identify and locate degrading assets and risks of failure in the distribution system, to enable proactive maintenance and further safety and resiliency. Field demonstration of RF-based sensors is underway on live distribution circuits. The technology employs the use of pole-mounted RF-based sensors for incipient fault detection by monitoring partial discharge events, which may be caused by broken insulators, mechanical damage, or vegetation contact. In parallel, an alternative technology, which uses advanced algorithms to analyze voltage and current waveform data for proactive fault anticipation, is also being demonstrated to compare the performance and effectiveness of RF-based technologies. Project closeout is underway and is scheduled to be completed in Q3 2020.

- EPIC 3.03 – *ADERMS and Advanced Distribution Management System (ADMS)* is developing a DERMS head-end system and associated interfaces for DER telemetry & control and demonstrating this system on: (1) an operational remote grid and (2) non-grid DERs participating in a NWA project. If successful, this project could inform operating strategies and produce capabilities to significantly increase the flexibility of the grid and provide fundamental capabilities to reduce overall wildfire risk exposure and increase resilience for customers. The project could also reduce the cost of telemetry associated with large scale DERs interconnected to PG&E's grid.

- EPIC 3.11, *Location Targeted DERs* is configuring the Arcata-Eureka airport's local MG controller to integrate with PG&E's distribution network and enable Distribution Control Center visibility and control of the MG. The project is developing scalable and replicable approaches to planning, designing, deploying and operating multi-customer MGs. The results of this project could inform operating strategies and produce a foundational model to significantly increase the flexibility of the grid and provide fundamental capabilities to advance system resiliency.

- EPIC 3.15, Proactive Wire Down Mitigation is demonstrating the REFCL technology at a PG&E substation serving a high fire-risk area. The project will assess its effectiveness at automatic current reduction in wires-down events, with the goal of drastically reducing the likelihood of possible ignitions which may cause wildfires. The REFCL technology is only feasible for three-wire uni-grounded circuits, which make up the majority of PG&E's distribution circuits within high fire threat areas.

- EPIC 3.20, *Data Analytics for Predictive Maintenance* is leveraging Geographic Information System (GIS), weather, SmartMeter™, SCADA and other data to develop and demonstrate analytical models that predict when maintenance will be needed for distribution assets. If successful, this project could significantly improve PG&E's ability to proactively predict imminent asset failure. This will result in reducing the number of asset failures, which will reduce public safety risk and the risk of wildfire ignition.

- EPIC 3.32, System Harmonics is installing and testing the feasibility of using next generation meters to collect harmonics data on the distribution system, develop an 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. Harmonics data from next generation metering technology can also enable power quality engineers to monitor harmonics levels on the circuits and proactively address harmonics issues before they create a negative impact on PG&E and customers' equipment.

- EPIC 3.43, Momentary Outage Analytics is developing analytical models that use AMI momentary events and trap alarms 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.

EPIC Program	Approximate Cost Over Reporting Period related to projects mentioned: **$8.9 Million***

Description: The EPIC program provides funding to cost-effectively develop and demonstrate promising new technologies which can advance the company's core values of Safety, Reliability, and Affordability and determine their applicability to address future challenges. Additionally, the main goals of EPIC align closely with PG&E's grid modernization vision, which drives the advancement of innovative technologies that support PG&E's core values and an evolving grid. This vision calls for a secure, reliable, and resilient platform that enables continued gains for clean-energy technology to increase customer choice, prepare for climate change impacts and meet state policy goals. EPIC funded projects that are executed by PG&E are focused on four key areas: Renewables and DER Integration; Grid Modernization and Optimization; Customer Service and Enablement; and Cross-Cutting and Foundational Strategy. The program is currently authorized at the state level for three cycles, each cycle is three years.

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

Project status: Information about PG&E's EPIC projects can be found in PG&E's EPIC 2019 Annual Report, which was filed on February 28, 2020, and can be found on PG&E's website at www.pge.com/epic. All final reports for projects that are complete are publicly available at the same site.

Funding Source: The EPIC 1 Program is authorized via D.12-05-037, and the EPIC 2 Program via D.15-04-020. The Commission authorized the three IOUs to collect funding for the EPIC Program in the total amount of $162 million annually beginning January 1, 2013 and continuing through December 31, 2020. The total collection amount was adjusted on January 1, 2015 to $169.9 million annually, commensurate with the average change in the Consumer Price Index, and this adjustment will occur again. PG&E's share is 50.1 percent or approximately $81 million dollars annually. PG&E sends 80 percent of these funds to the CEC, for their use in addressing EPIC goals. The remaining 20 percent is retained by PG&E to run technology demonstrations. Note: Costs reflected in this report reflect PG&E expended projects costs over the reporting period of July 2019 – June 30,2020 for the projects related to Smart Grid. No CEC funds are included.

Status: Through the course of the reporting period, PG&E's EPIC Projects made significant progress. PG&E completed 34 EPIC projects to date. During the reporting period of this report there were six projects active, one project in closing stages and three projects about to launch right after the reporting period.

Some of PG&E's achievements in EPIC projects have also enabled PG&E was granted two patents during the reporting period:

- *EPIC 1.21 – Pilot Methods for Automatic Identification of Distributed Energy Resources (Such as Solar* PV*) as They Interconnect to the Grid to Improve Safety & Reliability*: Patent for an algorithm which can detect unauthorized PV interconnections**.**
- *EPIC 2.29 – Mobile Meter Applications (NextGen Meter – NGM):* Patent on mobile meter with modular housing/board assembly

There are additional five provisional and non-provisional filings for patent protection in prior terms. These patents may provide potential future revenue generating opportunities that would be shared with PG&E's customers and

EPIC Program	Approximate Cost Over Reporting Period related to projects mentioned: $8.9 Million*

shareholders,[38] 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.

Next Steps for EPIC Investment Plan

Original EPIC 3 projects were filed with the commission three years ago. In order to keep the project portfolio up to date with California's evolving energy, safety and reliability needs, on June 19th, PG&E hosted a public webinar and introduced proposed projects for its wave two of EPIC 3 projects. PG&E will submit these projects in an advice letter to CPUC for approval.

Technology innovation programs like EPIC are critical to continued advancement of the grid, both to enable increased customer choice and further California's clean energy objectives as well as to increase safety and resiliency. PG&E is excited to embark on new technology demonstrations which can help keep continuity on past projects, meet emerging grid needs and California policy objectives, and ensure that the customers and the state can leverage the maximum benefit of this program.

*Approximate cost over reporting period only includes direct costs included of EPIC projects included in the 2020 SGAR.

Telecommunications Architecture	Approximate Cost Over Reporting Period: $0.3 Million

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

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

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

Funding Source: This project is being funded in PG&E's 2011, 2014, 2017 and 2020 GRCs.

Status: We are continuing to consolidate the IP network edge, leveraging the completed MPLS core, to further reduce the devices in the IP network and bring the multi-service, multi-platform capability to the edge of the network. Testing of protection relay functions over carrier provided Ethernet services has been completed successfully. With the completion of this testing the migration off of legacy TDM circuits is resuming. Wireless edge technologies (Field Area Network (FAN)) deployments are continuing.

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

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

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

Workforce Development and Technology Training	Approximate Cost Over Reporting Period: N/A

Description: The evolution of the electric grid includes much more distributed intelligence, i.e., Smart Grid. PG&E supports this evolution by developing training in a wide variety of grid-related topics, all of which include elements of distributed intelligence, and offering them to the general workforce, targeting those who can use the information most effectively.

Funding Source: This work is funded through PG&E's EE program.

Status: PG&E is continuing to enhance workforce skills to support a smarter, more integrated grid. Between 7/1/2019 and 6/30/2020 PG&E offered 9 separate workforce education classes covering grid-related subjects through our Pacific Energy Center (PEC). A total of 1,402 attendees participated in these classes. Examples of class topics included:

Demand Response: Basic Concepts, Programs, and Site Assessment

DR can be a significant part of the energy picture for many commercial and industrial facilities, and an important way to lower energy costs. This class covers the basic concepts that building owners and facilities managers need to know to determine if and how DR might be applied to their building(s).

PV + Batteries: Integrating Storage with Grid-Tied PV Systems

As batteries become better and cheaper, they are increasingly being used in grid-tied solar electric systems. This course covers the latest in battery technology and how batteries of various sizes are integrated into PV systems, covering basic concepts, design criteria, and financials.

Benefit Description: PG&E's training helps develop the skilled workforce necessary to evolve the electrical grid and meet the energy goals of the state of California. Benefit Category: Engaged Consumer, Smart Markets and Smart Utility – Cross-cutting initiatives apply across all three segments.

Supplier Diversity	Approximate Cost Over Reporting Period: N/A

Description: PG&E's EPIC projects follow established program governance procedures and supplier contracting processes for externally sourced technology demonstrations. PG&E evaluates qualified suppliers on multiple factors, including but not limited to: quality, safety, value and supply chain responsibility. Through that process, PG&E continues to competitively award EPIC program work to WMDVLGBTBEs in technical assistance and other consulting services.

PG&E engages with industry stakeholders, including WMDVLGBTBEs, by participating in and presenting at conferences, as well as, hosting workshops/symposiums. EPIC administrators (CEC, PG&E, SDG&E, SCE) jointly organized educational events in 2019 and 2020, including:

- EPIC 2019 Annual Symposium in Sacramento, that focused on project presentations and preliminary Research Administration Plan (RAP) workshop with EPIC stakeholders.
- EPIC 2019 Fall Workshop in San Diego that focused on changes to the EPIC program such as the new Policy + Innovation Coordination Group, status overview of launched and upcoming EPIC 3 projects, and facilitated discussion on RAP and future stakeholder engagement plans. Public notice for these events is provided to a broad range of stakeholders including technology vendors, disadvantaged community groups, WMDVLGBTBEs, researchers, academics and energy consultants. EPIC administrators will continue to maintain transparency in the process via webinars and workshops.
- EPIC Spring 2020 Public Virtual Workshop, that focused on wave two of EPIC 3 projects that PG&E is considering, so that the attendees, including WMDVLGBTBEs, understand the next steps for the projects and have the opportunity to provide feedback to the proposed projects before more detailed project execution plans are developed and launched.

PG&E's EPIC portfolio of active projects continues to address challenges of the changing grid landscape and the threat of climate change, including enabling an increase in DERs adoption by customers, the need to modernize the grid to ensure continued safe, reliable, and resilient operation, and the need to continue improving affordability such as through advancing how to leverage data. These achievements from the EPIC projects, and their 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.

4.7 Customer Outreach & Engagement

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

1. Timeline that connects specific projects with specific marketing and outreach efforts, and
2. Specific steps to overcome roadblocks, as identified in the workshops and included in this report.[39]

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

Timeline: PG&E has adapted the CPUC Staff's template to reflect the existing and planned work that is related to the Smart Grid, including approved initiatives in place that meet the customer objectives outlined in SB 17 and D.10-06-047. Since the Marketing, Education, and Outreach proposal in the Smart Grid pilot deployment Application (A.) 11-11-017 was denied, the only outreach that provides support to the Smart Grid initiative is conducted through funding approvals of individual program and their initiatives as listed in Table 4-2.

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

Table 4-2 below provides an annual illustration of PG&E's customer engagement timeline.

Customer Engagement Timeline - Table 4-2	2014	2015	2016	2017	2018	2019	2020
Energy Management Enablement Tools:							
PG&E Online Account Web Tools	X	X	X	X	X	X	X
Universal Audit Tools (UAT)	X	X	X	X	X	X	X
Energy Usage Alerts	X	X	X	X	X	X	X
HERs	X	X	X	X	X	X	X
Third-Party CDA Tools (e.g., Share My Data, CDA)*	X	X	X	X	X	X	X

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

EPIC**				X	X	X	X
<u>Behind-the-Meter (Customer Premise) Devices</u>:							
SmartAC	X	X	X	X	X	X	
DG (Solar Water Heating, Solar PV, etc.)	X	X	X	X	X	X	X
HAN; Local Area Network; Smart Thermostat, etc.	X	X	X	X		X	X
EV Supply Equipment	X	X	X	X	X	X	X
<u>Rates Options:</u>							
SmartRate and Related Residential Time Varying Rates	X	X	X	X	X	X	X
TOU	X	X	X	X	X	X	X
PDP	X	X	X	X	X	X	X
EV Rates	X	X	X	X	X	X	X
* These programs are available but are not being actively promoted. ** Various EPIC demonstration projects have some component of customer outreach/marketing.							

EPIC Investment Planning Phase

During the up-front investment planning phase of each EPIC cycle, PG&E collaborates with the other IOUs to share with stakeholders sources and databases on R&D projects being undertaken by other entities[40]. The goal is to help identify EPIC project needs, coordinate investment plans and ensure avoidance of redundancy in the project selection process. These activities include internal brainstorming with subject matter experts and other stakeholders to determine the status of existing technology implementation activities and identify what major voids in capabilities exist that might be filled by pre-commercial demonstration of emerging technology solutions. PG&E's internal experts also participate in the workshops and peer reviews for other major R&D program sponsors, such as DOE, EPRI, and the National Laboratories.

The routine sharing among the EPIC Administrators of results and lessons learned from projects executed in preceding investment cycles contributes to the development of EPIC applications. EPIC Administrators also hold a number of in-person and phone-based joint portfolio review meetings to coordinate investment plans and ensure funding initiatives are complementary and

40 Joint Response of SCE (U 338-E), PG&E (U 39-E), and SDG&E (U 902-E) to Administrative Law Judge's Ruling Requiring Joint Applicant Responses to Questions, A.19-04-026

not unnecessarily duplicative. These information sharing mechanisms cast the net more widely on RD&D information sources and databases than any one EPIC Administrator could do alone. PG&E goes one step further by contributing its expertise and experience to CEC workshops that help shape the CEC EPIC program content.

The project ideas that evolve from the coordinated processes of the EPIC Administrators are vetted in public stakeholder workshops. There are at least two workshops held during the writing process for an EPIC application cycle. The first workshop screens the candidate project ideas and seeks additional ideas from public stakeholders. The second workshop reviews the Research Administration Plan (RAP) for the EPIC prospective content of the application. The participants in these workshops include stakeholders in the project results as well as entities that may bid on project contractor opportunities. Participants often provide information on external activities with which the EPIC work should be coordinated. Additionally, there are often follow-up inquiries after the workshops from prospective bidders on project opportunities.

Educating Customers on Benefits of Smart Grid and Technology

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

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

- Customer education on available tools designed to help customers understand their energy use;
- Customer education on choices for rate options and new technology that will help customers manage their energy bills; and

- Communicating with customers through communication methods they prefer, including digital self-service, email, SMS and by mail.

4.8 Smart Grid and Technology Customer Engagement by Initiative Area

In this section PG&E describes the customer engagement elements that are promoted or are available to customers for each initiative area identified in Table 4-2 above, as requested by CPUC Staff in its March 1, 2012 Smart Grid Workshop Report.

Enablement Tool: Energy Management*	
Project Description	Marketing, Education and Outreach (ME&O) to customers about interactive tools to evaluate and manage their energy use and meet their costs saving, sustainability or energy management goals.
Target Audience	Focused on Residential and SMB Customers.
Sample Message	"PG&E offers a number of ways to help you evaluate your energy use and learn how to save time, energy and money."
Source of Message	Energy Company.
Current Customer Engagement Road Block(s)	• Low engagement category. • There is a low baseline incentive for customers to be interested in incremental savings on their energy statement given the low engagement level of the utility category. • While customers are increasingly interested in digital communications, not all customers prefer communications through online channels. • The COVID-19 pandemic both helps overcome and increase the barriers to customer engagement. More customers are seeking ways to manage their energy use and save money as they are sheltering at home or out of work. At the same time, the increased usage and energy costs make incremental behavior changes less effective.
Strategy to Overcome Roadblocks	• Continue to use a variety of outreach methods to ensure highest penetration possible of relevant and targeted information with residential customers. • Leverage new automation capabilities and retargeting with customers who show interest in tools or abandon during the engagement process. • Demonstrate available energy savings by highlighting customer case studies and relevant syndicated or internally developed content. • Ongoing, frequent customer communication through the Small Business and residential digital newsletters. • Increased personalization of messaging to generate relevance.

<table>
<tr><th colspan="2">Enablement Tool: Behind the Meter (Customer Premises) Devices*</th></tr>
<tr><td>Project Description</td><td>ME&O to educate customers about available home or businesses devices that:
1) Facilitate market adoption of EVs through increased access and availability of EV infrastructure.
2) Support transportation electrification through programs such as EV Fleet and EV FastCharge.</td></tr>
<tr><td>Target Audience</td><td>Residential, Large and SMB customers.</td></tr>
<tr><td>Sample Message</td><td>“Save energy and money by providing RT electricity data through an energy-monitoring device.”
“EV Fleet is a comprehensive program that encompasses incentives and rebates, site design and permitting, construction and activation, maintenance and upgrades.”</td></tr>
<tr><td>Source of Message</td><td>Energy Company.</td></tr>
<tr><td>Current Customer Engagement Road Block(s)</td><td>• Concerns about ceding control of customer premises to utility through installed devices.
• Immediate economic impact (i.e., cost savings) is not always easily seen.
• Long payback periods on technology investments can make the Investment infeasible.</td></tr>
<tr><td>Strategy to Overcome Roadblocks</td><td>• Provide customers with information about devices, focusing on:
o The benefits and energy management.
o The potential to positively impact the customer’s economic bottom line with cost savings.
o Positive impact on grid stability and reliability.
• Provide tools and calculators where applicable to help customers understand the choices they have. Examples include:
o Solar Calculator (https://pge.wattplan.com/pv/) to review a personal estimate to understand customer specific solar savings potential
o EV Calculator (https://ev.pge.com), to estimate and compare costs including savings, incentives and charger locations</td></tr>
<tr><th colspan="2">Rate Options*</th></tr>
<tr><td>Project Description</td><td>ME&O to educate customers about rate options. Includes both opt-in and default TOU rate plans for residential customers and default rates for SMB customers.</td></tr>
<tr><td>Target Audience</td><td>Residential, Large and SMB customers.</td></tr>
<tr><td>Sample Message</td><td>“PG&E has rate options and encourages customers to choose the one that is best for their business and home.”</td></tr>
<tr><td>Source of Message</td><td>Energy Company.</td></tr>
</table>

<table>
<tr><td>Current Customer Engagement Road Block(s)</td><td>Lack of customer awareness that they have rate plan options and customer understanding about how they can benefit from various rate options, rates lack differentiation from a customer's perspective.
Lack of customer understanding about why TOU rates are important for the environment in a default scenario, leads to anxiety and dissatisfaction from some customers; emphasis on customer choice, when available, helps alleviate this.
TOU and critical peak pricing requires action from the customer during peak hours or on event days; the utility perspective of peak hours may not align with all customer segments.
Late afternoon and evening hours of TOU rate plans are significant barrier for many residential customers.</td></tr>
<tr><td>Strategy to Overcome Roadblocks</td><td>Sustained, ongoing outreach about default rates for both Residential and SMB (prior to and after default), including context for why rates are important to the utility and environment, as well as providing information on bill protection are critical to success of default TOU.
Encourage participation in opt-in residential rates.
Provide customers examples of how to benefit from rate options on peak event days and how to prepare for an event day, including developing an action plan.
Provide education to encourage customers to shift some of their energy usage to off-peak hours.
For residential customers, a focus on educating customers on the choices and control they have over their bill by familiarizing customers with different rate options, tools, programs and tips that can help them better manage their energy use. Emphasize that small shifts in energy can make a difference on TOU rate plans.
For SMB customers, the focus will be on the changing hours of TOU. Most customers will benefit from this change, but customer have several rate options to choose from depending on their energy needs and tools to help them save.</td></tr>
</table>

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

4.9 Security (Physical- and Cyber-)

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

In December of 2019, PG&E closed out the five-year CES-21 Program in partnership with SCE, SDG&E and Lawrence Livermore National Laboratory (LLNL). CES-21 was a research effort with the primary objective of exploring the next generation of Industrial Control Systems cybersecurity and developing the foundation for Machine-to-Machine Automated Threat Response. Research programs such as CES-21 leverage IOU, academic, and/or private sector expertise and further strengthen PG&E's grid security in the presence of increased threats.

PG&E is positioned to address the risks presented by the evolving Utility business, including Smart Grid and technology integration.

Since the publication of the Smart Grid Deployment Plan, PG&E completed the Advanced Detection and Analysis of Persistent Threats (ADAPT) cybersecurity project that was primarily focused on increasing the Utility's capability to effectively anticipate, prevent, and respond to a new and emerging class of cyber and physical threats. Following the conclusion of the ADAPT project, PG&E has undertaken the implementation of a second program, the Identity and Access Management (IAM) program. This is a multi-year investment focused on improving PG&E's core access control capabilities. Discussion of PG&E's overall Cybersecurity Risk Management Program is provided in sections 4.10.1 and 4.10.2 .

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

Identity and Access Management Program	Approximate Cost Over Reporting Period: $ 13.3 Million

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

Funding Source: This program is funded in PG&E's 2011, 2014, 2017, and 2020 GRCs, and through TO funds for the NERC CIP Program.

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

Upcoming Plans (Subject to Change): The program is continuing to deploy several enterprise enhancements and expansions to extend and augment existing technologies for access management. One current focus is on migrating the MyElectronicAccess (MEA) enterprise identity governance system to a new intuitive, industry leading platform . This migration reduces the cost and complexity associated with maintaining the MEA identity governance system. An additional focus is on NERC CIP regulated logical access control enhancements to improve regulatory compliance. Future work will focus on further automation and control enhancements to continue reducing the cost of ownership.

Benefit Description: As of July 2020, PG&E has decreased the risk of unauthorized physical and logical access through: automated creation of network login credentials for approved and authorized users; automated removal of access from up to hundreds of separate facility access control systems for decommissioned users; centralized server access provisioning/de-provisioning, monitoring and reporting; improved governance processes for enterprise user access functions contributing to a reduction in Segregation of Duties violations by 91 percent; deployed controls to restrict and better monitor privileged accounts; deployed a centralized logical and physical access management portal called MyAccess for both physical and logical access; and retired the legacy provisioning system for SOX applications. The program also created controls for cross-layer segregations of duties, instituted role-based access controls for critical functions, integrated additional applications with the MEA platform including key regulatory systems (e.g., SOX, NERC CIP, and Customer Energy Usage Data systems), updated legacy technology to support customer authentication to externally facing PG&E applications, strengthened controls for shared administrative and service accounts, and increased efficiency and effectiveness of re-certification tasks. The program continues to provide benefits including improved technology and processes associated with NERC CIP logical access management, migrating to a modernized web authentication and federation platform, and improving the user experience of managing access while reducing costs and the associated architectural footprint of PG&E's identity governance system.

Benefit Category: Engaged Consumer, Smart Market, and Smart Utility – The IAM Program enhances controls across PG&E's infrastructure and is not limited to the Smart Grid. Each of the Engaged Consumer, Smart Market, and Smart Utility areas benefit from these improved controls that protect key processes and systems across the enterprise. For example, the infrastructure that allows customers to log in to PG&E applications will be enhanced with increased security and control

mechanisms to validate that only authorized customers and their approved designees can access their customer information online.

CES-21 Program	**Approximate Cost Over Reporting Period:** **$0.56 Million**

Description: The CES-21 Program was a public-private collaborative research and development program between PG&E, SCE, SDG&E, and LLNL. The CES-21 Program was divided into two projects which research challenges of cybersecurity and the applicability of grid flexibility metrics as the grid becomes more dynamic and complex.

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

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

Status: The CPUC approved the Advice Letter (PG&E AL 4402-E) and CRADA in October 2014, allowing the IOUs and LLNL to initiate the cybersecurity and grid integration projects at the beginning of 2015. Please note that the CES-21 initiative filed comprehensive annual reports as well as a final program report in December 2019.

The Grid Integration Flexibility Metrics project was completed in September 2017. The results of its modeling have been socialized through the stakeholders of the Commission's Integrated Resource Planning proceeding.

For the Cybersecurity R&D project, from July until project closeout in December of 2019, the program team focused on concluding all remaining technical workstreams, documenting results, identifying candidate topics for future work, open sourcing additional tools, and releasing a comprehensive final report to the Commission. The project was broken into three major workstreams:

1. The development of a modeling & simulation platform, to explore the potential effects of various threat and response scenarios at grid scale
2. The establishment of a physical testbed with separate substation instances from each of the IOUs, to evaluate threats and responses on actual substation equipment
3. The development of a research package consisting of several capabilities to support the industry's evolution towards automated threat response and other next-generation cybersecurity techniques

Throughout the program, there was extensive collaboration between the program team and national laboratories, federal departments, academic institutions and industry organizations. Several of the tools developed through the program were made available to the open source community, to enable faster adoption and continued development of important cybersecurity capabilities. While this program began to develop much of the foundation for automated threat response, much work remains to be done, and the final program report provided a series of recommendations on next steps.

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

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

Operational Data Network (ODN) Security Program	Approximate Cost Over Reporting Period: $6.0 Million

Description: The landscape of threats is increasing and evolving. Attack "playbooks", attack tools, and basic computing technologies are becoming more commonly available and more powerful. The defenses crafted in past years are no longer a viable means to protect against advanced attacks. Sophisticated attackers understand not only the tools and processes to breach defenses but to do so in a way that does not attract attention.

Threats to the Operational Technology environment is evolving with legacy and new assets. Our vendors are not complying with the latest security and regulatory compliance requirements. We have legacy assets that no longer are supported and open us to unnecessary risk to our critical assets.

The current protections and security controls for the components of this network vary, as does the ability to detect anomalous activity. Compromise of the ODN in a small unmonitored substation can result the same level of disruption as compromise in a large capacity substation.

Funding Source: This program is funded in PG&E's 2017 and 2020 GRCs, and through TO funds.

Status: The program started in 2017, is ongoing, and remains in progress.

Upcoming Plans (Subject to Change): ODN security shall introduce cybersecurity industry best practices as part of the design, build, and implementation of the new/enhance security capabilities. To enable these best practices, certain technological investments must be made, including:

- High-availability next-generation firewall technology at each Electric Transmission Control Centers;
- Next-generation firewall technology for critical transmission substations;
- Identity and privilege access management infrastructure;
- Security monitoring tools specific to operational technology environments and systems;
- Vulnerability management systems and endpoint protection;
- Incident response and forensic tooling;
- New threat monitoring use cases and event collection infrastructure; and
- Enhanced and secured remote engineering access control systems.

Benefit Description:

Cyber-attack: ODN security reduces the probability and effects of cyber-attacks against distribution infrastructure by enabling a flexible and proactive response to emerging cybersecurity threats through cybersecurity solutions: Enhanced firewall technology to significantly reduce attack surfaces on critical systems. Vulnerability management systems to expedite the discovery and closure of cybersecurity gaps present in critical systems. Security intrusion detection and prevention capabilities to enable response to threats and to restrict their propagation from higher risk environments to critical transmission systems and applications. Implement cybersecurity solutions that reduces the possibility of cyber-attacks by increasing monitoring and automated response of control center systems. The investments will address Cyber Security Session D items, including ODN compromise (P95) and Real-Time Supervisory Control and Data Acquisition (RTSCADA) compromise.

Physical Attack: ODN Security limits exposure to a physical attack by building to NERC Critical Infrastructure Protection (CIP) design standards and creating a single redundant platform backed up at multiple control centers and data centers that can be run from any connected facility. Physical attacks are further mitigated through the upgrade to an IP-based network that is more resilient to physical and cyber-attacks. We will implement solutions that allow user access to be controlled and monitored for malicious behaviors to a far greater degree than is possible today.

Benefit Category: Smart Markets and Smart Utility – Cross-cutting initiatives apply across

Integrated Grid Platform (IGP) Security Program	Approximate Cost Over Reporting Period: $2.0 Million

Description: IGP will modernize PG&E's distribution control systems to improve cybersecurity, situational awareness, operational efficiency, and DER integration capabilities through a coordinated portfolio of software and infrastructure investments starting in July 2018 and completing overall project closure by December 2024. The expected future distribution network presents exciting opportunities together with complex problems. The scale of change requires us to act now by investing in fundamental capabilities to communicate, manage data and control a more complex two-way grid, with multiple owners, new DERs, new markets and new cyber security threats.

The electric grid is facing an increasing number of cybersecurity threats, which have advanced in capability over the last few years. In January 2019, Daniel R. Coats, Director of National Intelligence, provided testimony to the Senate Committee on Intelligence that certain nation-states, including China and Russia, have capabilities to launch attacks against critical infrastructure. In this same testimony, United States (U.S.) Intelligence also indicated that Russia is "actively mapping our critical infrastructure, with the long-term goal of being able to cause substantial damage." Furthermore, new malware frameworks specifically targeting industrial controls systems and applications, such as Crash override and Triton, have emerged over the last 5 years. This new family of malware pose threats to distribution management systems and SCADA. Current cyber tools and processes applied to DMS and SCADA systems are limited in their effectiveness and have not evolved to these new threat capabilities. Cyber technology and tools, along with ADMS itself, will need to be upgraded to ensure the new ADMS platform is positioned for resiliency against both current and future states of the threat landscape.

Funding Source: This program is funded in PG&E's 2020 GRCs.

Status: The program started in 2018, is ongoing, and remains in progress.

Upcoming Plans (Subject to Change): IGP security shall introduce cybersecurity industry best practices as part of the design, build, and implementation of the new ADMS platform. To enable these best practices, certain technological investments must be made, including:

- High-availability next-generation firewall technology at each Electric Distribution Control Centers;
- Next-generation firewall technology for critical distribution substations;

- Identity and privilege access management infrastructure;
- Security monitoring tools specific to operational technology environments and systems;
- Vulnerability management systems and endpoint protection;
- Incident response and forensic tooling;
- New threat monitoring use cases and event collection infrastructure; and
- Enhanced and secured remote engineering access control systems.

Benefit Description:

Cyber-attack: IGP security reduces the probability and effects of cyber-attacks against distribution infrastructure by enabling a flexible and proactive response to emerging cybersecurity threats through cybersecurity solutions: Enhanced firewall technology to significantly reduce attack surfaces on critical systems. Vulnerability management systems to expedite the discovery and closure of cyber security gaps present in critical systems. Security intrusion detection and prevention capabilities to enable response to threats and to restrict their propagation from higher risk environments to critical distribution systems and applications. Implement cybersecurity solutions that reduces the possibility of cyber-attacks by increasing monitoring and automated response of control center systems. The investments will address Cyber Security Session D items, including ODN compromise (P95), RTSCADA compromise, and DMS workstation compromise scenarios.

Physical Attack: IGP limits exposure to a physical attack by building to NERC Critical Infrastructure Protection (CIP) design standards and creating a single redundant platform backed up at multiple control centers and data centers that can b e run from any connected facility. Physical attacks are further mitigated through the upgrade to an IP-based network that is more resilient to physical and cyber-attacks. We will implement solutions that allow user access to be controlled and monitored for malicious behaviors to a far greater degree than is possible today.

Benefit Category: Smart Markets and Smart Utility – Cross-cutting initiatives apply across

4.10 Key Risks Overview

The electric grid is facing an increasing number of cybersecurity threats, which have advanced in capability over the last few years. In January 2019, Daniel R. Coats, Director of National Intelligence, provided testimony to the Senate Committee on Intelligence that certain nation-states, including China and Russia, have capabilities to launch attacks against critical infrastructure. In this same testimony, U.S. Intelligence also indicated that Russia is “actively mapping our critical infrastructure, with the long-term goal of being able to cause substantial damage." Furthermore, new malware frameworks specifically targeting industrial controls systems and applications, such as Crash override and Triton, have emerged over the last 5 years. This new family of malware pose threats to distribution management systems, SCADA, and the grid.

4.10.1 Key Risks and Actions Taken to Address Them

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

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

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

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

4.10.2 Managing Cyber Security Risk Through Control Baseline

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

- Access Control
- Security Awareness and Training
- Audit and Accountability
- Security Assessment and Authorization
- Configuration Management
- Contingency Planning
- Cybersecurity Program
- Identification and Authentication
- Incident Response
- System Maintenance
- Media Protection
- Physical and Environmental Protection
- Security Planning
- Risk Assessment
- System and Services Acquisition
- System and Communications Protection
- System and Information Integrity

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

4.10.3 PG&E's Compliance with NERC Security Rules and Other Security Guidelines and Standards as Identified by NIST and Adopted by FERC

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

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

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

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

4.10.4 Key Risks Conclusions

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

CHAPTER 5

SMART GRID METRICS AND GOALS

5 Smart Grid Metrics and Goals

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

5.1 Customer/Advanced Metering Infrastructure Metrics

Metric 1: Number of advanced meter malfunctions where customer electric service is disrupted, and the percentage this number represents of the total of installed advanced meters. The reporting period for all Metric 1 values is July 1, 2019 – June 30, 2020.

Number of PG&E Advanced Meter Malfunctions Where Customer Electric Service is Disrupted; Percentage of Total Installed Advanced Meters	
Metric	Value
Number of Meter Malfunctions	41 meters
Percentage of Total Meters	0.00075%
Note: Reporting date: July 1, 2019 through June 30, 2020	

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

Other Advanced Meter Malfunctions Metrics	
Metric	Value
1a. Amount of Electric Smart Meters Installed	5,491,222
1b. Amount of Electric Smart Meters Activated	5,281,640
1c. Number of Electric Opt-Out SPIDs	41,103
1d. Amount of Electric non-Smart Meters and/or amount of meters still manually read **	69,310
Notes: **Counts as of end of June 2020. **The count of meters still manually read includes Opt-Out meters.	

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

Load Impact in MW of Peak Load Reduction From the Summer Peak and From the Winter Peak Due to Smart Grid-enabled, Utility Administered DR (in total and by customer class) – Automated DR Program	
Metric	Value
From the Summer Peak (May 2019 – October 2019)	
Residential*	0.62 MW
Non-Residential < 200 kW	1.96 MW
`Non-Residential ≥ 200 kW	5.90 MW
Other (Agricultural)	2.63 MW
From the Winter Peak (November 2019 – April 2020)**	
Residential	0 MW
Non-Residential < 200 kW	0 MW
Non-Residential ≥ 200 kW	0 MW
Other (Agricultural)	0 MW
Note: The MW values are the average kW shed across all of the events in 2019 on a per Service Account Identification (SAID) basis and then summed. Therefore, this is not the cumulative MW load impact but the average load impact that could be expected on a pe r event basis. The Non-Residential <200 was determined on an SAID basis the average baseline kW for each event and if that average baseline across the events was <200 it was included in that sum. *Residential value is estimated based on the number of smart thermostat recipients multiplied by .43 kW per customer as based on the PG&E's 2016 T&D Third-Party Bring Your Own Thermostat Pilot results. **DR programs eligible for AutoDR are active over the timeframe of May-October.	

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

Percentage of PG&E DR Enabled by AutoDR in Each Individual DR Impact Program (2018)	
Metric	Value
Percentage of DR enabled by AutoDR –PDP Program	12.4%
Percentage of DR enabled by AutoDR –CBP	60.3%
Note: Percentage represents the Verified kW load reductions (engineering analysis) available for DR programs in 2019, divided by total DR portfolio kW, with the resulting number multiplied by 100. This table is not referencing cumulative load shed across the 2019 DR season.	

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

Number and Percentage of PG&E Owned Advanced Meters with Consumer Devices with HAN or Comparable Consumer Energy Monitoring or Measurement Devices Registered With PG&E		
Metric	Number	Percentage
Residential	4242	<1%
Non-Residential < 200 kW	86	<1%
Non-Residential ≥ 200 kW	4	<1%
Other	0	0%
Total	4332	<1%
CARE	222	0%
Non-CARE	4110	<1%
Total (CARE and Non-CARE)	4332	<1%
Climate Zone P	86	<1%
Climate Zone Q	44	<1%
Climate Zone R	146	<1%
Climate Zone S	427	<1%
Climate Zone T	971	<1%
Climate Zone V	15	<1%
Climate Zone W	46	<1%
Climate Zone X	2576	<1%
Climate Zone Y	18	<1%
Climate Zone Z	3	<1%
Total by Climate Zone	4332	<1%
Note: Percentage is defined as the number of advanced meters with consumer devices with HAN or comparable consumer energy devices registered with the utility divided by the number of advanced meters installed for the group of concern, with the resulting number multiplied by 100.		

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

Number and Percentage of Customers on a Time-Variant or Dynamic Pricing Tariff		
Metric	Number	Percentage
Residential	695,407	14%
Non-Residential < 200 kW	536,582	79%
Non-Residential ≥ 200 kW	11,250	2%
Total	1,243,239	23%
CARE	116,618	9%
Non-CARE	1,126,621	27%
Total (CARE and Non-CARE)	1,243,239	23%
Climate Zone P	45,822	26%
Climate Zone Q	3,509	24%
Climate Zone R	167,912	27%
Climate Zone S	254,513	27%
Climate Zone T	223,816	18%
Climate Zone V	12,676	21%
Climate Zone W	82,331	27%
Climate Zone X	431,473	21%
Climate Zone Y	19,491	29%
Climate Zone Z	1,696	7%
Total by Climate Zone	1,243,239	23%
Note: Percentage is defined as the number of customers that are on a time-variant or dynamic pricing tariff divided by the number of customers in the group of concern, with the resulting number multiplied by 100.		

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

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

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

Number and Percentage of Advanced Meters Replaced Before the End of Their Expected Useful Life for One Year, Reported Annually, With an Explanation for the Replacement		
Metric	Number	Percentage
Advanced meters replaced	26,990	0.49%
Explanation for the replacements: These advanced electric meters were replaced due to a malfunction before the end of their expected useful life (e.g., damaged meter, etc.).		
Note: Percentage is defined as the number of advanced meters replaced before the end of their expected useful life for one year, reported annually, divided by the number of advanced meters installed, with that resulting number multiplied by 100.		

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

Number and Percentage of Advanced Meters Field Tested at the Request of Customers Pursuant to Utility Tariffs Providing for Such Field Tests, and the Number of Advance Meters Tested Measuring Usage Outside the Commission-Mandated Accuracy Bands		
Metric	Number	Percentage
Advanced meters field tested at the request of customers[a]	2,698	0.05%
Advanced meters tested measuring usage outside the Commission-mandated accuracy bands[b]	25	0.93%
(a) Percentage is defined as the number of advanced meters field tested divided by the number of advanced meters installed, with that resulting number multiplied by 100.		
(b) Percentage is defined as the number of advanced meters field tested found outside of the Commission-mandated accuracy bands divided by the number of advanced meters tested at the request of the customer between 7/1/19 and 6/30/20 with that resulting number multiplied by 100.		

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

Number and Percentage of Customers Using a PG&E Web-based Portal to Access Energy Usage Information or to Enroll in PG&E Energy Information Programs or Who Have Authorized PG&E to Provide a Third-Party with Energy Usage Data		
Metric	Number	Percentage
Customers using a PG&E web-based portal to access energy usage information[1]	1,854,829	33.6%
Customers using a PG&E web-based portal to enroll in PG&E energy information programs	2,436,948	44.2%
Customers who have authorized PG&E to provide a third-party with energy usage data[2][3]	201,798	3.6%
(1) This number represents the unique number of customers who have accessed their usage information online within Your Account at least one time during the reporting period (July 1, 2019 through June 30, 2020). (2) Total number and percentage provided covers multiple programs. (3) This number includes Share My Data and BBP.		

5.2 Plug-In Electric Vehicle (PEV) Metric

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

5.2 Plug-In Electric Vehicle (PEV) Metric

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

Number of PG&E Residential Customers Enrolled in a Time-Variant EV Tariffs	
Metric	Value
Number of EV-A Customers	16,385 customers
Number of EV2-A Customers	46,407 customers
Number of EV-B Customers	394 customers
Number of identified EV owners* on other time-variant tariffs	13,625 customers
Note: Utilities currently have limited ability to determine which customers have EVs, outside of enrollment in EV rate schedules, and participation in EV rebate programs. *Identified EV owners include customers that have applied for and received PG&E's Clean Fuel Rebate. Customers included in this count are on the following time-variant rates: E-6, ETOU-A, ETOU-B, or other time-variant tariffs.	

5.3 Energy Storage Metric

Metric 1: MW and MWh per year of utility-owned or operated energy storage interconnected at the transmission or distribution system level. As measured at the storage device electricity output terminals as of June 30, 2020

MW and MWh of PG&E-Owned or Operated Energy Storage Interconnected at the Distribution System Level		
Metric	Location	Value
Sodium Sulfur Batteries	Vaca Dixon	1MW/7MWh*
	Yerba Buena	4MW/28MWh
Lithium Ion Batteries	Brown Valley	0.5MW/2MWh
Note: A 2 MW/14 MWh battery storage system was commissioned at a PG&E substation near Vacaville in August 2012 and a 4 MW/28 MWh battery storage system on a distribution circuit in San Jose California in May 2013. *In December 2019, 1 MW of the 2 MW of the Vaca Dixon BESS nameplate capacity was permanently retired in PowerPlan (the ratebase system of record) due to an unexpected module cooling event. It was determined, through conversations with the manufacturer and internal PG&E environmental teams, that the cooled modules can safely stay onsite until the whole system is decommissioned in the future.		

5.4 Grid Operations Metrics

Note for reliability metrics 1 to 4: Data for all reporting periods are pulled and refreshed from the Integrated Logging and Information System (ILIS) Operations Database, which may have resulted in differences compared to prior year reported values. ILIS is used by Distribution Operators to log outage switching operations (and ancillary information about network state for System Average Interruption Duration Index (SAIDI)/Customer Average Interruption Duration Index calculations) and other relevant operations data (i.e., equipment out of service, etc.). The data used includes both unplanned and planned outages that were reported on the T&D systems. The historical Major Events determined from each annual study was used.

Metric 1: The systemwide total number of minutes per year of sustained outage per customer served as reflected by the SAIDI Major Events Included and Excluded for each year starting on July 1, 2011 through the latest year that this information is available. There were 23 major events in the latest time period of July 1, 2019 through June 30, 2020.

PG&E's System Average Interruption Duration Index, Major Events Included and Excluded		
Period	Metric	Value
2019-2020	SAIDI – Major Events Included	1,300.1
2019-2020	SAIDI – Major Events Excluded	144.4
2018-2019	SAIDI – Major Events Included	458.4
2018-2019	SAIDI – Major Events Excluded	138.7
2017-2018	SAIDI – Major Events Included	229.8
2017-2018	SAIDI – Major Events Excluded	116.5
2016-2017	SAIDI – Major Events Included	267.7
2016-2017	SAIDI – Major Events Excluded	109.4
2015-2016	SAIDI – Major Events Included	136.4
2015-2016	SAIDI – Major Events Excluded	109.8
2014-2015	SAIDI – Major Events Included	174.1
2014-2015	SAIDI – Major Events Excluded	99.7
2013-2014	SAIDI – Major Events Included	123.8
2013-2014	SAIDI – Major Events Excluded	110.6
2012-2013	SAIDI – Major Events Included	160.9
2012-2013	SAIDI – Major Events Excluded	122.2
2011-2012	SAIDI – Major Events Included	171.9
2011-2012	SAIDI – Major Events Excluded	132.0

Metric 2: How often the systemwide average customer was interrupted in the reporting year as reflected by the System Average Interruption Frequency Index (SAIFI), Major Events Included and Excluded for each year starting on July 1, 2011 through the latest year that this information is available. There were 23 major events in the latest time period of July 1, 2019 through June 30, 2020.

PG&E's SAIFI Major Events Included and Excluded		
Period	Metric	Value
2019-2020	SAIFI – Major Events Included	1.781
2019-2020	SAIFI – Major Events Excluded	1.121
2018-2019	SAIFI – Major Events Included	1.505
2018-2019	SAIFI – Major Events Excluded	1.104
2017-2018	SAIFI – Major Events Included	1.141
2017-2018	SAIFI – Major Events Excluded	1.005
2016-2017	SAIFI – Major Events Included	1.462
2016-2017	SAIFI – Major Events Excluded	0.959
2015-2016	SAIFI – Major Events Included	1.132
2015-2016	SAIFI – Major Events Excluded	1.002
2014-2015	SAIFI – Major Events Included	1.155
2014-2015	SAIFI – Major Events Excluded	0.884
2013-2014	SAIFI – Major Events Included	1.090
2013-2014	SAIFI – Major Events Excluded	1.038
2012-2013	SAIFI – Major Events Included	1.211
2012-2013	SAIFI – Major Events Excluded	1.067
2011-2012	SAIFI – Major Events Included	1.191
2011-2012	SAIFI – Major Events Excluded	1.097

Metric 3: The number of momentary outages per customer systemwide per year as reflected by the Momentary Average Interruption Frequency Index (MAIFI), Major Events Included and Excluded for each year starting on July 1, 2011 through the latest year that this information is available. There were 23 major events in the latest time period of July 1, 2019 through June 30, 2020.

PG&E's MAIFI Major Events Included/ Major Events Excluded		
Period	Metric	Value
2019-2020	MAIFI – Major Events Included	1.571
2019-2020	MAIFI – Major Events Excluded	1.264
2018-2019	MAIFI – Major Events Included	1.899
2018-2019	MAIFI – Major Events Excluded	1.465
2017-2018	MAIFI – Major Events Included	1.807
2017-2018	MAIFI – Major Events Excluded	1.638
2016-2017	MAIFI – Major Events Included	2.208
2016-2017	MAIFI – Major Events Excluded	1.493
2015-2016	MAIFI – Major Events Included	1.856
2015-2016	MAIFI – Major Events Excluded	1.684
2014-2015	MAIFI – Major Events Included	1.698
2014-2015	MAIFI – Major Events Excluded	1.393
2013-2014	MAIFI – Major Events Included	1.506
2013-2014	MAIFI – Major Events Excluded	1.443
2012-2013	MAIFI – Major Events Included	1.820
2012-2013	MAIFI – Major Events Excluded	1.650
2011-2012	MAIFI – Major Events Included	1.636
2011-2012	MAIFI – Major Events Excluded	1.501

Metric 4: Number and percentage of customers per year and circuits per year experiencing greater than 12 sustained outages for each year starting on July 1, 2011 through the latest year that this information is available. There were 23 major events in the latest time period of July 1, 2019 through June 30, 2020.

Number and Percentage of PG&E's Customers Per Year and Circuits Per Year Experiencing Greater Than 12 Sustained Outages Per Year (Major Events excluded)			
Period	Metric	Number	Percentage
2019-2020	Customers Experiencing Greater Than 12 Sustained Outages Per Year	2,781	0.05%
2019-2020	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	39	1.17%
2018-2019	Customers Experiencing Greater Than 12 Sustained Outages Per Year	2,540	0.05%
2018-2019	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	30	0.97%
2017-2018	Customers Experiencing Greater Than 12 Sustained Outages Per Year	538	0.01%
2017-2018	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	13	0.42%
2016-2017	Customers Experiencing Greater Than 12 Sustained Outages Per Year	2,532	0.05%
2016-2017	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	26	0.84%
2015-2016	Customers Experiencing Greater Than 12 Sustained Outages Per Year	1,287	0.02%
2015-2016	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	17	0.55%
2014-2015	Customers Experiencing Greater Than 12 Sustained Outages Per Year	327	0.01%
2014-2015	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	6	0.20%
2013-2014	Customers Experiencing Greater Than 12 Sustained Outages Per Year	284	0.01%
2013-2014	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	6	0.20%
2012-2013	Customers Experiencing Greater Than 12 Sustained Outages Per Year	812	0.02%
2012-2013	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	15	0.49%
2011-2012	Customers Experiencing Greater Than 12 Sustained Outages Per Year	2,115	0.04%
2011-2012	Circuits Experiencing Greater Than 12 Sustained Outages Per Year	34	1.12%
Note: Percentage of customers experiencing greater than 12 sustained outages per year equals [(the number of customers experiencing greater than 12 sustained outages in a year) divided by (the total number of customers)] with the resulting number multiplied by 100. Percentage of circuits experiencing greater than 12 sustained outages per year equals [(the number of circuits experiencing greater than 12 sustained outages in a year) divided by (the total number of circuits)] with the resulting number multiplied by 100.			

Metric 5: System load factor and load factor by customer class for January 1, 2019 through December 31, 2019. Load factors are calculated on a calendar year basis.

PG&E's Load Factors	
Metric	Value
System Load Factor	51.14%
Residential Load Factor	34.92%
Non-Residential < 200 kW Load Factor	Small L&P: 48.96% Medium L&P: 47.10%
Non-Residential ≥ 200 kW Load Factor	Large L&P: 67.30%
Other (Agriculture) Load Factor	41.13%
Note: Some residential, small C&I, and small agriculture customers, don't have interval meters, therefore, for these, load factors will be calculated using estimates, rather than measured directly.	

Metric 6: Number of and total nameplate capacity of customer-owned or operated, grid-connected DG facilities. The data are cumulative through June 30, 2020.

Number and Total Nameplate Capacity of PG&E's Customer-Owned or Operated Grid Connected DG Facilities		
Technology Category	Count	Capacity (MW)
Solar	494,191	4,775
Storage	12,223	159
Fuel Cells	277	136
Wind	271	21
Other DG	254	381
Totals	507,216	5,472

Notes:

PG&E defines DG as generation less than 20 MW in size, designed primarily to offset on-site load, that is interconnected on the customer side of the utility meter under CPUC jurisdiction (Rule 21).

D.12-04-025 defines DG as "Customer-owned or operated generating systems that are enrolled with a utility in the SGIP or the California Solar Initiative (CSI) or otherwise operating under a Feed in Tariff (FIT)." Generation facilities receiving FITs are generally not designed to offset customer load and so are not included in the Table for Metric 6.

At this time, most DG facilities interconnected in PG&E's service territory were not incentivized through the CSI or SGIP program, but rather through Net Energy Metering that provides credits for exports to the grid. Additionally, some DG is simply installed by customers on a Non-Export tariff to offset onsite load without exporting to the grid. PG&E thus believes it is more useful to present a table for Metric 6 that shows the installed count and capacity of DG by technology type rather than by incentive program as was presented in prior years. We also include storage in the table though it is not a generation technology, as it plays an important role in shaping customer load served by PG&E's grid.

The capacity for solar generating facilities is reported as the PV CEC-AC rating, while for non-solar facilities, capacity is reported as the nameplate capacity of the generation facility. Counts reference distinct service points in each category. Totals will include duplicate service points in the case where one customer has multiple technologies installed (ex: Solar plus Storage customer will be counted twice in Totals.)

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

CSI also funds a rebate program, administered by Grid Alternatives, for low-income residents that own their own single-family home and meet a variety of income and housing eligibility criteria. This program is called the Single-family Affordable Solar Homes Program. Additionally, PG&E administers a CSI-funded solar rebate Program for multifamily affordable housing. This program is called the Multifamily Affordable Solar Housing Program.

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

Metric 7: Total electricity deliveries from customer-owned or operated, grid-connected DG facilities, reported by month. This information is for July 1, 2019 through June 30, 2020.

Year	Month	Approximate Exports*(GWh)
2019	Jul	434.0
2019	Aug	372.8
2019	Sept	337.7
2019	Oct	305.1
2019	Nov	199.1
2019	Dec	152.2
2020	Jan	195.1
2020	Feb	339.7
2020	Mar	363.8
2020	Apr	459.7
2020	May	533.3
2020	Jun	511.0
Note: Information and estimates about production of DG facilities that serve on-site customer load is produced annually by the CEC in their California Energy Demand Forecast. *Exports listed are approximate and subject to slight variation due to changes to PG&E's internal database structures and rounding. * Information for GWh exports sourced through service point interval usage data maintained in PG&E Teradata database. Detailed Sub Load Aggregation Point (SubLAP) data not shown due to temporal nature of SubLAP and Service Point ID mapping (i.e. one service point ID could be mapped to different SubLAPs at different points in time based on grid configuration.)		

Metric 8: Number and percentage of distribution circuits equipped with automation or remote-control equipment, including SCADA systems. The measure is for July 1, 2019 through June 30, 2020.

Number and Percentage of PG&E's Distribution Circuits Equipped with Automation or Remote-Control Equipment, Including SCADA			
Metric	# of Automated Circuits	Total Circuits	Percentage
PG&E Distribution Circuits Equipped with SCADA at the Breaker	3,126	3,165	98.8%
Note: Percentage of distribution circuits equipped with automation or remote-control equipment equals the number of distribution circuits equipped with automation or remote-control equipment) divided by the total number of distribution circuits with the resulting number multiplied by 100.			

CHAPTER 6

APPENDIX I

6 Appendix I

2019/2020 Smart Grid Annual Report

Approximate Recorded Smart Grid Project Costs from July 1, 2019 Through June 30, 2020[41]

Project Name	7/1/19 to 6/30/20 Approximate Recorded Amount
Community Wildfire Safety Program	
PGE.com Portal Enhancements	$0.58 Million
DMS/OMT/ILIS Enhancements	NA
Enhanced Asset Inspections – Drone/AI	$5.8 Million
Weather Station Deployment / Hi-Def Camera Deployment	$8.5 Million
Wildfire Spread Modelling	$6 Million
POMMS Enhanced Fire-Risk Modelling	$3.5 Million
Temporary MGs – Preinstalled Interconnection Hub (PIH)	$13.7 Million
Accelerated Vegetation Management – IT Field Tool	$2.4 Million
Customer Engagement and Empowerment Projects	
Supply Side (SSP) / SSP II DR Pilot (Continuation of Intermittent Resource Management Pilot Phase 2)	$0.47 Million
XSP	$0.36 Million
AC Cycling Next Generation Technology Assessment	$2.5 Million
EV Rates	$0.1 Million
EV Infrastructure	$35 Million
ED&M	$3.96 Million
BFA	NA
Share My Data (CDA) Project	$0.4 Million
Energy Data Access	$0.2 Million
Stream My Data aka HAN	$0.08 Million
BBP	$0.33 Million
TVP Rates	$2.96 Million
AutoDR Program	$2.1 Million
Smart Thermostat Study	NA
Distribution Automation and Reliability Projects	
ADMS	$22.5 Million
Distribution Substation SCADA Program	$23.1 Million

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

Project Name	7/1/19 to 6/30/20 Approximate Recorded Amount
Smart Grid FLISR	$4.29 Million
Transmission Automation and Reliability Projects	
Transmission Substation SCADA Program	$2.2 Million
MPAC Installation Program	$34 Million
Synchrophasor Project Realization	$0.7 Million
EMS	$4.5 Million
AM and Operational Efficiency Projects	
Network SCADA Monitoring Project	2018 $7.7Million / 2019 $8.5 Million
Wind Loading Assessments	$12 Million
STAR for Transmission Line	$1.96 Million
Security (Physical and Cyber) Projects	
Identity and Access Management (IAM) Project	$13.3 Million
ODN Security Program	$6.0 Million
IGP Security Program	$2.0 Million
Integrated and Cross-cutting Systems Projects	
Telecommunications Architecture	$0.3 Million
CES-21 Program	$0.56 Million
EPIC Program	$8.9 Million

2019/2020 Smart Grid Annual Report
Closed Smart Grid Projects

Project Name (Closed)	Completion Date
Customer Engagement and Empowerment Projects	
Intermittent Renewable Resource Management (IRRM) Pilot Phase 1 In the IRRM Pilot Phase 1, PG&E leveraged work performed under the C&I DR Participating Load Pilot to provide regulation services to the CAISO. The objective of the IRRM Pilot Phase 1 was to demonstrate whether customers can provide second by second frequency-regulation service needs to the CAISO.	2011
Plug-In Hybrid Electric Vehicle (PHEV)/EV Smart Charging Pilot In the PHEV/EV Smart Charging Pilot, PG&E and the EPRI tested baseline functionalities of PEV charging hardware by conducting an end-to-end system connectivity to evaluate potential residential smart charging capabilities utilizing the load management software over the SmartMeter network.	December 2011
UAT PG&E provides the Home Energy Checkup and Business Energy Checkup (also known as UATs) for residential and SMB customers through My Energy. These tools utilize SmartMeter data along with other customer insights to make it easy for our customers to find energy savings ideas that are particular to how they use energy. The tools are progressive in nature, continually learning based on the information the customer provides, and include recommendations across EE, DR, DG, and behavioral changes.	September 2012
The Green Button Initiative In PG&E's Green Button Initiative, the Green Button tool provides customers with a means of easily accessing and downloading their energy use online in a standardized format that can be shared with energy service providers.	October 2012
My Energy Web Tools PG&E's customer website – My Energy – allows residential, SMB, and small agricultural customers to view usage, price and cost, and take advantage of various rate analysis tools. The usage information is displayed in a variety of formats including year-to-year comparison, peak/ off-peak, hourly and 15-minute interval data (depending on the granularity of the SmartMeter data), bill to date and monthly bill forecast. The "My Energy" website will also include a rate calculator which will calculate the customer bill under a variety of available rate plans.	November 2012
PDR Program Phase 1 As part of the Commission's vision of integrating retail-wholesale DR programs, in the PDR Program Phase 1, PG&E is in the process of enabling its retail DR programs to directly participate in the CAISO's wholesale market – PDR product. Phase 1 of this project was focused on assembling the proper tools (i.e., telemetry, forecasting) and integrating interfaces (procurement back-end systems to schedule, notify and settle) that PG&E needs to operate when bidding available DR resources in the CAISO market.	2013
Energy and Carbon Management System (ECMS) In the ECMS, PG&E has developed tools specifically for PG&E's large C&I customer account representatives to identify opportunity customers and enable a consultative energy discussion with those customers using advanced usage analytics and financial metrics for proposed EE projects.	December 2013

Project Name (Closed)	Completion Date
SmartMeter Program PG&E's SmartMeter Program launched the deployment of foundational technology to help PG&E's customers understand how and when they use energy, including through automated home energy management. The SmartMeter system improved infrastructure integrity, helped PG&E manage energy demand, and enabled PG&E to provide more reliable service. Through these broad systemwide enhancements, the SmartMeter Program has served the vital foundational step to enable creation of the Smart Grid, which in turn fosters a clean energy economy and sustainable economic expansion.	December 2013
HAN Enablement Program – Phase 1 & Phase 2 PG&E's HAN Enablement Program is an infrastructure that allows customers to register and commission a standards compliant device with PG&E's AMI network to receive near RT data from their SmartMeter. In HAN Phase 1 (Initial Deployment), which ran from March 1, 2012 through April 30, 2013, PG&E installed and supported 430 in-home displays with residential customers. Starting in January 2013, PG&E launched HAN as a platform, making the capability to register a device and received near real time usage information from a customer's electric SmartMeter available to all eligible customers across its service territory.	April 2013 and February 2014
Opower/Honeywell Smart Thermostat Assessment Pilot PG&E conducted a Smart Thermostat field assessment with Opower and Honeywell to evaluate the energy benefits that accrue to customers who utilize internet-enabled thermostats, when exposed to behavioral energy saving messaging. This effort was a component of the EE Portfolio's Emerging Technologies Program. PG&E successfully installed Honeywell Smart Thermostats in 505 residential homes in the San Francisco Bay Area and the Central Valley in February 2013. Opower and PG&E monitored usage differences between the test and control groups for a 12-month period.	July 2014
Opower/Honeywell Smart Thermostat Assessment Pilot PG&E conducted a Smart Thermostat field assessment with Opower and Honeywell to evaluate the energy benefits that accrue to customers who utilize internet-enabled thermostats, when exposed to behavioral energy saving messaging. This effort was a component of the EE Portfolio's Emerging Technologies Program. PG&E successfully installed Honeywell Smart Thermostats in 505 residential homes in the San Francisco Bay Area and the Central Valley in February 2013. Opower and PG&E monitored usage differences between the test and control groups for a 12-month period.	July 2014
Green Button Connect (GBC) Beta GBC is a software interface that allows PG&E customers to easily share their SmartMeter enabled energy usage data with other energy service providers. These developers can then "mash up" the data in unique ways to provide valuable insights to customers. GBC was retired when PG&E launched its Share My Data platform.	March 2015
DR T&D System Integration In T&D System Integration, PG&E evaluated areas where existing and future DR programs can be implemented and designed to support PG&E's T&D planning and operations. The first phase included a study of the required DR resource characteristics to meet distribution needs. The pilot conducted field demonstration projects as part of 2015-2016 DR Bridge Funding Activities (D.14-05-025). Demonstration projects included the deployment of local DR resource zones that can be called by Distribution Operations to maintain local system reliability, development of behavioral DR resources that can be locally called by Distribution Operations and testing the feasibility of automated calling of DR resources linked to SCADA.	April 2017

Project Name (Closed)	Completion Date
DR PEV Pilot The DR PEV Pilot demonstrated the technical feasibility as well as the value of managed charging of EVs as a flexible and controllable grid resource. The main goal of this project was to understand the potential of using EVs for grid services, which can result in cost savings associated with operating and maintaining the grid as well as owning and operating a vehicle. The pilot required Bavarian Motor Works (BMW) to provide a minimum of 100 kW of capacity at any given time, regardless of how many BMW i3 EVs are charging. Once an event is called, BMW utilized proprietary aggregation software to delay charging of participating customers (via telematics embedded in the vehicle) to reduce load on the grid. The algorithm prioritized the reduction of electricity consumption from charging without interfering on customers' mobility needs; however, drivers can opt-out of event participation at any time. To address uncontrollable fluctuations regarding managed charging capacity, BMW developed a stationary battery system made up of eight used MINI E batteries (100 kW/225 kWh) as back-up storage to fill the gap between available load drop from managed charging and the required DR capacity.	December 2016
Demonstrate Subtractive Billing With Submetering for EVs to Increase Customer Billing Flexibility This project evaluated 3rd party submetering for EVs to separately meter EV charging load with the goal of saving EV owners money on charging costs while better aligning EV charging with periods of low electricity demand. Subtractive billing paired with submetering utilizes charging data from submeters, embedded in or associated with EV charging stations, and subtracts it from a customer's standard utility bill. This system allows utilities to offer a customer one electric rate for their EV charging, and a different rate for their primary source of load. The results of EPIC 1.22 have led PG&E to determine that third-party submeters cannot currently provide the reliability and data accuracy required for retail billing, and that there is currently no path to production for such a use. The customer benefits in terms of saving on charging equipment are modest when compared to installing a separate utility grade meter and the upgrades required to accommodate third-party submeter data.	November 2019

Project Name (Closed)	Completion Date
Distribution Automation and Reliability Projects	
Cornerstone Improvement Project – Feeder Automation The Cornerstone Improvement Project includes the installation of distribution feeder FLISR systems on select urban and suburban circuits. The project is expected to result in reliability improvements for PG&E customers. The Feeder Automation component of Cornerstone Improvement Project involves implementing feeder automation on approximately 400 distribution circuits. The project scope includes automating mainline protection equipment utilizing FLISR schemes to restore unaffected customers within five minutes.	December 2013
Regional Synchrophasor Investment Project As part of this project, PG&E installed or upgraded Synchrophasor technology, also known as PMUs, throughout its service territory, has networked them together, and provided the data in a secured interface to PG&E's ET operators, Western Electricity Coordinating Council (WECC), neighboring utilities, and the CAISO. The data exchange portion of the project includes positioning PG&E to share data with WECC. Nine other partner entities can coordinate and exchange data amongst partner entities, including PG&E.	May 2014

Project Name (Closed)	Completion Date
SmartMeter Outage Management Integration Project The SmartMeter Outage Management Integration project integrates the SmartMeter "Last Gasp" and Restoration messages into PG&E's OMS for outage notification to operators and dispatchers and improved outage restoration. Phase I project delivered: (1) the capability to create trouble reports from AMI alarms when an associated customer call has been received; (2) the capability to ping a transformer to determine if an outage is larger than it was inferred to be; and (3) the capability to ping individual meters to determine whether they have been restored. Phase 2 of the project delivered functionality to identify and isolate downstream outages that have occurred prior to a larger upstream outage. Additionally, it will enhance the capability introduced in Phase 1 by removing the requirement for an associated customer call and automatically creating trouble reports using AMI only reports.	November 2015
EPIC 1.01: Energy Storage for Market Operations EPIC 1.01 Energy Storage for Market Operations project successfully utilized PG&E's Vaca-Dixon and Yerba Buena BESSs to gain experience and data by participating in CAISO's NGR market model. PG&E developed and deployed an automated communications and control solution to fully utilize and evaluate BESS fast-response functionalities.	September 2016
Install Smart Grid Line Sensors Pilot The objective of the project was to pilot how line sensors can: (1) provide more accurate information about the fault location area, allow faster outage restoration by reducing outage response time, and improve customer satisfaction; (2) provide accurate current flow information to operators and engineers to plan and reconfigure the system without overloading equipment based on actual current measurements instead of models; and (3) provide more accurate current flow information to engineers to support better planning of the distribution system rather than relying exclusively on models.	December 2016
Voltage and Reactive Power (Volt/Var) Optimization System Pilot This project piloted a voltage and reactive power (Volt/Var) optimization technology to evaluate the technology's ability to reduce customer energy usage and reduce utility system losses by managing the distribution voltage from the substation to the customer's service point (distribution primary, secondary and service systems). Volt-Var Optimization (VVO) is a software based solution that analyzes grid conditions, determines the device-level adjustments necessary to regulate voltage, and communicates coordinated commands to grid devices in real time. VVO control systems act as a centralized voltage and reactive power control "brain" of the electric distribution system, for evaluating and signaling the actions needed for better voltage and reactive power regulation.	December 2016
Detect and Locate Faulted Circuit Conditions Pilot This project installed and evaluated a fault-finding software system and systems that assist in more precisely locating failed equipment that caused an outage and determined if there are additional benefits of providing a more accurate location to utility first responders to outages.	December 2016
Transmission Automation and Reliability Projects	
Compressed Air Energy Storage (CAES) Demonstration Project The purpose of this demonstration project was to determine the technical and economic feasibility of an approximately 300 MW CAES plant using a porous rock structure for up to 10 hours of air storage at a location within California. CAES technology consists of compressing air into an underground porous rock formation during periods of excess generation and then releasing the stored air to generate electricity during periods of peak demand.	2017
AM and Operational Efficiency Projects	
Transformer Load Management Project The SmartMeter Transformer Loading Management project enables T&D electric planning engineers and estimators to access actual customer usage data from SmartMeter for analysis in equipment sizing and voltage analysis. The solution will enable PG&E to report transformer (or multiple transformers) load based on interval usage data and the ability to drill down to month, week, day, and Service Point level to see the peak usage. The solution will also identify	June 2012

Project Name (Closed)	Completion Date
transformer (or multiple transformers) by load category (over loaded, under loaded) over the entire SmartMeter population.	
Load Forecasting Automation Program The Load Forecasting Automation Program will automate existing manual electric distribution system load forecasting to increase accuracy of the process and improve forecast documentation. Current and future SCADA data will be gathered and stored within the existing data historian system and will become an input to the new forecasting tool. Circuits with SCADA will provide hourly load data into the historian system and non-SCADA circuits will provide a single monthly peak load from monthly substation inspections. Additionally, this project will replace analog bank demand meters with electronic recording meters.	October 2012
CBM – Substation Project The CBM Substation Project was a PG&E initiative to convert substation inspections collected on paper to a centralized electronic form. Centralizing the data aids in identifying problematic substation assets based on inspected condition trends in a predictive manner. The CBM technology solution for substation provides the platform for equipment inspection readings, temperature, and other data points to provide equipment predictive maintenance. The solution will automate many of the manual processes that are used today including: (1) review of station inspection and test data to identify abnormal conditions; (2) update maintenance trigger plans from oil condition assessment results, counter readings, etc.; and (3) equipment ranking for replacement decisions. The tool is also designed to provide easy access to inspection and test data to asset strategy and engineering personnel that do not have it readily available today. The data will be used to adjust maintenance triggers and for capital investment strategy.	February 2013
Electric Distribution Geographic Information System and Asset Management (Electric Distribution GIS/AM) Project The Electric Distribution GIS/AM project is a continuation of and enhanced approach to the Automated Mapping and Facilities Management (AM/FM) Project, where PG&E upgraded hardware and software components from 2008 2010 and completed alignment of electric and gas maps to a common coordinate scheme or "land base," to prepare the maps for migration and conversion into a new enterprise GIS solution. While the purpose and scope of the Electric Distribution GIS/AM project is consistent with and leverages work completed as part of the predecessor AM/FM project, key enhancements are being made to drive increased business value with the integrated GIS and enterprise AM system (SAP) data. A significantly more rigorous approach to assure data quality and implement data governance processes is included as part of the new Electric Distribution GIS/AM project. In addition, the scope of the Electric Distribution GIS/AM project has been expanded to include web based analytics for multiple Electric Distribution functions. These and other capabilities are more fully detailed and scoped in the GIS/AM project as compared to the 2011 GRC AM/FM forecast, resulting in a more comprehensive and longer duration project.	December 2015
Security (Physical and Cyber) Projects	
ADAPT Cyber Security Project The ADAPT project is focused on increasing PG&E's ability to effectively anticipate, prevent, and respond to current and shifting cyber and physical threats by enhancing the following three control areas: a) Intelligence and threat management controls: Build specific "early-warning" controls that electronically collect, analyze, and correlate information on Utility targeting threats before they "approach" the Utility's logical perimeter. b) Advanced detective and preventative controls: Develop controls that "harden" the Utility's cyber security infrastructure with multiple layers of technology to filter, quarantine, and send alarms on questionable data. c) Adaptive response controls: Enhance incident monitoring, response, and investigation capabilities to quickly respond to potential security incidents.	May 2012
Integrated and Cross-Cutting Systems Projects	
SmartMeter™ Operations Center (SMOC)	July 2012

Project Name (Closed)	Completion Date
The SMOC project implements telecommunication network operations management capabilities to support PG&E's SmartMeter network to handle growth in the number of deployed meters, effectively monitor the increased amount of data communications from the meters, bring new SmartMeter-related customer services on-line efficiently, and enable timely customer response as well as proactive reliability and availability management. This scope includes designing and implementing a new SMOC for the day to day operations of the existing installed systems and ensure vendor production and operational commitments.	
Applied Technology Services (ATS) Distribution Test Yard (DTY) The DTY will serve as an electrical laboratory that includes simulated distribution capabilities for monitoring and evaluating various new distribution tools, equipment, and applications. It will include the necessary primary line equipment with isolated communications networks to allow safe and thorough testing without risking network security issues. This DTY is part of the overall ATS end to end test capability for distribution systems of the future.	September 2012
Data Historian Foundation Project This project will implement enhanced data historian software for managing and analyzing operational data with select user groups in ET, gas operations, power generation, and energy procurement. When deployed and integrated with other electric systems such as EMS and SCADA, the new data historian will serve as the central data archiving and analysis system for all-time series operational data. This solution enables PG&E operators, engineers, managers and executives to analyze, visualize, and share operational and business data in a manner that not only makes the most sense to them, but also informs intelligent decision-making throughout the utility value chain. The benefits of this capability include productivity improvements, situational awareness, reliability improvements, and regulatory compliance. A separate project is required to enable these capabilities for electric distribution.	July 2014
Information Management Architecture PG&E proposed to invest in a core set of Information Management and processing capabilities to allow participants in the Smart Grid to have timely access to the best available data to drive their energy related decisions. The Information Architecture foundation includes enhanced decision support tools to more accurately analyze, predict, and respond to energy impacting events based on data processed from a multitude of systems and stakeholders. The approach to information management is being optimized and will launch as a new project in 2017.	January 2016
EPIC 2.22-Demand Reduction - Analytics This project used load, interval and other sources of data to develop a new analytical tool to identify strategic customers and target demand reduction in local areas by combining and integrating multiple DSM technologies (e.g., EE, DR, DER, Consumer-oriented Energy Tools). The project investigated whether PG&E can achieve a sufficient amount of demand reduction, give visibility into the customer-side resources and improve the reliability of customer-side resources at the local level in order to delay the need for local capacity expansion expenditures. Main project phases: 1) Screening tool 2) TDSM dashboard 2.0, capturing algorithm insight for 3rd parties, and 3) Tracking/monitoring.	February 2018
EPIC 2.14-Phase ID This project successfully developed and demonstrated automated analytical methods for determining meter phasing and meter-to-transformer connectivity using SmartMeter™, SCADA and GIS data.	July 2018
EPIC 2.07 - Real Time Loading Data for Distribution Operations and Planning 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 system generation, GIS and weather data for two of the eight Areas of Responsibility (AOR) within PG&E's service territory.	November 2018
EPIC 2.14 - Automatically Map Phasing Information 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 distribution network model is central to multiple existing control systems,	December 2018

Project Name (Closed)	Completion Date
system analyses, and work processes. As the load characteristics of the distribution network evolve, such as with the growth of DER, it is becoming more important to have accurate and up-to-date network model information to be able to actively manage the distribution system. Automated approaches for obtaining this information can offer a more efficient alternative to the conventional boots-on-the-ground approach.	
EPIC 2.02- DERMS This 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 ground-breaking 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 (FTM) energy storage to provide distribution capacity and voltage support services while also allowing for participation of these same DERs in the CAISO wholesale market.	December 2018
EPIC 2.03A SIs This project conducted field demonstration of commercial SIs on a high PV-penetration distribution feeder ("Location 2"), the evaluation of a vendor-agnostic SI aggregation platform, and lab testing of multiple SI models. The project established that there is significant potential for local voltage support from SIs to help mitigate local secondary voltage challenges caused by high PV penetration in a cost-effective manner. Efforts undertaken within the project were not able to establish that individual or aggregations of SIs were able to substantially affect primary voltage.	February 2019
EPIC 2.05 - Inertia Response Emulation for DG Impact Improvement 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.	February 2019