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December 30, 2016

Advice 4990-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

<u>Subject:</u> **Smart Grid Pilot Program Final Status Reports Pursuant to Decision 13-03-032**

<u>Purpose</u>

The purpose of this advice letter is to comply with Ordering Paragraph (OP) 9 of Decision (D.) 13-03-032, which directs Pacific Gas and Electric Company (PG&E) to submit a status report via a Tier 2 Advice Letter within 14 days of the completion of each phase of each approved Smart Grid Pilot Deployment Project.

This advice letter marks the end of PG&E's Smart Grid Pilot Program and provides the final status reports. The Smart Grid Short Term Demand Forecasting Pilot Project (STDF Pilot) has completed Phase 3. The Smart Grid Distribution Line Outages and Faulted Circuit Conditions (FDL Pilot), Smart Grid Line Sensors (LS Pilot), and Smart Grid Voltage and Reactive Power (Volt/VAR Pilot) Optimization Pilot Projects have completed Phase 2. The Pilot Implementation Plan describing each of the Phases for each Smart Grid Pilot Deployment Project was approved by the California Public Utilities Commission (CPUC or Commission) in Advice Letter 4227-E[1].

The filing would not increase any current rate or charge, cause the withdrawal of service, or conflict with any rate schedule or rule.

<u>Background</u>

On November 21, 2011, PG&E filed Application (A.) 11-11-017 requesting authorization to recover costs for implementing six Smart Grid Pilot Deployment Projects over four years. The Smart Grid Pilot Deployment Projects seek to advance the modernization of PG&E's electric grid consistent with California's energy policies as described in Senate

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[1] PG&E's Advice Letter 4227-E, *Smart Grid Pilot Deployment Projects Implementation Plan, Pursuant to D.13-03-032*, submitted for filing on May 22, 2013 and approved effective June 21, 2013 by the CPUC's Energy Division.

Bill (SB) 17 and PG&E's Smart Grid Deployment Plan, which was filed on June 30, 2011 and approved on July 25, 2013.

On March 27, 2013, in D.13-03-032, the Commission approved four of the Smart Grid Pilot Deployment Projects proposed by PG&E in its November 2011 application: the STDF Pilot Project, the FDL Pilot Project, the Volt/VAR Pilot Project, and the LS Pilot Project. OP 9 of D.13-03-032 states:

> "Within 14 days of the completion of each phase of each approved pilot, PG&E shall submit a status report via a Tier 2 Advice Letter to Commission staff. Each status report must include a) details of the activities occurring in the phase; b) a detailed breakdown of the costs of those activities; c) the results of the phase including evaluation and measurements of pre-selected metrics to portray the success or failure of the pilot phase; and d) a recommendation and rationalization of whether the pilot should advance to its next phase. PG&E should ensure that status reports are detailed, both quantitatively and qualitatively. Funding for subsequent phases, although approved in this decision, may not be spent by PG&E until the Advice Letter for the current phase is submitted and approved."

Request

In compliance with OP 9 of D.13-03-032, PG&E provides these final status reports and notifies the Commission that PG&E will be closing the program.

Protests

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than January 19, 2017, which is 20 days after the date of this filing. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B10C
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-1448
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

PG&E requests that this Tier 2 advice filing become effective on regular notice, January 30, 2017, which is 31 calendar days after the date of filing.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service list for A.11-11-017. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Erik Jacobson
Director, Regulatory Relations

Attachments:

1. Final Report – Short Term Demand Forecasting Project
2. Final Report – Line Sensors Project
3. Final Report – Detect and Location Distribution Line Outages and Faulted Circuit Conditions (Fault Detection and Location) Project
4. Final Report – Voltage and Reactive Power Optimization (Volt Var Optimization) Project

cc: Service List A.11-11-017

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 E)**

Utility type:	Contact Person: Kingsley Cheng
☑ ELC ☐ GAS	Phone #: (415) 973-5265
☐ PLC ☐ HEAT ☐ WATER	E-mail: k2c0@pge.com and PGETariffs@pge.com

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL) #: **4990-E** **Tier: 2**

Subject of AL: **Smart Grid Pilot Program Final Status Reports Pursuant to Decision 13-03-032**

Keywords (choose from CPUC listing): Compliance

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ______________________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.13-03-032

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: ____________________

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: No

Confidential information will be made available to those who have executed a nondisclosure agreement: N/A

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: ____

Resolution Required? ☐Yes ☑No

Requested effective date: **January 30, 2017** No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: **N/A**

Service affected and changes proposed: N/A

Pending advice letters that revise the same tariff sheets: N/A

Protests, dispositions, and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division
EDTariffUnit
505 Van Ness Ave., 4th Flr.
San Francisco, CA 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Pacific Gas and Electric Company
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Pacific Gas and Electric Company

Final Report

Short Term Demand Forecasting

Smart Grid Pilots Program

December 30, 2016

Project Lead: Gary Yeung
Subject Matter Experts: Laura Lowe & Ann Segesman
Project Sponsor: Aparna Narang

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List of Supporting Documents (Previous Filings)

- AL 4227-E: Smart Grid Pilots Implementation Plan
  Effective Date: June 21, 2013
  URL: https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4227-E.pdf
- AL 4429-E: STDF Phase 1 Advice Letter
  Effective Date: June 29, 2014
  URL: https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4429-E.pdf
- AL 4470-E: STDF Phase 2 Advice Letter
  Effective Date: February 9, 2016
  URL: https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4770-E.pdf

1 Executive Summary

The Smart Grid Short Term Demand Forecasting Pilot (STDF Pilot) was one of the four Smart Grid initiatives that the California Public Utilities Commission (CPUC) approved in its final decision granting part of Pacific Gas and Electric Company's (PG&E) Application for Smart Grid Pilot Deployment Projects (Decision (D.) 13-03-032). Each initiative was to leverage investments made in the Smart Grid and eventually may provide leverage for future projects.

The STDF Pilot was designed to test the concept of using more granular data (such as Supervisory Control and Data Acquisition (SCADA) telemetry and SmartMeter™ usage data) to forecast load. The hypothesis was that by forecasting load using more granular data, regional variation of load due to factors such as microclimate could be captured. When taken on an aggregate basis, this could improve the accuracy of PG&E's short term electricity forecasts for bundled customer demand.

PG&E successfully completed the goal of building the infrastructure to incorporate more granular load data and determining whether this could out-perform traditional methodologies. The main finding is that the forecast for the two selected pilot areas using more granular data did not result in a more accurate forecast than the top-down approach for the system. The lesson learned was that the forecast volume size is important, that a smaller area is not necessarily easier to forecast accurately than a larger area. The larger volume makes the load relatively more predictable to forecast as a larger area likely has the customer diversity to balance out the impact of load outliers. Another lesson learned is that when conducting a local area level forecast, one needs to know detailed customers' information such as their load profiles, which requires intensive analytical work. In light of the result, PG&E's assessment is to keep the current forecasting process.

However, the data analysis in the pilot provided significant alternate benefits. Primarily, the customer usage (e.g., SmartMeter™) data segmented by the processes needed for the pilot were useful in estimating PG&E's bundled load by helping inform the adjustments associated with the unbundled demand (depending on whether the customer is contracted with PG&E or a third party energy service provider) to remove from the load forecast. Another significant potential benefit is that there is a need to improve settlement data quality for load using granular customer usage data and the infrastructure built for this pilot would provide a head start. The separate initiative, *Settlement Quality Meter Data Replacement* (SQMD), may realize savings of approximately $688 thousand by leveraging the STDF infrastructure.

Based on the pilot local area load forecasting results, PG&E's assessment is to not deploy the more granular load forecasting methodology further at this point for daily load forecasting for procurement, hence keeping the current top-down methodology for operations. A potential opportunity in the future, pending evaluation, is to take advantage of the SQMD project to use its customer usage data for estimating any adjustments needed to account for changes to customers in PG&E's bundled load.

Even though the original hypothesis of improving load forecast accuracy was not proven, there were soft and hard benefits that were generated out of the pilot. The use of a pilot to test out concepts before broader implementation has been proven valuable. This report details the work accomplished, results, lessons learned, and the deployment assessment of this pilot project.

2 Project Description

2.1 Program Background

PG&E's vision for the Smart Grid is to provide customers safe, reliable, secure, cost-effective, sustainable and flexible energy services through the integration of advanced communications and control technologies to transform the operations of our electric network, from generation to the customer's premise. This aligns with the policy goals of the Commission and the California legislature. Senate Bill (SB) 17 established that California would increase the use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid. In response to SB 17, the Commission adopted D.10-06-047, which established the requirements for the Smart Grid Deployment Plans, and explained that "subsequent utility requests to make specific Smart Grid-related investments, however, would occur in utility-specific proceedings where the reasonableness of particular Smart Grid investments can be determined." These proceedings include both General Rate Case (GRC) filings, and applications for specific projects. On November 21, 2011, PG&E filed Application 11-11-017 requesting authorization to recover costs for implementing six specific Smart Grid Deployment Pilot Projects over four years. In 2013, in D.13-03-032, the Commission approved four of the projects, including the STDF Pilot.

2.2 Supporting the Smart Grid Vision

2.2.1 Relevance to PG&E's Strategic Goals

In alignment with PG&E's strategic goals, the STDF Pilot methodology aimed to contribute to the following:

- Enhanced decision making: STDF processes and the processed hourly data could be leveraged by other technology projects with similar data needs
- Affordability: Increased certainty of load forecast could reduce unnecessary exposure to the more expensive or volatile market

2.2.2 Relevance to Utility Industry

Short term load forecasting is of tremendous interest to the industry. However, the portability of PG&E's load forecasting process is limited since the design is proprietary in nature to meet PG&E's unique needs and requirements. It remains valuable for counterparts of other investor-owned utilities' (IOU) Short Term Electric Supply teams to know that:

- There is not an immediate or easily-achievable reduction in load forecasting error from incorporating granular data into forecasting models; the variability of large users that is smoothed out in a top-down forecast causes too many fluctuations in small-territory forecasts.
- Using customer usage data to identify a specific group of end-users in the service area, such as those who are not the utility's bundled customers, does benefit from the inclusion of granular data.

2.2.3 Relevance to California Energy Policy Goals

The Short Term Demand project supports a number of SB 17 goals, by working to leveraging digital information to provide more reliable estimates for energy procurement. For details, please refer to Advice Letter 4227-E.

2.3 Technology Description

PG&E procures short term electricity on behalf of over 5 million bundled electric customers in the California Independent System Operator (CAISO) markets. PG&E's current short term forecast model for its bundled customer demand is driven by actual load, actual weather, and forecasted weather. PG&E currently utilizes a "top-down" methodology to forecast its bundled customer demand. Similar to the load forecasting methodology of other entities, such as the CAISO, the total load in PG&E's service area is based on the sum of in-area generation and net flows on transmission lines that interconnect PG&E with other service areas; this sum serves as the input for the load forecasting model. The load forecast is primarily driven by a weighted-average temperature forecast for the service territory. PG&E makes adjustments to the total load forecast to account for transmission losses, wholesale customer load, and municipal loads in the service area. Further adjustments are made to exclude the unbundled customer demand using historical billing data that is a mixture of hourly data and profiled data. The remaining load after adjustments are made is PG&E's bundled load forecast.

The STDF Pilot was an innovative "bottom-up" approach to test the concept of using granular data sources, such as SCADA data at distribution and transmission circuits, as input to the load forecasting model, which is a proprietary machine-learning model (neural network, genetic algorithm, and fuzzy logic). This approach provides the flexibility for PG&E to configure local areas based on micro-climates. PG&E also tested the concept of using the historical customer usage data (e.g., customer usage data is defined as data from SmartMeter™, MV90 which are interval meters for large commercial and industrial customers, and profiled analog meter) to adjust the total load forecast to PG&E's bundled load forecast.

The table below illustrates the comparison between PG&E's current load forecasting methodology and the STDF methodology tested.

Table 1 Comparison of PG&E's Load Forecasting Methodology With the STDF Pilot

	Current State	**Pilot Approach**
Approach	Top down	Bottom up
Load	Net flows on transmission lines and generation point data used for service area load	Local area load based flow data from distribution banks and for customers connected directly to transmission lines as input into the forecast model
Temperature	Composite system temperature forecasts	Local temperature forecasts
Non-PG&E Customers	Back out non-PG&E customer load based on internal information	Use customer usage data to determine relationship between total local area and bundled customer demand

The diagram below illustrates the STDF methodology as detailed in the project application. The set of transformer circuits in PG&E's lower voltage distribution network and the transmission system were identified to define the local areas. The new granular data were values from the SCADA system for these circuits. The aggregation of this granular data represents the total local area load for all customers and was the input into a local area forecast model. PG&E then applied adjustment factors to exclude PG&E's unbundled electric customers (e.g., wholesale customers, municipalities, DA and CCA customers that supply or acquire their own electric power) from the total local area load. PG&E also utilized local area weather data in the forecast model to capture the impact of micro-climates on load forecasts.

Figure 1 STDF Data Sources and Key Customers
Source: U.S.-Canada Power System Outage Task Force

2.4 Pilot Objective

The STDF Pilot goal was to determine if a new demand forecasting methodology using more granular sources of data for a local area would improve the accuracy of PG&E's bundled customer load forecast. The results of the STDF Pilot would inform the recommendation to deploy the new methodology on a broader basis in PG&E's service territory. The broader deployment would be an assessment of whether or not it is feasible and cost-effective to forecast PG&E's systemwide short term electricity demand with location specific information and the new granular data sources.

2.5 Planned Benefits of Recommended Deployment

In this section the benefits as described in D.13-03-32 are listed and then the benefits of full deployment as PG&E currently views them are discussed.

2.5.1 Primary Benefits

D.13-03-032 referenced PG&E's testimony that "PG&E estimates total benefits at full deployment ranging from a low of $3.2 million to a high of $47.5 million in energy procurement cost savings through

2030." This savings was based on the assumption that the new forecasting methodology would reduce procurement costs with an improved forecast to reduce the exposure to the more volatile real-time market prices.

Under the current CAISO market process, load can be bid in and settled financially in the day-ahead market (an auction process executed one day before the bid day). Any imbalance realized in real-time would be settled at the more volatile real-time prices. The increase in renewable generation in recent years has also contributed to increased uncertainty in real-time prices, as the large fluctuations in supply minute-by-minute has caused significantly higher frequency of extreme prices (both positive and negative). A more accurate day-ahead load forecast provides the opportunity to settle more of the load in the day-ahead market and reduces the amount of imbalance that needs to be settled at the real-time prices. However, the Pilot did not provide evidence of a more accurate service area forecast, so this benefit cannot be realized at this point.

Another challenge for PG&E's load forecasting process is the estimation of unbundled load in the service area. As previously described, the load from the current forecast model is for all customers in the service area and must be adjusted to become PG&E's bundled forecast only. The benefit of the improved estimation of unbundled load could reduce error in the load forecast.

2.5.2 Secondary Benefits

In D.13-03-32, the operational benefits were identified from using a more granular approach to demand forecasting as listed below. Though PG&E does make a contribution to these operational benefits, they are not quantifiable as a benefit from PG&E's load forecast since PG&E is not the only driver. The CAISO relies on its own forecast for load and ancillary services procurement (e.g., reserve, regulation). PG&E's load forecast drives its load bid, which impacts the supply-demand balance as well as the prices in the day-ahead market.

- Reduce the amount of uncertainty of the load that is seen by the CAISO and potentially decrease the procurement of ancillary services to manage that uncertainty. The CAISO procures certain ancillary services to manage the forecast uncertainty of demand and supply;
- Increased system reliability by ensuring sufficient resources are matched and available to meet demand; and
- Improved accounting for unaccounted for energy and associated costs.

2.6 Technical Metrics

In Advice Letter 4227-E, PG&E planned to perform statistical analysis to compare the forecasting accuracy from this pilot project to the existing forecasting process in the following ways:

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

In this report for Phase 3, PG&E compares the statistical performances of the PG&E service area forecast to the local areas. However, the results of the local areas should not be extrapolated to be comparable to the system results due to the unique customer characteristic of each area.

The statistical performance of the load forecast were measured in the following terms:

- Mean Absolute Percentage Error (MAPE): The MAPE is the absolute difference between the forecasted and actual values divided by the actual value and is expressed as a percentage.
- Root Mean Square Error (RMSE): The RMSE is the square root of the sum of the square of the difference between the forecasted and actual values and is expressed in MW.

These are common statistical metrics in evaluating forecasts: MAPE is more widely published and RMSE is more stringent (due to its sensitivity to single large variations). Typically, a lower MAPE and/or RMSE implies better accuracy. The statistical performance of the local areas of the STDF Pilot were evaluated on their own merit as described in Section 3.2.

3 Project Activities

This section summarizes the activities and achievements of the three STDF Pilot phases to analyze, build, and pilot the new load forecasting methodology. Table 2 provides a summary of the project phases. Also provided in this section is a recap of Phases 1 and 2, and details about the completion of Phase 3.

Table 2 Project Phases

Phase	Description	Advice Letter
Phase 1 – Analysis	PG&E selected two appropriate local areas and extracted, collected, and evaluated granular data for data quality.	AL 4429-E
Phase 2 – Build	PG&E built the infrastructure to process and house the integrated granular data sources, including local weather data, into a central repository for input into a demand forecasting model for Peninsula and DeAnza.	AL 4470-E
Phase 3 – Pilot	PG&E executed and evaluated the new Short Term Demand Forecasting process for Peninsula and DeAnza.	

3.1 Phases 1 and 2 (Analysis and Build)

In Phase 1, PG&E defined and selected Peninsula and DeAnza areas as the two local areas for the STDF Pilot. PG&E collected, processed, and analyzed the SCADA and customer usage data in prototype form. The full prototyping enabled the team to make changes quickly to the process from new learnings developed about the data, and made building the infrastructure in Phase 2 more efficient as it was based on a working prototype.

3.1.1 Data Collection and Integrity Checks

Once the local areas were selected, the SCADA telemetry data[1] was aggregated at transmission and lower-voltage distribution substation banks levels. The aggregated SCADA values were stored in four second intervals in the data warehouse from November 2013 onward. STDF processed aggregated SCADA into average hourly values into the STDF database beginning in 2016. This aggregation of SCADA data (SCADA_New) was a key input to the local forecasting model.

The second primary granular data obtained for the STDF Pilot was the customer usage data. The intended use of this data was to process electric usage of 200-300 thousand customers into a more manageable dataset, to calculate the amount of bundled load in the local areas. Initially, only the hourly SmartMeter™ and MV90 data was extracted for analysis. As a check on data quality, the pilot team identified that there was a ~10% average gap in data when comparing the aggregated SCADA to the customer usage data for the small data set.

To reduce the gap, the team acquired additional SCADA data at the individual transformer bank level. After mapping the customer usage data to feeders, transformer banks, and substations, the team could compare the cleaned usage data to the SCADA data by substation. This process identified data integrity issues with the extracted customer usage data. To reduce this gap in Phase 2, missing hourly MV90 data was identified, and process was built to profile billing segment data for those customers without

[1] If telemetry data was unavailable for the individual substation banks, State Estimated values were used.

interval meter data (i.e., without Smart Meters). The average gap between the two datasets was thereby reduced to within 5%.

The table below shows the end result of the data quality from Phase 1 and 2.

Table 3 Data Source Performance

Data Quality Criteria	Test Result
The difference between the SCADA_Old and SCADA_New should be within 5%.	Criteria met.
Comparison between SCADA_New and interval meter data.	Criteria met. The relationship between SCADA_New and aggregated interval meter data is reasonable since the data sets have consistent similar profiles. The average difference between the two datasets were within the +/-5%.
Mapping of interval meter data at distribution feeders and transmission circuits for local area must be consistent to that area that is electrically isolated by SCADA for the pilot	Criteria met. The interval meter data has been successfully mapped to substation banks for each area with some manual effort.
The customer meter data can be used to develop load adjustment factors to convert the forecasted total local area load to PG&E bundled load for the area.	In Phase 2, calibration factors to adjust total local area load to PG&E bundled load for the area were developed using the customer usage data stored in the STDF repository.
Support Data is available to process data	Rate profiles and distribution loss factors have been incorporated into the customer usage process

3.1.2 Data Processing Infrastructure

In Phase 2, PG&E designed and built the infrastructure to process and store the granular data for the two local areas of DeAnza and Peninsula. The items built for the STDF infrastructure were:

- SCADA load data and customer usage data extracted and processed into hourly values
- An operational database that is updated hourly with SCADA load and the vendor's forecast data
- A central repository that stores the detailed data (SCADA load, forecast, customer usage, supporting data)
- Data for calibration factors
- Demand forecasting models for the pilot areas
- Logic, algorithms and controls of the processes and systems
- Interfaces to the different disparate systems
- Graphical User Interfaces (GUI)

3.1.3 New Demand Forecasting Model Development

In Phase 2, PG&E worked with a load forecasting vendor to develop the new local demand forecasting model for each local area. PG&E provided scrubbed historical SCADA_New load data for each pilot area to the vendor. The vendor analyzed the weather stations in the pilot area and built a correlation of the historical SCADA_New data to local temperature data for each of the local areas to utilize in the vendor's proprietary forecasting model. The vendor's product is a 24/7 online load forecasting service for electric load data run by an engine made up of multiple intelligent system-based models that employ artificial neural networks, fuzzy logic, and evolutionary computing/genetic algorithms technologies.

PG&E's connectivity with the vendor was successfully tested to securely send and receive data based on the local area models. PG&E's infrastructure to process and store the forecast data performed as expected.

3.1.4 Transition to Phase 3

As indicated by the data quality, the new forecasting models, and the performance tests verifying that the infrastructure was ready, Phase 3 of the Pilot was fully prepared for execution.

3.2 Phase 3 (Field Pilot)

This section describes the work completed in Phase 3 including the performance results of the STDF components.

3.2.1 Project Activities

PG&E began Phase 3 with the work as outlined in AL 4770-E. The work was prioritized so that the load forecast methodology was utilized and evaluated for the maximum amount of time to meet the STDF Pilot objective. As the Phase 3 work progressed, the STDF team completed work as proof of concept for data processing techniques, which is described in this section.

PG&E utilized the STDF infrastructure build in Phase 1 and 2 to produce the load forecast for the target geographies on a 24/7 basis. After the top of each hour, PG&E sent the aggregated, SCADA actual data for each local area to the vendor. This actual value represented the near real-time demand for all customers in the local area. The vendor used the actual values and the corresponding local temperature forecast to produce the local area forecast for the remaining hours in the current day and the following six days. Within minutes of sending the actual value, PG&E retrieved the local load forecast from the vendor and stored that forecast in the STDF operational database.

A variety of operational priorities were pursued in testing the load forecasting technology in the field:

- **Data Integrity:** The vendor's load forecasting work is based on machine learning, in which the model is constantly changing in response to recent inputs. It was therefore critical to resolve issues such as SCADA data input errors as quickly possible, since the errors (especially those in the SCADA actual values) could have a lingering impact on the load forecast model. When issues arose, the cause was investigated, and the process was corrected. Two examples of these process corrections were:
    - PI/SCADA improvements: Improved logics to reduce data errors and automatic data substitution for erroneous data.

  - Web API: Streamlined the data transfer between Pilot system and vendor system (model) to reduce errors and issues.
- **Cybersecurity Authentication:** The planned work to revise the cyber security authentication process in Phase 3 was also a priority. When the security process was designed in Phase 2 of the STDF Pilot, it was a proof of concept solution to secure the data and to prevent hacking into PG&E's systems as data is transferred between PG&E and the outside vendor. In Phase 3, the security process that was built in Phase 2 was re-evaluated and was deemed adequate under the current cybersecurity requirements.
- **Automating Topology Mapping:** The utilization of Electric Distribution Asset Management/Geographic Information System enables the STDF Pilot to map the areas' feeders to the transformer banks with less manual intervention. This mapping streamlines the deep-dive comparison to check the data quality between the SCADA at transformer banks to the customer usage data which has been aggregated to a feeder level for the STDF Pilot in a more efficient manner.
- **Proofs of Concept of STDF Infrastructure:** the STDF team pursued a set of enhancements to the load forecasting methodology as a proof of concept.
  - **Customer usage:** Developed a process to extract usage data for a future unbundled customer group as they begin to transition from bundled to unbundled status.
  - **Integrating Granular Solar Irradiance:** the STDF team worked to integrate the historical and near real time forecasted Behind the Meter solar data provided by *EPIC Project 1.05 – POMMS (PG&E Operational Mesoscale Modeling System)*.
  - **GUI Performance:** Improved the speed for intensive data extractions and calculations by upgrading software and hardware.

During Phase 3, each process of the STDF infrastructure was evaluated in terms of the feasibility to scale the process for full deployment. Additionally, the cost and benefits to deploy the new forecasting methodology to the broader PG&E system was assessed. Both of these items are discussed in more detail in the deployment assessment section of this report.

3.2.2 Performance Results

Local Load Forecasts Performance

The statistical performances of each local area forecasts were determined and compared to those of the existing PG&E "top-down" system forecast. Forecast performance is the main driver in determining whether to replace the existing forecast by the new methodology. The local load forecasting statistics were calculated using the day-ahead and real-time forecasts.[2] The day-ahead load forecast in the analysis was produced by the vendor at ~ 7 a.m. the day before the operating day. This day-ahead forecast would typically be used to bid and schedule load in the CAISO day-ahead market, which closes at 10 a.m. the day before the operating day. The real-time forecast for each hour was produced before each upcoming hour of the current day so that PG&E could gauge the portfolio position.

[2] Note: total local area load, and not the adjusted bundled load, were used to calculate the statistics.

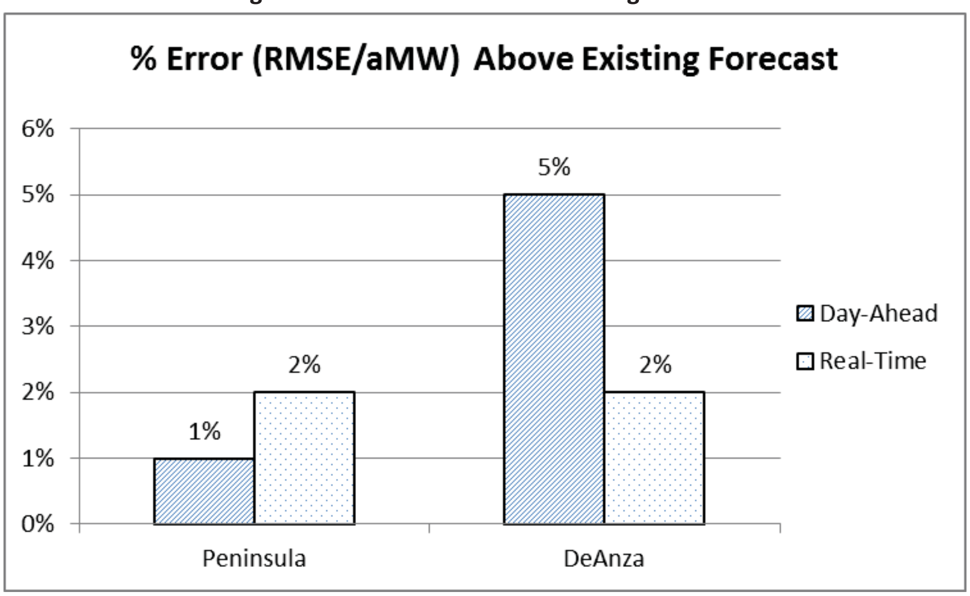
The MAPE and RMSE statistics for each local area are qualitatively compared to the system forecast for the period January-October 2016 in the table below. In summary, the forecast for the local areas (more granular data) has higher error (lower accuracy) than the forecast for the System (existing) in all the statistical metrics used.

Table 4 Summary of the Statistical Comparison of Local Area to System Results

Local Areas vs System Forecast	MAPE (%)	RMSE (MW)
Variation between day-ahead forecasts	Local areas greater than System	Local areas greater than System, with DeAnza values materially higher and Peninsula values comparable
Variation between day-ahead forecasts and real-time forecasts for each area	Real-time less than day-ahead in all cases	Real-time less than day-ahead primarily
Variation between real-time forecast	Local areas greater than System	Local areas greater than System for the period

The following figure illustrates the RMSE results graphically in terms of a normalized RMSE, i.e., RMSE divided by the average load of the area. The day-ahead normalized RMSE for Peninsula was 1% higher than the system forecast and 5% higher for DeAnza. The real-time normalized RMSEs for both local areas were 2% greater than the system forecast.

Figure 2 Percent Error Above Existing Forecast



In summary, the local load forecast performance was as follows:

Table 5 Local Load Forecast Performance

Criteria	Local Area Performance
STDF infrastructure	Successful in processing and storing the data needed for the local forecasting model.
Statistical results: day-ahead and real-time MAPEs	MAPEs higher than expected
Statistical Results: day-ahead and real-time RMSEs	Comparable day-ahead RMES for Peninsula
Real-time statistics	Real-time statistics were better than the day-ahead statistics in all cases

As described in Section 2.6, MAPE and RMSE were used as measures of accuracy and typically a lower MAPE and/or RMSE implies better accuracy. The Pilot team believes that the large MAPEs for the local areas might be attributable to customer load variations that were not predictable nor were balanced out by other customers. When forecasting a small area, the volatility of individual customers becomes more proportionally significant. A handful of customers with irregular pattern could introduce significant noise. For a large area, the volatility is averaged out and becomes more muted, so the total load is more predictable and weather-driven, which is crucial to the success of the forecasting model. Furthermore, though MAPE may be easier to interpret, it may not be a fair representation of model performance for these local areas since the small load values tends to lead to a higher MAPE values compared to the systemwide MAPE.

Customer Usage Data Performance

On a weekly basis, the customer usage data for the local areas for the last full 13 months were processed satisfactorily. This includes the profiling of billing segment data into hourly values for those customers without hourly interval meter data. The STDF process categorizes the customer usage data into bundled or unbundled status. The status changes from bundled to unbundled status as the energy service provider changes from PG&E to a third party provider (and vice versa). This is a key component for the adjustment factor calculation discussed below.

As an indicator of adequate data quality, the processed customer usage data was comparable to the SCADA data for each of the local areas, as discussed in the Phase 2 advice letter. For example, the August 2015 customer usage data for Peninsula on average was only 15 MW less than the SCADA data and the hourly load profiles of the two data sets were similar. We continue to analyze the customer usage data to understand the customer loads for the areas.

In summary, the performance of the customer usage data met the criteria as follows:

Table 6 Customer Usage Data Performance

Criteria	Performance
Customer usage data comparable to SCADA data for each area	The two data sources are comparable
Bundled/Unbundled status	Successful process for historical and current status to develop adjustment factors

Adjustment Factor Process Performance

Using adjustment factors, the total local area load forecast from the vendor was adjusted to become PG&E's bundled local load forecast. The historical customer usage data for bundled customers and the new SCADA data were used to calculate the adjustment factors for each local area.

In Phase 3, the STDF infrastructure satisfactorily processed and stored the data used for the adjustment factors calculation. For example, prior to the start of a month, the historical data for a similar month was exported from the STDF repository. For each hour, the percentage of bundled customer usage to SCADA_New was calculated. The percentages were then averaged together to develop hourly adjustment factors for a typical weekday, Saturday, and Sunday for the month. The hourly adjustment factors were imported back into the STDF repository and then were applied to adjust the hourly load values.

The adjustment factor calculation for the local areas of the pilot was comparable to the calculation needed for the PG&E system. In Phase 3, the STDF team analyzed the customer usage data and built a process to estimate the amount of unbundled adjustment that can be applied to the entire PG&E service area.

In summary, the adjustment factor process met the criteria as follows:

Table 7 Adjustment Factor Process Performance

Criteria	Performance
Calculation of adjustment factors	The STDF process successfully aggregated the customer usage as bundled/unbundled status. The STDF data was successfully utilized to calculate hourly load adjustment profiles for a typical weekday, Saturday, and Sunday for an upcoming month.
Adjustment Factors	The adjustment factors developed are reasonable for the local areas, as compared to typical adjustment factors for the System.
Estimate large bundled to unbundled status (vice versa)	Process built and has produced reasonable results that can be applied to the entire PG&E service area.

3.3 Cost Breakdown of Final Phase

The actual/forecast of the STDF project costs have been updated below. The final cost to complete the project was approximately 54% less than the forecasted budget in AL 4227-E. This is primarily due to the careful sequencing of activities by which PG&E sought to minimize spending in planning, analyzing, and building the STDF infrastructure to test the pilot hypothesis cost-effectively. Approximately 84% of the total expenditure was IT infrastructure development work that is classified as capital work, the rest was expense work that included analysis and finalizing results.

Table 8 Cost breakdown

Phase	Phases 1 and 2	Phase 3	Total
Year	2013-2015	2016	
Capital	3,888	1,141	5,029
Expense	521	448	969
Total	**4,409**	**1,589**	**5,998**

All values in thousands – figures above based on Actual spend through November 2016, forecast for December. Total Administrative spend over life of the project was 4% of project costs.

4 Lessons Learned

A business priority for the STDF Pilot was to resolve quality issues for the SCADA and customer usage data because of their significant impact on PG&E's forecasted bundled load. The issues that arose and the lessons learned to resolve these issues included:

4.1 Variances in Customer Usage Data

Based on our investigation, the customer usage data could be significantly different from the aggregated SCADA for the local area, due to:

- The initial mapping of feeders to transformer banks did not include the 4 kilovolt (kV) feeders that are downstream of other higher voltage feeders. This made it difficult to do deep-dive comparisons of the SCADA-to-customer-usage-data without manual mapping. In Phase 3, the automated topology mapping process identifies these 4 kV feeders and maps them to the correct parent circuit.
- Hourly data from PG&E's customer data warehouse needs to be validated and billing segment data needs to be processed for those customers without SmartMeter™ devices and for those customers without hourly data. After the calendar month is complete, STDF Pilot aggregates the hourly customer meter data and profiles the billing segment data for these customers without hourly data.
- Circuits can supply customers across local area boundaries. The STDF process was modified to identify all circuits in the local area and then aggregated all the meters supplied by the circuit even if the physical location of the meter is outside of the local area boundaries.
- SCADA data reflects real-time load as one circuit dynamically switches to other circuits. However, customer meters are statically mapped to a specific circuit and the mapping does not change as the switching occurs. This will remain an issue for STDF when a deep-dive analysis is necessary (e.g., when usage data is not equal to transformer banks when circuit switching occurs).

4.2 System Support

The current data transfer methodology for Phase 3 simplified the data submission and forecast retrieval process from Phase 2. However, errors can occur during these data migrations which have lasting impact on a machine learning model. Since it was a pilot, the STDF system is not a critical business function, and support for pilot process was occasionally deprioritized in favor of mission-critical IT needs. Any production use of this methodology in the future will require a service agreement with all systems about the level of support needed for load forecasting.

4.3 Local Area Selection

The statistical errors recorded for the local area forecast were higher than excepted. This may be due to the selection criteria being too restrictive. Smaller geographies that met the site selection criteria contained load variations that did not balance by each other out as they do in the larger systemwide forecast.

4.4 Data Availability

When the STDF Pilot began in 2013, granular data from other technologies were not available in real time as input into the load forecasting models. For example, distributed behind-the-meter solar generation data was not at a necessary maturity level until this year. Once we learned that data provided by the EPIC project 1.05 were available, STDF worked to incorporate the BTM solar data into the new load forecasting methodology. We are currently evaluating the impact of this data on the load forecast as the model learns from more recent actuals.

5 Deployment Assessment

The deployment of the STDF methodology to the broader PG&E system is discussed in this section in terms of the load forecasting methodology and customer usage data process. Scalability refers to the implementation feasibility of full deployment (i.e., extending the process to the broader PG&E system).

5.1 Load Forecasting Methodology

The load forecasting component should not be deployed to the full system at this point due to the lack of supportive evidence from the pilot predominantly driven by the unacceptable levels of the local area MAPEs.

- **Scalability:** granular data sources are available to expand the load forecasting process systemwide. From the STDF project, we determined that the granular SCADA data at PG&E's lower voltage distribution and transmission network are available and when aggregated, can be used as input into the vendor's forecasting model. The granular data does provide a great deal of flexibility to configure the local areas, and a unique load forecasting model could be developed by the vendor for each local area using the same machine learning program.

5.2 Customer Usage Data Process

- **Assessment:** The STDF infrastructure for customer usage data will be explored for full deployment use by PG&E's *Settlement Quality Meter Data Replacement* (SQMD) and for the system adjustment factor calculation.
- **Benefits:** The two activities that will benefit from the full deployment of the STDF customer usage data infrastructure are the SQMD Replacement and the adjustment factor calculation for the system forecast that is used in daily electricity procurement for load. Some modifications may be necessary to the STDF infrastructure for the two projects to share the same database:
    - The current SQMD systems are obsolete and redundant, causing issues in the areas of data quality, process efficiency, systems support, and scalability needed to support changing CAISO and retail requirements. Access to the retail hourly meter data (i.e., bundled usage) would help improve this situation. Though SQMD is justified on its own merit by soft and hard benefits, the only cost/benefit savings considered in this document are the benefits of reducing the costs by leveraging the STDF infrastructure for SQMD data collection.
    - The adjustment factors used to adjust the system forecast to PG&E bundled load are currently based on a data source from one of PG&E mainframes. Since the mainframe process currently used to generate the factors is expected to retire, another data source or process needs to be developed as customers move back and forth from bundled to unbundled status.
- **Scalability:** In Phase 3, PG&E tested the STDF infrastructure design to process electric customer usage data for the PG&E system (i.e., beyond the two pilot areas). This included the profiling of billing segment data into hourly values for those customers without hourly interval meter data. The STDF process categorized the customer usage data into bundled or unbundled status. The status changes from bundled to unbundled status as the energy service provider changes from PG&E to a third party provider (and vice versa).

To summarize, PG&E recommends the SQMD project to build upon the customer usage data infrastructure from this pilot and deploy it systemwide. The benefit was an estimated saving of $688 thousand for the SQMD replacement project by leveraging the STDF infrastructure.

6 Next Steps

6.1 Expansion of Bundled Load Adjustment

The bundled load adjustment factor calculation using smart meter (customer usage) data will be expanded to the entire service area through PG&E's SQMD Replacement project. The infrastructure already built in the STDF Pilot will be repurposed and the final system will provide the needed underlying data for the calculation.

6.2 Dissemination of Best Practices

- PG&E will reach out to the CAISO to describe the STDF Pilot and lessons learned. The CAISO encounters some of the same challenges, if not more, as PG&E in forecasting regional demand, and would benefit from a discussion of PG&E's experiences in translating granular information sources into territory-wide forecasts.
- Advice Letter 4227-E calls for a plan to "disseminate best practices and lessons learned from the pilot to all California utilities." However, because Short Term Electric Supply's work helps advance our position in a competitive market, we will not be able to share with other IOUs any information that will put us at a competitive disadvantage. As such, we expect the releasable information to IOUs to be similar to the content of the Advice Letter. If the other California IOUs request a best practices meeting after the publishing of the final Advice Letter, PG&E will accommodate these requests.

7 Conclusion

Every day, PG&E purchases electricity to supply electric service to more than 5 million homes and businesses. In the Smart Grid Pilot Project *Short Term Demand Forecasting,* PG&E successfully tested the hypothesis of improving the load forecast with granular data. PG&E participates in a marketplace that is dynamic and complex, where net demand can change dramatically over the course of the day, and consumers are offered alternatives to utility provided power. To overcome this growing complexity, PG&E is continuously exploring ways to improve the load forecast process.

As SmartMeter™ devices, SCADA-enabled distribution equipment, and end point devices become more common, electric utilities are increasingly armed with new data sources. Identifying processes that can benefit from leveraging new data and computing power, and proving the efficacy of these solutions, is a foundational component of PG&E's smart grid vision. The STDF Pilot successfully demonstrated that granular sources of data can be collected, formatted, and incorporated into the daily forecasting process. The STDF system field pilot for the two local areas did not offer a superior statistical improvement to the current top-down process. The lack of improvement may have been due to the demand volatility from individual customers that had a much larger impact on a small area load than that for larger systemwide forecast. This result is counter to the original hypothesis of the project which was that the forecasting accuracy should be improved for a smaller territory with localized temperatures and other granular data. This outcome of exploration into innovative new processes is the reason it was conducted as an intensive pilot project in the field to test the hypothesis, rather than implementation directly into systemwide deployment. Confirming the hypothesis, the cost, and benefit assumptions behind the new technologies is a key approach to advance technology in the most affordable manner.

Creating the data infrastructure to test the load forecasting hypothesis required building an innovative way to categorize end users. One of these steps was to build a process that categorized the customer usage data into bundled or unbundled status (depending on whether the customer contracts with PG&E or a third party energy service provider). The STDF infrastructure for customer usage data will be explored for full deployment use by PG&E's SQMD project and for the system adjustment factor calculation.

The STDF Pilot, as a proof of concept exercise, has answered the questions in the project application, and the infrastructure it built will continue to be leveraged by PG&E's Energy Procurement and Settlement teams.

Final Report

Line Sensors

Smart Grid Pilots Program
December 30, 2016

Project Lead: Tom Martin
Project Sponsor: Ferhaan Jawed

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List of Supporting Documents (Previous Filings)

Advice Letter 4227-E
Advice Letter 4538-E

1 Executive Summary

The Smart Grid Line Sensor Pilot project demonstrates a modern, cost-effective alternative to analog devices for detecting and locating electric distribution line faults, while also providing significant additional operational benefits. Line sensors are devices that, when installed on a power line, can wirelessly send an alert to distribution personnel when a fault occurs, assisting operators in taking action to safely and expediently isolate the damaged line and restore power to customers. Line sensors also communicate valuable information about the state of a power line that can help engineers to better manage the grid. This is a great improvement over simple analog devices, theoretical system modeling, and manual approaches. Line sensor data enhances electric service restoration efforts and helps manage key electric distribution processes such as customer capacity planning and distributed energy resources. Because of their relative low cost, they offer Pacific Gas and Electric Company (PG&E) the opportunity to cost-effectively monitor many locations, and can provide an important advancement that supports PG&E's Smart Grid vision on behalf of serving its customers.

Line sensors with advanced computing and analytic capabilities will also be a valuable information resource to help monitor and safely manage Distributed Energy Resources (DER), as an increasing number of customers contribute to generation through renewable resources such as solar. In the past, power primarily flowed in only one direction—from the substation to the customer. With renewable energy resources, power can flow in both directions, both to and from the customer, which complicates management of the electric grid. Line sensors give operators and engineers the real-time and historic power flow information they need to manage a grid that is becoming increasingly complex.

Through limited and targeted deployment, the Line Sensor project demonstrated applications that can provide benefits in the near term and hold promise for additional benefits as vendors develop more applications and provide further improvements and operational personnel become more familiar with sensor capabilities. The ability to more extensively monitor the distribution system improves grid intelligence and supports wider automation. Advanced functionalities of line sensors may eventually assist PG&E in identifying incipient failures and avoiding future outages through improved asset management.

This project was one of four in the PG&E Smart Grid Pilot Deployment Program, approved in 2013 by the California Public Utilities Commission (CPUC or Commission), in Decision (D.) 13-03-032, to test the value and challenges of deploying new Smart Grid technologies. Work was initiated following the CPUC's approval of the VVO implementation plan filed in Advice Letter 4227-E. This pilot was complementary to the concurrent Smart Grid Detect and Locate Distribution Line Outages and Faulted Circuit Conditions pilot project ("Fault Detection and Location project"). The Line Sensor project demonstrated the value of deploying line sensors to collect timely data about the condition of PG&E's electric grid. The Fault Detection and Location project used the data from these line sensors along with Calculated Fault Location (CFL) and other analytics to narrow down the possible location of a fault to the smallest possible area.

The following report details the activities and lessons learned in the final phase of this project.

1.1.1 Supporting the Smart Grid Vision

Line sensors can help PG&E to achieve the goal of integrating advanced communications and monitoring systems that can improve system reliability and safety. As the electric grid becomes more complex and dynamic, PG&E needs to have more immediate and granular data about the entire electric system. Increased sensing is critical for more flexible power systems that include Distributed Generation (DG), and it supports practical and more reliable system operations. Line sensors can help PG&E to move beyond traditional monitoring and control to a world where the significance and quantity of sensing devices is much more important in managing an increasingly complex distribution system.

Line sensors support PG&E's core Smart Grid strategies to provide customers reliable, affordable, and safe electric service:

Improve Reliability: The core benefit of line sensors is the reliability they can provide by enabling greater operational insight. When line sensors are deployed in multiple locations, they provide a finer granularity of real-time system data to help determine the location of a fault. Having greater and more extensive knowledge about the state of the electric grid offers improved efficiency in situations where switches and other isolation points can be opened, and non-damaged line sections restored safely with limited or no field patrol.

Increase Affordability: Line sensors offer a relatively low-cost means to remotely monitor the distribution system, which enables more extensive monitoring. The cost level of line sensors allows a more widespread deployment than other technologies to increase reliability across the largest segments of the distribution network to an increasing number of customers. This can increase affordability both by reducing patrol times and by enabling better and more extensive monitoring. Line sensors can provide valuable information about power flow and capacity, which supports better asset and capacity management.

More Effectively Integrate Distributed Renewable Energy: A challenge for increasing DER is maintaining or even increasing reliability in the face of a more dynamic and complicated distribution system. Line sensors can provide real-time power flow information, which directly supports distributed energy resources through more extensive monitoring.

Reduce Environmental Impact of System Operation: A reduction in line patrol time has a direct impact on vehicle-based carbon emissions. Line sensors enable field technicians to patrol a smaller area to find the source of a fault, narrowing the possible fault zone in some cases from miles down to only a few hundred feet.

1.2 Project Activities

The project deployed line sensors in a variety of locations to demonstrate and evaluate their performance and capabilities, and to assess their potential benefits. The project followed a prudent path which included:

- A complete analysis of the line sensor vendor industry, including emerging products such as sensors capable of operating in extreme locations such as underground vaults or metallic cabinets.

- Pre-installation assessment and testing to assure that line sensors and their associated systems were functional and reliable enough to support a useful pilot.
- Diverse input for the selection of locations to maximize the potential to demonstrate a variety of use cases and situations.
- Stakeholder engagement and training to assure user acceptance, targeting practical benefits.
- Sufficient integration with the production Distribution Management System (DMS) system to demonstrate real-world operational benefits.
- Hands-on operation for over a year of field activity, which included a utility storm season, while directly supporting distribution operations teams.
- Working with vendors to coordinate failure analysis, analytic systems, user training, provisioning and de-commissioning, and other required activities.

1.2.1 Use Cases

The use cases developed for the project focused on real time operations/reliability, operational awareness, capacity management, asset management, and safety. The primary use case is faster identification of faults and reduced patrol time due to the ability to better identify the possible fault zone in areas where line sensors have been deployed. Safety use cases are supported through reliability and fault avoidance. Additional use cases involved looking at the operational data that can be collected from line sensors on non-faulted lines. Use cases that required additional analytics to analyze this data, or ones that used line sensor data in conjunction with more sophisticated CFL were explored in the concurrent Fault Detection and Location project.

1.3 Project Achievements

The primary achievement of this project was demonstrating the value of having line sensor data available to support restoration operations during the 2015-2016 storm season. The additional operational intelligence provided by line sensors helped operations engineers to more easily identify faults and reduce the area that field technicians needed to patrol. As DG increases the complexity of grid operations, increased intelligence is a valuable input to a more flexible and resilient grid. The knowledge gained has helped PG&E to better understand how line sensors can help to support the company's overall reliability improvement portfolio, and laid the groundwork for targeted use of a new technology that might cost-effectively improve reliability.

1.3.1 Technical Achievements

- Deployed 1,542 line sensors (1,452 overhead and 90 underground) supporting more than a half dozen different use cases. (See Section 4.1.)
- Reliability benefits: 12.6% reduced Customer Minutes of Interruption (C-MIN) and 12.2% reduced cost of field patrol when line sensor data is made available to operators. (See Section 4.1.1.)
- Demonstrated a method to maximize reliability benefits as high as 18% reduction in C-MIN with business process changes that involved using line sensor data to better determine which switches to open and close to isolate a fault more efficiently. (See Section 4.1.1.)
- Provided real-time loading information to assist in real-time switching, load balancing, and capacity planning. (See Section 4.1.1.)

- Developed and executed Evaluation, Measurement & Verification system for line sensors that demonstrated a strong business case for line sensors showing savings potential of 600,000 customer outage minutes during the 2016 storm season. (See Section 2.7.2.)
- Produced a business case for implementation that demonstrates a positive benefit-to-cost ratio on 1,457 of PG&E's extensive 3,170 distribution feeder electric network. (See Section 5.)

1.3.2 Additional Achievements

- Demonstrated line sensor integration with PG&E's operational systems via a dedicated line sensor Diagnostic Center (DC) to support deployment and operation.
- Designed and executed an overall design study for communications. Evaluated and learned from challenging communications environments such as underground locations.
- Demonstrated that line sensor data, including waveforms (unique time-series patterns of current, captured at a very high sample rate), can be passed through the Advanced Metering Infrastructure (AMI) mesh network without hindering day-to-day metering operations.
- Assessed line sensor features and determined how they can support specific use cases, both near- and long-term.
- Disseminated best practices and shared knowledge with other utilities at industry conferences and meetings.

1.4 Lessons Learned

1.4.1 Product/Technology Assessment

Although this project demonstrated specific products from several vendors, the primary goal of this project was to determine to what extent line sensor technology in general is ready for PG&E to proceed with a larger-scale deployment.

The conclusion of the technical assessment is that products—including but not limited to those demonstrated—are commercially available today that can be deployed at volume to cost-effectively deliver the data required for the core system reliability use cases of fault detection, location, and load monitoring. This is still an evolving market, and while PG&E expects to see products with greater capabilities in the future—for example, line sensors that are able to function at extremely low line current levels—today's products are cost-effective and mature enough for extensive deployment. In addition, they can also play an important role in supporting electric system reliability in a grid that is becoming more complex, as distributed generation becomes more widespread.

This project found that the line sensor market is represented by a narrow range of specialist vendors providing products with a similar set of essential characteristics. The products demonstrated in PG&E's pilot deployment represent both low-end and mid-range products, which are the most practical for deployment. The largest distinction between these products is the ability to capture and transmit electric current waveforms. Even with this distinction, the products were found to be more similar than not, and several products can provide features that provide clear value today.

1.4.2 Industry Recommendations

PG&E has worked closely with vendors to identify product strengths and weaknesses, and to address defects. The goal of this project has been to identify the best-in-class features of each product, which PG&E can then use to determine its requirements, and vendors more broadly can integrate into their future product roadmaps.

Vendor recommendations include a desire to see line sensors that are able to function at extremely low line current for locations that are near the end of the line, as well as sensors that can communicate wirelessly, even when deployed in underground vaults. The pilot also allowed PG&E the opportunity to test locations on the electric grid where line sensors would provide the greatest benefits.

PG&E is the first known major utility to operate line sensors within a *converged*[1] AMI network. PG&E has demonstrated that real-time data, logs, and even large waveform files can be transferred without adversely impacting other critical operational network traffic such as day-to-day metering operations. The ability to leverage an existing infrastructure asset also contributes to the cost-effectiveness of line sensors, however few vendors support this mode of communication, and sensors that do offer this capability tend to require a higher line current to operate than those sensors that use cellular communications.

1.4.3 PG&E Deployment/Implementation

For the deployment and operation of line sensors and their associated systems, PG&E implemented a dedicated DC to support line sensors and their associated systems. Field technologies such as line sensors need a single point-of-contact owner to track these systems to maximize their value. Other utilities that have deployed line sensors in the field have confirmed the value of establishing ongoing technology operating centers as a good strategy to support both the technologies and the users of these systems. This includes technical support for Distribution Operations such as training and analyzing the line sensor output to support fault location, switching, and line monitoring.

With a small staff, the DC supported the implementation of four line sensor products from three vendors, maintaining their individual head-end[2] systems, and supported operations personnel by monitoring and identifying electric distribution issues (e.g., faults) as they occurred. The integration into real-time production electric distribution systems for two of the four products provided valuable information that helped PG&E to develop production integration requirements that would be needed for a full-scale implementation. Demonstrating new technologies in a pilot project increases affordability by demonstrating them on a smaller scale, which minimizes the possibility of costly mistakes that could occur in a full deployment without the benefit of research and preparation.

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[1] In a *converged* communications architecture, traffic for line sensors uses the same AMI relays and access points as the SmartMeter™ Network. In a *separate* architecture, additional relays are deployed to support line sensor communications.

[2] A head-end system is the operating system and applications used to communicate with line sensors.

1.5 Deployment Recommendations

PG&E determined that line sensors can provide attractive Benefit-Cost ratios and will consider deploying line sensors on up to 1,457 of PG&E's 3,250 feeders. The analysis performed during the pilot indicates that deploying to these feeders provides a Benefit-Cost ratio greater than one.

PG&E identified methods and requirements that would be valuable in a full-scale deployment to reduce the cost of installing and configuring the line sensors. These included recommendations for vendors to make the installation process more efficient, methodologies for reducing the amount of time it takes to physically install the sensors, as well as operational efficiencies for configuring the sensors in the system.

1.6 Conclusion

PG&E demonstrated with this project that line sensors are a cost-effective means to improve reliability, increase operational awareness, optimize capacity management, and increase safety. They provide additional operational intelligence in areas where more expensive monitoring would not be practical or cost-effective.

The line sensors that are available today can be deployed to a number of locations where they will provide immediate benefits, including an estimated 12-18% reduction in total outage time due to faster identification of faults. Further operational benefits can be obtained by implementing fault detection and location analytics such as those explored in the concurrent Smart Grid Fault Detection and Location Pilot Project to more precisely pinpoint fault location.

Line sensors can help PG&E achieve its goal of integrating advanced communications and monitoring systems that improve system reliability and safety. As the electric grid becomes more complex and dynamic, PG&E needs to have more immediate and granular data about the entire electric system. Line sensors offer a relatively low cost option to provide this near real-time data. Increased sensing is critical for more flexible power systems that include distributed generation, and it supports practical and more reliable system operations.

Line sensors can be a significant part of PG&E's portfolio of reliability improvements that will help PG&E to provide reliable, affordable, and safe power today and into the future.

2 Project Background

2.1 Program Background

PG&E's vision for the Smart Grid is to provide customers safe, reliable, secure, cost-effective, sustainable and flexible energy services through the integration of advanced, communications, and control technologies to transform the operations of PG&E's electric network, from generation to the customer's premise. This aligns with the policy goals of the Commission and the California legislature. Senate Bill 17 established that California would increase the use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid. In response to SB 17, the Commission adopted D.10-06-047, which established requirements for the Smart Grid Deployment Plans. D.10-6-047 specified that "[s]ubsequent utility requests to make specific Smart Grid-related investments, however, would occur in utility-specific proceedings where the reasonableness of particular Smart Grid investments can be determined." These proceedings include both General Rate Case (GRC) filings, and applications for specific projects. On November 21, 2011, PG&E filed Application (A.) 11-11-017 requesting authorization to recover costs for implementing six specific Smart Grid Deployment Pilot Projects over four years. In 2013, the Commission in D.13-03-032 approved four of the projects, including the Smart Grid Line Sensor Pilot project. Work was initiated following the CPUC's approval of the VVO implementation plan filed in AL 4227-E.

2.2 Supporting the Smart Grid Vision

Line Sensors support the goal of integrating advanced sensing and communications systems that help to support reliability in an increasingly complex electric distribution system. Line sensors can sense when there is a change in power on a line and communicate that information immediately, which allows system operators to better understand system conditions. The relatively low cost of line sensors means that they can be deployed in less critical or remote locations that are not candidates for Supervisory Control and Data Acquisition (SCADA) or Fault Location, Isolation, and Service Restoration (FLISR) implementation and they can be deployed on a much larger scale, improving reliability and optimizing distribution system operations over a much larger area.

PG&E is committed to supporting its vision for the Grid of Things™—a "plug and play" distribution grid platform that facilitates emerging energy technologies such as rooftop solar to be interconnected with each other and integrated into the larger grid. Low cost line sensors help to support this vision by providing an increased number of sensing devices to better monitor a more complex electric grid.

Increased monitoring throughout the grid provides for a more optimized operation of the distribution system and better supports DG and Distributed Energy Resource Management Systems. The ability to monitor a greater number of locations in real time will become increasingly important as more customers add generation capabilities, which complicates voltage regulation and protection systems as the flow of electricity changes from one-way (from the substation to the customer) to multi-directional.

Increasing adoption of electric vehicles can also add complexity to the traditional electric grid, as fast-charging stations can create a significant impact on load. Line sensors provide real-time loading information to better manage loading on local circuits and ensure that the system stays in balance.

2.2.1 Relevance to Strategic Goals

This project has identified use cases for line sensors that support the strategic goals of system reliability and safety by enabling faster identification of faults. Faster fault location identification improves crew response time which subsequently reduces costs for patrol and isolation of the faulted area and reduces the possibility of public exposure to hazardous wire-down conditions.

2.2.2 Relevance to Utility Industry

PG&E has progressed the industry forward by being one of the first utilities to operate line sensors within a converged AMI mesh network. Other utilities have used AMI technology, but deploy additional communications hardware rather than use their existing AMI network relays and access points. PG&E has demonstrated with this pilot that real-time line sensor data can flow through the AMI network with no measurable impact on meter reading success; and has demonstrated that even large waveform files can be transferred from line sensors without affecting day-to-day metering operations.[3] This approach allows PG&E to leverage its investment in its Electric SmartMeter™ network with limited incremental investment, and is relevant to other utilities with a similar infrastructure.

Another aspect of this project that supports the industry as a whole was to provide feedback to vendors to help them plan future improvements that would benefit all utilities. Line sensors are in an early-adoption phase, and vendors are eager to grow the market by meeting the needs of utilities. This puts utilities in a position of both power and responsibility to provide market direction. In this project, PG&E developed a catalog of desired features that can be integrated into the purchasing process and shared through industry meetings and standards committees to improve future line sensor products. Some items identified are fairly obvious—for example, developing underground line sensors that can communicate wirelessly when enclosed in a metal vault. Others are more nuanced—such as improvements in the operational logging within the line sensors, which would make managing the systems easier. For more information, please see Section 4.3.2.

2.3 Technology Description

Line Sensors are fundamentally a technologically advanced, communicating version of a Faulted Circuit Indicator (FCI), augmented with additional sensing and monitoring capabilities. While the traditional FCI is simply an analog device that is attached to the wire and displays a blinking light when a fault occurs, modern line sensors provide, at a minimum, immediate communication of a fault to a distribution operator to assist in faster fault location and isolation and line load measurements to assist in switching decisions. Some line sensors also provide advanced functionality such as electric field strength (e-field) measurements and electricity waveform capture for advanced analytics. Line sensors also provide data for system monitoring, operational awareness, capacity management, and asset management.

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[3] For more information about the capabilities of the AMI network, please see PG&E's *EPIC 1-14 Next Generation SmartMeter™ Telecom Network Functionalities* final report.

Line sensors harvest their operating power from the magnetic field of the energized line. Minimum power line requirements for normal operations vary by vendor and communication method (e.g., cellular or AMI network). Carryover power for when the line is not energized is provided either by supercapacitors[4] or lithium batteries. Many line sensors have an orientation indicator that specifies which end of the line sensor should be pointed towards the power source. This enables the line sensors to determine current flow direction if that functionality is enabled. Some line sensors are able to automatically identify the phase[5] of the line that they are attached to, while for others, the phase must be determined using a separate phase identification tool when the sensor is installed on the line.

The project classified available communicating line sensors into three general categories: (1) *low-end* products that have only fault and load current measurement capabilities and are the lowest cost, (2) slightly more expensive *mid-range* products that also offer advanced capabilities like data logging and electric current characteristic signature or electricity waveform capture, and (3) more expensive *high-end* products that include accurate voltage measurement capabilities or other advanced features.

The Phase 2 pilot demonstrated one low-end product and three mid-range devices from three vendors. One high-end sensor was evaluated during the Phase 1 lab testing, but was not promoted to the Phase 2 pilot because it did not have a positive Benefit-Cost ratio.

2.4 Project Objectives

The project's objective was to install line sensors in a variety of locations and situations to evaluate their ability to provide a cost-effective means to more extensively monitor the electric grid. The pilot phase of the project specifically included a traditional utility storm season, as this would provide an opportunity to capture the greatest number of faults and maximize the potential for assessing their reliability benefits.

2.5 Planned Benefits of Recommended Deployment

The Line Sensor project focused on applications that could provide the greatest benefit now: Real-Time Operational, Operational Awareness, Capacity Management, basic Asset Management (not involving analytics), and Safety. The most advanced applications, particularly for asset management, require

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[4] Supercapacitors are capacitors that can support operation for longer periods of time and conventional capacitors and avoids the maintenance needed for batteries.

[5] Power delivery is most efficient when each of the three Phases A, B and C have similar current flow so knowing the phase monitored is important. Three phase power delivery is standard for the industry.

significant analytics in addition to line sensor data and are therefore addressed in the concurrent Fault Detection and Location project.

2.5.1 Real-Time Operational

The project needed to determine if line sensors could provide a cost-effective means to remotely monitor a greater number of locations in real time throughout the grid for faults than more expensive monitoring and control systems.

- ***Fault location***. Reliable bracketing of the fault location allows for faster isolation and restoration switching without the need for time-consuming line patrol.
- ***Loading for switching decisions.*** Gives operators timely knowledge to manage customer load without conducting an engineering study.
- ***Verification of Line and Phase energized.*** Provides the ability for operations personnel to verify exactly which lines and phases are energized during restoration operations.

2.5.2 Operational Awareness

Operational awareness supports distribution operators on a daily basis. The project needed to determine if line sensors could provide benefits to operators beyond fault identification.

- ***Line loading data for load transfer plans.*** More extensive real-time monitoring supports operations such as load transfers that can be planned based on actual field conditions. This reduces the safety margin needed and allows for streamlining of switching plans which can reduce field time and, in some cases, reduce the number of customers impacted by switching-based outages.
- ***Line to line contact and other multiple fault conditions.*** Assures all fault issues are addressed to help avoid future faults.
- ***Data for "no problem found" investigations.*** Provides information needed to identify the root cause of persistent faults.
- ***Power Quality.*** The project also deployed line sensors to determine if they would be effective in helping to investigate power quality issues, for example to see if large electric vehicle charging stations might be producing high levels of electrical harmonics (electrical "noise") impacting reliability. The line sensors might theoretically allow power quality engineers to track when harmonics that may be introduced by electric vehicle charging exceed a set threshold.[6]

2.5.3 Capacity Management

PG&E needs to monitor the distribution system to ensure that there is sufficient capacity throughout the system. The project needed to identify if line sensors could help to support distribution capacity management.

- ***Line loading data for potential system upgrade deferral.*** Line sensors can also help PG&E to make more informed decisions about capacity management. Presently, the process of re-conductoring—replacing conductors with larger ones to increase capacity—often involves estimating the loading on lines based on system modeling. Line sensors can

[6] This is a long-term study that began towards the end of the pilot, and the results are not yet available at the time of this report.

provide actual loading data for locations being considered for re-conductoring so that PG&E can make more informed decisions about where to expand capacity.

- ***Phase balance management provided capacity gains.*** Helps ensure that transformers and lines deliver power in the most efficient manner.
- ***General DG studies***. Line sensors are also important tools for monitoring the impacts of increasing distributed resources. Traditional capacity planning assumed that the utility provided electricity from the distribution substation to the customer. This one-way flow could readily be modeled, and the utility could verify the model between substation SCADA data and aggregating meter data. In the future, all of these key factors are subject to change. Power flows both to and from customers and metering only provides net usage—the difference between generated and used power. Line sensors deployed in this pilot are being used to gain insights into the challenges that will develop as DG increases. Ultimately, line sensor data will be a key component of more sophisticated distribution modeling tools and real-time operational business processes.

2.5.4 Asset Management & Fault Anticipation

The ultimate goal of fault identification is to anticipate faults before they happen. The project needed to determine if line sensors could help operators to identify equipment failures before they happen.

- ***Bad capacitor switch or blown cap fuse.*** Failed switches or blown fuses in capacitor banks may be detectable using line sensor data. Likewise, underground splice[7] failures have a high current waveform signature that is recognizable. These failures that occur when water gets into the splice tend to self-clear because the heat of the fault current dries the splice. Although the splice can continue to operate for weeks or months afterwards, it will eventually fail.[8] Line sensors that can collect waveform data may make identification of these situations easier.
- ***Fault count and energy throughput for non-SCADA reclosers.*** Provides the potential to extend maintenance cycles for reclosers.
- ***Overall condition based maintenance.*** Provides the potential to extend maintenance cycles. The ultimate goal of using line sensors for asset management is to avoid outages by knowing that an asset is about to fail and repairing or replacing it before failure and outages occur. The next step from this functionality is the ability to anticipate faults, but this is not yet supported with the integrated sensor analytics software applications currently available.

2.5.5 Safety

Improvements in reliability support increased safety by improving the potential speed of response to dangerous situations:

- ***Faster restoration of power of public safety equipment.*** Many public safety systems such as traffic lights and railroad crossing barriers are dependent on electrical power. Loss of air conditioning during hot weather can be hazardous for people in weakened conditions.
- ***Faster identification of potential energized downed wires.*** Line sensors also offer the potential for improved safety by giving operators the ability to identify energized broken

[7] A location where two ends of a line have been joined together.
[8] Reported by Manitoba Hydro and FPL.

wires so that they can de-energized faster on circuits with SCADA controls, which reduces the potential for fires and electric shock.

- ***Avoided hazards from failing equipment.*** If line sensors can help to identify failing equipment, safety is also improved. Reduces potential for failures caused by wires falling, enclosures being breached, etc. by identifying potential problems before they occur.

2.6 Metrics

2.6.1 Regulatory Metrics

Refer to Advice Letter 4227-E, cited in Appendix A, to see how this project met the nine requirements of the application detailed in D.13-03-032.

2.6.2 Technical Metrics

The technical metrics used to determine success emphasized the practical aspects of introducing line sensors into PG&E's distribution system and included:

- Would the line sensors be able to be installed by a single field technician?
- Would they function correctly?
- Would they report data accurately?
- Would the line sensor data be available to operators?
- Would line sensors support the identified use cases, in particular, faster fault identification?

2.6.3 Financial Metrics

In order to identify the recommended level of deployment for line sensors, PG&E performed a Benefit-Cost analysis for Line Sensors for this project, incorporating the same Value of Service[9] analysis used for the other reliability initiatives. The pilot provided a basis to study the estimated percentage of customer minutes that could be saved with the information collected from line sensors.

2.7 Scope

The scope of the Line Sensor project was to determine how the deployment of line sensors could support reduced outage times by enhancing grid outage detection, problem isolation, and more timely restoration. An additional goal of the Line Sensor Pilot Project was to provide granular loading data to facilitate distribution system operations, planning decisions, and analysis. This loading data could provide additional grid reliability and could also be a useful tool as PG&E works to integrate distributed energy resources.

[9] The Value of Service (VOS) analyses are based on survey data collected for each customer class. The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated by the Electric Power Research Institute (EPRI) and other parties.

2.7.1 Major Tasks/Initiatives

The project consisted of two phases: Phase 1, Analysis and Laboratory Testing; and Phase 2, Field Testing.

The Phase 1 included assessing commercially available line sensor products, reviewing against PG&E's performance requirements, determining how to integrate them with PG&E's existing systems, and assessing vendor performance and viability. Phase 1 also included benchmarking with other utilities and laboratory testing of the line sensors that had a high probability of success to use in the field trial.

The Phase 2 pilot included deploying line sensors on a sufficient number of feeders to be able to validate the potential benefits of reliability and reduced cost of outage response; integrate the sensor head-end systems into DMS; demonstrate other use case benefits; and better understand the ongoing support requirements and model for a larger scale deployment.

For more information about the specific project activities, please see Section 3.

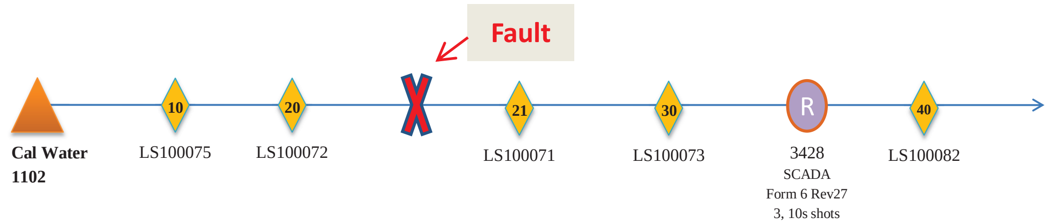
In support of the Phase 2 deployment and operation of the line sensor systems, PG&E developed a dedicated line sensor DC, staffed with a small number of analysts to support the line sensor deployment and operation. Field technologies need to have a single point-of-contact owner to track these systems on a daily basis with the expertise required to maximize the value obtained from these systems. In PG&E's benchmarking interviews with other utilities that have deployed line sensors in the field, these utilities confirmed that this is a good strategy, and have also indicated a trend toward establishing on-going technology operations centers to support line sensors.

The main duties of the DC included provisioning the installed line sensors into the sensor head-end systems and PG&E data management systems ((Electric Distribution Asset Management/ Geographical Information System (ED AM/GIS), PG&E's data historian, and DMS). Additionally the DC monitored the performance of the line sensors and their associated head-end systems, coordinated with vendors for system and device issues, and issued Return to Manufacturer Authorizations (RMA) for defective sensors.

The DC supported Operators and Operating Engineers during the pilot, by providing training and answering questions about line sensor operations during normal working hours. The DC issued *Fault Report Cards* with detailed line sensor data taken directly from the line sensor head-end systems to assist in identifying the faulted zones on a feeder.

Figure 1. Fault Report Identifying the Location of a Fault Between Two Line Sensors

Permanent Outage - Circuit: CAL WATER 1102, At: 2016-01-07 04:35:19



Sensor Location	Date/Time	Sensor Name	Phase	Start Event	End Event	RMS Current	End Current	End Voltage	Fault Location
10	1/7/2016 4:35	LS100075_3	B	I-Trip	Faulted	3282	OFF	NA	NA
10	1/7/2016 4:35	LS100075_2	A	I-Trip	Faulted	3667	OFF	NA	NA
10	1/7/2016 4:35	LS100075_1	C	I-Trip	Faulted	3151	OFF	NA	NA
20	1/7/2016 4:35	LS100072_3	A	I-Trip	Faulted	3649	OFF	NA	NA
20	1/7/2016 4:35	LS100072_1	C	I-Trip	Faulted	3258	OFF	NA	NA
20	1/7/2016 4:35	LS100072_2	B	I-Trip	Faulted	3448	OFF	NA	Y
21	1/7/2016 4:35	LS100071_3	A	Power Off	Disturbance	0	OFF	NA	NA
21	1/7/2016 4:35	LS100071_2	C	Power Off	Disturbance	0	OFF	NA	NA
21	1/7/2016 4:35	LS100071_1	B	Power Off	Disturbance	0	OFF	NA	NA
30	1/7/2016 4:35	LS100073_2	B	Power Off	Disturbance	0	OFF	NA	NA
30	1/7/2016 4:35	LS100073_3	A	Power Off	Disturbance	0	OFF	NA	NA
30	1/7/2016 4:35	LS100073_1	C	Power Off	Disturbance	0	OFF	NA	NA
40	1/7/2016 4:35	LS100082_1	C	Power Off	Disturbance	0	OFF	NA	NA
40	1/7/2016 4:35	LS100082_3	A	Power Off	Disturbance	0	OFF	NA	NA
40	1/7/2016 4:35	LS100082_2	B	Power Off	Disturbance	0	OFF	NA	NA

2/23/2016 9:27 AM

These Fault Report Cards were sent to Operating Supervisors and Engineers within 10 minutes of a sustained main line fault by group email lists to the correct Distribution Control Centers and Operating personnel. The Operating personnel were encouraged to use the information in the Fault Report Cards to support Distribution Operators with restoration activities, if appropriate. To capture all of the sustained outages, the DC performed a daily review of all outages recorded by the sensor head-end systems and prepared report cards documenting all sustained mainline outages, including those occurring outside of normal working hours.

2.7.2 Measurement and Verification Components of Business Case

The Business Case analysis for line sensors used a feeder-by-feeder approach, comparing the potential addressable mainline customer outage minutes with an estimated number of line sensor sets per feeder, based on customer count, mainline mileage, and the number of devices per feeder, in order to rank each feeder based on its Benefit-Cost potential.

Potential addressable mainline customer outage minutes were based on a study of actual outages reported in PG&E's Integrated Logging Information System (ILIS) from January 1, 2013 – June 30, 2016. This analysis excluded planned outages and non-mainline distribution circuit outages (e.g., Generation, Transmission, Substation, Independent System Operator, and Fuse outages), to identify the subset of outage minutes which Line Sensor data could help reduce.

In addition, PG&E performed a detailed study of mainline sustained outages from the 2015-2016 storm season (December 2015 – April 2016) where line sensor data was captured during the pilot. This data was used to determine the average estimated percentage reduction to customer outage minutes attributable to the availability of line sensor data.

PG&E looked at how line sensor data might be able to help narrow the possible fault zone so that field technicians could more rapidly isolate the fault and perform switching operations to restore some customers faster and reduce patrol time in the field. For example, if line sensors would have decreased the patrol zone by 50%, then the savings in patrol time was also assumed to be 50%.

Finally, for the selected feeders, the Value of Service model was used on a Division-by-Division basis, based on the actual weighting of customer classes for each division, to determine the present value of outage duration reductions, compared with the present value of costs to deploy line sensors in that Division.

2.7.3 Integration Challenges

The pilot implemented devices and sensor head-end systems from several different vendors. This required support for a variety of protocols and data structures, which created a number of integration challenges. Challenges included understanding the maturity level of the integration options available from each vendor, along with how these options would adhere to PG&E's Information Technology and Cyber Security standards. Software systems and third party hosting facilities underwent standard Cyber Security reviews and mitigations as necessary.

3 Project Activities

3.1 Phase 1

The following sections provide an overview of the Phase 1 activities. For more detailed information, please see Advice Letter 4538-E cited in Appendix A.

3.1.1 Benchmarking

PG&E held benchmarking interviews with utilities including Florida Power & Light, Alabama Power, Baltimore Gas & Electric, and San Diego Gas & Electric to understand drivers for implementing line sensors, vendor selection processes, and outcomes that were experienced at other utilities. These interviews helped PG&E to develop test plans, implementation strategies, and use cases.

3.1.2 Prospective Vendor Evaluation

A key milestone in Phase 1 was to identify what products were available in the market and whether or not they would meet PG&E's requirements. PG&E issued a Request for Information (RFI) in December 2013 to evaluate the capabilities of available line sensor products. PG&E engaged industry experts to ensure that the RFI would provide information relevant for the selection of candidate vendors from whom additional information would be requested.

Eighteen line sensor vendors responded to the RFI and were evaluated by project stakeholders including PG&E Electric Operations, Asset Management, and Information Technology (IT) organizations. In addition to the technical evaluation of vendor responses, the vendor evaluation was aligned with the PG&E's sourcing policies and included consideration of supplier diversity, safety, and environmental responsibility. Seven vendor products were selected for detailed investigation in the evaluation process. Following this detailed investigation, four vendors' line sensor products were selected for testing at PG&E's Advanced Technical Services (ATS) facility.

These four vendors represented a cross-selection of vendor products, and included products that represented a cross section of low-end to high-end features, communications options (cellular vs. AMI), and suitability for both overhead and underground installations.

3.1.3 ATS Laboratory Testing

Testing performed at the ATS facility focused on safety, installation, operation, accuracy, integration, and communications. Testing also provided information that supported design development, operating instructions, and training in support of the Phase II field pilot.

PG&E requirements for line sensors included both *core* and *advanced* requirements. *Core* requirements are required for the device to be safe and reliable and to provide the critical functions of fault detection and line load monitoring and the ability to deploy the products at any location on a distribution circuit. Vendors needed to meet the core requirements in order to be recommended for field pilot. *Advanced* requirements, such as waveform capture and a finer granularity of data, support supplemental benefits and future product capabilities.

The extensive laboratory testing of vendor products indicated that two vendor products had the necessary core features and functions to provide grid outage detection, problem isolation and enable more timely restoration. Two other products encountered issues during testing at ATS. Both of these products showed promise in their unique capabilities for both core and advanced line sensor functionality. These product issues were discussed in detail with the vendors for remediation. One of the vendors did make the necessary changes to their product, and it was added to the assessment in the second half of the Phase 2 pilot.

3.1.4 Initial Benefits Assessment

At the end of Phase 1, PG&E determined that line sensors have the potential to provide the following benefits to customers:

- **Increased System Reliability**
  Line sensors can assist in reducing the duration of customer outages by more granularly helping to locate outages. Additionally, broad line sensor deployment would potentially improve customer power quality due to future line sensor device technological advances, providing information to assist in mitigating power quality disturbances.
- **Reduced Cost of Outage Response**
  Line sensors can help to reduce costs associated with outage response. They assist in pinpointing outages to a smaller area on the distribution circuit therefore reducing overall patrol time. Line sensors potentially accomplish outage response better than existing solutions by complementing SmartMeter™ outage data. SmartMeter™ data is effective at scoping the extent of an outage, i.e., customers impacted, and verifies restoration to each customer, but line sensor data has the potential to add information on where the fault is located within the outage area. The line sensors communicate back to distribution operations so that they can direct the field technician to a better defined area, reducing overall truck patrol time. The field technician can then locate the problem sooner, which reduces both hazardous situations as well as the time needed to repair the fault. Additionally, line sensors can potentially provide real-time loading information upon request to assist in real-time switching operations in support of balancing line loads, as well as provide information for planning engineers to use in future planning activities. If successful, this loading information may also provide additional visibility into the real-time operations of distributed energy resources.

3.1.5 Transition to Phase 2

At the conclusion of Phase I, PG&E made the following refinements to items mentioned in Advice Letter 4227-E:

- Installing line sensors on more than the 30 feeders initially proposed, provided that the project could do so while remaining under budget. Additional feeders would have the impact of significantly increasing the likelihood that the line sensors will encounter a wider variety of fault types and conditions.
- Continuing to monitor the vendor product industry, and if a significant product was introduced or modified, PG&E requested the ability to perform Phase I lab testing on that product and promote it to the field pilot during Phase II as appropriate.
- Of the two products that failed initial testing at ATS, one vendor made product modifications and their product was later added to the field pilot.

These refinements were approved in Advice Letter 4538-E, cited in Appendix A.

3.2 Phase 2

3.2.1 Device/Software Architecture Development

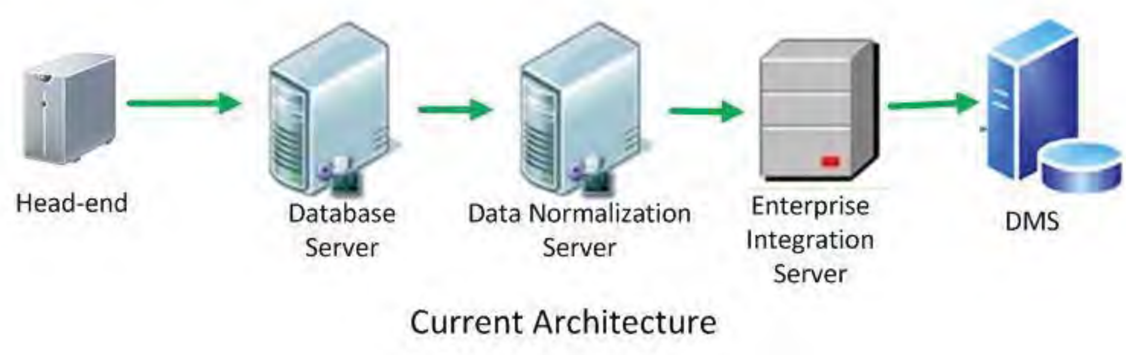
The line sensor data needed to be integrated into PG&E's existing systems for it to be useful to Operations personnel. The business requirements for establishing an IT architecture included the ability to provide fault data to operators for managing outage events and loading data for operators and engineers. Additionally, the architecture needed to support the ability to generally explore the capabilities of line sensors.

Three architecture options were considered for integration between the various line sensor head-end systems and DMS:

	Architecture	Evaluation	Decision
Option 1	Have the DMS vendor develop an ICCP[10] gateway to send data to DMS.	High cost and high risk to the schedule as a result of vendor development requirements.	✘
Option 2	License PG&E's DMS vendor's SCADA module and integrate the sensor head-end systems into that module via DNP3.[11]	High cost and expending of effort that would potentially not be needed after the pilot demonstration.	✘
Option 3	Integrate the sensor head-end systems to DMS via PG&E's data historian, using PG&E-developed custom code.	For a single storm season, this solution would meet the pilot's targets and achieve the goal of presenting line sensor data to Operators in a quick and low-cost manner.	✓

While the integration via PG&E's data historian was appropriate and robust enough for the pilot, and for a smaller-scale deployment, further integration would provide greater benefit in a larger scale deployment.

Figure 2. System Architecture Used in the Pilot Phase



[10] Inter-Control Center Communications Protocol.
[11] Distributed Network Protocol, Version 3.

The project scope included integration of the two line sensor products that were selected in Phase 1 and deployed for storm season (December 2015 – April 2016). Two additional line sensor products that addressed important gaps (such as underground locations and DG studies), were piloted after storm season, and were field-tested outside of DMS because further IT integration to DMS would have been costly and was not needed to demonstrate the results.

3.2.2 Use Case Development

The use cases developed for the project were grouped into the following categories:

- Real time operations/reliability/safety
- Operational awareness
- Capacity management
- Asset management

The primary use case and the only use case used for the benefits analysis is real-time operations and reliability. Line sensors are used for faster identification of faults and reduced patrol time due to the ability to better identify the possible fault zone in areas where line sensors have been deployed. Faster restoration of power also enhances safety, both in terms of support infrastructure (traffic lights, railroad crossings), and in reducing patrol time.

Operational awareness use cases include using sensor data to help in troubleshooting “no problem found” situations, where an incipient problem such as occasional line-to-line contact causes repeated momentary faults.

Capacity management use cases support engineering decisions by providing actual loading data in cases where engineers typically rely on system modeling. This enables engineers to better manage capacity in locations where there is significant distributed generation or circuits that are approaching maximum loading and require upgrades.

Asset management use cases include identifying failed or failing equipment or using data to impact maintenance decisions. More advanced asset management use cases involving line sensor data were explored in the concurrent Fault Detection and Location project.

3.2.3 Site Planning

As part of Phase 1, PG&E identified feeder location selection criteria and rationale or the Phase 2 field pilot. For Phase 2, project stakeholders were consulted during feeder selection to ensure that piloting line sensor technology would not adversely impact PG&E’s ability to deliver safe, reliable, and affordable electrical service to customers served by the pilot feeders. Factors considered in selection of test feeders included:

- Locations with a history of lower reliability relative to the rest of the system;
- Locations where line faults result in significant patrol time;
- Feeders that have sufficient interaction crossover with other feeders to support rapid circuit reconfiguration (where customers receive their electric service from a secondary source);
- Feeders that have significant distributed energy resources;

- Feeders with a representative sample of urban, suburban, and rural locations;
- Feeders with a representative sample of communications environments, particularly for evaluating AMI network communications;
- A diversity of locations that would enable discovery of uses not originally anticipated; and
- Site-specific deployments, such as SuperBowl 50 event locations in San Francisco and NBA Championship games in Oakland as part of enhanced emergency preparedness procedures.

An important criteria to use when selecting locations for the field pilot was to choose locations that would be more likely to generate data. These locations would be of the most use in providing sufficient data to determine whether line sensors could improve reliability and reduce outage duration time.

The feeder selection was not intended to demonstrate a final design approach—merely to gather data that would be useful for this study. Not all locations are the same—there isn't a "one size fits all" number of sensors per feeder. However, the team determined that a thinner spread across more feeders would assure that more events would be captured.

The following systems were instrumental in planning the locations where line sensors would be deployed for the pilot phase:

- **Integrated Logging Information System:** Captures details about a given outage when found. Typically, a field technician reports details to Distribution Operators in the Control Centers who enter the details into ILIS.
- **Electric Distribution Asset Management and Geographic Information System:** Contains asset details and circuit connectivity models with geospatial references. The ED AM/GIS information is used in PG&E's distribution modeling application by distribution engineers to model circuit loading and fault scenarios. The Distribution Operators use the ED AM/GIS in their DMS application to analyze and record circuit switching steps related to outages or clearances. The ED AM/GIS system was also used to determine distance to AMI Access Points and whether this type of line sensor could be used at a given location.

Outreach to Operators

Electric Distribution Engineers in local operating division offices are very knowledgeable about the circuits in their area. This includes knowing where there may be capacity constraints and where there are problem reliability areas. PG&E looked to these people as the primary source of information to help determine potential locations for line sensor installations.

PG&E conducted meetings with three division distribution engineering planning groups in March and April 2015. These groups were asked to select locations that would provide the best opportunity to gather data for the use cases of reliability and capacity planning. Based on their local knowledge, hundreds of potential locations were selected without regard to minimum loading or cellular communication coverage. The initial locations were then filtered based on minimum required current criteria, which at the time was 5 amps, and cellular coverage. Other considerations for narrowing potential site locations included:

- ***Load Flow.*** The engineers used distribution model seasonal load flow models to determine the low season peak current at the selected locations, then generally used 25% of that value as the minimum load. Later, PG&E raised the minimum current requirement to

10 amps for planning potential locations to ensure that the current would be sufficient to power the line sensors. This was because a number of installed locations were below the minimum current required for full operation.

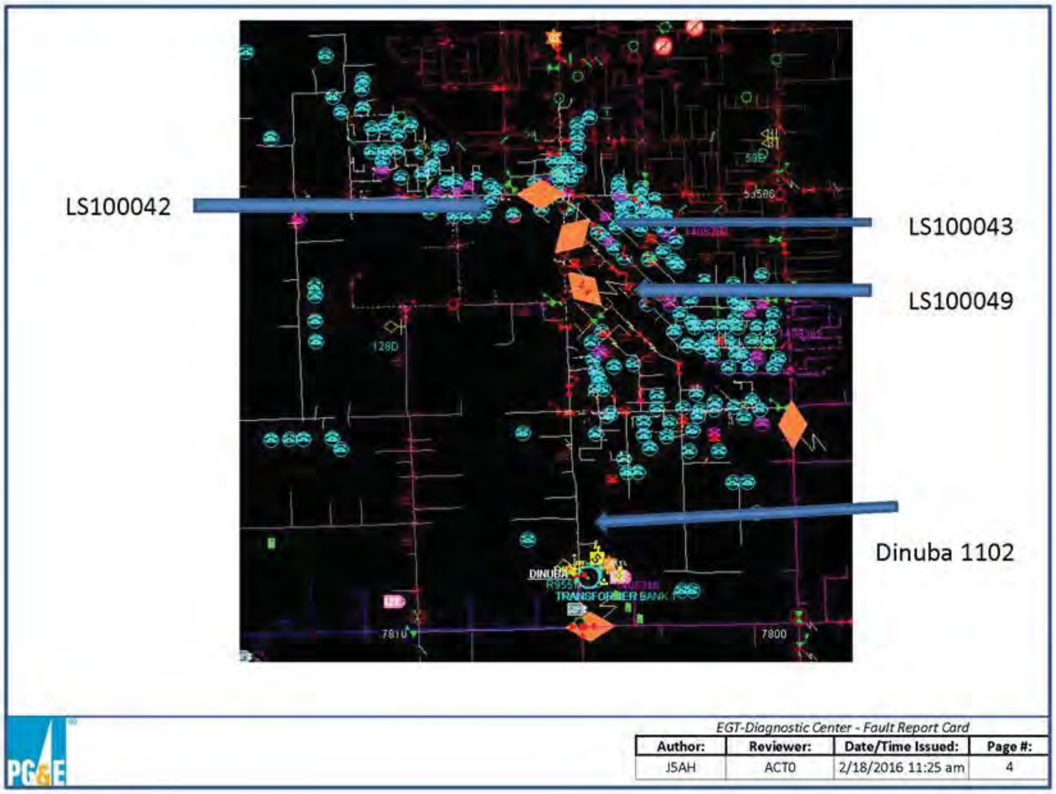
- ***Conductor Size.*** Generally, the vendor specification for the conductor sizes that would be suitable for installation covered the conductors commonly used on PG&E overhead distribution lines—generally from the smallest, 6CU, 4CU, 4ACSR, 2ACSR, to the largest, 715Al. However, construction concerns and other practical considerations resulted in generally avoiding installation on wires smaller than 4ACSR, unless deemed necessary to support a specific use case in the pilot.
- ***Communications Infrastructure.*** The locations were then also surveyed for cellular coverage, based on PG&E's wireless coverage maps of its service territory. The first line sensors that were deployed used cellular communications. When the line sensor that utilized AMI-based communications became available for deployment at the beginning of 2016, PG&E evaluated potential locations for communication strength using the distance to an AMI Access Point (AP). The AMI-networked line sensor needed to have a single-hop path to a battery-backed AMI network device. In PG&E's Electric SmartMeter™ network, currently these are limited to the Access Points that connect to the cellular backhaul network. Vendor guidance suggested a radius to the Access Point of a little over half-mile or 2,900 feet. Project testing found that a quarter-mile radius provided reliable communication to the sensor head-end system, and considered locations up to 1 mile away if the topography provided little interference potential.
- ***Special Site Planning Requirements.*** One of the line sensors that was deployed after storm season was a low-end device that has fault indication and line monitoring functions but did not offer waveform capture ability. However, this line sensor showed promise for use in underground installations because it is submersible, could fit around the largest underground cable (1000MCM AL XLP), and utilized a battery for low power carryover rather than supercapacitors, which allows it to maintain a sleep mode for longer than the other products tested. Initially, the deployment scope for these sensors only included underground locations and was relatively small at 30 locations. Therefore, only two division engineering groups were contacted to provide locations. The minimum loading criteria target for these installations was 20 amps. The Fault Detection and Location project also used the data from these line sensors for some of its use cases.

Line sensors were also deployed around downtown San Francisco in preparation for SuperBowl 50 events and in Oakland during the NBA Championship, to support emergency preparedness operations and provide additional grid intelligence during these high-profile events.

3.2.4 Technology Development

The DC team developed reports that could be used by operators during the pilot to analyze the data received from line sensors, including a *Fault Report Card* that highlights the impacted zones of the feeder and summarizes the outage event as reported by the line sensors, showing the fault event waveforms (if available) as recorded by the line sensor. It details whether the Line Sensor correctly recorded the event and makes an assessment of the benefit gained by having a Line Sensor deployed at feeder locations. Operations personnel were able to use these reports to aid in real-time fault investigations.

Figure 3. Fault Report Card



3.2.5 Installation/Integration/Iteration

Pre-Installation

After deployment locations had been finalized, the next step in deploying the line sensors on distribution lines was to produce maps that include enough information for the installer to find the location on the circuit; and for the overhead locations, to install the device in the correct orientation.

The map is referred to as a Circuit Map Change Sheet, and typically has a description of the circuit and equipment in the vicinity of the desired installation location, as well as a copy of the ED AM/GIS circuit map with an arrow indicating source direction. In the fire area use case deployments, the installers requested that in addition to the ED AM/GIS circuit map image, a satellite imagery version of the circuit map be included. This was so that inaccessible locations, such as backyard or gated construction and other hard-to-access areas could be more proactively identified and mitigated.

Installation

Line sensors are always installed in triplets – one for each of the three phases at a given location. Only one of the line sensors piloted offered automatic phase identification. For the other products, a separate phase identification tool needed to be used to identify the phase. This information is required to provision the sensor in the sensor head-end system.

When small wire (6CU, 4CU, 4ACSR, 2ACSR) installations could not be avoided, the project developed a method to install the line sensors using a tap guard[12] to increase the wire's diameter to ensure that the sensor makes sufficient contact with the wire.

Integration

Once the line sensors are installed at the identified locations, and before end users can access their data, a number of activities must be completed. The field paperwork with the device information must be obtained so that the details can be entered into the appropriate sensor head-end systems. For the AMI communications-based sensors, the sensors also needed to be integrated into the AMI network.

The line sensor assets must be mapped to the correct locations on the circuit in the ED AM/GIS system before they become visible in the downstream systems such as the DMS and PG&E's distribution modeling application. The ED AM/GIS mapping technicians perform this function and require the field paperwork and circuit map change sheets. These were provided by the project to mapping personnel via electronic copies in a shared folder on an internal server.

Other IT personnel map the sensors and integrate the line sensor data into the line sensor information page in DMS, as well creating the data historian line sensor database for each installed device. The data historian line sensor database stores a subset of the data points available in the sensor head-end systems and is where users can access historical data. Because the low-end line sensor and the cellular version of the AMI line sensor were not deployed until late in the project, and for special use cases, they were not integrated into the data historian line sensor database or DMS during the pilot.

3.2.6 User Feedback Collection

User feedback was provided through the project advisory group of two Operating Supervisors and two Senior Operating engineers, the staff of the DC, and a number of engineers and supervisors who specifically asked to participate. Examples of this latter group included Power Quality engineers who wanted to investigate the causes of potential harmonic interference, planning engineers who wanted data for assessing capacity needs, and distribution engineers studying locations with a high penetration of distributed generation.

3.2.7 User Experience

For the line sensors that were integrated into the DMS system, Distribution Operators and Operating Engineers were able to access line sensor data from within DMS. They would first navigate to the line sensor location, then launch a custom-built webpage that displayed all of the line sensors on the circuit with information such as faulted condition, fault current by phase if any, and a load current plot for a specifiable timeframe.

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[12] A *tap guard* (also called an *armor rod*) is a metallic wrap used to protect a conductor (line). Because it is metallic, it does not impede the ability of the line sensor to harvest power from the line.

> *"Line sensors identified lateral faults prior to receiving a call from a customer. Proactively catching these types of grid disruptions will help PG&E reduce CAIDI via improved response time, and increase customer satisfaction."*
>
> *- Electric Distribution Operations Engineer*

Feedback from DMS users who accessed data from the line sensor display screens was positive, and operators found the line sensor data to be very useful, and often requested increased deployments.

Four separate line sensor head-end systems were used by DC personnel, and a few distribution engineers had access to some of them. Three of the line sensor head-end systems were accessible through a standard web browser. User experience was positive but noted that implementations could benefit from improvements, primarily better integration with existing systems. Some examples of desired improvements include providing single-line diagrams that could change to reflect as-switched circuits instead of only as-designed configurations and supporting alarms in DMS. The operators need a fully integrated solution that highlights the fault zone, rather than having to deduce it from the line sensor fault indication. However, this is the current state of the industry. Improved implementations would extend the concepts of Outage Management Systems (OMS) to layer data from all data sources to provide the most focused and accurate information possible to the operator.

4 Project Results and Lessons Learned

4.1 Project Achievements

The Project deployed 1,542 sensors on 214 feeders. 804 sensors were integrated into DMS[13] to provide an interface to operators which included possible fault location notifications and also line loading information to assist in switching.

4.1.1 Business Case Benefits

Analysis showed that a savings of 12.6% of mainline Customer Average Interruption Duration Index and 12.2% in reduced outage response cost could be achieved if line sensors are used to more accurately identify the fault location. The original estimated savings, prior to the pilot project, used a savings assumptions of 10%. The ability to direct field technicians to a more specific location can reduce both patrol and outage time. The analysis also showed that if operators were to use the line sensor data to determine which switches to open and close to isolate a fault more efficiently, the reduction in outage response time could be as high as 18%. The project demonstrated that the primary benefit of fault identification and location worked well and provided the benefits expected.

4.1.2 Additional Benefits

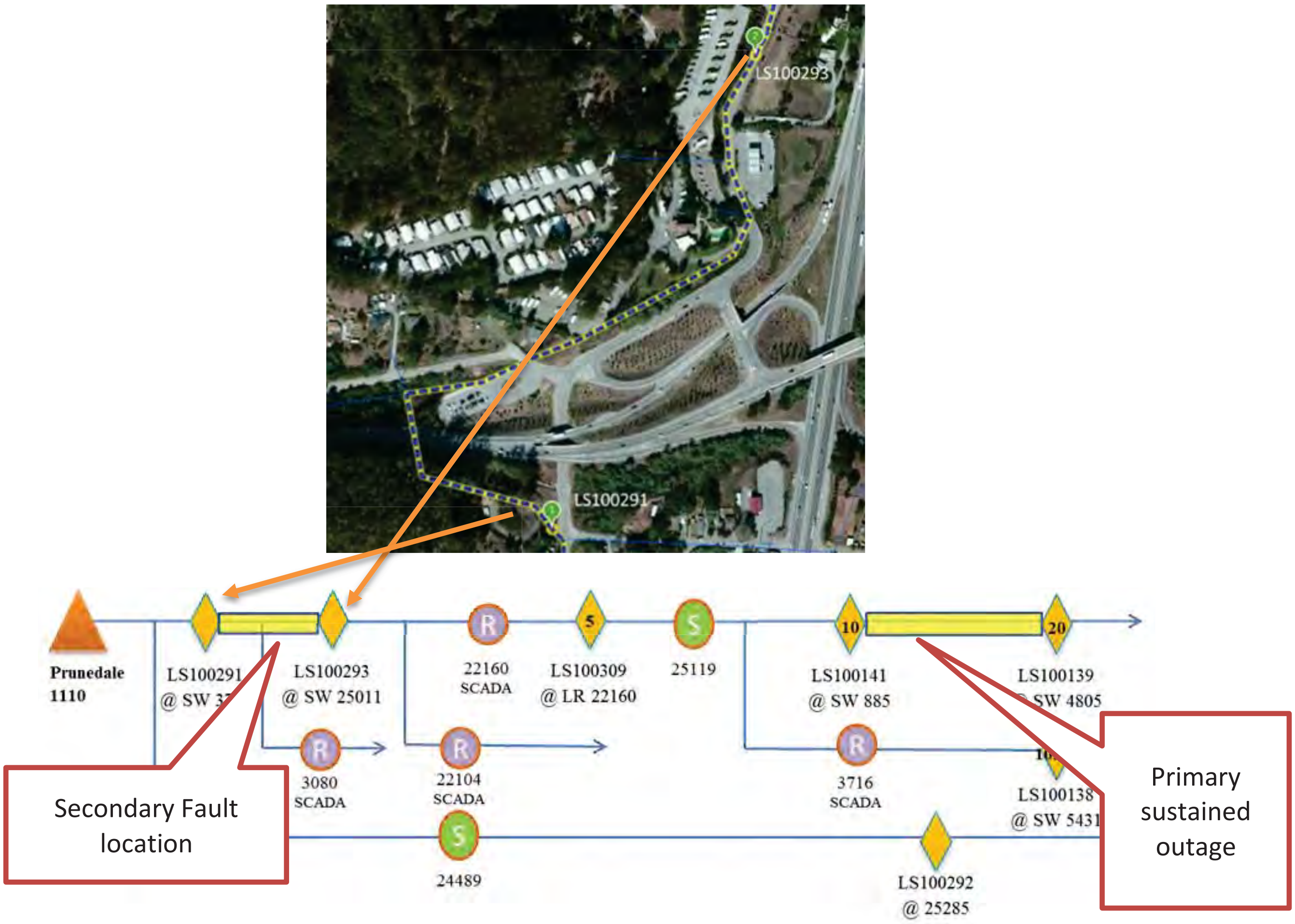
The following are some examples of additional benefits demonstrated using line sensors during the pilot phase of the project.

Secondary Fault Location

In the following example, in addition to the sustained outage, one sensor (close to the substation) saw double the fault current in a different location compared to other sensors. This prompted engineers to inquire further and check for line-to-line contact within the sensor zone. Patrol was conducted and the location was identified. Spreaders were installed to remedy the problem.

[13] Only the original two line sensor products initially deployed during the Phase 2 pilot for storm season were integrated into DMS. The two line sensor products deployed later in the pilot phase for special use cases were integrated into the DC systems, but not into DMS.

Figure 4. Line Sensors Identifying Secondary Fault location



Distributed Generation

The project also deployed sensors specifically to monitor major DG installations and locations where the cumulative impact of small-scale DG was significant. Planning engineers sought out support from the project and deployed line sensors to monitor both very large DG locations and areas with high penetrations of residential solar generation. At this time, these sensors are being used as part of a long-term study to define the impact of DG on the distribution lines. As DG increases, determining necessary changes to power flow modeling is a worthwhile goal. Line sensors may be able to provide valuable data for these models and might support real-time operational decisions.

Advanced Analytical Benefits

Line sensors can provide valuable data for analytics that can further refine and improve fault location. Advanced functionality use cases, such as using line sensor data in conjunction with SmartMeter™ data and advanced CFL technology, were examined as part of the concurrent Fault Detection and Location project, and those results are addressed in that project report. While the basic functionality was demonstrated, there is a need to further develop advanced functionality, particularly waveform analytics—the study of electrical waveforms produced by line sensors and other sensing devices to determine patterns—which is in its infancy.

4.2 Product/Technology Assessment

The conclusion of the technical assessment is that products, including but not limited to those demonstrated, are available today that can be deployed at volume for the core use cases of fault detection, location, and load monitoring. Vendor roadmap items such as the ability to operate on distribution lines with very low current will further increase potential deployment sites.

While the line sensors themselves generally performed as expected, the sensor head-end systems showed varying levels of maturity and functionality. Additionally, the integration into PG&E's DMS architecture that was developed for the pilot phase, while appropriate for the pilot, would not be robust enough for a large production environment. For a larger deployment, a better integrated architecture would need to be developed. Please see Section 3.2.1 for information about the architecture options studied during the project.

This project demonstrated that line sensors can provide value in improving reliability, reducing the cost of service restoration, and providing benefits to customers as described in Section 2.5. In order to demonstrate this, line sensors were installed on a sufficient number of feeders to significantly increase the likelihood that the line sensors would encounter faults of various types and conditions. Some highlights:

- In Phase 2 of this project, 1,542 line sensors were installed on 214 feeders in 4 regions. 1,044 were installed for the primary use case of reliability improvement and 498 were installed for other use cases such as those identified by distribution operations, or for planning, power quality, and reliability. All line sensors installed were available to support faster restoration as necessary.
- DC support of four sensor head-end systems, provisioning of devices into ED AM/GIS, PG&E's data historian and DMS, training and operational support.
- The DC analyzed 126 sustained faults from December 10, 2015 to October 3, 2016, including 25 analyzed during storm season (December 2015-April 2016) which were used in the benefits calculations for this report.

4.2.1 Device Requirements

The line sensors evaluated by PG&E all met the minimum standard certifications, environmental, physical and electrical testing, and functional performance tests. Performance was evaluated at ATS in Phase 1 and in the field during the Phase 2 pilot. PG&E identified a number of required and desired features over the course of this project:

Core Business Case Requirements:

- Ability to be installed on an energized line, electrically floating and inductively powered;
- Root Mean Square (RMS)[14] current sensing for faults, demand amps and current logging; and
- Reliably detect sustained and momentary faults.

The line sensors supplied by the three vendors piloted in Phase 2 met the minimum core requirements listed below for reliable fault detection and location of sustained and momentary

[14] For a cyclically alternating electric current, RMS is equal to the value of the direct current that would produce the same average power dissipation in a resistive load.

faults and load monitoring, which are the functions that support the reliability and operation expense reduction business cases.

Core Requirements:

- Provide pre-fault line loading;
- Ability to reset after a fault occurs;
- Provide fault magnitude;
- Provide recent loading data for switching and operational decisions;
- Detect flow reversal for DG monitoring;
- Robust network communications, cellular and/or AMI Network;
- Global Positioning System (GPS) enabled;
- Full operation at 12 amps with less preferred. Note: The minimum power requirement of the line sensors for full functionality is largely dependent on the communication method, (e.g., AMI mesh communications requires significantly more power than cellular), as well as the device design and power storage method;
- Energy storage for low or no power carryover (supercapacitor or battery) so that the line sensor can continue to operate after a fault occurs or the line current is less than the normal power requirement;
- Lightweight, supported by line conductor;
- One installer, single hot-stick for all wire sizes, quick several minute installation;
- Proven field performance;
- Vendor sensor head-end system application for device management and applications;
- Over-the-air firmware upgrade; and
- *For underground:* Submersible; large conductor capability; ability to communicate from underground structures.

Desired but not required:

- E-Field sensing for unreferenced line voltage monitoring;
- Oscillography for advanced waveform analysis;
- Auto Phase identification. *Note:* At the time of this pilot, only one vendor offered automatic phase identification. The phase of the line that each sensor in a triplet is installed on is required for provisioning the sensor in the sensor head-end system, as well as to identify which phase is faulted or for which phase the line loading is reported. Therefore, the ability to automatically sense the phase when the line sensor is first installed is a key feature to help reduce installation time, because the field technician will not have to manually determine the phase;
- Low minimum power requirements for full functionality (2 amps);
- Power carryover for 12 hours (required for DG use cases); and
- Device should report both entry and exit of low power conditions.

Additional Requirements:

- **Power Storage**
  While line sensors all harvest their power from the line's magnetic field, they need to have a means to store power so that they can continue to send data during an outage. The two technologies used in the products piloted were supercapacitors and batteries. Supercapacitors have a longer cycle life and 5-30 minutes of no-power and low-power carryover time. Batteries have a higher energy density which offers a longer carryover time and allows the line sensor to go into a lower power mode while on battery, and can continue to send data and fault alarms for up to 24 hours; however batteries have a shorter lifespan. Each of these power reserve systems have their pros and cons for different use cases, which can drive the potential distribution locations where these sensors could be deployed to provide the greatest value. The special use cases studied in this project that required a longer carryover time, such as the DG studies, used a line sensor that uses lithium batteries rather than supercapacitors because there may be times when the line is lightly loaded and the sensor would need to rely on the battery for power.

- **Communications Requirements**
  At the time of this pilot, only one vendor offered sensors that can communicate using the AMI network technology used in PG&E's SmartMeter™ network. These sensors were demonstrated in the Phase 2 field deployment. One other vendor has this feature in their future product roadmap and has demonstrated it in their testing. However, this is not yet available in their commercially available products today. PG&E noted that AMI communications currently require more power and a higher minimum line current than the cellular communication devices. PG&E's AMI network vendor is working on releasing a lower power communication module, which is being explored by line sensor vendors as an alternative to the currently available AMI communication implementation.

- **Underground Communications**
  As expected, underground installations are problematic when it comes to meeting the communications requirement. The concrete and steel structures containing the underground equipment make it difficult for the sensors to be able to communicate wirelessly due to signal attenuation. Solutions to this problem, such as remote antennas, need to be developed before large-scale underground line sensor projects can be implemented. Additionally, only one product met the underground requirement of submersibility as well as cable size, as underground cables are larger than overhead.

- **Installation Requirements**
  Ideally, line sensors should be able to be installed by a single field technician. However, when installing on smaller conductors, an additional device, such as a tap guard or other conductive wrap is required to be installed on the line first, to ensure that the sensor makes sufficient contact with the line. In this case, a full crew rather than just a single field technician is needed to install the tap guard and the line sensor, which significantly increases the time and cost of installation. PG&E recommended to the vendors that for production rather than pilot installations, they need to provide an alternative to using tap guards to alleviate the need to use a full crew for line sensor installation.

- **Waveform Capture**
  Two of the products had the ability to capture faulted circuit waveforms. One of these also provides an analysis engine to identify the waveforms for capacitor switching, line switching and disturbances, etc. Waveform analysis is still in its infancy and requires further development by the vendors, utilities, and third parties. There is also a significant difference in the waveform sampling rates of these devices. To define the value of

waveforms and the various sampling rates requires further work. Waveform analysis was included as part of the Fault Detection and Location project.

4.2.2 System/Software Requirements

For the Phase 2 pilot, the line sensors needed to be integrated into PG&E's production for the data to be useful to operations. Each of the line sensors piloted used an integrated head-end system to provision and monitor the line sensors. However, the pilot experience with three separate sensor head-end systems exposed the relative immaturity of these systems for line sensor management. Deficiencies in provisioning, device management, data management, integration capabilities, and analytics all indicate that this is still an emerging technology. Identifying the optimal functionality, the following capabilities should be considered as the minimum requirements to support a large-scale PG&E line sensor deployment.

Device Provisioning

Once a line sensor is physically installed on a line, it needs to be provisioned (configured) into the line sensor head-end system. Based on the experience from the pilot, PG&E determined that the following requirements would make this process easier:

- Complete metadata on devices: network MAC ID, serial number, hardware and firmware version, GPS coordinates (auto generated);
- Ability to track devices that are part of the inventory, but either not yet installed or those that are in the RMA process;
- Auto-phase identification;
- Bulk and interactive import of device metadata; and
- Installation reporting, either via the user interface screen or direct data access/integration.

Operations

- Operational status reporting: status, last communications time, power mode (including enter/exit reporting), firmware version, Received Signal Strength Indication, last amperage value w/timestamp. Data should be available in both table and geospatial formats;
- Device management history, cradle-to-grave including: event, timestamp, and user;
- Device availability history;
- Firmware upgrade status reporting (e.g., Started, In Progress %, Success, Failed);
- Configuration maintenance: ability to target individual sensors or group of sensors, report on status similar to firmware upgrade, configuration change recorded in device management history; and
- Device query: ping and status query functionality, by individual sensors, or group of sensors. Query mechanism should be interactive, e.g., by phase, current range, fault history.

Infrastructure and Integration

- Minimum requirement: full access to the entire data set, either by direct database access, or schedule and ad hoc data exports;

- Would be useful to have APIs exposed, e.g., Simple Object Access Protocol or JavaScript Object Notation web services; and
- Integration capability with distribution systems such as ED AM/GIS and PG&E's distribution modeling application.

Other Considerations

- *Advanced analytics*
  None of the offerings in the Line Sensor pilot had very useful or consistent analytics, which also speaks to the relative immaturity of this technology. The analytics were not consistent in identifying specific types of events, and occasionally mis-categorized events. For example, in some cases a capacitor switching event was identified as a load switching event or vice-versa. This is likely something that PG&E would need to develop internally or with third-party utility analytics specialists. This enforces the requirement for direct data access.
- *Model management*
  One vendor used a hierarchical model to map the location and interaction of the line sensors on any given segment. This is labor-intensive and the mapping would become inaccurate as soon as any switching operations are performed. Integration capabilities with ED AM/GIS and/or PG&E's distribution modeling application are much preferable.
- *Hosted solutions – Software as a Service*
  The line sensor pilot involved four separate line sensor head-end systems, three of which are hosted by the line sensor vendor or vendor partners. A full-scale deployment should arguably be hosted at PG&E in order to minimize cost and integration complexity, and to increase data security. This may require PG&E to increase support for IPv6 (Internet Protocol version 6) to integrate with the AMI network, which uses IPv6.
- *Support*
  Vendors need to provide support for line sensor performance, firmware, and software. Clear service level agreements should be developed and agreed to for a full deployment.

4.2.3 Cyber Security Requirements

In general, because line sensors only transmit data, they do not present any more of a cyber security risk than SmartMeter™ devices which all use strong Public Key Infrastructure (PKI) based encryption standards. PG&E previously performed extensive tests of this PKI encryption. The following are basic cyber security requirements for such devices:

- Web-based user interface to reduce application management;
- Authentication & authorization should integrate with PG&E's corporate Active Directory;
- Vendors should be moving to DNP3Secure; and
- Ability to secure all communication channels, or turn off if not used.

Future deployments should continue to verify that these devices will not negatively impact the network or create any cyber security risks.

4.2.4 Vendor Requirements

The PG&E ATS testing provided insight to the general state of the line sensor industry and technologies. These products are still evolving and vendors are still searching for where the largest opportunity will be for their products. For example, one vendor is evaluating the degree to which they may introduce further advanced functionalities, such as highly accurate GPS measurements. No single vendor is able to support all communications options of interest to PG&E, while at the same time supporting all installation conditions, including overhead, underground, and small conductor.

Line sensors are installed in sets of three, with one sensor on each phase of the triplet at a given location. One vendor currently ships three sensors to a box, which is preferable. Of the other two vendor products demonstrated in the pilot, one ships two sensors to a box and the other, one sensor to a box. PG&E recommends that vendors supply the sensors three to a box with all three sensors pre-labeled with PG&E device identification labels visible from ground level when installed, which would to help to reduce the installation time.

4.3 Industry Recommendations

The following findings of this project are relevant and adaptable to other utilities and the industry:

4.3.1 Utility Recommendations

Line sensors are ready to deploy, justified by their proven ability to detect faults and narrow the potential faulted zone. But they can also be a valuable tool for more extensively monitoring an increasingly complex distribution system, as distributed generation becomes more prevalent. Advanced analytics such as the ability to detect momentary faults and capture waveforms also hold valuable potential.

PG&E's efforts during the Smart Grid Line Sensor Pilot have contributed to the development and use of line sensors. PG&E is the first utility to operate line sensors within a converged AMI network, using the same relays and access points as the SmartMeter™ network. PG&E has demonstrated with this pilot that real-time and logging data can flow through the same network relays with no measurable impact on meter reading success, and even large waveform files can be transferred without adversely affecting other key operational network traffic. This approach allows PG&E to leverage its investment in the SmartMeter™ network with only a minimal additional investment.

PG&E also verified that in general, line sensors are ready for large-scale deployment today. PG&E's experience is consistent with that of other utilities who have validated that these technologies are ready today to support basic features. However, utilities must use caution in rolling out new technologies, as this is still an emerging technology. As the line sensor market matures, new features will benefit line sensor users.

4.3.2 Vendor Recommendations

PG&E's experience with both installation and sensor availability identified a need for low-power sensors that could be installed near the end of lines or on low power circuits. Conversations with the vendors and other utilities noted that this is a key milestone in future product development roadmaps for some of the vendors.

Further development of underground line sensors that can offer effective wireless communications from underground vaults needs to be completed. Coordination between potential users and vendors could advance this development and provide an effective solution.

Product offerings can benefit greatly from the integration of more and better-quality system health monitoring and tools for troubleshooting. Vendors should evolve their system-level and application-level capabilities to better meet the operational needs of utilities. Applications that track field switching or equipment operation must be fully reliable before a utility can gain benefit.

Advanced analytics such as the use of waveform signatures was explored in the Fault Detection and Location project, and the findings are discussed in that project report.

4.4 Additional Learnings

4.4.1 Technology Readiness Assessment

The conclusion of the technical assessment is that products, including but not limited to those demonstrated, are available today that can be deployed at volume for the core use cases of fault detection, location, and load monitoring. There are constraints as to where the line sensors can be deployed for full functionality (e.g., communications coverage and minimum current), but overall there are many locations that meet the minimum requirements where there is currently no automated monitoring that would benefit from the introduction of line sensors.

Vendors are eager to work with PG&E to meet its needs and to make improvements to sensor head-end systems so that they can be more easily integrated into production systems such as DMS. For a larger deployment, PG&E will need to develop a production-level planning, installation, and provisioning process that minimizes the amount of manual data entry. This may require modifications by the vendors to accommodate a more automated provisioning methodology.

5 Deployment Recommendations

5.1 Recommended Deployment

Based on knowledge gained from the Line Sensor Pilot project, all feeders in the PG&E system were analyzed and ranked for purposes of prioritizing deployment. There were a total of 3,170 feeders considered in the ranking process.

5.1.1 Levels of Deployment

PG&E ranked its 3,170 feeders based on a number of factors, to determine the feeders that would benefit most by having line sensors deployed. PG&E prepared Benefit-Cost ratio analyses, ranking each individual feeder based on the potential value to be gained by deploying line sensors on that feeder. The result is a subset of 1,457 feeders which the pilot project found to have a Benefit to Cost ratio greater than one if equipped with an average 5-6 sets of line sensors per feeder (three sensors in a set). This subset can be ranked by Benefit to Cost ratio, allowing the most impactful locations to be addressed first.

5.1.2 Planning/Business Requirements

PG&E's Benefit-Cost analysis assumed that for each of the feeders prioritized for deployment, line sensors would be deployed at all of the recommended locations for that feeder in order to capture reductions in as many mainline outage minutes as possible. Experience during the pilot phase gave PG&E valuable information to help determine the optimal number of sensors to deploy at a given feeder. In actual implementation, there may be technical limitations to the number of line sensor locations on each feeder, based on line voltage, communications availability, and conductor size. Detailed planning will be required for each feeder to determine the actual number and location of line sensors that could be deployed there based on these technical limitations.

The benefits are captured incrementally with each set of sensors deployed. Therefore, the business case does not change if fewer sensors are deployed on more feeders. Deploying too many sensors on a feeder can reduce the benefits per triplet since the feeder can become oversaturated if sensors are very short distances apart. The pilot experience demonstrated that a thinner spread of line sensors over a greater area provides a greater benefit.

5.1.3 Use Case Identification

Reliability benefits are based on the use case of faster fault location and faster initial restoration. The primary use case is identification of isolation and restoration points during a fault event. The largest benefit is achieved when field personnel are able to open isolation points and restore undamaged line sections based on sensor data before patrolling to find the exact fault location. The second quantifiable use case is reduced patrol time to find the actual fault location.

5.1.4 Feeder/Site Identification

For this business case analysis, the first circuits excluded were those with FLISR already installed, or with near-term plans for FLISR, as there is an overlap in the reliability benefit potential. FLISR is planned for circuits that can demonstrate major reliability improvements which are needed to justify the deployment cost and feeders that have the capacity margin required for load switching without human intervention. There were 799 circuits identified with existing or planned FLISR deployment, leaving 2,371 as candidates for line sensors.

Next, PG&E considered the number of customers and determined the average annual mainline outage minutes for each feeder, based on data from January 1, 2013 – June 30, 2016. Excluding feeders that had no C-MIN or no mainline outage minutes over the three and half year period further reduced the potential candidates for line sensors to 1,776 feeders.

An estimate was made for each feeder of the number of line sensor sets (or locations) that would be required to cover the mainline and provide potential reductions in outage durations, based on the number of customers, the number of mainline miles, and the number of sectionalizing devices (e.g., circuit breakers, line reclosers, sectionalizers, and interrupters) on each circuit. Comparing the average annual available mainline outage minutes with the estimated number of line sensor locations provided the ranking of the remaining feeders based on their Benefit-to-Cost potential.

Then assuming a 12.6% reduction of average annual mainline outage minutes (see Section 4.1.1), and a cost of deployment for each estimated Line Sensor location of $6,000 plus a pro-rata share of fixed costs (project management and IT labor costs), and using the VOS model to value the customer minute reductions, Benefit-Cost ratios were calculated for each feeder. Based on this analysis, PG&E determined that there are 1,457 candidate feeders that can provide a positive Benefit-Cost ratio.

For an actual system rollout, the funding levels would need to be matched to this type of analysis and prioritization and then final locations would be engineered, taking into account practical constraints such as communications coverage, wire size, etc., as well as other prioritization items such as areas with critical loads and secondary benefit opportunities. For example, if an area has backyard construction which is most difficult to patrol, these lines might be given higher priority by the engineers familiar with the area.

5.1.5 Testing

Test requirements for the line sensors being considered for deployment should consist of:

Table 1. Testing Requirements

Certification Testing	Vendor submits test results for Federal Communications Commission wireless requirements, FCI tests, Electromagnetic Interference susceptibility, etc. with final proposal. Complete list of required tests selected and released by ATS/Standards Engineering, provided at time of Request for Proposal (RFP) release.
Vendor Qualification Tests	Vendors will release test results from internal qualification testing to compliment ATS testing and certification testing. Test list will be established by ATS and Standards.
ATS Test Plan, Updated	Satisfactory performance under an updated PG&E ATS test plan. The updated test plan will be designed by ATS to demonstrate adequate functionality against the benefit cases generated by the Phase 2 pilot analysis. It is anticipated that devices would receive "pass" or "inadequate" ratings for each defined benefit.
Production Testing	Vendor production test plan for audit by PG&E.
Production Sample Tests	ATS will perform functional tests on a pre-determined sample schedule during production to ensure product quality over the course of the contract.
IT Testing	Module level, interfaces, and end–to-end testing. Full rollout would require some IT modification for scalability, and these will need design verification and user acceptance testing.
Acceptance Testing	Software and firmware performance with the line sensor head-end systems and end-to-end testing for integration into DMS.

5.1.6 Roll out

Line sensors are part of an overall system and their deployment requires tracking of installation activities, commissioning units, verification that data is mapped correctly and flowing through to DMS and databases. This effort is most efficient when managed as a dedicated program rather than on an ad-hoc basis. PG&E recommends a program management approach be applied to each yearly rollout. Additional smaller ad-hoc deployments are possible and would be supported by the DC.

5.1.7 Change Management

As it applies to equipment and processes used in the pilot itself, change management is complete for the PG&E user groups (i.e., operators and engineers). A production-level roll out will need to address the final integration of line sensor equipment into construction and standards documents and purchasing systems, integration into technical maintenance groups, and IT operations. Much of this would be facilitated by PG&E's integration of the DC into operations after the completion of the pilot. Some changes will need to occur in the IT systems to support larger scale deployments. These changes will require change management.

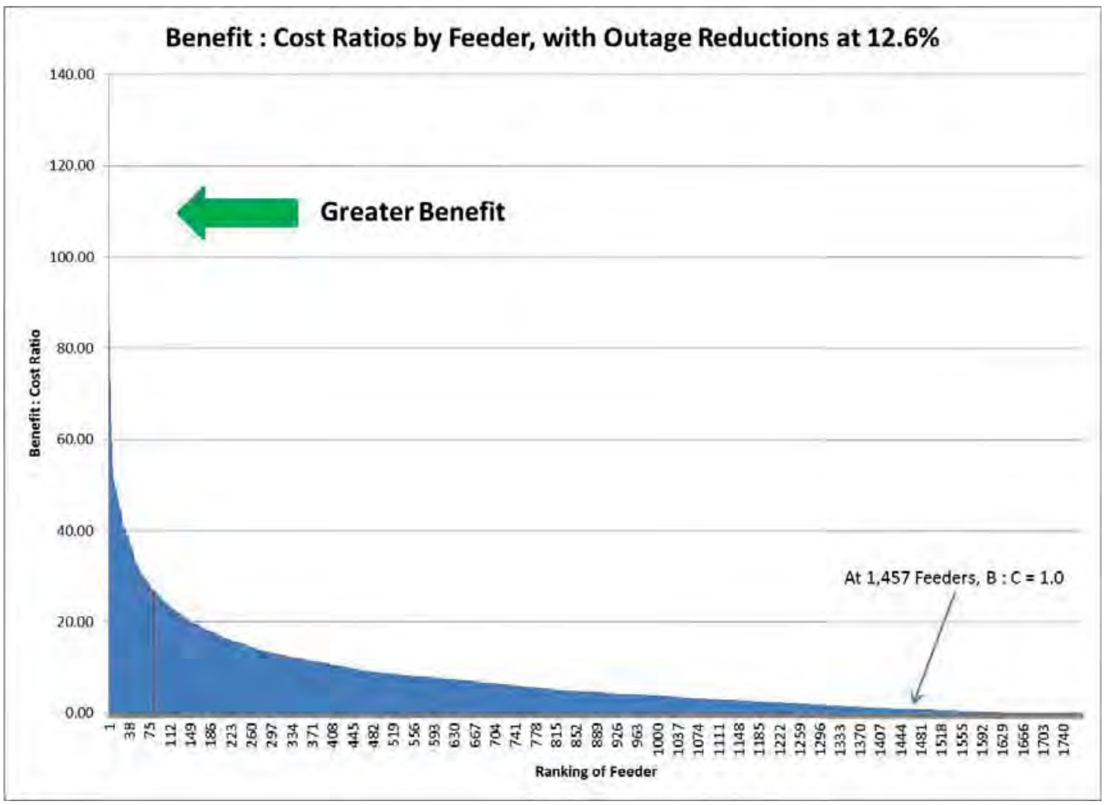
5.2 Alternatives to Recommended Deployment

Because the Benefit-Cost ratio analysis was performed for all feeders, ranking them based on their benefit potential, any level of deployment would cover the feeders that would benefit the most from line sensors, provided that this ranking is used to prioritize feeders in deployment plans.

5.3 Value Proposition

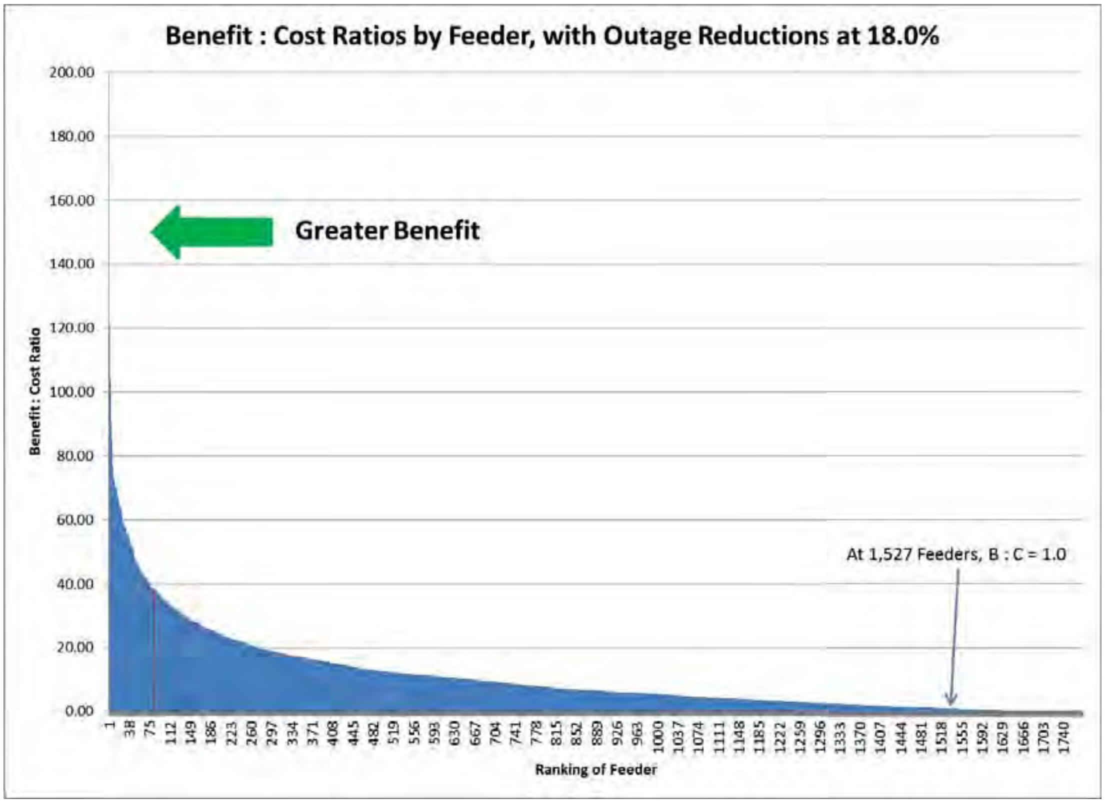
5.3.1 Relevance to PG&E Strategic Goals

The feeder-by-feeder analysis showed that the feeder with the highest potential for improvement with line sensors assuming an 18% outage reduction, had a Benefit-Cost ratio of approximately 140:1 ($1 spent would result in $140 in savings). In total, there were 1,776 feeders with mainline outage benefit potential, with a Benefit-Cost ratio curve as follows, calculated at the savings reduction of 12.6% (reduction alone) and 18% (reduction plus business process change enabled by line sensor deployment):[15]



[15] See Section 4.1.1.

Figure 5. Benefit-Cost Ratio Curve for Line Sensor Deployment



Line sensors are a key component of PG&E's Electric Distribution Reliability Program. By choosing feeders without FLISR (or near-term plans for FLISR), PG&E can avoid benefit redundancy, and ensure incremental benefits to the FLISR program.

5.4 Benefit-Cost Analysis

5.4.1 Cost Estimates

The results of the detailed analysis were based on actual field data, with adjustments made based on the actual deployment and device costs and actual measured benefits. The results of this detailed analysis show slightly higher benefits than originally anticipated with a somewhat lower recommended number of sensors deployed per feeder. The final benefits being 12.6% or better reduction of minutes as compared to the original pre-pilot phase estimate of 10% and the deployment recommendation being 5-6 sets per feeder rather than 10.

A summary of key assumptions driving the Benefit-Cost analysis are as follows:

Table 2. Benefit-Cost Analysis Key Assumptions

Category	Key Assumptions
Feeder Data	Considered 3,170 Feeders (per CEDSA Year-End 2015)
Mainline Outage Minutes Exclusions	Generation, Transmission, Substation, Independent System operator, 2.5 Beta, Transformer Only, Fuses, and Planned Outages
Average Annual Mainline Outage Minutes	264.7 Million Customer Minutes Interrupted (C-MIN) (2013-2016 average)
FLISR Overlap	FLISR Circuits were excluded due to functionality overlap
Average Cost per Line Sensor Set	$6,000 / triplet
Average Number of Line Sensor Sets/Feeder	5-6 sets per feeder (3 line sensors per set)

In addition to the variable costs of deploying line sensors in the field, PG&E's analysis incorporated fixed Program Management and IT Costs into the Benefit-Cost analysis. The Program Management cost was estimated at $250,000 to deploy 1,650 locations, or $150/location. The IT Costs to enable up to 10,000 locations are estimated at approximately $4,000,000, or $400/location. The total allocated cost per location used in the analysis is as follows:

Table 3. Fixed and Variable Costs for Line Sensor Deployment

Description		$ / Unit	
Line Sensors (triplets)	$	4,620.00	[1]
Planning Labor	$	480.00	[2]
Installation Labor	$	300.00	[3]
Additional Hosting / Maintenance	$	600.00	[4]
Line Sensor Locations (triplets)	$	6,000.00	
Project Management	$	150.00	[5]
IT Costs	$	400.00	[6]
Allocated Cost per Location	$	6,550.00	

Notes:

[1] - estimated cost per unit of $1,180 ($1,370 x 60% + $900 x 40%)
+ 30% materials loading (sales tax, warehouse, etc.) = $1,540 / sensor
$1,540 x 3 sensors per location = $4,620 / location
[2] - estimate assumes 2 hours x $240 / hr = $480 / location for Engineering
[3] - estimate assumes $300 per location for Installation
[4] - estimate $200 / sensor x 3 sensors per location = $600 / location
[5] - Per GRC request, $250,000 per year, estimated 1,650 locations / year
$250,000 / 1,650 locations = $150 / location
[6] - $650k plus $3.3M = approximately $4.0M to enable 10,000 locations
$4,000,000 / 10,000 locations = $400 / location

5.4.2 Deployment Benefits

A. Primary Benefits

Based on actual field experience and analysis of the 25 actual sustained faults that occurred in the target areas during the 2015-2016 storm season, benefits were calculated at a minimum of 12.6% reduction which is 2.6% higher than the original estimate prior to the Phase 2 pilot completion. The analysis determined whether or not line sensor data was used by the operator during the outage. If line sensor data was used, an estimate was made of how much longer the outage would have been without the line sensor data, and if the line sensor data was not used, an estimate was made of how much shorter the outage duration would have been if line sensor data had been available. The analysis considered whether switching operations to partially restore customers could have been performed sooner based on the fault zone identified by line sensors, as well as potential reductions to patrol time based on the narrowing of the fault zone with line sensor information. The analysis showed that of the total C-MIN of approximately 4.85 million minutes for the 25 outages, approximately 610,000 minutes (or 12.6%) either were saved, or could have been saved, with the use of line sensor information.

Also, as discussed above, the updated deployment analysis targets those feeders with the highest benefit potential, resulting in the following reliability impacts for the 1,457 feeders with a Benefit: Cost ratio > 1.0:

Category	**Pilot Findings**
Number of Feeders with B: C > 1.0	1,457
Total Mainline C-MIN Addressed	164,750,000
C-MIN Reductions @ 12.6%	20,750,000
Total Implementation Costs	$52,300,000
Average Cost $/C-MIN	$2.52

The savings in customer outage minutes are derived in part by the ability to sectionalize outages and restore a subset of customers more quickly, and also via a reduction of patrol times required to locate the source of the outage. This second portion of the reliability benefits (reduction in patrol times) provides a related reduction of PG&E field patrol costs, in addition to the Value of Service benefits used to calculate the Benefit-Cost ratio.

PG&E's study of the 25 mainline outages that occurred during the 2015-2016 storm season indicated that in addition to a 12.6% reduction in customer outage minutes, there was a corresponding 12.2% reduction of field technician patrol minutes for the outages studied. Reducing patrol time not only reduces the duration of the power outage but also reduces direct labor costs.

B. Secondary Benefits

The secondary benefits for line sensors are extensive and should be considered in deployment plans. Some of these benefits can be captured immediately, while some require additional application development. There are also strategic considerations such as spending a small incremental amount today to future-proof the system by purchasing feature-rich sensors for a time when advancements in use of data, particularly waveform data, are made.

It is important to note that the business case incorporates the primary benefits of line sensors. Some of the secondary benefits can be quantified, but the pilot did not capture enough empirical data to support accurate quantification of secondary benefits. For example, only one instance of identifying a defective piece of equipment, a capacitor bank, occurred. Clearly this was a benefit but it is not prudent to extrapolate that to quantify benefits without having validated how reliable the detection is across a variety of failure modes and differing field conditions.

Since the primary benefits more than justify deployment of line sensors, secondary benefits will be obtained and experience gained over time. If warranted, these benefits can be quantified once fully validated and added into future analyses.

It is also worth noting that secondary benefits will also develop as users become familiar with the systems and data. For example, during the pilot, Operators realized that they could use line sensors to verify restoration of power during outage restoration operations. This is a benefit that the project did not originally anticipate.

5.4.3 Sensitivity Analysis

PG&E ran sensitivity analyses across four of the key drivers of the Benefit-Cost ratio analysis. The key drivers identified were:

Table 4. Key Drivers of the Benefit-Cost Ratio Analysis

Key Model Drivers	Impact On Model	Values used in sensitivity analysis (+ or – 20%)		
Cost of Line Sensors	Cost of deployment and number of Feeders deployed	$7,200/set	$6,000/set	$4,800/set
Number of Line Sensors/Feeder	Cost of deployment and number of Feeders deployed	1 per 417 customers	1 per 500 customers	1 per 625 customers
		1 per 4.17 miles of mainline	1 per 5.00 miles of mainline	1 per 6.25 miles of mainline
		1 per 0.83 devices	1 per 1.00 devices	1 per 1.25 devices
Forecasted Mainline C-MIN Available	Customer Outage Minutes Saved with Line Sensors	80% of average annual C-MIN ('13-'16)	100% of average annual C-MIN ('13-'16)	120% of average annual C-MIN ('13-'16)
% Reduction of Available C-MIN	Customer Outage Minutes Saved with Line Sensors	10.00%	12.60%	18.00%

Varying each of the 4 key assumptions, the matrices below display the resulting Benefit-Cost Ratio based on the VOS model calculated benefits and present value of deployment costs for each scenario. It is worth noting that each of the three sensitivity scenarios described below provide a positive Benefit-Cost Ratio. In other words, all three scenarios generate a net positive benefit.

- The *Low Value Case* is defined by a higher cost of deployment (higher cost per line sensor set, higher number of locations per feeder) and a lower benefit potential (lower forecast of available mainline outage minutes and lower percentage reduction due to line sensors). The *Mid Value Case* represents PG&E's base-case assumptions.
- The *High Value Case* is defined by a lower cost of deployment (lower cost per line sensor set, lower number of locations per feeder) and a higher benefit potential (higher forecast of available mainline outage minutes and higher percentage reduction due to line sensors).
- The *Mid Value Case* yielded 1,457 feeders where the Benefit-Cost ratio is greater than 1.0. In the Low Value Case, 1,211 feeders have a Benefit-Cost ratio greater than 1.0, and in the High Value Case, 1,602 feeders have a Benefit-Cost ratio greater than 1.0.

The following matrix shows the corresponding number of feeders which meet the Benefit-Cost threshold of 1.0, varying each of the four key assumptions individually:

Savings Due to Line Sensors % of '13-'16 Mainline SAIDI	Low Savings Rate - 10.0% Low - 80%	 Mid - 100%	 High - 120%	Mid Savings Rate - 12.6% Low - 80%	 Mid - 100%	 High - 120%	High Savings Rate - 18.0% Low - 80%	 Mid - 100%	 High - 120%
	Number of Feeders where Benefit : Cost > 1.0								
Cost per Set: Low - $4,800+									
LS per Feeder: Low	1,439	1,489	1,529	1,490	1,537	1,558	1,550	1,583	1,602
LS per Feeder: Mid	1,396	1,447	1,488	1,452	1,501	1,530	1,522	1,560	1,580
LS per Feeder: High	1,336	1,393	1,429	1,395	1,443	1,483	1,472	1,520	1,546
Cost per Set: Mid - $6,000+									
LS per Feeder: Low	1,393	1,449	1,486	1,452	1,497	1,533	1,526	1,554	1,579
LS per Feeder: Mid	1,349	1,401	1,444	1,405	1,457	1,495	1,482	1,527	1,555
LS per Feeder: High	1,270	1,345	1,391	1,345	1,399	1,439	1,428	1,478	1,515
Cost per Set: High - $7,200+									
LS per Feeder: Low	1,348	1,405	1,452	1,406	1,466	1,502	1,488	1,534	1,555
LS per Feeder: Mid	1,290	1,368	1,407	1,368	1,416	1,461	1,446	1,496	1,528
LS per Feeder: High	1,211	1,284	1,346	1,288	1,359	1,401	1,392	1,440	1,481

+ - plus allocation of PMO and IT Costs

6 Pilot Financials

The table below captures the actual project costs. The project completed on-time and under the approved project budget of $16.399 million.

Table 5. Pilot Financials

	Phase 1	Phase 2	Total
	2013 & 2014	**2015 & 2016**	**2013-2016**
Capital	$2,787	$11,027	$13,814
Expense	$4	$2,281	$2,285
Total	$2,791	$13,308	$16,099

All values in thousands – figures above based on Actual spend through November 2016, and forecasts for December. Total Administrative spend over life of the project was 2% of project costs.

6.1 Drivers of Cost Savings

PG&E identified early in Phase 2 that the more costly integrated IT solution (see Section 3.2.1) was not needed for the pilot phase, which enabled use of authorized budget to expand the test areas. This allowed PG&E to assess a wider variety of locations and more challenging use cases by deploying additional line sensors.

6.2 Capital Accounting

For Phase 2, the project capitalized all costs associated with purchasing line sensors, installing devices in the field, purchasing and installing associated software, integrating line sensor data into operational systems, troubleshooting the system, and overall management of these activities until the project deemed each vendors' integrated solution operational. The project declared the integrated solution for one vendor operational as of March 1, 2016. The project declared the other two vendors operational as of April 1, 2016. After the respective operational dates, the project expensed the ongoing cost related to analysis, assessment, support, report writing, and project management.

7 Next Steps

Line sensors have been deployed and operated on a pilot basis. Based on the positive Benefit-Cost calculations, PG&E has a variety of potential next steps to build off of the success of this pilot project:

- **Move pilot IT systems to production.** Production systems require a higher level of reliability and scalability. This is supported by interfaces that include maintenance tools, failover capabilities, more complete operational playbooks and other items.
- **Explore formalizing the DC.** Line sensors are the field component of a system. There is value in a single-point-of-contact application owner for the overall system to provide maintenance, operation, and to continue to increase the value extracted from sensor data.
- **Issue an RFP for product purchase that includes improvements and vendor recommendations identified during the pilot.** PG&E's pilot RFI provided an understanding of the overall sensor market and capabilities. A targeted RFP or other sourcing negotiation would secure competitive prices for equipment that includes requirements identified as important for certain use cases during this pilot project.
- **Create a rollout plan and implement a leveraged deployment as a project for highest efficiency.** As opposed to deployment of devices (e.g., fuses) that can be installed and left to operate, line sensors require verification of communications, configuring databases and other system activities to operate. Grouping deployments into a rollout is most efficient for these types of deployments.

7.1 General Rate Case

The 2017 rate case includes funding for deployment of line sensors. PG&E will consider including a funding request into the 2020 GRC as long the Benefit-Cost calculation is sufficiently positive.

7.2 Technology Transfer Plan

The knowledge gained during this project by PG&E's and its internal stakeholders is detailed in vendor documents, reports, and presentations. The line sensors deployed by this project will remain installed and in operation for continued use by operations and asset engineers. The DC will remain in operation in some form after the conclusion of this project, and is being integrated into PG&E's ongoing operations to maintain the software applications and daily production of line sensor data.

7.3 Dissemination of Best Practices

PG&E will continue to participate in formal and informal industry meetings and discussions regarding this project and the lessons learned. Many learnings are being shared with vendors and will be reflected in feature and process developments. Industry engagement was continual, and contribution to the industry was validated by requests for presentation for both 2016 and 2017 by DistribuTECH and in 2016 by CEGRI industry conferences.

PG&E also has already shared information and best practices with Southern California Edison Company, Sacramento Municipal Utility District, Florida Power and Light, Commonwealth Edison, and Detroit Edison.

8 Conclusion

PG&E's primary achievement in this project was gaining the knowledge, experience, and confidence needed for a large-scale adoption of line sensors. Feedback from groups across operations and engineering has been overwhelmingly positive. Significant individual accomplishments were the steps to this overall achievement and include:

- Identification of locations where line sensor deployments would offer the greatest benefit to improve system reliability;
- Definition and creation of a DC to support line sensors;
- Repeated industry survey and engagement;
- Lab testing of seven product versions provided by four vendors;
- Creation of testing protocols and processes for future testing;
- Deployment of over 1,500 sensors supporting more than a half dozen different use cases;
- Refining of benefits assumptions;
- Evaluation and learnings from challenging communications environments such as underground deployments;
- Feature assessments and mapping to near and long term applications; and
- Identification of firmware and hardware defects with vendor concurrence and correction.

The conclusion of the technical assessment is that products, including the ones piloted, are available today that can be deployed for the core applications of fault detection, location, and load monitoring. The project demonstrated that line sensors can provide an average of 12.6% reduced C-MIN and 12.2% reduced cost of field patrol when line sensor data is made available to operators. The results of the business case support positive Benefit-Cost ratios on a deployment of up to 1,457 total feeders.

The project found the line sensor market is small and largely homogeneous. The products used in the project's pilot phase deployments represent the low-end and mid-range products available in the market, with the largest distinction between these two being the ability to capture waveforms. Even with this distinction, the products were found to be more similar than dissimilar, and they all can provide features that can provide clear value today.

Line sensors can help PG&E to achieve its goal of integrating advanced communications and monitoring systems that can improve system reliability and safety systemwide. As the electric grid becomes more complex and dynamic, PG&E needs to have more immediate and granular data about the entire electric system. Increased sensing is critical for more flexible power systems that include distributed generation, and it supports practical and more reliable system operations. Line sensors can be a significant part of PG&E's portfolio of reliability improvements that will help PG&E to provide reliable, affordable, and safe power today and into the future.

9 Appendix A - Regulatory Filings

Advice Letter 4227-E: Smart Grid Pilot Deployment Projects Implementation Plan, Pursuant to D.13-03-032
Effective Date: June 21, 2013
URL: https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4227-E.pdf

Advice Letter 4538-E: Smart Grid Line Sensor Pilot Project - Phase 1 Status Report, Pursuant to D.13-03-032
Effective Date: December 21, 2014
URL: https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4538-E.pdf

10 Appendix B - Glossary

AMI – Advanced Metering Infrastructure
AP – Access Point
ASCR – Advanced Scientific Computing Research
ATS – Advanced Technical Services
CAIDI – Customer Average Interruption Duration Index. This index is based on the average restoration time. It is determined by dividing the SAIDI by the SAIFI.
C-MIN – Customer Minutes Interrupted
Conductor – a power line
CPUC – California Public Utilities Commission
Cu – Copper
DC – Diagnostic Center
DER – Distributed Energy Resources
DERMS – Distributed Energy Resource Management System
DG – Distributed Generation
DMS – Distribution Management System
DNP3 – Distributed Network Protocol, Version 3
ED AM/GIS – Electric Distribution Asset Management / Geographical Information System
E-Field – Electric Field
EI – Enterprise Integration
Feeder – the connection between the output terminals of a distribution substation and the input terminals of primary circuits.
FCI – Faulted Circuit Indicator
FLISR – Fault Location, Isolation, and Service Restoration
GPS – Global Positioning System
GRC – General Rate Case
ICCP – Inter-Control Center Communications Protocol
ILIS – Integrated Logging Information System
JSON – JavaScript Object Notation
M&V – Measurement and Verification
NPV – Net Present Value
Recloser – a circuit breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault.
Recloser – a pole installed protective device that interrupts faults and "recloses" if the fault is cleared
RFI – Request for Information
RFP – Request for Proposal
RMA – Return to Manufacturer Authorization
RMS – Root Mean Square
RSSI – Received Signal Strength Indication
SaaS – Software as a Service
SAIDI – System Average Interruption Duration Index. This index is based on the amount of time the average PG&E customer experiences a sustained outage (being without power for more than five minutes) in a given year.
SAIFI – System Average Interruption Frequency Index. This metric represents the number of times the average PG&E customer experiences a sustained outage in a given year.
SB17 – Senate Bill 17
SCADA – Supervisory Control and Data Acquisition

Sectionalizer – a self-contained, circuit-opening device used in conjunction with source-side protective device.
SOAP – Simple Object Access Protocol
STDF – Short Term Demand Forecasting
Tap guards –
TCP/IP – Transmission Control Protocol / Internet Protocol
UI – User Interface
VOS – Value of Service

Final Report

Detect and Locate Distribution Line Outages and Faulted Circuit Conditions

Smart Grid Pilots Program

December 30, 2016

Reference Name: Fault Detection and Location (FDL)

Project Lead: Tom Martin

Project Sponsor: Ferhaan Jawed

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1 Executive Summary

Pacific Gas and Electric Company (PG&E) serves over 5,000,000 electric customers connected to over 140,000 miles of distribution circuits. In an average year, approximately 20,000-25,000 electric faults occur in PG&E's territory. When a fault occurs that causes an outage on the distribution network, distribution operators need to determine as quickly and precisely as possible the exact location of the fault, so that field technicians can be dispatched to isolate, make repairs, and restore power to customers.

The Smart Grid Detect and Locate Distribution Line Outages and Faulted Circuit Conditions (hereafter, "Fault Detection and Location" or FDL) project investigated and demonstrated new analytics that leverage data from traditional substation protective devices, as well as smart grid sensing technologies and SmartMeter™ data to detect faults in real time and pinpoint the fault location with greater accuracy. The project also investigated the possibility of using SmartMeter™ data and advanced analytics to detect faults that are difficult to identify using conventional methods. The project also investigated using advanced data such as electric waveform signatures from line sensors and other devices to anticipate faults by identifying conditions that can lead to faults in the future.

This project was one of four in the PG&E Smart Grid Pilot Deployment Program, approved in 2013 by the California Public Utilities Commission (CPUC) in Decision (D.) 13-03-032, to test the value and challenges of deploying new smart grid technologies. Another of these four projects that was complementary to this project was the Smart Grid Line Sensor Project, which focused on installing wireless communicating line sensors for load monitoring and locating faults. Line sensors accomplish this by indicating when a fault occurs at a point on the line past the sensor. These sensors also have additional capabilities such as electric current waveform capture that are only useful when coupled with the analytics that are studied in this project.

Pilot projects are critical for emerging technology efforts such as this, because significant work needs to be completed before PG&E can determine to what extent these technologies will provide benefits to PG&E's grid and its customers. Many of the capabilities demonstrated in the Fault Detection and Location project have been available previously. However, prior to making long-term investment and deployment decisions, PG&E needed to perform a detailed investigation of these technologies' precise behaviors, their effectiveness, and their potential applications in PG&E's service territory. Demonstrating new technologies and methodologies in a pilot project also increases affordability by demonstrating their opportunities and risks on a smaller scale, which minimizes the possibility of costly mistakes that could occur in a large-scale deployment without sufficient research and preparation. This project confirmed the effectiveness of analytics in identifying and locating faults, and provided the foundational knowledge of how these technologies might be leveraged to support PG&E's strategic goals of delivering affordable and reliable electric service.

1.1 Supporting the Smart Grid Vision

The Fault Detection and Location project supports PG&E's Smart Grid vision by unleashing the power of data and analytics to improve reliability and affordability. These technologies have the potential to form the basis of automation and control systems that are becoming critical to managing the more diverse and dynamic distribution systems of today and into the future.

The following are the specific Smart Grid goals supported by Fault Detection and Location:

Improved Reliability: FDL's main goal is improved detection and location of faults for faster restoration of power. These analytics also contribute to reliability by supporting improved asset management, which has the potential to avoid certain outages completely by proactively identifying failing equipment and vegetation intrusion.

Increased Affordability: The technologies and analytics demonstrated in this project offer a low-cost means to strengthen PG&E's existing infrastructure by applying new analytics to existing data from sources such as Supervisory Control and Data Acquisition (SCADA), SmartMeter™, and other sensing devices to improve fault detection. This can improve affordability by reducing the amount of time and resources required to detect, locate, and repair faults.

Improved Safety: Data and analytics also have the potential to help PG&E to identify high impedance faults[1] that can be caused by situations such as hazardous downed electrical lines, which are traditionally difficult to identify remotely by substation relays, fuses, or line sensors. Faster fault detection and location also supports safety infrastructure, such as streetlights and railroad crossings by helping to ensure that these resources are restored in a timely manner when an outage occurs.

More Effectively Integrate Distributed Renewable Energy: Traditionally, utility infrastructure was designed for one-way power flow—from the utility to the customer. As more customers adopt renewable energy generation, such as rooftop solar, the electric grid becomes more complex. A grid that was designed for one-way power flow is now supporting thousands of customers who are both consumers and generators. Increasing distributed energy resources (DER) make it more challenging for utilities to maintain reliability in the face of a more dynamic and complicated distribution system. Data and analytics can be an important tool to help manage this increasing complexity and support effective reliability management. Advanced fault detection and location supports increased DER integration through higher accuracy for increased potential fault points on the distribution network that are currently indistinguishable with current fault detection and location methods.

Reduce Environmental Impact of System Operation: Better pinpointing of fault locations leads to reduced time required for field technicians to find faults and make repairs. This has a direct impact on vehicle-based carbon emissions.

1.2 Project Activities

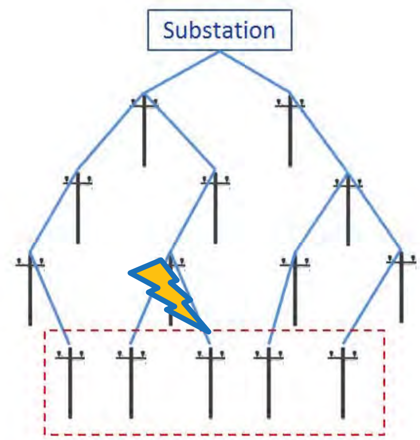
PG&E assessed three existing approaches—calculated fault location (CFL), SmartMeter™ alarms, and fault anticipation—to asses which may be most effective in producing actionable fault location and detection, individually or in combination. Possible approaches were also assessed to see if they could be adopted for

[1] A high impedance fault occurs when a conductor makes unwanted electrical contact with an object, such as a tree limb or other object, which restricts the flow of fault current to a level below that which can be detected by conventional means. Often this leaves the conductor energized, which poses a danger to the public, particularly in cases where there is a downed wire.

real-time operations today and, if not, what practical enhancements would be required to make them useful. This project also explored using new and innovative data sources to improve fault location and detection methodologies.

The Fault Detection and Location project is one of the Smart Grid projects that was authorized pursuant to Advice Letter 4227-E (see Appendix A). The FDL project goals were to explore and, if possible, position PG&E to adopt analytics for rapid and reliable fault location as well as expand measurement-based detection of faults, including detection of high impedance faults which are difficult to detect using traditional overcurrent protection devices.

Figure 1. Challenge of Calculated Fault Location, Simplified Example



Calculating the distance from the substation to a fault can be accurate, but if there are branches on the circuit, it may indicate multiple locations that are widely dispersed.

Calculated fault location was the primary technology studied in this project. CFL is essentially a system that uses mathematical formulas for locating faults, using data recorded when a fault occurs to calculate the distance between the substation or measurement location and the fault. While CFL does reduce the possible fault zone, it often returns too many possible results, for example, in cases where there are multiple branches on the circuit. This project explored using additional data to further refine the results to reduce the possible fault zone even further.

Another focus of this project was to study ***SmartMeter™ data and alarms*** to determine if they could be used for real-time fault location. SmartMeter™ alarms are already being used to help identify outages in PG&E’s distribution management system (DMS), but this project specifically studied using this data to better pinpoint the location of faults.

Another important aspect of this project was ***fault anticipation***. There are a number of conditions that can pose an immediate threat to a distribution line, including unanticipated vegetation growth, arcing of line splices, and partial failure of capacitor banks or line regulators. While these conditions do not immediately cause an outage, it may be possible to detect them before they cause an outage by analyzing real-time and historical system data.

1.2.1 Use Cases

The use cases developed for this project were:

- **Calculated Fault Location** – Narrowing possible fault zones, with particular emphasis on:
  - Reducing the area that field technicians need to patrol to find the fault;
  - The ability to perform switching operations to better isolate the fault ahead of patrol (on circuits that do not have Fault Location, Isolation and System Restoration (FLISR)[2] control); and
  - Identifying situations where multiple faults have occurred to facilitate prioritizing potential hazard locations.

[2] FLISR, which began as part of PG&E’s Cornerstone Improvement Project. FLISR can reduce the impact of outages by quickly opening and closing automated switches to reduce the outage time.

- **High Impedance Faults** – Identifying traditionally difficult-to-identify faults caused by a disruption in a line including:
  - Broken wires (energized or not);
  - Single fuse operation on multi-phase laterals; and
  - Burnt jumpers.
- **Fault Anticipation** – identifying situations that will likely lead to faults using waveforms and other advanced data sources:
  - Increasing vegetation contact, particularly in rural and fire areas;
  - Line-to-line contact;
  - Failing cables and equipment; and
  - Damage or ordinary wear-and-tear to equipment that will result in near-term failures or significantly reduce service life.

1.3 Project Achievements

The Fault Detection and Location project has been successful in moving PG&E and the broader industry forward by using analytics as an operational tool rather than simply as an academic study. PG&E evaluated the current state of the industry and demonstrated the technologies and analytics that held the most promise for effective fault detection and location today.

There is no single off-the-shelf product currently available that provides a fully capable and automated solution for fault analytics, but vendors have provided the foundational building blocks that can be used to create layered solutions that can accomplish effective fault detection and location.

PG&E demonstrated key advancements across several areas including:

- Validating traditional electric system model-based CFL;
- Integrating and leveraging the latest line sensor capabilities like waveform capture;
- Demonstrating advanced use of voltage measurement as a fault detection and location tool; and
- Leveraging SmartMeter™ data to advance the difficult challenge of high impedance fault detection.

1.3.1 Technical Achievements

- Demonstrated that CFL, when combined with data from wireless line sensors, can produce actionable fault location information that can reduce fault restoration time by at least an additional 1.4%[3] over the 12.2% reduction enabled by the recommended line sensor deployment;
- Demonstrated that voltage measurements can provide valuable information to further refine CFL calculations, and that voltage data can often improve CFL location accuracy by 10% or more over that of CFL and line sensor data alone. The project also demonstrated that using fault voltage measurements alone can be used to better locate faults;
- Identified high impedance faults, which have previously been very difficult for utilities to identify because these faults do not produce sufficient fault current, using data from

[3] Calculated based on observations during the pilot; however, as more line sensors are deployed, additional fault data will be available that should increase the savings percentage.

SmartMeter™ devices. When this data is combined with waveform analysis to identify arcing, it is possible to identify certain energized wire down situations in minutes;

- Demonstrated that fault analysis using SmartMeter™ event and alarm data can reduce the outage duration by up to 17.5% on the subset of outages that involve open jumpers, which have lengthy manual fault detection timeframes. A corresponding saving of 20 minutes of patrol time for each of these outages could reduce annual customer outage minutes by 2.3 million;
- Identified a variety of asset management incidents, including: damaged fuses that required replacement; failed capacitor banks that had previously passed field inspection; line-to-line contact that was triggering momentary outages; and vegetation intrusion into a capacitor bank that was triggering momentary outages.

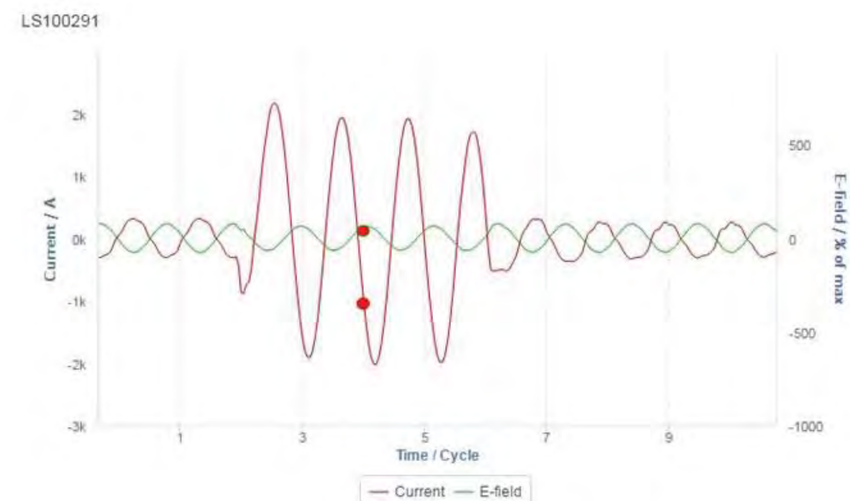


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Figure 2. Waveform showing the change in current and electric field (relative voltage) a fuse operates

1.3.2 Additional Achievements

- Created a technical specification that might be supported in next generation SmartMeter™ devices to enable voltage collection data over PG&E's entire service territory, potentially improving the ability to pinpoint faults;
- Implemented a new real-time data collection capability over the currently existing SCADA system to support CFL calculations;
- Demonstrated that line sensors can provide additional real-time data collection from substations that do not have SCADA controls;
- Demonstrated that waveform capture has the potential to be used proactively to predict impending field conditions that will lead to outages. These conditions, such as vegetation contact with primary voltage circuits or imminent equipment failures, would most likely have resulted in a customer outage in the very near future; and
- Demonstrated an ability to use impedance-based calculated fault data for effective troubleshooting by operating engineers or through support from the Diagnostic Center[4] today.

[4] PG&E implemented a targeted Diagnostic Center as part of the concurrent Line Sensor Pilot project to manage line sensors and was leveraged to support the analytic systems of this project.

1.4 Lessons Learned

This project placed a high priority on practical use cases that could be supported with new analytic concepts, and its significant achievements reflect that focus. This project included work that resulted in identifying solutions that can be implemented now, others that were demonstrated but that will require further work to provide a complete solution, and solutions that show promise for the future but will require longer-term development.

1.4.1 Product/Technology Assessment

Project experience demonstrated that CFL products that seemed to be ready off-the-shelf required additional data layering to provide useful operational results. Conversely, other goals like high impedance fault detection, which was thought to be very challenging to achieve, can be demonstrated today with data from SmartMeter™ devices. Analyzing electric waveforms to predict future faults holds great promise for the future, but will not be operationally useful until there is a complete library of waveform signatures and applications that can perform real-time analysis to match against that library.

1.4.2 Industry Recommendations

The state of the industry was monitored throughout the project. Monitoring was accomplished with a combination of vendor engagement, participation in industry meetings, as well as informal utility meetings and discussions. Utilities have a high level of interest in the areas studied by the Fault Detection and Location project. SmartMeter™ data holds the potential for helping utilities to identify service entrance connection issues, shorting of the windings in transformers, and cross-checking meter-to-transformer mapping. Existing CFL implementations are not being used extensively, because they tend to identify too many possible fault locations. All major vendor substation circuit breaker relays support high impedance fault detection. However, that feature is rarely used due to too many false positives. The observed state of the industry is very consistent with PG&E's finding that these technologies are rich in potential but currently lack complete end-to-end solutions.

Utilities are adopting line sensors at an increasing rate due to their low cost and attractive business case for load monitoring and fault location. Utilities are also very interested in fault anticipation, and this interest has grown as line sensors can now provide more sophisticated data, in particular electric waveform capture. However, PG&E did not find any utility that is using these software analytics in real-time operations today.

Because the Fault Detection and Location project took advantage of the data provided by the line sensors deployed by the concurrent Line Sensor project, the Fault Detection and Location project shared resources with the Line Sensor project's dedicated Diagnostic Center.

The Line Sensor Project's Diagnostic Center provided an incubator for the technologies, analytics, and methodologies studied in this project to guide them through the following lifecycle:

Figure 3. Lifecycle of Project Development at Diagnostic Center

PG&E found value in creating a "sandbox" where these technologies and analytics can be developed and piloted, and would recommend that other utilities consider this tactic.

1.4.3 PG&E Deployment/Implementation

The project identified a number of possible current and future solutions:

Solutions with Potential for Direct Implementation:

Diagnostic Center support for:

- *CFL*
    - Using CFL in locations where line sensors are installed to further reduce the area for potential fault locations;
    - Using CFL to help prioritize hazard reports and troubleshoot "no problem found" situations;
    - Reports on cumulative and fault-voltage-adjusted CFL for pinpointing vegetation issues;
    - Identifying failing capacitor banks, partial fuse operations, etc.;
    - Identifying momentary faults due to line-to-line contact;
    - Increased capture of fault values for CFL and engineering with Real-Time Automation Controller (RTAC) relay communications and line sensors at substations;
    - Updated SmartMeter™ query approach for more reliable customer meter status when responding to customer calls;
    - New data collection techniques and recommendations for protection equipment connected over SCADA systems; and
    - Line sensors installed at substations with sensitive settings/fault analytics to provide a low-cost alternative to full SCADA implementation and identify fault magnitude for fault location.
- *High Impedance Faults*: Manually using SmartMeter™ data to identify and locate high impedance faults such as broken wires for potential hazard prioritization and more effective dispatch.

Solutions Proven Through Demonstration That Require Further Development:

- CFL
    - The advantages of layering applications to combine historic and real-time line sensor, SmartMeter™, and other data for trouble monitoring and fault location; and
    - Deploying dedicated voltage measurement monitors for improved CFL and fault location, in advance of higher resolution SmartMeter™ voltage data.
- *High Impedance Faults:* Implementing a solution to reliably automate SmartMeter™-based broken wire high impedance fault detection from relays or line sensors.
- *Fault Anticipation:* Demonstrating fault location techniques that are necessary in locations where there is significant distributed generation.

Solutions That Require Long Term Development:

- *CFL and High Impedance Faults:* Upgrades to SmartMeter™ devices to provide fully-automated voltage measurement data recording ability and communication that would aid in fault location and high impedance fault detection. The ability to identify arcing indicative of an energized wire down situation using waveforms from line sensors and substation relays; and

- *Fault Anticipation:* Long-term development of a useful library of waveform signatures for predictive fault and waveform analytics by utilities and vendors, and systems that can use that data to automatically alert distribution operators.

1.4.4 Additional Lessons Learned

- Making all data from line sensors and other SCADA equipment available to technical operating and engineering groups opens up a valuable resource for those teams. During the project, there was increasing interest in this data and participation by non-project stakeholder groups;
- Applications like the ability to monitor capacitor switching to eliminate routine maintenance patrols are near-term goals; and
- Maintaining the Diagnostic Center to provide support to stakeholder groups and making all data available from sensors (rather than just the specific data elements identified for early use cases) may stimulate advancements and provide greater benefits.

1.5 Deployment Recommendations

Analytics based on line sensor and SmartMeter™ data can provide significant opportunities for better and more efficient operation of the electric distribution system and increase the value of existing and new infrastructure data sources.

Near-term Solutions Supported by Business Cases
These are supported with solid business cases that provide attractive benefit-cost ratios and their implementations are low-risk and practical:

- ***CFL:*** Using CFL in conjunction with sensing equipment such as line sensors for better pinpointing of faults; and
- ***High Impedance Faults:*** Using the SmartMeter™ system of outage messaging and alarms along with PG&E's DMS to detect and locate high impedance fault open wire conditions which can provide reduced patrol and identify potentially hazardous conditions.

Items Warranting Further Investigation, Development, and Testing:
The following are important concepts that should be reviewed and considered for future research and development projects:

- ***CFL:*** Working with vendors to implement better voltage measurement capabilities in SmartMeter™ devices;
- ***High Impedance Faults:*** Augmenting SmartMeter™ data with line sensor analytics to identify hazardous wire-down conditions; and
- ***Fault Anticipation:*** Advancing waveform analytics to detect pre-failure conditions by participating in larger-scale waveform signature analysis efforts that leverage industry partnering.

1.6 Conclusion

Smart Grid fault detection and location technologies and analytics have the potential to support a safer and more reliable electric grid. With this project, PG&E has demonstrated innovative ways of combining data from intelligent sensing devices in conjunction with advanced analytics to provide the knowledge needed to maintain and support a dynamic distribution system.

Calculated fault location solutions are an evolving technology space, and as new sensing devices are developed and deployed, these solutions need to be able to adapt to incorporate these valuable data sources. This has the potential to provide even greater levels of awareness that can enable faster outage response and improved asset management. In the near-term, PG&E can make use of today's data sources to improve and refine the fault locating capabilities of the products available today.

PG&E has demonstrated the value of using data from SmartMeter™ devices to identify previously difficult-to-detect high impedance faults, which can include hazardous energized downed wires. SmartMeter™ devices have the potential to provide even greater value with improvements to their voltage sensing capabilities, which would make every one of PG&E's five million SmartMeter™ devices a potential data source to strengthen the electric grid.

Fault anticipation—the ability to know that an asset is about to fail—is still very much an emerging technology space. More research needs to be done to create a library of individual waveform signatures that have the potential to identify incipient problems before they become faults.

As Smart Grid technologies become more prevalent, PG&E needs to find smarter ways to manage an ever-changing and increasingly complex electric distribution system. The grid of the future will be made stronger and more reliable by tools and capabilities built on sophisticated data and analytics. The *Detect and Locate Distribution Line Outages and Faulted Circuit Conditions* Smart Grid Pilot Project have been an important early step on the road to making PG&E's electric grid more reliable and resilient through the power of advanced data and analytics.

2 Project Background

2.1 Program Background

PG&E's vision for its Smart Grid is to provide customers safe, reliable, secure, cost-effective, sustainable and flexible energy services through the integration of advanced communications and control technologies to transform the operations of the electric network, from generation to the customer's premise. This aligns with the policy goals of the Commission and the California legislature. Senate Bill (SB) 17 established that California would increase the use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid. In response to SB 17, the Commission adopted D.10-06-047, which established the requirements for the Smart Grid Deployment Plans. D.10-06-047 specified that "[s]ubsequent utility requests to make specific Smart Grid-related investments, however, would occur in utility-specific proceedings where the reasonableness of particular Smart Grid investments can be determined." These proceedings include both General Rate Case filings, and applications for specific projects. On November 21, 2011, PG&E filed Application 11-11-017 requesting authorization to recover costs for implementing six specific Smart Grid Deployment Pilot Projects over four years. In 2013, the Commission in D. 13-03-032 approved four of the projects, including Fault Detection and Location Project. Work was initiated following the CPUC's approval of the Volt-Var Optimization implementation plan filed in AL 4227-E.

2.2 Supporting the Smart Grid Vision

The utility of the future will be driven by data and analytics. While SCADA equipment, line sensors, and SmartMeter™ devices can provide that data, their full value can only be realized when the data is analyzed and interpreted to produce operational knowledge that can power real-time decision-making.

2.2.1 Relevance to Strategic Goals

The Smart Grid future is closely tied to PG&E's concept of the Grid of Things™. Like the Internet of Things, where people are connecting millions of devices to the Internet, more and more of PG&E's customers are connecting devices to the grid to create new value and new services to meet their energy needs, such as rooftop solar generation and electric vehicles.

To ensure reliability in a Grid of Things™, where both energy and data flows in multiple directions, PG&E needs to move beyond traditional monitor and control SCADA implementations to a world where the significance and quantity of sensing devices throughout the electric grid is much greater. These new methodologies should also maximize the use of existing data and focus on affordable solutions that provide the best benefit-to-cost ratio.

The Fault Detection and Location project specifically supported PG&E's strategic goals for the utility of the future by focusing on innovation, minimizing hardware investments, maximizing the value of data, and avoiding expensive traditional solutions.

2.2.2 Relevance to Utility Industry

PG&E has demonstrated industry leadership with this project, particularly in the areas of: practical implementation of existing calculated fault location analytics, using data from SCADA-connected devices, wireless line sensors, fault voltage measurements, and using SmartMeter™ data for high impedance fault detection.

This project leveraged the resources of the Diagnostic Center, which was created as part of the concurrent Line Sensor project, to provide an incubator where different data sources and analytics could be combined in different ways to produce actionable results. The freedom to experiment with different analytics and data sources on a small scale is an element of this project's success.

2.3 Technology Description

Calculated Fault Location

CFL is an algorithm used by DMS and modeling applications to determine the location of a fault using data from distribution devices. The data sources include electrical fault current measurements from SCADA-connected equipment and wireless line sensors. The project used analytics software from vendors and internally-developed solutions using development platforms such as Python. CFL has the potential to significantly improve reliability by reducing the amount of time it takes to locate faults. CFL is not a new concept, but the addition of new data sources providing fault current data has strengthened its potential to improve fault location.

High Impedance Fault
High impedance faults occur when there is a break or disruption in a line, which impedes the flow of electricity. These faults do not produce a detectable amount of fault current, and are therefore difficult to identify using traditional overcurrent protection devices. These faults can go undetected for hours. Often, this leaves a conductor energized, which poses a danger to the public, particularly in cases where there is a downed wire. The data sources for the high impedance fault study were SmartMeter™ outage alarms and logs, as well as results of ping requests to meters from PG&E's DMS. This data was manually analyzed and compared against records of historic field events to correlate with high impedance faults and prove the effectiveness of the analytics.

Fault Anticipation and Waveform Analytics
Fault anticipation is the ability to identify situations that will eventually lead to faults, such as aging equipment and vegetation overgrowth. With the increasing availability of electric waveform capture available from both SCADA equipment and wireless line sensors, PG&E wanted to determine if studying these waveform signatures might indicate conditions that will lead to faults in the future. This project explored waveform analytics, both with off-the-shelf applications that were available from line sensor and other vendors, as well as manual analysis. Waveform data was obtained from substation relays, line sensors, and voltage monitoring devices. Analytics applications were provided by vendors and data was provided to third-party data scientists. PG&E engineers and researchers evaluated the data both directly and with software tools.

2.4 Project Objectives

One prime objective was to demonstrate improved fault location, using CFL software and analytics. Improved fault location accuracy reduces the area and patrol time needed for field technicians to find and repair the fault. The project began with evaluating existing vendor offerings to determine if they could be deployed now and how they could be improved or advanced to provide the greatest benefits. The project then pursued options to improve the effectiveness, accuracy and practicalities of analytics-based fault location. Better fault location enables operations personnel to perform switching operations prior to dispatching field technicians in locations that do not have FLISR, and enables better prioritization in cases where there are multiple faults on the same circuit.

A second objective was better fault detection. In particular, the project focused on detection of faults not normally detected using conventional approaches and devices, including high impedance (HiZ) faults. A fault that has high impedance is difficult to detect using standard overcurrent protection devices. These faults are caused when there is a disruption in the line, such as a broken wire, single fuse operation on a multi-phase lateral, or an open jumper.

Fault anticipation—detection of incipient faults—was a final objective and focused primarily on waveform analytics. Incipient faults are faults that develop due to failing equipment or changing field conditions, such as increasing vegetation contact. This objective was expanded to a minor extent to include gaining a better overall understanding of the value of waveform capture and whether studying these waveforms can identify pending failures and indicate the overall status and health of the distribution system.

These objectives represent key tools for monitoring and managing an increasingly more complex electric grid. These methodologies support addressing the higher-level challenges of increased Distributed Generation and Distributed Energy Resource Management System, and the demand for higher levels of reliability and safety. FDL has the potential to improve fault location in a DER environment where there are multiple distributed generation sources, which increases the complexity of the distribution system.

PG&E pursued these objectives through a pilot rather than going straight to deployment because of the innovative and evolving nature of these technologies. None of the technologies considered are in widespread operational use today, and it would be unrealistic to expect trouble-free adoption or performance that would meet PG&E's expectations. Also, without real world experience using these analytics, PG&E would not be able to develop a clear and practical product definition or specification to provide to vendors.

2.5 Planned Benefits of Recommended Deployment

There are four primary areas where PG&E can benefit from employing new analytics and data sources to improve system reliability: Real-Time Operational, Operational Awareness, Asset Management/Fault Anticipation, and Safety. These areas represent the goal of the project, which is enabling PG&E to implement practical improvements in fault location and detection. Fault location and detection analytics are directly relevant to all of these areas.

2.5.1 Real-Time Operational

The project needed to determine if FDL could provide a cost-effective means to more accurately identify faults in real time throughout the grid.

- ***Fault location***. CFL analytics paired with line sensor and SCADA recloser data enables fast identification of faults and allows switching ahead of patrol. The core real-time operational benefits from FDL all relate to improving reliability. Better fault location is a core benefit, as it directly affects the ability to restore power to customers in an outage situation; and
- ***High Impedance Fault Detection.*** Better detection and location of high impedance faults, including hazardous energized downed wires was one of the primary goals of this project.

2.5.2 Operational Awareness

Operational awareness supports distribution operators on a daily basis. The project needed to determine if FDL could provide benefits to operators beyond fault identification.

- ***Data for "no problem found" investigations.*** CFL and line sensors can help to uncover the root causes of problems that create repeated faults elsewhere in the system;
- ***Line to line contact and other multiple fault conditions.*** Assures all fault issues are addressed and avoid future fault. In storm season, multiple fault events often occur in close proximity, and better fault location can help to better identify these situations and aid in prioritizing repairs; and
- ***Power Quality Issues.*** Power quality issues can also be better identified by studying harmonic distortions.

2.5.3 Asset Management and Fault Anticipation

The ultimate goal of fault identification is to anticipate faults before they happen. The project needed to determine if FDL could help operators to identify equipment failures before they happen.

- ***Bad capacitor switch or blown cap fuse.*** Better fault detection can help to identify situations such as bad capacitor switches or blown capacitor fuses and support condition-based maintenance. This can help to avoid voltage complaints, and reduces field investigations;
- ***Fault count and energy throughput for non-SCADA reclosers.*** Deploying line sensors to substations that do not have SCADA control to provide remote data about the distribution system can assist in fault count and energy throughput. This has the potential to extend maintenance cycles; and
- ***Overall condition-based maintenance.*** This also has the potential to extend maintenance cycles.

2.5.4 Safety

Improvements in reliability can have a positive effect on safety. A fault needs to be detected before it can be made safe.

- ***Faster restoration of power of public safety equipment.*** Reduces potential for traffic and other accidents by restoring power to public safety infrastructure such as streetlights, traffic lights, and railroad crossings;
- ***Faster identification of potentially energized downed wires.*** The ability to better detect high impedance faults that may be caused by energized downed wires is particularly relevant to safety. This reduces the potential for fires and electric shock; and
- ***Avoided hazards from failing equipment.*** The ability to prevent hazards from failing equipment such as falling wires and enclosures being breached can improve public safety.

2.6 Metrics

2.6.1 Regulatory Metrics

The Fault Detection and Location project meets a number of regulatory goals, by providing real-time data to operators that can improve reliability, efficiency, and safety; and better support distributed generation. Please refer to Advice Letter 4227-E (cited in Appendix A) to see how this project met the nine requirements of the application detailed in Decision 13-03-032.

2.6.2 Technical Metrics

FDL required a sufficient number of events to prove to engineers and operators that the location results were reliable and accurate and, in fact, high impedance faults could be detected. This required:

- Analyses of all sustained faults captured in the Line Sensor pilot;
- Review of hundreds of fault events using substation fault values for calculation;
- Detailed meter data analysis of 30+ wire down events;
- Lab testing of all SmartMeter™ types in common use at PG&E.
- Analysis of fault voltage measurements for all events where data was available.

2.6.3 Financial Metrics

PG&E performed a Benefit-Cost analysis for both CFL and the meter ping application for detecting high impedance faults. In the case of CFL, PG&E analyzed enabling CFL in conjunction with deploying line sensors, and calculated the minimum number of feeders that would need to have line sensors deployed to yield a Benefit-Cost ratio greater than one, given the fixed costs of enabling CFL in DMS, and the incremental reliability benefits driven by CFL over those that could be achieved with line sensors alone. In addition, PG&E analyzed the reliability benefits associated with reductions to field patrol time enabled by the implementation of an enhanced meter ping algorithm to help pinpoint high impedance faults.

2.7 Scope

The primary scope of this project was to evaluate the technological capabilities of analytics to better identify faults, and events and conditions that could lead to an outage and/or adversely impact public safety, such as detection of open phases and high impedance faults. The desired outcomes include reducing outage and hazard response time and providing enhanced data to improve the efficiency and operation of the distribution system. The project also sought to find ways to anticipate faults by using analytics and electric waveform data.

2.7.1 Major Tasks/Initiatives

The project included three main efforts: Calculated Fault Location, detecting High Impedance Faults, and Fault Anticipation and Waveform Analytics.

- **Calculated Fault Location**
  This effort involved analyzing fault data collected from PG&E's DMS and system modeling information analyzed with CFL software, and then layering that with data from wireless communicating line sensors and voltage data to further refine the results. The objective was to reduce the possible fault zone down to the smallest possible area, which would result in more efficient line patrol for field technicians. Further narrowing of the fault zone also enables operations personnel to perform switching operations prior to dispatching field technicians, which improves safety and enables faster restoration for customers not directly affected. It also enables operations personnel to better prioritize restoration operations in cases where multiple faults have occurred, which can often happen during storm season;
- **High Impedance Faults**
  This effort sought to find ways to identify high impedance faults using SmartMeter™ data and alarms. These are faults that tend to be caused by a break or disruption in an electrical line, for example, a broken wire which may be energized and present a danger to the public. Other conditions that can cause a high impedance fault are burnt jumpers and fuses that operate on only one of the three phases. These types of faults are difficult to identify using traditional system protection devices like fuses or overcurrent relays.
- **Fault Anticipation and Waveform Analytics**
  PG&E hoped to determine if there might be ways to identify situations where a fault will likely occur in the future due to conditions such as vegetation overgrowth and equipment wear and tear. Methods demonstrated included studying the waveforms and other data produced by line sensors to determine if there are specific patterns that would indicate conditions that will eventually result in faults.

2.7.2 Measurement and Verification Components of Business Case

The Business Case analysis for CFL used the same methodology as the Line Sensor pilot project for reliability benefits, as the effectiveness of CFL analytics depend on the additional data points that can be provided by line sensors.

Potential addressable mainline customer outage minutes were based on a study of actual outages reported in PG&E's Integrated Logging Information System from January 1, 2013-June 30, 2016. This analysis excluded Generation, Transmission, Substation, Independent System Operator, Transformer Only, and Fuse and Planned Outages, to identify the subset of outage minutes that line sensor data coupled with CFL could help reduce.

In the Line Sensor Project business case, PG&E performed a detailed feeder-by-feeder study of the potential reductions to mainline customer outage minutes that could be attributable to line sensor data alone, without CFL. Then, in this CFL business case, PG&E performed an analysis to determine the amount of incremental duration reductions that could be achieved on top of the line sensor benefits, based on further refinement to the potential fault patrol zone with the use of CFL.

Finally, for the selected feeders, the Value of Service (VoS) model[5] (VOSCalc-2.0c) was used on a division-by-division basis, based on the actual weighting of customer classes for each division, to determine the present value of the incremental CFL-enabled outage duration reductions, compared with the present value of the costs required to overlay line sensor fault zones with the potential calculated fault locations in DMS.

2.7.3 Integration Challenges

The project identified significant challenges with getting data from SCADA devices, and addressed that by implementing a methodology to acquire data from substation relays[6] and performing a thorough investigation and documentation of the work that would be needed to acquire data from SCADA line reclosers.[7] The project also deployed line sensors to smaller substations that do not have SCADA controls to see if they could provide data to support fault detection and location calculations.

[5] The VOS analyses are based on survey data collected for each customer class. The responses were used to estimate the value of service reliability for each customer segment, using procedures that have been developed and validated by the Electric Power Research Institute and other parties.
[6] SCADA-enabled substations often include digital protective relays that not only trip the substation breaker when a fault occurs, but also capture fault current measurements and waveforms. Standard SCADA operation only uses breaker status information and does not retrieve this advanced data.
[7] Line Reclosers are protective devices functionally similar to a substation circuit breaker but that can be installed in the field. The recloser control is comparable to the substation relay with similar features.

3 Project Activities

3.1 Phase 1

The following sections provide an overview of the Phase 1 activities. For more detailed information, please see Advice Letter 4576-E (cited in Appendix A).

3.1.1 Benchmarking

PG&E held benchmarking interviews with utilities including Florida Power & Light, Commonwealth Edison, San Diego Gas & Electric, Oklahoma Gas & Electric, and Entergy to understand drivers for implementing CFL solutions, vendor selection processes and outcomes as experienced at other utilities. These benchmarking sessions helped PG&E to develop test plans and determine which methods and technologies (or combinations of them) would be most advantageous to pursue.

3.1.2 Prospective Vendor Evaluation

PG&E issued a Request for Information (RFI) in December 2013 to evaluate the capabilities of available CFL products. PG&E engaged industry experts to ensure that the RFI would provide information relevant for the selection of candidate vendors from whom additional information would be requested. The RFI focused on the following attributes of the vendor technologies:

- Overall CFL Solution Approach
- Solution Functionality
- Reporting, Analytics, and Evaluation, Measurement and Verification Capabilities
- System Maintenance and Support Requirements
- Security
- Application Architecture
- Network and Communications
- System Integration
- Existing Installations / Customers
- Total Cost of Ownership

Twelve calculated fault location vendors responded to the RFI and were evaluated by project stakeholders including PG&E Electric Distribution Operations, Asset Management, and Information Technology (IT) organizations. The vendor evaluation was aligned with the PG&E's sourcing policies and included consideration of supplier diversity, safety, and environmental responsibility, in addition to the technical evaluation of vendor responses. Seven vendor offerings were selected for detailed investigation in the evaluation process.

Two CFL vendors were selected for laboratory testing after passing the RFI product evaluation. The products evaluated in the lab included a cross section of "simple" to "advanced" options. The selected vendors were evaluated in the Phase 1 testing and evaluation at PG&E's Applied Technology Services (ATS) laboratory in San Ramon.

3.1.3 ATS Laboratory Testing

Laboratory Testing performed at the ATS facility focused on evaluating the accuracy of vendor solutions and gathered the information needed to support design development, operating instructions, and training that would be required for the Phase 2 field pilot. The lab testing was conducted using actual confirmed historic field fault data which was processed using the vendor solutions to calculate the estimated fault locations.

The extensive laboratory testing of vendor products indicated that both vendor products had the necessary features and functions to demonstrate capabilities of calculated fault detection.

3.1.4 Initial Benefits Assessment

High level benefits estimates were provided in Advice Letter 4227-E. Phase 1 testing and analysis did not uncover material new issues, relevant to costs or benefits, for the core value applications of improved reliability and optimized operation of distribution lines. PG&E validated that CFL technology offers the potential direct benefits to customers of increased system reliability, reduced cost of outage response, and improved safety.

Based on engineering analysis performed in the lab during Phase 1, PG&E prepared demonstrations to confirm that CFL has the potential to offer these system reliability and outage response benefits. In the Phase 1 lab study, the benefits could only be estimated by simulating real events. Phase 2 pilot deployments would use real operational data and inform PG&E regarding all targeted benefit elements. Cost and benefit models would also be enhanced during the deployment and operation stages.

3.1.5 Transition to Phase 2

Phase 1 testing demonstrated viable calculated fault location solutions that were ready for pilot field deployment. Therefore, PG&E recommended that the Fault Detection and Location project move into Phase 2. In Phase 2, PG&E planned to perform field trials of CFL solutions on distribution feeders on a subset of PG&E's divisions and proceed to operate, evaluate and demonstrate the project in a field trial, which included the 2015-16 storm season. In addition to testing the field capabilities of CFL solutions, PG&E planned to utilize SmartMeter™ and line sensor data to augment these solutions to improve the clarity of the results. During 2016, the pilot would continue to study basic CFL and also to explore potential advanced functionality.

3.2 Phase 2

The initial scope for Phase 2 specified that PG&E would perform field trials of two vendor CFL solutions on a small number of distribution feeders, and would attempt to leverage and complement SmartMeter™ technology. However, early in Phase 2, it was determined that only one of the two vendor solutions provided a reasonable and cost-effective solution. While this solution did provide accurate CFL results, it was based on mathematical formulas that frequently returned more than one possible result. CFL solutions were not mature enough to provide an off-the-shelf solution and would only be of practical use when other data, such as line sensor data and voltage measurements, could be layered in to further refine the results.

For this reason, the project shifted focus to also take advantage of the data provided by the wireless communicating line sensors that were being piloted in the concurrent Smart Grid Line Sensor Project. The Line Sensor Project's Diagnostic Center helped in developing the processes and methodologies that were studied in the Fault Detection and Location project.

3.2.1 Device/Software Architecture Development

Calculated Fault Location

The scope for Phase 2 was to evaluate the application of analytics for improved fault location and detection. The initial Phase 2 effort described deploying the vendor's CFL solution in the production environment. However, this would have limited the evaluation to only a few feeders. Early in Phase 2 of the project, it also became clear that the CFL solution that had been chosen in Phase 1 would not have provided an out-of-the-box solution for immediate operational use, and therefore investing in the IT work and licensing to enable CFL directly in DMS would not have resulted in an operationally useful solution. It was a more effective use of the project budget to shift focus towards piloting the CFL solution by developing demonstration-level applications that leverage the existing and already-licensed power flow model and system data. In fact, this approach was not only much less costly, it allowed experimentation would have otherwise not been possible, and introduced the concept of layered solutions to provide more reliable results.

Being a pilot project as opposed to a staged deployment, the project was able to adapt the implementation approach to a final arrangement of: (1) obtaining data from existing substation relays rather than installing additional relays; (2) increasing fault data by including measurements from line sensors; (3) running CFL calculations using the lab DMS system and PG&E's power flow modeling tool; and (4) post-event evaluation of faults. These choices greatly increased the amount of data available for analysis and allowed the flexibility to introduce other data sources such as fault voltage measurements.

PG&E leveraged the Line Sensor Project's Diagnostic Center to provide a "sandbox" where the project could demonstrate the CFL functions in parallel to production DMS operations. As experience was gained, new ideas were developed to augment the CFL capabilities with added data, and PG&E shifted focus to work on layering applications to enhance the solution. Several architectures were investigated and documented, and a gateway/middleware approach was demonstrated under lab conditions by one vendor. Also, PG&E implemented a number of pilot applications. For location, the most relevant application was semi-automation of CFL based on the PG&E system model supported by the PG&E's power flow modeling application. To obtain fault measurement data in an effective manner from substations, PG&E introduced a server that could query the existing SCADA system.

High Impedance Faults

Because the methods used in this project initiative were experimental, the high impedance fault location studies using SmartMeter™ data were executed at a data extract and test level so they did not require implementation. However, a significant amount of work was required to enable access to data sources from PG&E's operational systems including the SmartMeter™ system, including temporary enabling of enhanced data capabilities not in production use at PG&E at the time.

Fault Anticipation

For the fault anticipation activities, PG&E needed to acquire waveform data from the line sensors being piloted in the concurrent Line Sensor project. This required developing special applications to extract the data and reformat it for use by PG&E and third-party analytics.

3.2.2 Use Case Development

In Phase 1 of the project, PG&E consulted with relevant stakeholder groups to identify and prioritize use cases. The use cases developed for this project were:

- Narrowing of the possible fault zones, with emphasis on:
  - Reducing the area that field technicians need to patrol to find the fault;
  - The ability to perform switching operations to better isolate the fault ahead of patrol (on circuits that do not have FLISR control); and
  - Identifying situations where multiple faults have occurred to facilitate prioritizing potential hazard locations.
- Identification of traditionally difficult-to-identify high impedance faults including:
  - Broken wires (energized or not);
  - Single fuse operation on multi-phase laterals; and
  - Burnt jumpers.
- Fault anticipation – the ability to identify situations that will likely lead to faults using waveforms and other data:
  - Increasing vegetation contact, particularly in rural and fire areas;
  - Line-to-line contact;
  - Failing cables and equipment; and
  - Damage or ordinary wear-and-tear to equipment that will result in near-term failures or significantly reduce service life.

3.2.3 Site Planning

The project analyzed historical and real-time data from PG&E's entire DMS and SCADA system. Additionally, there were several site-specific use cases involving line sensors[8] that were investigated as part of this project:

- Line sensors were deployed in several substation locations to investigate whether they could provide an alternative low cost data source for substations that do not currently have SCADA. Line sensors can provide all the sensing features of SCADA but no control functions. If line sensors are installed around the substation, they can detect faults and trigger alarms in DMS and can determine if the fault is sustained or momentary. They can also provide fault magnitude, timing, and faulted phases, as well as line loading, both real time and historical, for daily operations and for operational and planning studies.
- Line sensors were also deployed in rural areas that are a fire risk to see if they could provide valuable data in areas that are difficult to patrol. In these deployments, the installers requested that in addition to the Electric Distribution Asset Management and Geographic Information System circuit map image, a satellite imagery version of the circuit map be included. This was so that inaccessible locations, such as backyard or gated construction and other hard-to-access areas could be more proactively identified and mitigated.
- Line sensors were also deployed near overhead line to underground line transitions to provide additional CFL data points for underground line faults.

3.2.4 Technology Development

Today's SmartMeter™ devices are not optimized for measuring very low voltage sags, but rather for normal power quality applications. If the sag amount exceeds about 20% of nominal, the meter shut-down logic overrides the sag measurement. Because the sag events that would be most useful for CFL

[8] Technical evaluation of line sensors is included in the concurrent Line Sensor Project. Advanced use cases involving analysis of line sensor data were included in this project.

calculations would be 90% or greater, PG&E determined that SmartMeter™ devices as deployed today would not provide the data needed. It is possible that firmware changes to SmartMeter™ devices might allow them to capture voltage sag data beyond 20%, however it is likely that this is a hardware limitation that could only be addressed by future meter hardware.

As a proxy for future SmartMeter™ capabilities, PG&E had fault voltage measuring *voltage sag monitors* (VSM) custom-built and deployed to about 100 locations during the pilot project and maintained by the Line Sensor Project's Diagnostic Center. This data was used for refining CFL calculations, and was investigated for the high impedance fault location use case.

PG&E's network vendor also offers an application designed to perform high frequency voltage readings to identify voltage sags or swells which was evaluated as part of the *Electric Program Investment Charge (EPIC) 1-14 Next Generation SmartMeter™ Telecom Network Functionalities Project*. This application provides the ability to collect high frequency instantaneous voltage data from meters. However, this application has a per-meter cost structure, and there is no current business case for systemwide deployment.

3.2.5 Installation/Integration/Iteration

Calculated fault location software alone often provides multiple possible fault locations, particularly in areas where there is branching of the lines. As a result of this finding, PG&E investigated methods to better refine the results. Various data source overlays were tested, and the most promising ones pursued. Integration via an RTAC server automated obtaining the fault data from substation SCADA relays to PG&E's data historian to support the project studies. The data from the line sensors piloted in the concurrent Line Sensor Project was also integrated into this project.

For high impedance fault detection, the data from SmartMeter™ devices needed to be verified to determine a baseline response from meters when no faults were present. A great deal of effort was required to understand and characterize both meter and system characteristics before events could be analyzed and conclusions determined.

VSM devices were installed on feeders in conjunction with line sensors. Initial installations were scattered to obtain a wide variety of data. Monitors were also placed near the substation feeder source and near the end of each major branch of the feeder. The VSM head-end system was vendor-hosted with no integration beyond email notifications.

3.2.6 User Feedback Collection

The project established an advisory group of Operating Engineers and Distribution Operation supervisors to obtain advice, directions, and feedback. Input was gathered from non-advisory group stakeholders through informal meetings and holding Open House informational sessions.

User feedback was focused by use case. For example, the primary user of fault location is Distribution Operations so they were most engaged on that topic. Waveform analytics was most relevant to Operating Engineers, Project Engineers, and ATS Engineers. These groups attended vendor meetings and participated directly in both their use and in the project conclusions.

3.2.7 User Experience

Direct users included Operating Engineers and the Line Sensor Project's Diagnostic Center. Operators reviewed screenshot exports and slides illustrating potential data displays. User feedback indicted CFL could not be simply "turned on" for distribution operators because multiple, and sometimes inaccurate results were often returned. They indicated that an implementation that could provide reliable and clear fault location would be highly valuable, as would high impedance fault detection. The latter includes energized and non-energized broken wire conditions and related events such as failed jumpers and one-fuse operation and a multi-wire lateral. Operating engineers participated directly with CFL tools and reported good value when CFL is combined with line sensor data to narrow the fault zone. Operators also found the fault anticipation, line disturbance, and other data provided by this project to be operationally useful.

Operators identified several use cases where CFL data would have significant benefits. These include reduced patrol time, reduced safety hazards, filtering of hazard call information and dispatch prioritization. Engineers found that CFL, voltage data, and waveforms were helpful as tools for identifying system problems, solving "no problem found" challenges (when an unknown underlying condition causes persistent faults), and post-event forensics.

Dispatch personnel brought to the project's attention the challenge of multiple hazard reports during power outage events. Modern technology is making it increasingly convenient for customers to alert PG&E to in-field issues. Although this is overall very beneficial, it also results in many unclear or incorrect reports. This poses a problem for prioritizing field efforts. Dispatch management indicated that CFL data, even if not perfectly accurate, and providing more than one potential fault location, could help prioritize reported hazard locations. Locations where multiple data sources pointed to the same location would be dispatched to first.

4 Project Results and Lessons Learned

4.1 Project Achievements

Calculated Fault Location

- Effective use of CFL augmented by line sensor data;
- Improvement of CFL accuracy using fault voltage measurement;
- Enabled fault magnitude collection from digital-capable devices (circuit breakers or line reclosers) on 1,100 circuit breakers, and provided a method for enabling it on 1,550 line reclosers;
- Captured over 800 faults for current-based CFL, hundreds evaluated between current or voltage measurements and, when possible, using the overlap of these with each other along with line sensor data;
- Installed more than 100 fault VSM devices and captured thousands of voltage sag waveforms;
- Discovered and exploited the benefits of measuring fault voltage often improving CFL location accuracy on average by 10% and more;
- Used fault voltage for direct location of faults without CFL calculations;
- Quantifying the actual benefits potential with enhanced field restorations using CFL layers with line sensors, voltage sags, or both in progress;
- Lab-tested and characterized line sensor electric field measurement performance;
- Installed and enabled high sensitivity data capture on 46 feeders adjacent to substations; and
- Reviewed hundreds of line sensor-reported line disturbances.

High Impedance Faults

- Demonstrating successful detection of high impedance faults using SmartMeter™ data;
- Executed more than a half million SmartMeter™ ping tests;
- Performed detailed post-event analysis of multiple wires down events and SmartMeter™ performance.

Fault Anticipation and Waveform Analytics

- Identified equipment condition using fault and waveform analytics, which enables the ability to predict faults and to determine readiness for operations; and
- Engaged four third-party industry expert groups for additional evaluations of waveform analytic and high impedance fault capabilities.

4.2 Product/Technology Assessment

Calculated Fault Location

The CFL solution provided by the vendor uses a mathematical calculation that relies on predicted current to determine the distance from the measurement location to the fault. While this can be accurate, there are many factors that can contribute to both accuracy errors and number of possible mathematically valid locations that are returned. The most obvious example is a situation where there are multiple branches in the distribution line—the fault could be on any one of the lines. This would result in a situation where the field technician would need to patrol all branches to find the fault. Therefore, today's CFL solutions are not yet able to provide a simple off-the-shelf solution to better locate faults, and that further data sources beyond those used by the vendor's CFL solution were needed to better refine the results.

PG&E then looked at the data provided by line sensors. Line sensors can identify areas where a line is experiencing a fault, but because a sensor can only identify that a fault has occurred somewhere beyond it, the usefulness of line sensors is dependent on how many are deployed and their locations.

While PG&E expected to be able to use the voltage measurement capabilities of SmartMeter™ devices for this project, it was determined that their ability to return useable voltage data today was limited. For this project, PG&E chose to deploy 120 custom-built voltage monitoring devices to demonstrate whether communicating voltage measurement devices could aid in narrowing down possible fault locations. By using the voltage sag measurement from multiple monitors, a possible fault area can be identified.

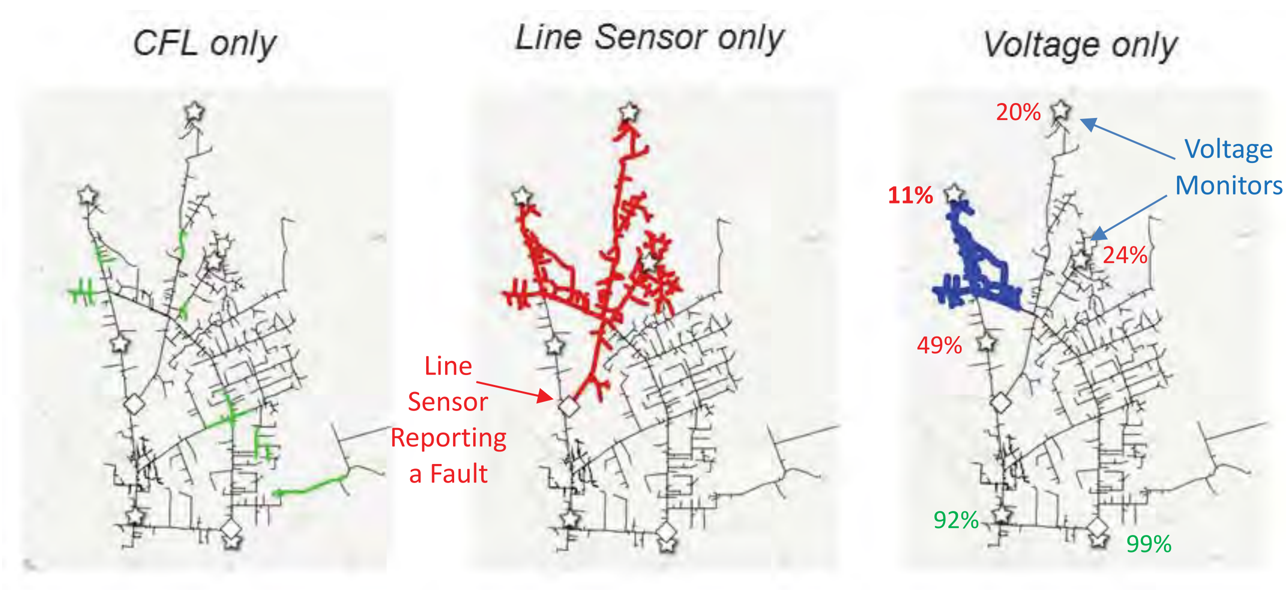

Figure 4. Maps Comparing Fault Location

When the results from all these methods are combined, the potential fault zone can be reduced significantly—from miles of patrol down to perhaps a few yards.

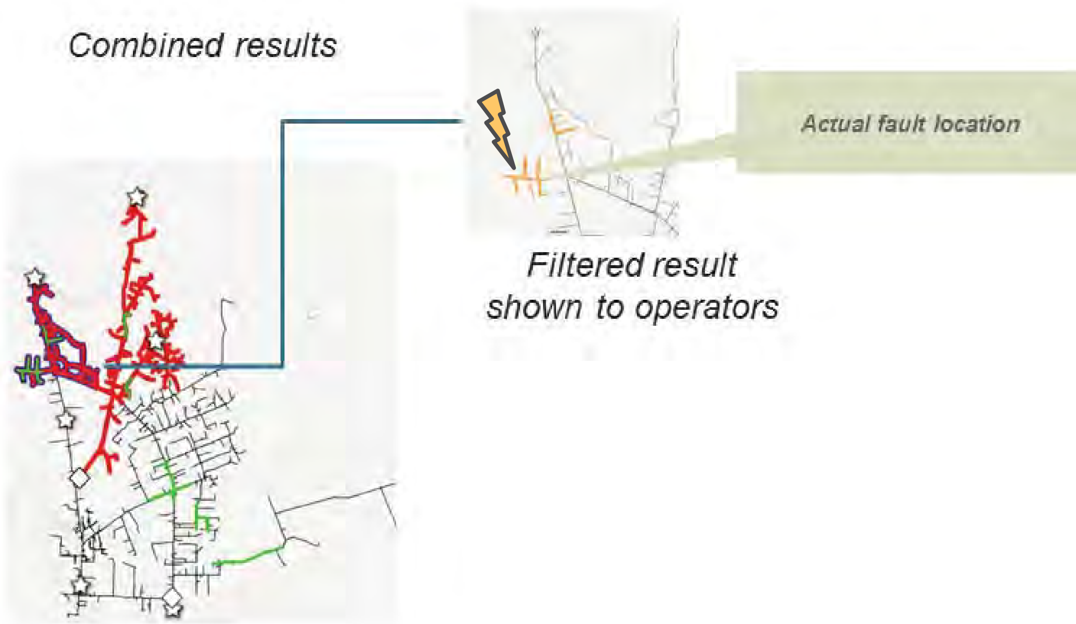

Figure 5. Combined Fault Location Data

CFL and data layering can also be very helpful in "no problem found" investigations. These are situations where field technicians repair the immediate cause of the fault, but not the underlying condition that caused the fault. In one example of a "no problem found" investigation, for a week-long period during the 2016 storm season, 586 customers experienced four sustained outages, totaling 317,416 of customer minutes of outage (C-MIN). The CFL solution demonstrated in this project indicated a specific zone to patrol. The area identified included a rear yard easement where two phases near one another had been slapping together ("line-to-line contact"), which caused the fuses to blow repeatedly, resulting in the outages. If CFL and line sensor data had not identified the root cause of the fuses blowing, these outages would have continued.

High Impedance Faults

High Impedance Faults are defined in an extremely broad manner and include any line failure that occurs when there is an interruption in the flow of electricity that is not detected using conventional current-based measurements. This project focused on the most common type of high impedance fault—and the one with the greatest safety concern—a broken wire, which may be energized. High impedance faults can also include open jumpers and unidentified single fuse operations that cause an open condition in the line. They are traditionally hard to detect because they have impedance that is high enough that the faults do not produce sufficient fault current to be detected by conventional overcurrent protection devices. Most high impedance fault current is less than 100 amperes and is often a result of an energized conductor making contact with a poor conducting surface such as a tree, a structure, or the ground. These undetected high impedance faults can pose a serious public safety hazard.

PG&E investigated a novel method of detecting high impedance faults—by studying the events and alarms reported by SmartMeter™ devices. When studying these events and alarms, PG&E noted that the meters on the source side of the break or disruption operate normally, while meters on the other side of the break will either have no voltage or partial voltage (enough to power the meter's radio or network interface card (NIC), but not enough to power the meter's electronics). Other meters that are past the break may go into a distressed mode and send out repeated alarms as partial voltage fluctuates.

Meters on the source side of the fault will not send any alarms, and not all meters past the break will successfully send an alarm. To reliably confirm meter status, there needs to be a reliable method to determine meter status. Distress alarms can indicate that an open wire condition is likely and trigger other system actions. PG&E demonstrated *pinging* (querying) meters to determine their field condition. Meters that do not respond to the ping request at all are assumed to be in a full no-power state. If only the meter's NIC responds, then it is experiencing partial voltage, and meters that send a normal response are in a full voltage powered state. Since a "no response" condition is used to infer that a meter is out of power, the effort began with testing the ability of meters to return a ping request when the SmartMeter™ system was in a normal, fully functional state. Ping results were very reliable, with a response rate better than 99%, which supports the theory that a no-response is a reliable indication that the meter has lost power.

A conclusive technical understanding also required extensive lab testing of meters under differing voltage conditions to fully map their expected behavior during high impedance fault events. This knowledge was combined initially with attempts to deduce the open wire locations using the meter's outage alarm messages, and then adding in the other meter stress alarms, and finally by adding ping responses. The effort also included actual field implementation of ping algorithms and a large amount of data analysis.

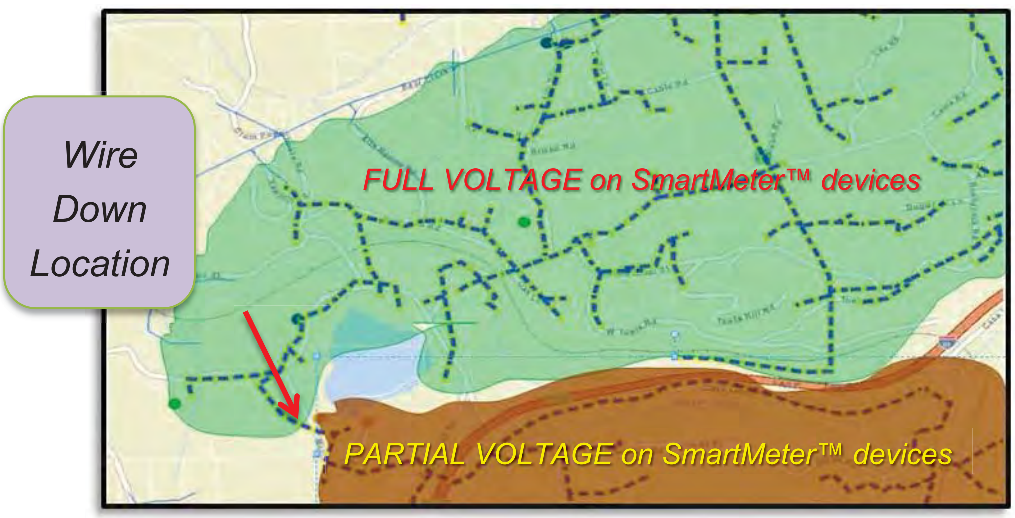

Figure 6. SmartMeter™ Voltage Used to Indicate a Downed Wire

Results were conclusive that partial voltage behavior occurs in many high impedance, open wire events and that this condition can be detected using PG&E's existing SmartMeter™ infrastructure. Normal outage messaging is not sufficient to provide usable information regarding the fault conditions and locations, but distress messaging provided a clear indication of a partial voltage event. A full implementation of ping logic would result in the most accurate and reliable results. Converting some of the ping response messages to meter-initiated alarms would support a better optimized implementation by reducing the amount of ping communications needed and other logic simplifications.

An important observation is that combining this ability to detect open wires with an indication that a wire is arcing implies that there is a dangerous energized wire down condition. The project investigated the reliability of arcing detection by substation relays and line sensors and captured one arcing event with line sensor waveforms. The ability of substation relays to detect arcing is well accepted in the industry and PG&E studies indicate that line sensors can provide this same capability for reliable arc detection.

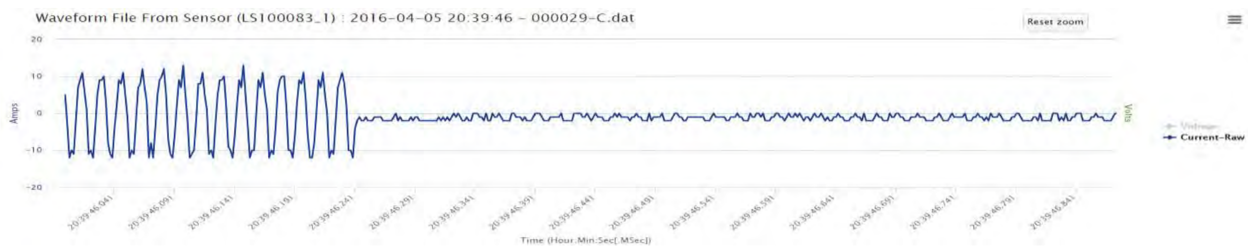

Figure 7. Waveform Showing Arcing that Occurs Prior to an Outage

Fault Anticipation and Waveform Analysis

Fault anticipation is the ultimate goal of fault detection—the ability to detect conditions that will lead to faults before a fault actually occurs. Examples include vegetation overgrowth and equipment deterioration. PG&E attempted to determine if these conditions could be identified using analysis of momentary faults which might be caused by a situation such as a branch occasionally hitting a line. Another route was to study the waveforms produced by line sensors to determine if there are distinct patterns that may occur in these situations which might identify a specific condition that could lead to a fault.

As an engineering tool, predictive fault analytics were effective for several uses including:

- Predicting fuse damage;
- Finding fault locations initially missed in patrol;
- Identifying bad capacitors and bad capacitor switches; and
- Detecting secondary fault events due to line-to-line contact caused by the primary fault.

Waveform analytics demonstrated potential for detecting failing cable splices,[9] confirming capacitor operation, and other types of failure anticipation. However, vendor implementations are not consistent, and no vendor has yet established an extensive library of waveform signatures. While this is still a developing technology, there is a good chance that the capabilities will evolve as this technical area matures.

Waveforms from line sensors can also help to identify bad capacitor banks. During the pilot phase, a line sensor detected periodic line disturbances on a circuit. An operating engineer noticed that these disturbances happened whenever a capacitor bank went online. Field technicians investigated and discovered that one of the capacitor units was bad and was replaced. While this did not result in a quantifiable benefit, capacitor failures and power quality issues do in many cases impact sensitive customers and can cause outages.

[9] A splice is a location where two ends of a line have been joined together.

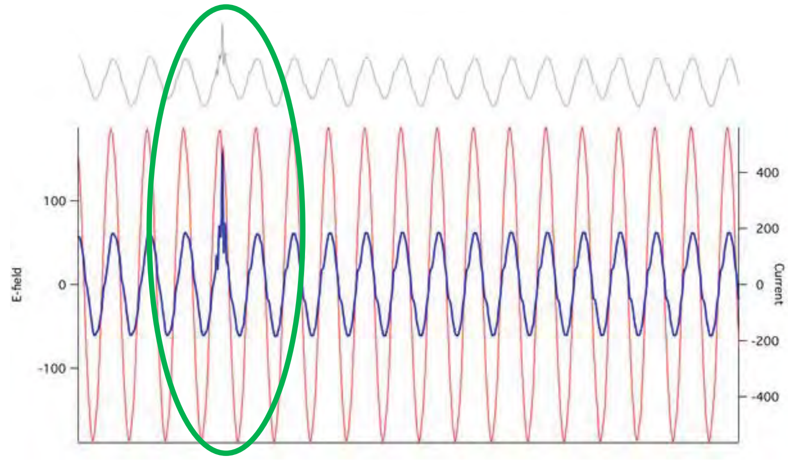

Figure 8. Waveform showing A Cable Join Fault or Splice Failure.

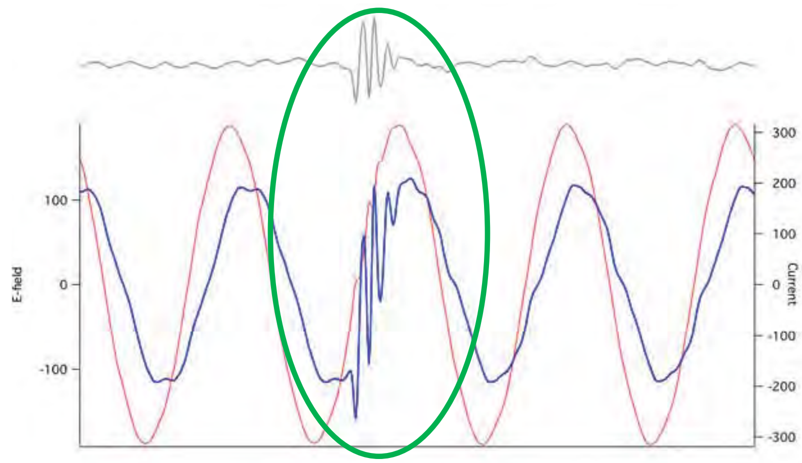

Figure 9. Waveform Showing a Capacitor Bank Operating.

Fault anticipation was identified as a highly valuable use case, but vendor products as-delivered did not support or claim to support that capability today in production-level implementations. Therefore, fault anticipation was evaluated as an engineering tool and for potential post-project development.

4.2.1 System and Device Requirements

Calculated Fault Location

If CFL is to be useful for real-time operations, it must provide actionable location information. That is a combination of (1) the accuracy of the predicted fault location, which impacts the size of the area that needs to be patrolled; (2) the reliability of results; and (3) the clarity of the results. This last item is particularly relevant to CFL because these calculations almost always return more than one location that is mathematically correct. The project found that none of these three requirements were fully met by products that are available today.

Accuracy was impacted by measurement errors, system model errors, and the fact that one of the variables in the equation—fault impedance—is not known. The project looked in detail at all of the reasons for inaccurate results to determine how much they impact the overall result, and how they could be practically addressed.

Accuracy-related findings are:

1. The measurement error when comparing readily-available measurement sources including substation relays, line reclosers, and line sensors are similar and data from any of these devices can be used.
2. More accurate measurement data can provide more accurate CFL results.
3. Fault impedance is a significant factor in location accuracy and can be determined by measuring voltage during the fault event. This is termed the *sag measurement*. Measuring fault impedance impacts the location accuracy by about 10% in many cases.

The accuracy requirements based on these findings are that a number of incremental improvements are possible, but inaccurate fault voltage measurement is the single largest contributor to fault location error. Accurate fault voltage measurement should be considered in any rollout of these systems. SmartMeter™ devices have a good potential for providing this data, but the meters and the system would need some modifications to provide it. Dedicated voltage monitors are a practical and reliable near-term alternative.

Assessment results showed that CFL was often reliable and incorrect results were rare. However, because the operational goal is to find and repair faults as quickly as possible, field technicians should never be sent to the wrong location. Generally, unreliable results occurred due to an incorrect model. The project investigated using the proportional change in electric field—something that is measured in many line sensor products—to calculate the source impedance rather than depending on the model value. This proved correct both in mathematical theory and lab testing. The project finding is that using measured data that is independent of the model, or to correct the model, is useful and provides some benefit, but is not critical for use. The alternate approach for increasing reliability is to use sensors, either line sensors, voltage sensors, or functionally upgraded SmartMeter™ devices to filter out bad CFL locations. If adequate sensors are deployed and enabled, this is the most effective approach to provide increased reliability.

Clear CFL results direct field personal to a single area rather than multiple possible locations. Results should provide as few locations as possible, and those locations should be grouped by general location. The goal is for field personnel to immediately know the fault vicinity and not have to spend time patrolling other possible locations. Improvements in accuracy and results, and improvement in reliability have little impact on reducing the number of possible locations. The project requirement for improved clarity of results is the same as the recommendation for increased reliability. Combining CFL with sensor or meter results is critical to obtaining an operationally usable result.

High Impedance Faults

the ability to detect faults using SmartMeter™ data requires that the meter data can clearly distinguish the line condition as energized, de-energized, or partially energized, and requires reliable communication of that information.

The project findings are that SmartMeter™ devices as implemented today can be used to detect high impedance faults. Although SmartMeter™ data was not intended to be used for fault location, there are inherent communications and meter operation characteristics that can be used for this purpose. The fact that partial voltage can be inferred from these meters provides a reliable way to identify backfeed conditions that occur during partial faults that are not detected and cleared by traditional protective devices.

The basic requirements for using SmartMeter™ data for high impedance fault detection are:

1. Meters today operate differently under normal, partial, and no voltage conditions and this characteristic can be used for detecting open wires and other types of line discontinuities.
2. Adding specific requirements can assure that this capability is not accidently lost, and can contribute to higher accuracy and reliability of results.
3. Creating alarms that could communicate a partial voltage state would support an optimized implementation of high impedance fault detection. This would reduce the need for extensive pinging of meters and would make the initial detection more reliable.
4. Adding arcing detection using line sensors or substation relays can differentiate hazardous energized wire down conditions from other types of open wire events.

Fault Anticipation and Waveform Analytics

The fault anticipation efforts used waveform data from substation relays and line sensors, data from voltage sag monitors, and overcurrent fault measurements to determine if they could be used to anticipate faults. This data was used in vendor-provided applications and PG&E-developed demonstration applications and manually analyzed. Because this is still an emerging technology space, vendor offerings were insufficient, so PG&E secured internal and external experts for assessing this technology and it's potential.

There are a number of device-level capabilities that should be included in selecting future equipment and potential enhancements. Many applications can be supported with data from older substation relays and lower feature line sensors that sample waveforms as a rate of 16 times per cycle or lower, but the data is much more rich and has more potential for future applications when sampled at higher rates. Modern substation relays provide a minimum sample rate of 32 samples per cycle and one line sensor tested sampled at better than 128 samples per cycle. These higher sample rates provide more information on how the electric waveforms are distorted and that eventually will result in a larger and more precise library of waveform signatures.

Maximizing processing at the sensor device reduces the burden on the communications network and distributes the processing effort for waveform analytics which will be needed for real-time analysis.

The time stamping accuracy and time resolution of events should be consistent between all SCADA, protection, and sensing devices to allow correlation between devices during analytics. The ability for a trigger event on one sensor to initiate data capture on adjacent sensors is not available for line sensors today, but would be a great help in monitoring line equipment and understanding events. Electric field measurements were shown as a means to increase the accuracy of fault location but on-board processing of data at the line sensor is needed for actual production implementation.

4.2.2 System/Software Requirements

None of the applications presented can be adopted into real time operations as-is. The systems and data do provide value to engineers, but each area would benefit from continued development.

CFL

The system needs for CFL include enabling data flow from SCADA substation relays and line reclosers, and DMS system line sensors and then combining that data with system model data and analytics. Both PG&E's DMS system and power model application support an identical mathematical CFL, so either can be used for analytics. Ultimately, CFL needs to be rendered on the same display as DMS for operator convenience.

The project did extensive work to access and leverage data from SCADA devices, including implementation of a gateway server that automatically queries the SCADA sub-master stations for fault values whenever a relay causes feeder tripping for an outage. This work avoided the originally consider, limited approach which would have installed instrumentation at 15 feeders, and instead enabled the ability to obtain data from close to 1,000 feeders.

Layered applications—a combination of software and post-event analytics—can provide more useful CFL. However, CFL should only be enabled on the operator's screen if the locations can be filtered and augmented with some combination of Line Sensor and voltage data so that the results are as clear and unambiguous as possible.

The level of the development effort will be dependent on the level of implementation. Simply combining CFL results with line sensor fault zones is a relatively small development that could be provided directly by PG&E's DMS vendor. Adding in voltage data from dedicated voltage monitors or SmartMeter™ devices and layering in historic fault and voltage events provides further location information, but requires significantly more development, possibly involving a gateway middleware product.

The recommended full-scale architecture introduces this middleware approach to function in many ways like the Meter Data Management System used in most SmartMeter™ implementations. The gateway would combine the different communication requirements from different types of substation and line sensor equipment, normalize the data provided by those devices, and only pass validated data to other systems. It would also support analytic logics that could be developed by PG&E, third parties, or device suppliers.

The project found fault voltage measurements to be particularly useful, particularly at the end of lines where the load current may be below the minimum level to power line sensors. Voltage sags during a fault event and the amount of sag provided important information about the impedance of the fault and the location of the fault. The most effective advancement would be to upgrade the ability of SmartMeter™ devices to transmit a fault voltage measurement when an outage occurs and then simply create a heat map that shows the points of lowest voltage, which would correspond directly with the fault location.

High Impedance Faults

PG&E fully evaluated the SmartMeter™ system for use in detecting high impedance faults by running ping tests on more than 500 thousand meters and evaluating the impact on the mesh communications performance and success rate of messaging. The project identified issues in the present implementation of ping automation[10] for outage detection and provided important system characterization which will be useful in future projects.

The conclusion was that the Electric SmartMeter™ network is well suited for the detection application, and a basic level of detection can be achieved with software modifications alone. Increased performance and reliability could be obtained by enabling more flexible and higher resolution real-time data capture with the use of recently developed SmartMeter™ vendor tools. These tools require firmware upgrades to the meters as well as back office and database changes. Performance could be maximized by implementing changes to the outage messaging.

Using data from line sensors or substation relays would help to identify and prioritize potential hazard conditions, but only if this data is available to and integrated with a DMS or other analysis platform.

Fault Anticipation

The project obtained hundreds of disturbance events classified by vendor applications, evaluated data capture and display, and provided waveform data to third-party vendors for their analysis and comments.

The systems and application finding was that no applications are currently mature enough to meet the reliability needs of operations. However, in some cases, only minor development would be required to achieve a useful level of reliability. For example, capacitor bank switching is regularly detected and correctly classified, but is not always detected or automatically checked against expected switching performance. However, taking the existing applications and adding some cross-checking from meter voltage data and monitoring it over a rolling interval of some number of days could easily detect a blown fuse or failed switch on one or more phases.

Much of the analytics benefit was obtained simply by tracking momentary overcurrent and the value of those fault currents. An example of this, also involving capacitors, was found when fault currents occurred at the same time a capacitor was programmed to switch and then was identified as the cause of those high currents.

A particularly promising application—but which did not provide sufficient data for evaluation at the time of this report—is creating heat maps of CFL locations based on multiple momentary over-currents that are corrected by fault voltage measurements. The expectation is that these would pinpoint vegetation contact at an accuracy level that makes patrol viable before outages or fires result. This application, if demonstrated to be reliable, would only require migrating the demonstration-level heat map application to a product-level application.

Beyond vegetation contact, PG&E did not identify failing splices or other equipment, but other utilities have identified clear pre-total failure waveform signatures for these events. Development of truly reliable detection requires very large amounts of field data, testing, and then field verification. The correct system requirements cannot be established until that research effort is complete. Due to the scale needed and the dependency on gathering data from many equipment failures, this effort would be most effective if developed in partnership with other utilities along with vendors.

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[10] Presently, when a meter reports an outage, PG&E's DMS sends a ping (a simple query & response) to all other meters under the same transformer to see if they are also without power.

4.2.3 Cyber Security Requirements

The primary systems used for fault location and analytics are the DMS system, and those used by line sensors, and SmartMeter™ devices. These systems have already passed PG&E's security reviews for design and implementation and are continually monitored within PG&E's security context. Adding or turning on analytic features does not increase any traditional security risks. For example, no new interfaces are created, so no new penetration points are created. New analytic applications would reside as applications on existing environments such as DMS or alongside those environments, but within the same security boundaries. In all likelihood, these projects will increase security. Increased sensing and analytic capabilities will by their very nature make PG&E's grid more resistant to cyber-attacks.

4.2.4 Vendor Requirements

These applications touch on many vendors and many system elements. Vendors must implement clear interface requirements and business approaches for joint developments for any rapid progress.

- Applications demonstrated today are supported with modest data resolution, but higher resolution data can increase the potential of future applications.
- Devices should support the ability to be configured to trigger for both operational fault events and engineering analytic events and to parse these in such a way that operational systems would only receive real-time fault data.
- Sensor data would align better with traditional power analytics if that data is captured for all three phases of current and electric field for each event. Today, data capture is only triggered for the most impacted phase.
- Data is most useful if it is time-stamped with sufficient accuracy to be used in a protection[11] sequence of event analysis and can be aligned with data from other protective devices.
- Data formats should be industry-standard to ensure consistency.
- Transporting large numbers of waveforms via field communications, storage, and back office processing is difficult. Some level of filtering and analysis is needed at the field device to prevent unnecessary network traffic.

4.3 Industry Recommendations

The following findings of this project are relevant and adaptable to other utilities and the industry:

4.3.1 Utility Recommendations

PG&E has been invited to participate in informal utility meetings and present at utility conferences due to the high level of interest in the Fault Detection and Location project findings. The most important findings which are generally applicable to other utilities are that:

- CFL data must be combined with other sensor or meter data to obtain the reliability needed for use in real-time operations.
- High impedance faults can be detected on circuits with line-to-line connected loads by partial voltage measurements. Some SmartMeter™ systems can detect partial voltage.

[11] An operation that isolates the faulted area from the rest of the system.

- The Advanced Metering Infrastructure (AMI) network can be used to transmit waveform data from field devices and is also useful for high impedance fault detection.
- Fault voltage can be a valuable tool for improved CFL and alternate approaches to rapid fault location.
- Waveform analytics is promising but needs continued development to provide useful fault anticipation.

4.3.2 Vendor Recommendations

The vendors involved during the pilot were found to be highly responsive and engaged. However, significant future product roadmap commitments are more likely if PG&E and other utilities take leadership roles and commit to introducing technologies if the roadmap item passes tests successfully.

Vendors should understand that the whole product needs to be delivered in order to provide value. This includes devices, communications, asset management systems, applications, and integration to multiple utility enterprise systems, including line sensor data. Adoption rates are limited unless complete solutions are available. Application development will enhance or make practical all vendor products assessed. These requirements need to be provided in detail as part of future product roadmap or development projects.

Vendors should continue to enhance analytic capabilities and should keep in mind that the utility does not gain benefit unless the applications provide actionable results. Predicting that equipment *might* be failing has some use to engineers, but *knowing* it is going to fail and approximately when (e.g., in the next few weeks), can provide a clear benefit to actual operating procedures.

In the longer term, PG&E will consider exploring the feasibility of using SmartMeter™ devices to collect and send voltage sag data and events. Potential next steps include discussions with meter manufacturers to explore this possibility and determine whether it requires a firmware, software, or hardware update.

4.4 Additional Learnings

4.4.1 Technology Readiness Assessment

None of the assessed technologies are ready for deployment without at least minimal additional development. The three key project goals of CFL, HiZ, and fault anticipation demonstrated value and with development could be used by stakeholder groups today:

- CFL could be turned on in DMS for operators when deployed with sensors. Once appropriate filtering is in place, the only calculated location results that would be displayed would be ones that are overlapped with line sensor-bracketed fault zones;
- It is possible to implement high impedance fault detection for additional operational awareness with modifications to the DMS ping messaging and logics to better identify the operational state of meters.; and
- Fault anticipation and waveform analytics can be used to monitor capacitor operation and heat map locations of momentary faults with modest in-house or vendor application development.

Employing a Diagnostic Center can potentially allow value to be derived from customer and internal applications before production versions are available from vendors, and provides an incubator environment for testing applications and determining final requirements. The vendor analytics for calculating fault location, detecting line disturbances, and investigating transient behavior with waveforms can be used today as a tool for use by a Diagnostic Center and engineering groups.

Expansive use of CFL requires line sensor data and fault voltage measurements deployed on a larger scale. This would require interface and data storage modifications. These applications will become more useful if there are better and more effective visualization implementations. All of this progress will require some internal investment (including product management and change management) to integrate these systems in a seamless manner for operating engineers.

Using SmartMeter™ devices for fault voltage measurements is not technically risky, but would require firmware and software modifications at a minimum, and due to power supply factors, will likely require introduction of new meter hardware. New meters can be specified to have slightly longer power carryover, which would provide more time to communicate the fault voltage data. Both meter and AMI mesh vendors have indicated an interest in pursuing this. Larger deployment of HiZ detection by SmartMeter™ devices would benefit in performance and reliability from firmware changes to the meter and modest back office application development. If this capability is possible with only firmware updates, implementation could be rapid and ubiquitous. If hardware upgrades are required, this could be implemented as part of the normal meter replacement process. PG&E typically replaces about 50 thousand meters per year throughout its service territory.

Detection of electrical arcing patterns could augment SmartMeter™ HiZ results to suggest that an energized wire is in contact with a tree, an object, or the ground, and allow higher prioritization of those events. This approach needs testing of existing substation relay capabilities and development of line sensor-based detection. Project efforts concluded that line sensors should be able to support methods already implemented in substation equipment, so this would be a low-risk development. Field as well as lab testing is critical, however, for full confidence in this application.

5 Deployment Recommendations

5.1 Recommended Deployment

With this project, PG&E validated that analytics can increase detection of faults not identified today and improve the prediction of where the fault is located without requiring patrol. Available products can provide value if combined, e.g., using CFL in conjunction with line sensor deployments. These deployment recommendations reflect practical relatively near-term implementations that PG&E may pursue once evaluated against other investments and approaches.

Reduce Patrol Using CFL in Conjunction with Line Sensors

CFL could be deployed in conjunction with line sensors in the near future to provide value if that implementation includes a fault zone filter for operators that would only display CFL results that correspond to line sensor-identified fault zones. This would require working with PG&E's DMS vendor to implement on a production basis, and is dependent on line sensor deployments. This approach is appropriate for both overhead and underground line sensor deployments, and could also be extended by using low line current sensors farther toward the end of the circuit. Ultimately, the ideal solution would be to deploy SmartMeter™ devices that have improved voltage measurement and reporting capabilities to provide voltage data, however this will require working with vendors to develop and implement.

Reduce Patrol using SmartMeter™ Outage Reporting Capabilities

Outage scope today is limited to indicating a protective line device location. In cases of broken wires and failed jumpers, the actual location does not correspond with a specific protective device. Open wire detection can be implemented at an initial level with changes to the existing meter ping and outage scope applications already in use by PG&E's DMS system. This would support the use case of reduced patrol by better pinpointing faults to the actual failure location rather than an upstream equipment location.

Flagging of High Impedance Faults Indicative of Broken Wires

There are operational benefits to notifying operators and dispatchers of conditions that may be caused by a broken wire. Implementation of SmartMeter™ advanced analytics will enable this capability. Initial implementation would only indicate a possible broken wire. Further verification of a likely hazard condition requires adding line sensor arcing detection analytics. Implementation of this application would be based on PG&E's existing DMS and SmartMeter™ architectures and no significant architectural changes are anticipated. Some interfaces might have added data elements and some logics would be implemented in DMS.

5.1.1 Levels of Deployment

These deployments are all analytics- and system-based so the potential is available across the whole system when implemented. However, the recommended CFL implementation is dependent on line sensor deployment and so would only be enabled post-deployment and for the feeders equipped with line sensors. Benefits would grow as those deployments increase. In addition, PG&E would need to work with vendors to incorporate desired features and better integrate their products with PG&E's production systems.

Based on projected one-time implementation costs of approximately $2.5 million, and incremental outage duration reductions of at least 1.4% above those that would be achieved with line sensors alone, a Benefit-Cost ratio of 1.0 could be achieved by implementing CFL provided that line sensors are deployed to as few as 20 feeders. The Line Sensor Project prioritized feeders for deployment to provide the greatest benefit at any deployment level.

The SmartMeter™ ping application to detect a line break or open jumper would become available systemwide as soon as it is implemented in production systems. Similarly, the meter ping application required to enable the detection of a line break or open jumper and display that point in DMS is a one-time cost. Once the estimated internal IT development costs of approximately $700k are implemented, this system would provide potential outage duration reductions on open jumpers across the system.

5.1.2 Planning/Business Requirements

Both these efforts would need to go through a standard requirements and business change management process. These are straightforward projects and distribution operators would be the only significantly-impacted work group. The minimum implementation for CFL would be to overlay the CFL analysis on top of the line section already identified as having a fault by line sensors. Similarly, High Impedance Fault detection would simply identify the expected fault location on the operator's DMS screen. The business change for this would simply be a brief training for operators to explain how to use the additional information.

5.1.3 Use Case Identification

All efforts address the use case of reducing patrol time to find faults. The project recommendations have been limited to the most practical options for near-term implementation. Other use cases, such as continual monitoring of distribution line devices and fault anticipation would need to be addressed in future efforts.

5.1.4 Feeder/Site Identification

No additional feeder or site identification is required, as these applications would be available system-wide, if enabled. Again, the CFL application would be used in conjunction with the feeders deployed as part of the Line Sensor project. The additional pinpointing of faults enabled by implementing CFL would not change the site selection for line sensors.

5.1.5 Testing

These are low technical risk efforts. However, they should be implemented on a staged and fully-tested basis. Testing would include IT development testing, user acceptance of the simulated operation, user acceptance of restricted in-field operation, and then full scale deployment.

5.1.6 Roll out

This effort is an IT deployment, and therefore the roll-out would only affect computer systems relating to distribution operations.

5.1.7 Change Management

As described in section 5.1.2, normal change management for operational uses is required. Implementation only provides more information for fault location and is unlikely to require any process changes by the business unit. IT systems would need to be maintained and processes updated for testing. More advanced applications were not included in these recommendations because they require more development and would have greater change management requirements. For example, if arcing detection were to be implemented, then dispatchers and operators might change where they send field technicians to first, and might notify public agencies such as the fire department, if there were a danger from an energized wire on the ground.

5.1.8 Alternatives to Recommended Deployment

The alternative to this recommendation is to not deploy these methodologies and continue with PG&E's current methods of detecting and locating faults. The result is a missed or delayed opportunity for greater reliability and savings benefits at a relatively low cost. If it is not possible to fund these efforts, the Diagnostic Center may continue to operate and provide results from semi-automated processes.

Another alternative is to wait for CFL vendors to incorporate additional data layering, such as line sensor fault zone bracketing, and wait for meter vendors to implement better voltage sensing and reporting capabilities. This too would result in missed opportunities for PG&E to provide input to vendors to help develop products that would provide the greatest benefit.

5.2 Value Proposition

5.2.1 Relevance to PG&E Strategic Goals

CFL is an augmentation of line sensors which are a key component of PG&E's portfolio of reliability improvement projects. As described above, for a relatively low incremental fixed cost, enabling CFL leverages the investment in line sensors by further aiding in faulting location, and helps to maximize the reductions to outage durations.

5.2.2 Relevance to Senate Bill 71 and CPUC Goals

The Fault Detection and Location project meets several SB 17 goals, by providing real-time data to operators that can improve reliability, efficiency, and safety; and better support distributed generation. For details, please refer to Advice Letter 4227-E, cited in Appendix A.

5.3 Cost-Benefit Analysis

5.3.1 Cost Estimates

The incremental cost of enabling CFL in conjunction with line sensor deployment includes approximately $1.5 million in vendor costs in addition to approximately $1.0 million of internal IT development, for a total one-time cost of approximately $2.5 million.

The internal IT development costs associated with the Meter Ping application is a one-time cost of approximately $700 thousand. This is a one-time cost that enables automated meter pings to determine where a line break or open exists and displays that open point in DMS.

5.3.2 Deployment Benefits

Primary Benefits

Calculated Fault Location

The primary benefit of enabling CFL relates to greater outage duration benefits than those provided by line sensors alone, by further pinpointing the fault location and reducing the associated patrol time. The analysis of the 25 storm season outages studied in the Line Sensor pilot indicated that CFL data was available in 19 of those outages, and that CFL analysis could have provided at least an additional 1.4% reduction in outage duration.

The total value of the minimum 1.4% incremental reduction in outage duration in terms of VoS depends on the level of line sensor deployment. Assuming the recommended deployment on all 1,457 feeders where the Benefit to Cost ratio for Line Sensors is greater than 1, the present value of the VoS associated with incremental CFL is approximately $47 million.

High Impedance Fault Detection

The primary benefit for improved fault detection is also an increase in outage duration benefits (i.e., further reduction of customer minutes) and is viable with or without line sensor deployment. The highest value occurrence based on field experience was identified as a failure of line jumpers that connect power lines together. This application is SmartMeter™-based and so would apply across PG&E's entire service territory as soon as implemented. In the twelve-month period ending September 2016, PG&E experienced 590 sustained outages related to jumper failures. Of these, a sample was reviewed (representing 5% of the total Customer Minutes incurred during these outages) to identify how much of the total outage duration was associated with the field patrol to locate the open jumper. Given that an inability to implement this solution in the field to validate the potential level of savings, the analysis assumed a conservative estimate of a 20-minute reduction to patrol times (or 33% of the average patrol time of just over 60 minutes), which would result in a net reduction to the total C-MIN of approximately 17.5%. Projecting this 17.5% against the total 12.9 million C-MIN of the 590 open jumper outages, indicates annual reductions to C-MIN of approximately 2.3 million C-MIN.

Using the Value of Service model to value annual C-MIN reductions of 2.3 million across the divisions where the 590 open jumper outages occurred resulted in a present value of VoS benefit of approximately $54.9 million, which far exceeds the present value of the $700K of implementation costs.

These numbers reflect the savings for just one type of wire open event. Much greater benefits may be gained since the application could potentially also support finding single blown fuse events and broken wire down events. Historic outage data indicates that broken wire events occur with five times greater frequency than burnt jumpers. It may be valuable to include the potential benefits from identifying broken wire events in future Benefit-Cost analyses.

Secondary Benefits

Secondary benefits are also important, but harder to quantify, such as safety. Secondary benefits also include items where some development is needed and final benefits cannot be accurately determined without yet knowing the technical success or having sufficient field validation. Secondary benefits include but are not limited to:

- Monitor capacitors and regulators to verify operation rather than physical patrols;
- Detect outages in vacation areas that impact only a few vacant homes and so can go unnoticed;
- Provide data to dispatchers to help in prioritizing patrols when multiple hazard locations are reported for a single event;
- Detect and repair failing underground splices, overhead insulators and other equipment prior to failure;
- Identify fuses that have been subjected to damaging current levels and so will fail in the future under normal loading;
- Increase in safety due to shorter outages and avoided equipment failures; and
- Avoided damage to customer equipment.

5.3.3 Sensitivity Analysis

These applications are not hardware-based and would be deployed throughout the system. CFL benefits will be achieved only in locations where line sensors are deployed. This application provided an incremental benefit to line sensor deployments but would not drive different deployment strategies.

6 Pilot Financials

The table below captures the actual project costs. The project completed on-time and under the approved project budget of $12.63 million. Administrative costs were 1% of the overall project spend.

Table 1. Project Financials

	Phase 1 2013 & 2014	Phase 2 2015 & 2016	Total 2013-2016
Capital	$1,948	$4,986	$6,934
Expense	4	5,412	5416
Total	$1,952	$10,398	$12,350

All values in thousands—figures above based on Actual spend through November 2016, and forecasts for December. Total Administrative spend over life of the project was 1% of project costs

7 Next Steps

7.1 Technology Transfer Plan

This project produced a number of very promising findings that have the potential to improve fault detection, including detecting high impedance faults. Fault anticipation, however, requires further development before it can be implemented on a wider scale.

Items Warranting Further Investigation, Development, and Testing

The following items are important concepts that should be reviewed and potentially considered for EPIC or other pilot projects, operational funding and development, or as part of other development efforts to ensure that their requirements, development, and change management processes are fully considered prior to full implementation:

- Implementation of additional features in SmartMeter™ devices and their communications coupled with substation and line sensor arcing fault detection for highly reliable high impedance fault and energized wired down detection;
- Industry partnering to enable significant progress in waveform signature analysis for fault anticipation;
- Fault voltage measurements by SmartMeter™ devices for direct heat-mapping of fault events for fault pinpointing.

The above projects might provide significant safety and reliability benefits. It is worth exploring whether SmartMeter™ based implementations can be cost-effective if new features are implemented and adopted in the normal course of meter updates and new business installations.

The Diagnostic Center developed for the Line Sensor Project and leveraged for this project may be transitioned to production to continue to support the line sensors that were deployed and leveraged for both projects.

7.2 Dissemination of Best Practices

PG&E will continue to participate in formal and informal industry meetings and discussions regarding this project and the lessons learned. The knowledge gained in this project is being shared with vendors and will be reflected in features and process developments. PG&E has hosted an “innovation” meeting with Florida Power and Light (FPL), Commonwealth Edison (ComEd), American Electric Power, and Southern California Edison (SCE) that included discussions around the importance of this work and has presented selected papers on this project topic at the 2016 DistribuTECH conference and the 2016 CIGRE Grid of the Future symposium.

PG&E also shared information and best practices with SCE, Sacramento Municipal Utility District, FPL, ComEd, and Detroit Edison.

8 Conclusion

Smart Grid fault detection and location technologies and analytics have the potential to support a safer and more reliable electric grid. With this project, PG&E has demonstrated innovative ways of combining data from intelligent sensing devices in conjunction with advanced analytics to improve reliability and help maintain and support the increasingly dynamic electric distribution system.

Conventional calculated fault location solutions have transitioned from informational to operational by the advent of communicating line sensors. Fault zone bracketing enabled by line sensor deployments address the CFL limitations of providing too many potential locations and occasionally incorrect locations.

Fault location analytics are an evolving technology space, and as new sensing devices are developed and deployed, these solutions need to be able to adapt to incorporate these valuable data sources to provide even greater levels of awareness that can enable faster outage response and improved asset management. In the near-term, PG&E can make use of today's data sources to improve and refine the fault locating capabilities of available products.

PG&E has demonstrated the value of using data from SmartMeter™ devices to identify previously difficult to detect high impedance faults, which can include hazardous energized downed wires. SmartMeter™ devices have the potential to provide even greater value with improvements to their voltage sensing capabilities, which would make every one of PG&E's five million SmartMeter™ devices a potential data source to strengthen electric grid operations.

Fault anticipation—the ability to know that an asset is about to fail—is still very much an emerging technology space. The project was able identify failed equipment in isolated cases, but more research needs to be done to create a comprehensive library of waveform signatures to identify incipient problems before they become faults and applications need to be implemented to automate detection and notification.

PG&E demonstrated that it is possible to analyze electric current waveforms to monitor the operation of electric distribution line equipment such as switched capacitor banks and to help in field troubleshooting efforts including finding problems missed in initial "no problem found" patrols. Studying post-event waveforms can also be useful for forensic investigations to determine if there were incipient conditions that led to a fault.

As Smart Grid technologies become more prevalent, PG&E needs to incorporate more analytics to manage an ever-changing and increasingly complex electric distribution system. The grid of the future will be driven by data and analytics. The Smart Grid Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Pilot Project has been an important early step on the road to making PG&E's Smart Grid even smarter in an ever-changing future.

9 Appendix A – Regulatory Filings

Advice Letter 4227-E: Smart Grid Pilot Deployment Projects Implementation Plan, Pursuant to Decision D.13-03-032
Effective Date: June 21, 2013
URL: https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4227-E.pdf

Advice Letter 4576-E: Smart Grid Detect and Locate Distribution Line Outages and Faulted Circuit Conditions Pilot Project - Phase 1 Status Report, Pursuant to D.13-03-032
Effective Date: March 1, 2015
URL: https://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4576-E.pdf

10 Appendix B – Glossary

AMI – Advanced Metering Infrastructure
ATC – Applied Technology Services
CFL – Calculated Fault Location
C-MIN – Customer Minutes of Interruption
ComEd – Commonwealth Edison
Conductor – a power line
CPUC – California Public Utilities Commission
DC – Diagnostic Center
DER – Distributed Energy Resources
DMS – Distribution Management System
EPIC – Electric Program Investment Charge
FDL – Fault Detection and Location
Feeder – the connection between the output terminals of a distribution substation and the input terminals of primary circuits.
FLISR – Fault Location, Isolation, and Service Restoration
FPL – Florida Power and Light
HiZ – High Impedance (Z)
IT – Information Technology
Recloser – a circuit breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault.
RFI – Request for Information
RFP – Request for Proposal
RTAC – Real-Time Automation Controller.
SB17 – Senate Bill 17
SCADA – Supervisory Control and Data Acquisition
Sectionalizer – a self-contained, circuit-opening device used in conjunction with source-side protective device.
SCE — Southern California Edison
VoS – Value of Service
VSM – Voltage Sag Monitor

Final Report

Voltage and Reactive Power Optimization

Smart Grid Pilots Program

December 30, 2016

Reference Name: Volt VAR Optimization (VVO)

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Project Sponsor: Ferhaan Jawed

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1 Executive Summary

Pacific Gas and Electric Company's (PG&E) Voltage and Reactive Power Optimization Project demonstrates innovative approaches to coordinating the voltage and reactive power-controlling devices on the electric distribution grid. Voltage and Reactive Power Optimization is commonly referred to as Volt VAR Optimization, or VVO. VVO is a software-based solution that provides value by sensing grid conditions, determining the device-level adjustments necessary to regulate voltage, and communicating coordinated commands to grid devices in real-time. In essence, VVO control systems act as a centralized voltage and reactive power control "brain" of the electric distribution system, for evaluating and signaling the actions needed for better voltage and reactive power regulation. Over the multi-year pilot, PG&E tested these VVO solutions in a laboratory environment and then field-trialed promising solutions on 14 distribution circuits in PG&E's Fresno Division. The aim was to assess the potential benefits of VVO technology to PG&E's customers. Through executing the pilot, PG&E gained valuable information on how to implement VVO, how to forecast the benefits and costs associated with a deployment of VVO, and how other anticipated grid technology advancements (e.g., adoption of Smart Inverters by customers and Advanced Distribution Management Systems (DMS) by utilities) can influence the value proposition and cost-effectiveness of VVO.

Upon completing the pilot, PG&E established that a VVO control system can be a cost-effective solution to enhance voltage regulation on a portion of the circuits on PG&E's distribution grid. There are three main benefits that VVO solutions deliver:

1. Enhances distribution grid monitoring and control.
2. Reduces potential barriers to PG&E's support of customer in adopting Distributed Energy Resources (DER), namely solar photovoltaic (PV) generation, by enabling more dynamic voltage control which reduces the risk of Electric Rule 2 violations.
3. Drives customer energy savings. VVO reduces energy and generation capacity procurement costs by reducing customers' energy consumption and utility line losses. VVO does this by delivering a more advanced form of Conservation Voltage Reduction (CVR).

Of VVO's three benefits streams (Enhancement of Grid Monitoring & Control, Enablement of DERs, and CVR), only CVR benefits have broadly accepted methods of being measured, estimated, and economically valued. Given the uncertainty in the assumptions pertaining to DER enablement and enhancement of grid monitoring and control, PG&E calculated the VVO benefits valuation without including these two benefit streams in the Cost-Benefit analysis. VVO's CVR-specific benefits offer equivalent benefits that demand side management (DSM) programs, such as Energy Efficiency (EE), deliver. Thus, in order to measure the value of VVO, PG&E applied the Total Resource Cost[1] (TRC) framework, which is the methodology used to evaluate EE programs.

After evaluating the pilot findings, PG&E will evaluate a future deployment of VVO. PG&E's present analysis forecasts that deploying VVO to roughly 15% of PG&E's electric distribution system would achieve a customer Benefit/Cost (B/C) TRC Ratio of 1.5-2.7.[2] This deployment can drive conservation and affordability benefits to help achieve California Senate Bill 350 (SB 350) conservation targets. This deployment should take place after PG&E integrates the DMS with the Distribution Supervisory Control and Data Acquisition (SCADA) system. Through deploying VVO upon this enhanced foundational system, VVO can achieve the solution availability (i.e., Up Time) needed to deliver meaningful benefits at a large scale without significant engineer and operator oversight. Until the DMS and Distribution SCADA systems are integrated, PG&E will continue reevaluating the benefits offered of VVO by doing the following. First, given changing market conditions, PG&E can efficiently reforecast the VVO deployment B/C Ratio. Second, PG&E can leverage additional learnings from California's Electric Program Investment Charge (EPIC) Program to understand how Smart Inverters can be efficiently and automatically coordinated with VVO systems to enhance the benefits VVO delivers. While Smart Inverters can incrementally improve benefits derived by VVO, at present, no technology exists that could make it cost-effective to integrate Smart Inverters with VVO. In time, with sufficient research and development and utility demonstration projects, utilization of Smart Inverters to enhance VVO's performance could become cost-effective.

1.1 Supporting the Smart Grid Vision

This project was one of four in the PG&E Smart Grid Pilot Deployment Program, approved by the California Public Utilities Commission (CPUC or Commission), in Decision (D.) 13-03-032 in 2013 to test the value and challenges of deploying new Smart Grid technologies. Work was initiated following the CPUC's approval of the VVO implementation plan filed in Advice Letter 4227-E.

VVO technology aligns with the vision of SB 17, which established that California would increase the use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid. VVO and the work performed by the VVO Pilot align with PG&E's strategic vision of building and maintaining the grid of the future—an "always on" platform that enables the integration of new energy devices and technologies and allows customers to achieve greater value from their energy technology

[1] As defined in the California Standard Practice Manual, the Total Resource Cost (TRC) test measures the net costs of a demand-side management program as a resource option based on the total costs of the program.
[2] Energy savings of 1.53% and peak demand reduction of 0.81% accompany the ***low*** estimated B/C Ratio. Energy savings of 1.97% and peak demand reduction of 1.04% accompany the ***high*** estimated B/C Ratio. These figures are discussed in Section 5.3.

investments (including private solar, electric vehicles (EV), energy storage, and demand response technologies) by virtue of their grid connectivity. VVO assists in achieving this vision, through supporting three capabilities: (1) integrating DERs; (2) enhancing decision making; and (3) increasing grid automation and self-healing.

1.2 Project Activities

The pilot had four key parts:

1. **Evaluate the VVO Technology Landscape and Utility Benchmarking**: PG&E assessed the VVO systems available in the industry in production and/or being used by other utilities to identify solutions that would meet PG&E's needs.

2. **Evaluate Prospective Vendors and Define the Technical Specifications**: PG&E analyzed and identified the technology requirements necessary to support VVO system implementation.

3. **Validate Performance through Laboratory Testing**: In a laboratory environment, PG&E tested VVO systems and devices to identify the specific solution and supporting technologies needed for a field pilot. This included a benefits assessment to support a recommendation to proceed to a field trial.

4. **Deploy a Field Trial**: PG&E deployed a field trial of VVO solutions on 14 distribution circuits. To do so, PG&E engaged stakeholders, implemented change management, and developed VVO operating practices. Then, PG&E performed field modifications to enable VVO and proceeded to install, integrate, configure and commission the VVO software. Post-commissioning, PG&E evaluated the field trial's performance through the use of sophisticated statistical techniques and prototypes of analytics tools. Through applying the knowledge gained from the field trial, PG&E also refined its business case for VVO deployment.

The VVO pilot was designed in two distinct phases. Phase 1 included parts 1 through 3, from *Evaluating Technology Landscape* to *Validating Performance.*[3] Phase 2 pertained to Part 4 – *Deploying a Field Trial.*[4] The specific activities performed in Phase 1 and Phase 2 are discussed in detail in *Section 3 – Project Activities*. For all four Smart Grid Deployment Program pilot projects, the Commission approved staged progress reporting via advice letters. The VVO Pilot issued a Phase 1 status report, which was approved by the CPUC prior to the commencement of Phase 2.

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[3] Phase 1 key objectives were presented in Advice Letter 4227-E.

[4] Upon the completion of Phase 1, a Tier 2 Advice Letter 4528-E presented the status report of Phase 1 [issued on October 31, 2014]. The CPUC's approval of the Advice Letter 4528-E triggered the start of Phase 2.

1.3 Project Achievements

The VVO pilot attained the following achievements:

- *Delivery of energy conservation and peak demand reduction benefits*: PG&E proved that VVO vendor solutions available on the market today can drive statistically significant reductions in energy consumed by customers, utility line losses, and California Independent System Operator (CAISO) system peak demand. The achieved reductions are shown and discussed in *Section 4.2 – Pilot Project Metrics*.

- *Demonstrate the soft benefits of enhanced grid monitoring and control*: The VVO pilot successfully applied advanced data analytics to better monitor the grid and identify necessary corrective action. Specifically, it developed methods of utilizing SmartMeter™ voltage data to enable proactive corrective action of observed voltage issues. Proactive resolution of voltage issues can yield soft benefits of improving both the customer experience and the efficiency of the field operations that resolve issues.

- *Leverage PG&E's SmartMeter™ devices to achieve additional customer benefits:* To enhance VVO, PG&E began collecting voltage data measurements from SmartMeter™ devices on a more frequent basis. These voltage measurements enabled one pilot vendor's VVO algorithm to deliver energy conservation and peak demand reduction. The VVO pilot introduced new ways of analyzing SmartMeter™ voltage data to more proactively manage voltage issues. The major benefit of this access to more granular data, as extracted from the SmartMeter™ devices, is greater visibility into the health of the grid down to the customer-level. Specifically, this visibility benefits customers as PG&E can more quickly and effectively identify customer-level voltage anomalies and plan in work to make corrections before a customer calls to notify PG&E of voltage issues.

- *Gain initial learnings about how Smart Inverters can work alongside VVO to deliver customer benefits*: After extensive lab testing, PG&E worked with a Smart Inverter aggregator to install Smart Inverters at 12 customer locations on one VVO-enabled bank. PG&E engineers monitored and controlled these inverters to collect field data on Smart Inverter performance. This trial yielded initial learnings on how Smart Inverters can add additional value to VVO in order to deliver greater benefits to customers.

1.4 Lessons Learned

Through the VVO pilot, PG&E derived these key learnings:

- *Understanding benefit and cost drivers of VVO, and bank selection for VVO deployment*: PG&E's knowledge of benefit and cost drivers has grown through the pilot. Through the application of data science techniques to analyze more than one billion voltage measurements from over half a million SmartMeter™ devices, PG&E has implemented a benefits forecast method that offers improved accuracy over other benefits forecast approaches. By implementing the VVO pilot, PG&E better understands the cost drivers of VVO and can more accurately forecast the cost of a wide-scale deployment. PG&E has also learned how to apply the pilot findings to better identify circuit characteristics that are expected to yield the most effective VVO results. Specifically, the evaluation of benefits Measurement and Verification (M&V) results has shown how bank and circuit electrical characteristics and customer characteristics facilitate or prevent VVO from delivering benefits.
- *People, process, and technology needed to implement VVO*: Although the methods to implement VVO are well understood by industry, applying VVO on any utility's distribution infrastructure is complex. The successful implementation of VVO required a rigorous process of engaging key operations, Information Technology (IT), and engineering stakeholders. In operating VVO, PG&E developed key insights about where PG&E is well suited to implement technology like VVO at scale, and where there are gaps. As the distribution system becomes more complex, the software required to regulate the grid will require higher levels of skill and talent within a utility's Engineering and IT workforce.
- *Information Technology and Operational Technology (OT) integration*: Utilities have historically had minimal integration between IT and OT systems. As the grid becomes more complex, exchanging data between these systems is becoming required to optimize grid operations, but also must be designed to ensure grid security. The VVO pilot tested a novel integration of IT and OT systems. Specifically, irradiance forecasts and SmartMeter™ voltage measurements (data stored in IT systems) were fed into the VVO algorithm, which in turn used SCADA (an OT system) to send commands to field devices. The integration of IT and OT systems has significant security implications. PG&E learned how its existing IT and OT infrastructure design creates challenges for continued IT-OT integration.
- *Maturity of tools to enable the cost-effective use of Smart Inverters to improve VVO's benefits*: While Smart Inverters have the ability to support grid voltage to deliver CVR benefits, the process of selecting Smart Inverter reactive power control operating modes and set points to optimally deliver

CVR benefits is currently quite complex, especially on a large scale. This process can be significantly improved as tools (namely modeling and data analysis software) evolve and improve. The anticipated adoption of Smart Inverters in California is expected to drive more investment and improvements in these tools.

PG&E shared lessons learned at public forums throughout the U.S. PG&E's presentations provided an emphasis on net new learnings achieved by the VVO Pilot that either had not been implemented by other utilities, or where few utilities were in the process of implementing. Common new learnings presented at public fell into the following key categories:

- Operating VVO on circuits with high penetrations of distributed solar PV generation;
- Modeling, lab tests, and field trials of Smart Inverters to understand how Smart Inverters can enhance VVO's benefits;
- Use of advanced data analytics approaches to understand the impact of distributed solar PV generation on voltage in the presence of VVO; and
- Use of SmartMeter™ voltage data visualization approaches to understand and enhance VVO's performance and proactively address voltage issues (not related to VVO) before customers call to notify PG&E of a problem.

1.5 Deployment Recommendations

PG&E forecasts that a VVO deployment to approximately 170 distribution banks (510 circuits) can yield a B/C TRC ratio of 1.5 to 2.7. Thus, VVO is a cost-effective means of reducing customer energy use and achieving energy conservation targets set forth in SB 350. At a 170-bank deployment scale, the expected annual reduction in energy consumption [megawatt-hour (MWh)] delivers a reduction of approximately 80,000 tons of carbon dioxide (CO_2) emissions per year,[5] which is equivalent to the CO_2 emitted from a 4-mile stretch of railway cars filled with coal to be burned for energy production.[6] The timing of the recommended 170-bank deployment depends on the timing of PG&E's completion of an upgrade of the base systems and technologies upon which VVO relies. The VVO project's results indicate that VVO deployment has an improved value proposition *after* PG&E integrates DMS with Distribution SCADA. While the VVO pilot showed that PG&E is able to implement VVO within its current Distribution SCADA and DMS

[5] This was calculated based off the Climate Registry's official 2014 Emissions Factor of pounds of CO_2 emissions/MWh for PG&E's System Average Electricity Delivered.
[6] The conversion of tons of CO_2 Emissions to other Equivalencies was performed utilizing the EPA's Greenhouse Gas Equivalencies Calculator [https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator].

systems, improvements to these foundational systems can reduce the costs of deploying VVO and additionally, improve the benefits of VVO.

By deferring the deployment of VVO until after the DMS-SCADA integration, PG&E can continue to determine how VVO and Smart Inverters can complement each other at scale. As PG&E's customers begin to connect distributed PV generation to the grid with Smart Inverters, PG&E can leverage advancements in knowledge and technology to determine where Smart Inverters can support voltage and reactive power control for compliance and optimization. Smart Inverters have the potential to drive incremental CVR benefits by using reactive power injecting or absorbing capabilities to adjust voltages at or very near where customers connect to the grid. The ability of Smart Inverters to deliver benefits is highly dependent on their location and penetration. As industry continues to develop methods and tools to determine how to operationally leverage Smart Inverters to deliver customer benefits, PG&E will consider evaluating if Smart Inverter adoption is occurring on banks and circuits at the right locations to drive CVR benefits, and if the tools exist to cost-effectively deliver this. In addition, PG&E will consider evaluating if there are tools that are capable of coordinating Smart Inverters with VVO control software. As PG&E evaluates industry advancements that seek to automate the use of Smart Inverters at large scale, PG&E can assess if using Smart Inverters is a cost-effective means of achieving greater CVR benefits relative to VVO as it exists today. As Smart Inverters have not been widely adopted on electric distribution systems in the U.S., and California is expected to be an early adopter of this technology, EPIC offers a strong opportunity to advance the effectiveness of Smart Inverters' ability to drive CVR at scale, whether coordinated with or independent of VVO.

1.6 Conclusion

The VVO Pilot drove many firsts at PG&E, and was one of three initiatives to win PG&E's Margaret Mooney Award for Innovation[7] in 2016.

PG&E's VVO pilot drove solid incremental industry learnings, and showed the capabilities of VVO to achieve customer benefits. Many utilities have piloted VVO, but VVO is not in widespread use across the U.S. Furthermore, VVO has not been widely implemented in areas with high penetration of distributed solar PV generation. By driving substantial learning via a pilot, PG&E reduced the risk associated with deploying a complex technology.

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[7] The Margaret Mooney Award for Innovation is an internal company recognition program that acknowledges individuals or teams who apply creative solutions that help PG&E deliver safe, reliable and affordable service to customers.

2 Project Background

This section of the report contextualizes the VVO pilot project within the policy and technology landscape. It then discusses the specific pilot objective and design, as well as the anticipated benefits and metrics utilized for defining success.

2.1 Program Background

PG&E's vision for the Smart Grid is to provide customers safe, reliable, secure, cost-effective, sustainable and flexible energy services through the integration of advanced communications and control technologies to transform the operations of PG&E's electric network, from generation to the customer's premise.[8] This aligns with the policy goals of the Commission and the California legislature. SB 17 established that California would increase the use of cost-effective digital information and control technology to improve reliability, security, and efficiency of the electric grid. In response to SB 17, the Commission adopted D.10-06-047, which established the requirements for the Smart Grid Deployment Plans. D.10-06-047 specified that "[s]ubsequent utility requests to make specific Smart Grid-related investments, however, would occur in utility-specific proceedings where the reasonableness of particular Smart Grid investments can be determined." These proceedings include both General Rate Case (GRC) filings and applications for specific projects. On November 21, 2011, PG&E filed Application (A.) 11-11-017 requesting authorization to recover costs for implementing six specific Smart Grid Deployment Pilot Projects over four years. In 2013, the Commission (in D.13-03-032) approved four of the projects, including the Voltage and Reactive Power Optimization Smart Grid Pilot Project (hereafter referred to as the Volt VAR Optimization Pilot, or VVO Pilot).

The VVO Pilot was one of the six projects proposed within the A.11-11-017 as PG&E's 2011 Smart Grid Deployment Plan[9] (published in May 2011) had identified VVO as a promising technology with high potential for delivering significant customer benefits. In the A.11-11-017 filing, PG&E identified VVO's potential for advancing the modernization of the distribution grid while meeting the policy objectives of SB 17. The Smart Grid Pilot Program was tasked with testing and piloting the four technology projects, approved by the Commission, in a controlled, real-world environment. Given the results of the testing and fielding of these four Smart Grid technologies, the Smart Grid Pilot Program has also evaluated the business

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[8] PG&E's Smart Grid Deployment Plan, Definition as stated on page 4.
[9] PG&E's Smart Grid Deployment Plan was filed on June 30, 2011.

case for full-scale deployment of each technology.[10] See *section 5.3 Cost-Benefit Analysis* for more information on the business case for wide-scale deployment of VVO.

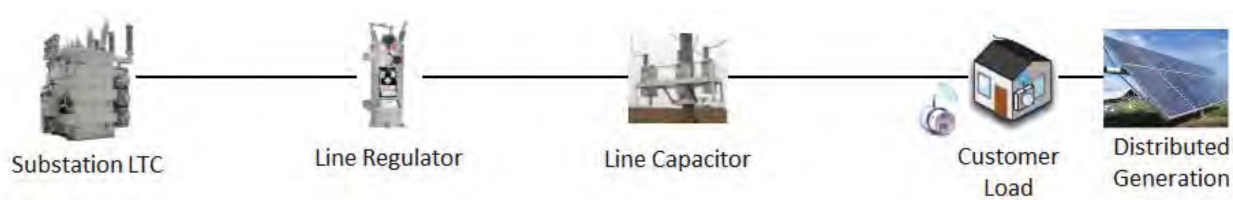
2.2 Technology Description

This section of the report introduces key concepts and components of VVO control systems to provide technical context to *Section 2.4 – Project Objectives and Scope*.

A VVO Control System is a software-based technology that performs two functions. First, it assesses the voltages along a bank of distribution circuits with SCADA-enabled distribution line devices (including Load Tap Changers (LTC), Line Regulators, Line Capacitors) and sometimes SmartMeter™ devices.[11] Second, as needed, it sends commands to the voltage and reactive power controlling devices via the SCADA system to adjust voltage and reactive power along the circuits. In essence, VVO control systems act as a centralized control brain of the distribution system for evaluating and signaling the actions needed for better voltage and reactive power regulation. The main value proposition of VVO is the potential to reduce energy consumption of the end customer by more effectively controlling and reducing voltage delivered to customers. In addition, VVO can help enable the integration of DERs, notably solar PV generation. As PG&E's distribution grid integrates more DERs, VVO control systems can perform the sophisticated decision-making necessary to manage voltage in a more complex load environment.

Figure 1 below shows the line devices on PG&E's circuits that VVO can control to deliver voltage at optimal levels and control reactive power to deliver benefits.

Figure 1 – Distribution System Voltage and Reactive Power Controlling Devices



Although VVO is a software-based technology, a number of hardware components on PG&E's distribution grid must be updated in order to be controlled through the VVO control system. Currently, very few line regulators and line capacitors on PG&E's grid are able to communicate with PG&E's Distribution SCADA system. In order to enable these devices to be controlled by VVO, field personnel must install new device controllers that are capable of communicating with SCADA. This activity of installing new device controllers for line regulator and capacitors is a major cost driver of VVO Deployment.

[10] A forecast for a VVO deployment program was included in PG&E's 2017-2019 GRC. There is a proposed settlement that relates to this forecast. The settlement was pending at the time this statement was written.
[11] Not all VVO control systems use SmartMeter™ data as an input.

Conservation Voltage Reduction (CVR)

PG&E has observed inconsistent interpretation of CVR in the utility industry. It has been used to describe both what occurs to energy loads when the supply voltage is changed, as well as to describe methods of delivering voltage at efficient levels to reduce energy consumption. In this report, PG&E utilizes the former interpretation of CVR—describing what occurs across a wide range of loads when supply voltage is changed. In this report, *Volt VAR Control* and *Volt VAR Optimization* describe the methods of leveraging CVR to reduce energy consumption and demand to achieve customer savings.

CVR is based on the physical characteristic of devices typically using less energy when supplied at a lower voltage. The physical properties of CVR are well understood and utilities have been utilizing forms of CVR for over 40 years to reduce energy consumption and system peak demand. Historically, PG&E has achieved CVR via physical modifications (e.g., reconductoring or adding line voltage regulators and capacitors) and through settings changes to line devices on all circuits where practicable in accordance with Electric Rule 2.[12] However, traditional modifications can be relatively more costly.

The Conservation Voltage Reduction Factor (CVRf) describes the sensitivity of energy change to voltage change, where CVR_f = % Change in Energy / % Change in Voltage. It is used to indicate the amount of energy reduction possible given a specified amount of voltage reduction achieved. A higher CVRf is preferable because for a given % voltage reduction, more energy savings can be achieved.

CVR can drive the following quantifiable benefits that can be assigned an economic value:

- Reduced Customer Energy Use (MWh) – The operation of distribution circuits at the lower end of the acceptable voltage range is expected to reduce customer energy use. Through reduced customer demand, PG&E would procure less energy from the wholesale market, thereby reducing the pass-through cost of energy procurement to customers. The cost savings resulting from the reduction in energy use would accrue directly to customers, thereby improving overall affordability.
- Reduced Peak Demand (megawatt (MW)) – Similar to the reduction in energy use, there is potential for a reduction in CAISO system peak demand through the use of VVO. The reduction in peak demand would lower the procurement quantity of generation capacity and, as with reduced energy

[12] Electric Rule 2 requires that distribution service voltage on residential and commercial circuits be regulated to the extent practicable between 114 volts (V) and 120 V and, where not practicable, regulated between 114 V and 126 V. Agricultural and industrial distribution circuits are to be regulated between 114 V and 126 V. Voltage values cited here on a 120 V basis. Rule 2 requires that voltage be delivered at +/- 5% of a nominal voltage. For simplicity, example Rule 2 upper and lower bounds are communicated on a 120 V basis.

use, the resulting cost savings through lower capacity procurement would accrue directly to customers.

- Reduced System Losses – The reduction in energy use and peak demand would incrementally reduce losses directly improving the efficiency of PG&E's distribution system. Reduced system losses translates to reduced energy procurement costs, which in turn benefits customers.

Volt VAR Control (VVC)

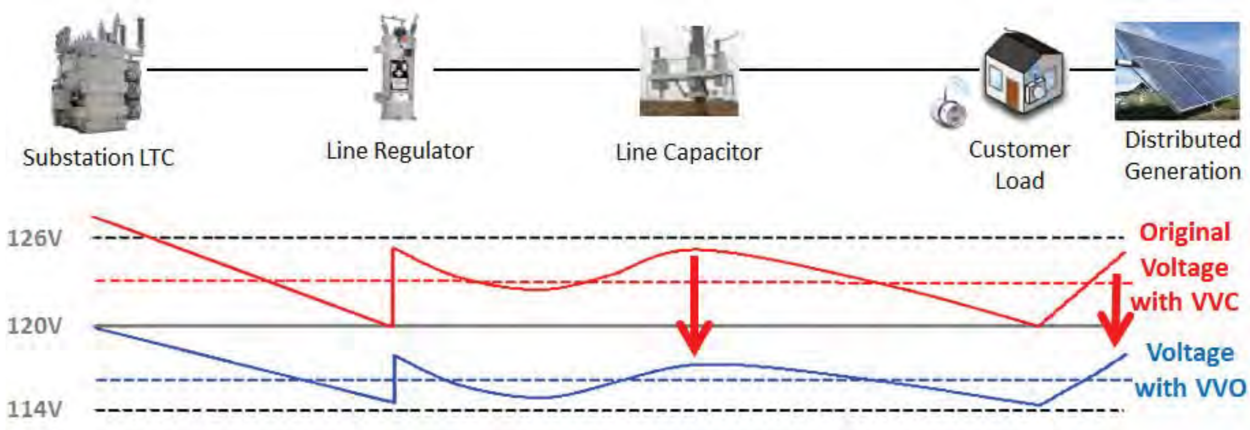
PG&E *presently* manages distribution system voltage and reactive power through VVC. VVC is the process in which voltage is regulated by implementing manual setting of grid devices along the distribution system from the substation to customers. Specifically, on a periodic basis, PG&E's engineers determine settings for device controllers for substation LTCs, line voltage regulators, and line capacitors. To implement any setting adjustments, PG&E personnel manually adjust the settings on each controller in the field. This manual VVC process in the field makes frequent adjustments to device settings potentially relatively more costly and operationally challenging.

Volt VAR Optimization (VVO)

In contrast to VVC, VVO offers a modern method of enabling CVR. VVO is a method for developing and executing optimal operations in a coordinated manner across all voltage and reactive power controlling devices. In order to achieve CVR, VVO monitors and automates the control of devices in coordination in order to flatten and lower voltage profiles across the circuit. VVO enables PG&E to monitor and control voltage along distribution circuits in real-time. Thus, voltages can be optimized continually over time, and in doing so, PG&E can maximize the CVR benefits delivered by adapting in real-time to the dynamic loading and generation conditions of the distribution grid.

Figure 2 below illustrates this concept. The red voltage profile shows a potential distribution of voltages along a circuit during an instance of low load with correspondingly little voltage drop along the circuit. The blue voltage profile shows the resulting reduced voltage levels which could be achieved through a VVO control command to adjust line device settings in this low loading instance.

Figure 2 – VVO and Use of Distribution System Voltage and Reactive Power Controlling Devices



Additionally, VVO algorithms can apply logic to avoid excess operation of the LTC and line devices that can potentially result from VVO seeking to drive optimal voltage levels and power factor. Excess operation of these devices increases wear and tear and reduces device useful life.

In states like California that have high penetrations of DERs, namely distributed PV generation, VVO provides an additional benefit by providing more dynamic voltage control. The adoption of DERs changes load patterns and creates two-way power (i.e., forward and reverse) flow on the distribution system. The key challenge associated with reverse flow coming from high distributed generation penetration is voltage rise. VVO helps address voltage rise by flattening and lowering a circuit's voltage profile. Specifically, the points with higher voltage levels (i.e., those already near the upper Electric Rule 2 limit) are lowered. Thus, the lowering of the range of voltages on the circuit can allow for a larger quantity of Distributed Generation (DG) to be connected to the circuit before their impact on voltage rise results in a violation of Electric Rule 2. Thus, tools like VVO can help PG&E better control distribution system voltages in contexts of shifting load conditions and high penetrations of DG.

Smart Inverters and VVO

Smart Inverters can be complementary technologies to VVO as their coordination can potentially yield incremental benefits above VVO as a stand-alone system. The added value of Smart Inverters is highly dependent on Smart Inverter penetration levels, the location of Smart Inverters, and circuit electrical characteristics. Smart Inverters will be connected to the secondary (low voltage) portions of the electric distribution system. Unless there are very high penetrations of these inverters, most of the effects will be seen on the secondary level. To achieve CVR benefits, utilities would still rely on VVO to control utility-owned voltage and reactive power controlling devices. For Smart Inverters to be able to provide more support on the primary level, much larger penetrations of Smart Inverters would be needed. For example, it would take hundreds of solar customers to offset the capabilities of just one common capacitor bank on a

VVO circuit, so significant installations would be required to affect meaningful change on the primary. Therefore, PG&E may leverage Smart Inverters for fine refinements on the secondary rather than to complement the coarse refinements of utility-owned equipment on the primary. Thus, the LTC, line regulators, and capacitors could drive significant movements in voltage across the entire bank, and Smart Inverters could make smaller adjustments on the secondary.

Optimal Levels of VVO Deployment on the Distribution Grid

Although VVO control systems can yield customer benefits, studies have been performed to evaluate the scale of deployment that would be most cost-effective given that VVO performance varies depending on circuit and customer characteristics. In 2010, Pacific Northwest National Labs estimated the potential benefits of implementing VVO across the U.S. This analysis involved performing detailed circuit modeling on a small sample of banks and corresponding distribution circuits (i.e., circuits), and extrapolating this across the population of circuits in the U.S. This study concluded that approximately 80% of VVO's potential benefits reside on approximately 35% of circuits.[13]

2.3 Supporting the Smart Grid Vision

The VVO pilot directly supports California's energy policy objectives and PG&E's strategic goals. The unique learnings from the VVO pilot can offer relevant knowledge extension that benefit other utilities. This section explores the specific strategic goals that VVO informs, relevant learnings for industry and alignment with specific policy goals.

2.3.1 *Relevance to PG&E's Strategic Goals*

Since releasing its initial Smart Grid Deployment Plan in 2011,[14] PG&E has further refined its vision. PG&E has identified three enhanced grid capabilities that can be enabled through technologies, including VVO solutions. VVO can enhance the grid by assisting in the *integration of more clean Distributed Energy Resources (DERs)*. Specifically, VVO can better manage the voltage impacts which arise from DERs and, thereby, enable more hosting capacity for DG on PG&E's circuits. The second capability that VVO enables is *enhanced decision-making*. VVO delivers additional visibility and enhanced control to PG&E grid operators by putting more substation and line devices on SCADA. Through SCADA enablement, the settings of these devices can be adjusted and controlled remotely from centralized control centers. Through VVO integration, these devices can also be set up to be controlled via algorithms rather than people. Through the use of prototypes of voltage dashboards

[13] Pacific Northwest National Labs, "Evaluation of Conservation Voltage Reduction on a National Level" (2010).
[14] Vision described in Smart Grid Deployment Plan (May 2011).

(within the Performance Analysis Tool (PAT), as described in *Section 4.1 – Project Achievements*), operators can make more data-driven decisions due to the enhanced visibility and granularity of voltage data. *To automate and self-heal*, the third enhanced grid capability, can be propelled forward with VVO solutions, as VVO functions within a closed-loop control algorithm that automates the coordination of voltage and reaction power controlling devices. Additionally, VVO supports PG&E's existing overarching mission to provide safe, reliable, affordable and clean energy to our customers. VVO's benefits of reducing energy consumption and demand align with PG&E's strategic goal of affordability. These benefits are the same as demand side programs like Energy Efficiency.

2.3.2 *Relevance to Utility Industry*

VVO has been deployed by many utilities. The Department of Energy funded more than 23 VVO pilots at other U.S. utilities through Smart Grid Investment Grants as part of the American Recovery and Reinvestment Act of 2009. Through these pilots, industry knowledge about the costs and benefits of implementing VVO has grown significantly.

PG&E's VVO pilot differed from those by other utilities in that it was one of the first implementations of VVO on circuits with very high levels of distributed PV generation. PG&E's VVO pilot implemented one of the first VVO control algorithms that used a solar irradiance forecast as an algorithm input. By including solar irradiance forecasts within the algorithm, PG&E's VVO pilot tested the ability to proactively control voltage levels in anticipation of future voltage impacts caused by changes in DG production. Lastly, PG&E is one of the first U.S. utilities to pilot smart inverter autonomous Power Factor and Volt-VAR control settings[15] in conjunction with centralized VVO control of utility-owned voltage and reactive power controlling devices.

2.3.3 *Relevance to California's Energy Policy Goals*

The implementation of VVO advances the modernization of PG&E's electric grid consistent with California policy as described in SB 17. VVO has a particularly strong alignment with the following policy goals described in SB 17:

- Enable penetration of intermittent power generation sources: The adoption of DERs changes load patterns and creates two-way power flow on the distribution system. Tools like VVO help PG&E better control voltages on the parts of the distribution system that have shifting load conditions and high penetrations of distributed solar PV generation.

[15] Power Factor control and Volt-VAR control are two autonomous Smart Inverter functions.

- Run the grid more efficiently: VVO reduces utility line losses and delivers voltage to customers at efficient levels to drive CVR, making the grid more efficient on both sides of the meter.
- Significantly reduce the total environmental footprint of the current electric generation and delivery system in California: Over a one-year period, the VVO Pilot demonstrated that VVO can deliver over 1.5% energy efficiency savings on certain distribution circuits. Deploying VVO on PG&E's distribution system could deliver significant energy savings and thereby yield a positive environmental impact on the electric delivery system in California.

VVO also advances aspects of California's SB 350 energy policy by achieving CVR, one of the methods that SB 350 suggests can be implemented to achieve a doubling in energy efficiency-driven conservation by 2030.

2.4 Project Objectives and Scope

The objective of the VVO pilot was to evaluate the ability of VVO systems to deliver benefits to PG&E's customers.

The scope of the pilot had four parts:

1. **Evaluate the VVO Technology Landscape and Utility Benchmarking**: PG&E assessed the VVO systems available in production and/or being used by other utilities to identify solutions that would meet PG&E's needs.
2. **Evaluate Prospective Vendors and Define the Technical Specifications**: PG&E analyzed and identified the technology requirements necessary to support VVO system implementation.
3. **Validate Performance through Laboratory Testing**: In a laboratory environment, PG&E tested VVO systems and devices to identify the specific solution and the supporting technologies needed for a field pilot. This included a benefits assessment to support a recommendation to proceed to a field trial.
4. **Deploy a Field Trial**: PG&E deployed a field trial VVO solution on 14 distribution circuits.

The VVO pilot was designed in two distinct phases. Phase 1 included parts 1 through 3, from *Evaluating Technology Landscape* to *Validating Performance.*[16] Phase 2 pertained to Part 4 – *Deploying a Field Trial.*[17] The specific activities performed in Phase 2 are discussed in detail in *Section 3 - Project Activities*.

2.5 Metrics

This section lists the metrics used to measure the pilot's performance. For pilot results on these metrics, turn to *Section 4.2 – Pilot Project Metrics*.

<u>Benefits Measurement & Verification Metrics</u>

By substation bank and by circuit:

1. **Percent change in voltage reduction (%ΔV):** This metric is intended to measure the *effectiveness* of VVO in adjusting voltage to drive CVR benefits.
2. **Percent change in energy consumed (%ΔE):** This quantifies the relative change in energy consumption delivered by VVO.
3. **Energy Conserved (MWh):** This quantifies the actual conservation impact from VVO.
4. **Conservation Voltage Reduction Factor (CVR_f):** This metric is intended to measure the efficiency of VVO in yielding energy and demand reductions given adjustments in voltage.
5. **Percent change in reactive power demand (%ΔQ):** This metric indicates the effectiveness of VVO in reducing line losses by optimizing power factor.
6. **Change in real power (%ΔP and ΔMW) demand at CAISO system peak days**: This metric is intended to measure the ability of VVO to reduce demand on the days with highest associated energy procurement cost.

<u>VVO Solution Up-Time Metrics</u>

These metrics are intended to measure the *availability* of the VVO Control System. Solution Up-Time is defined as, by substation bank, the percentage of time that VVO was scheduled to be operating and was operating. It is calculated as:

$$Up - Time\ Percentage = \frac{\text{total \# of hours in which VVO was operating}}{\text{total \# of hours in which VVO was scheduled to be operating}}$$

[16] Phase 1 key objectives were presented in Advice Letter 4227-E.
[17] Upon the completion of Phase 1, a Tier 2 Advice Letter 4528-E presented the status report of Phase 1 [published on October 31, 2014]. The CPUC's approval of the Advice Letter 4528-E triggered the start of Phase 2.

To further understand this metric, the unavailable hours (i.e., those in which VVO was not operating when it was scheduled to be operating) are further analyzed between planned and unplanned unavailability. *Planned Unavailability* is the number of hours in which VVO was unavailable due to planned disables when VVO was scheduled to be operating. Planned disables include events such as scheduled foundational system maintenance. *Un-Planned Unavailability* is the number of hours in which VVO was unavailable due to unplanned disables when VVO was scheduled to be operating. An example of an unplanned disable is a system disruption due to major event. By analyzing the quantity and proportion of planned and unplanned disable events by bank, PG&E can enhance VVO solution design for future deployment in order to reduce unplanned unavailability (thereby, effectively increasing the benefits realized through VVO).

SCADA Communications Health Metrics

SCADA Communication Health is the percentage of time that SCADA communications was available to substation and line devices requiring communications for VVO to operate.

3 Project Activities

This section summarizes the specific activities undertaken during each of the pilot phases 1 and 2.

3.1 Phase 1 Analysis and Laboratory Testing

Phase 1 began in May 2013 and concluded in December 2014.[18]

3.1.1 *Evaluate the VVO Technology Landscape and Utility Benchmarking*

PG&E conducted benchmarking interviews with American Electric Power, Arizona Public Service, National Grid, Oklahoma Gas & Electric, Kauai Island Utility Cooperative, and Central Lincoln Public Utility District. These utilities were specifically selected for benchmarking as they had already completed VVO pilot projects. Post pilot, some chose to deploy VVO wide-scale whereas others did not. The objective of these interviews was to gain insights about each utility's drivers for piloting VVO, their vendor selection processes, pilot results, and decisions to deploy.

3.1.2 *Evaluate Prospective Vendors and Define the Technical Specifications*

PG&E issued a Request for Information (RFI) in November 2013 to evaluate the capabilities of available VVO products. PG&E engaged industry experts to ensure the RFI would provide information relevant for the selection of candidate vendors. The 11 VVO vendor responses to the RFIs were evaluated by project stakeholders representing the Electric Transmission & Distribution and IT organizations within PG&E. The vendor evaluation was aligned with the PG&E's sourcing policies and included consideration of supplier diversity, safety, and environmental responsibility, in addition to the technical evaluation of vendor responses. Two of the 11 vendors were selected for testing at the PG&E's Applied Technology Services (ATS) laboratory in San Ramon. In parallel with RFI evaluation and vendor selection, PG&E developed an initial set of technical specifications for VVO in the form of Business and IT Requirements.

3.1.3 *Validate Performance Through Laboratory Testing*

Following vendor selection, PG&E commenced laboratory testing at the ATS facility in San Ramon. Laboratory testing was designed to: (1) identify any needed vendor software enhancements; (2) test hardware needed to deploy VVO at PG&E; (3) determine how to integrate VVO with existing PG&E systems; and (4) develop processes, operating instructions, and training in support of the Phase 2 Field Trial.

To perform testing, PG&E developed an IT integration and test harness architecture. The test harness enabled PG&E to dynamically simulate circuit performance under VVO control using *hardware in the*

[18] Advice Letter A4258-E (Phase 1 Completion Report) contains a detailed description of Phase 1 activities.

loop, which provided realistic feedback to the VVO control algorithms under test. Thirty-two test cases, built based on the business requirements and operating needs of PG&E, assessed the functionality of the VVO vendor solutions. Laboratory testing focused on the safety, operations, and systems integration efforts required to implement a field trial. PG&E developed the field installation and operating instructions and training for the project to move from the laboratory environment to the field trial.

PG&E concluded the validation of performance by evaluating the candidate circuits for Phase 2 Field deployment. For each circuit, PG&E forecasted the benefits of: (1) Reduced Customer Energy Use (MWh); (2) Reduced Peak Demand (MW); and (3) Reduced System Losses. To do so, PG&E performed power flow engineering analysis for candidate circuits. SCADA and SmartMeter™ loading information for each circuit were inputs into the modelling and analysis. This analysis was undertaken to confirm that VVO could deliver benefits on the banks under consideration for Phase 2.

3.1.4 *Transition to Phase 2*

Phase 1 provided evidence showing that a viable VVO solution was ready for field deployment. PG&E recommended that the CPUC approve the start of Phase 2 (Field Trial), given that:

1) Utility benchmarking indicated continued adoption of VVO systems across the U.S.;
2) Lab testing at PG&E's ATS facility proved that VVO could integrate with PG&E systems and operate autonomously while not adversely impacting the safety or reliability of the distribution system; and
3) Analysis confirmed potential benefits of VVO—as demonstrated through an engineering assessment of the benefits potential of the circuits targeted for the field trial.

3.2 Phase 2 Field Trial

The Phase 2 Field Trial began in January 2015 and concluded in December 2016. In Phase 2 of the VVO, Pilot PG&E performed the following major activities:

7. Change management and development of VVO operating practices
8. Confirm bank selection for VVO Pilot
9. Field modifications to enable VVO
10. Field modifications to improve VVO performance
11. Design, build, and use SmartMeter™ voltage visualization and analysis prototype tool

12. VVO software installation, integration, configuration, and commissioning
13. Operate VVO to support M&V protocol
14. Test and field trial software enhancements to improve VVO performance
15. Test and field trial Smart Inverters to improve VVO performance
16. Collect SmartMeter™ voltage data to forecast benefits of wide-scale deployment

The rest of Section 3.2 details the actions taken under each of the 10 activities listed above.

3.2.1 *Change Management and Development of VVO Operating Practices*

Change management is a key enabler of pilots like VVO that involve changes to technology that affect people and business processes across PG&E. While stakeholders were engaged throughout Phase 1, engagement ramped up significantly in Phase 2 as PG&E prepared to operate VVO in the field. The steps PG&E took to integrate change management were as follows. First, the VVO pilot team evaluated the change impact of VVO by defining the following:

- *Desired outcomes and conditions for success*: what the VVO pilot was trying to achieve and what must be true for the VVO pilot to be successful;
- *Impacted people's behaviors and mindsets*: how people may need to act and think differently to enable the change;
- *Impacted systems and processes*: process areas, technologies, metrics, and organizational structures that are affected by VVO deployment; and
- *Key partners*: key people needed to help deliver change.

Then, the team used this impact assessment to focus change management efforts on the key stakeholders whose buy-in was pivotal to Phase 2's success. Key stakeholders included the following groups whose existing work pertained to the five banks selected for the pilot:

- Distribution Operators and Operations Engineers at the South Distribution Control Center
- SCADA Specialists
- Distribution Line Technicians and Troublemen (T-men)
- Telecom Technicians
- Distribution Planning Engineers
- Customer Relationship Managers

- Standards Engineers
- The PG&E team leading Distribution Control Center Consolidation efforts, which included changes to technology and business process

Engaging in sessions with these stakeholders, the VVO pilot team gained insights into the challenges and successes from recent technology implementations, specifically the deployment of Fault Location, Isolation, and Service Restoration (FLISR) technology. After understanding pain points, PG&E developed a VVO operating procedure. This operating procedure assigns the roles and responsibilities of each stakeholder and defines the process for enabling and disabling VVO. PG&E trained approximately 30 Distribution Operators and 6 Operations Engineers on this procedure prior to VVO Go Live and Commissioning. Distribution Line Technicians and Troublemen were trained on new hardware installed in the field. To ensure effective knowledge transfer, VVO subject matter experts (SME) from the VVO pilot team delivered all training directly to stakeholders. Three Distribution Operator and three Operations Engineer "Super Users" were given in-depth VVO training. The VVO team intentionally delivered all trainings through SMEs in order to ensure that all questions posed by stakeholders were thoroughly answered. The training was effective in developing general awareness of VVO operating procedures. The "Super User" method proved effective in creating a small group of highly knowledgeable individuals in the South Distribution Control Center to support continued operations of VVO once commissioning was complete. In addition, PG&E engaged stakeholders to design modifications to existing SCADA screens and create new SCADA screens needed for VVO.

3.2.2 *Confirming Bank Selection for VVO Pilot*

PG&E deployed VVO on 14 circuits in the pilot. The initial bank selection process was *not* intended to identify only circuits best suited for achieving CVR benefits. The bank selection process was instead designed to select a variety of circuits that were diverse enough to observe the impacts of bank characteristics on performance while being similar enough to effectively compare performance of the VVO systems by vendor.

The general methodology for selecting the first 12 circuits for VVO deployment was as follows:

1) **Identify the subset of banks and circuits with the prerequisites for utilizing VVO:** In order for a bank to be considered for VVO, the bank needed to be SCADA-enabled. Substations that did not have SCADA did not qualify for VVO. Additionally, the banks needed to be within the Central Valley region, have communications coverage and could not have large planned work projects during the pilot period that would disrupt data collection and observation.

2) **Include a diverse set of circuits within the test sample:** Within the subset of qualified circuits, include a broad set of circuits with varying characteristics, including DG penetration, circuit length, customer type, number of line regulators and capacitors, and primary circuit voltage level (12 kilovolts (kV) and 21 kV).

More specifically, the following prerequisites were applied to identify the pool of circuits for consideration.

- *Central Valley Region*: Candidate circuits were located in PG&E's Central Valley Region, which was the first of PG&E's four geographic regions to undergo Distribution Control Center Consolidation. As PG&E's multi-year Distribution Control Center Consolidation project was occurring in parallel with the VVO Pilot, choosing Central Valley Region was done in consideration of the significant change associated with the consolidation effort. Central Valley Region consolidation completed before VVO commissioning began. The choice of Central Valley Region was made to mitigate exogenous factors from influencing the pilot performance. As consolidation of the three other regions was scheduled *after* VVO commissioning, field testing VVO in those areas would have increased the risk and challenge of executing the VVO Pilot.
- *SCADA Availability*: Candidate circuits were required to be sourced from substations already enabled with SCADA.
- *Communication Coverage*: Candidate circuits were required to have communication coverage from the existing PG&E communication systems, so as to limit the amount of modifications of circuits necessary for VVO integration (and thereby, control costs).
- *No Planned Disruptive Modifications*: Candidate circuits were not expected to have disruptive work (e.g., circuit reconfiguration, circuit breaker replacement) performed during the pilot period, that would require disabling VVO for a significant time during the pilot.

Of that subset of circuits fulfilling all four pre-requisites, these factors were further considered in selection of pilot banks:

- *Circuit Loading [MW]*: Candidate circuits were selected to provide variation in loading.
- *Circuit Length [miles]*: Candidate circuits were selected to provide variation in circuit length, both in terms of total circuit length and longest circuit length (substation to furthest device).
- *Customer Classification*: Candidate circuits were selected to provide the desired mix of customer classifications (Residential, Commercial, Industrial, and Agricultural) and location (urban, suburban, and rural).

- *Loading Characteristics*: Candidate circuits were selected to provide variation in load factor, circuit balance, and DG penetration.

Twelve circuits (across 4 banks) were selected based on application of the criteria outlined above. One additional bank (with 2 circuits) was added to the field trial scope[19] in early 2015. The characteristics of these 14 circuits are listed in Table 1.

Table 1 – Characteristics of Selected Banks

Bank	Circuit[20]	% Loaded	Total Circuit Length [miles]	Longest Circuit Length, *From Substation to Furthest Device* [miles]	Customer Classification [Residential/Commercial/ Industrial/Agricultural]	Bank 2016 Load Forecast [MW]	% DG/ Load
Airways Bk 1	A-1101	105%	46.4	4.3	95% / 1% / 3% / 1%	36	22%
	A-1102	98%	57.4	7.5	84% / 2% / 13% / 1%	36	29%
	A-1103	82%	32.0	3.2	48% / 10% / 39% / 3%	36	16%
Pinedale Bk 1	P-2101	86%	40.7	7.1	49% / 5% / 46% / 0%	60	15%
	P-2102	80%	46.5	5.1	76% / 5% / 19% / 0%	60	14%
	P-2103	47%	20.7	3.1	37% / 15% / 48% / 0%	60	10%
Barton Bk 3	B-1114	85%	24.5	2.9	75% / 5% / 20% / 0%	32	2%
	B-1115	92%	44.9	6.0	74% / 5% / 20% / 0%	32	8%
	B-1116	73%	22.7	5.4	46% / 6% / 48% / 0%	32	3%
Woodward Bk 2	W-2104	56%	38.7	6.2	48% / 4% / 46% / 1%	58	25%
	W-2105	60%	33.4	3.4	84% / 7% / 9%/ 0%	58	16%
	W-2106	54%	24.5	5.5	66% / 2% / 30% / 2%	58	35%
Dinuba Bk 1	D-1102	102%	45.9	4.9	57% / 10% / 25% / 8%	23	1%
	D-1104	93%	114.5	8.5	24% / 4% / 11% / 61%	23	34%

PG&E saw value in learnings that would come from expanding the circuit's scope of the pilot to implement VVO on 2 additional circuits with very different characteristics from the original 12 circuits. PG&E identified Dinuba Bank 1 (2 circuits) as a good candidate. Dinuba Bank 1 is a complex, rural circuit with 8-line voltage regulators and three large concentrated distributed solar PV generation facilities.

[19] CPUC Energy Division concurred with expanding VVO circuit scope from 12-14 circuits on June 23, 2015.
[20] Note that Circuits named with X-11xx indicate that the circuit is a 12 kV circuit, circuits named with X-21xx indicate that the circuit is a 21 kV circuit

Piloting VVO on Dinuba Bank 1 had the potential to inform PG&E as to whether VVO is a cost-effective means of improving solar PV hosting capacity on circuits similar to Dinuba.

3.2.3 *Field Modifications to Enable VVO*

Technological components along the 14 circuits were modified in order to deploy VVO. First, as discussed in Section 2.2, implementing VVO required installation of new capacitor bank and line regulator controllers, in order for VVO to be able to communicate with PG&E's Distribution SCADA system. Table 2 below shows the total number of controllers that were replaced to enable VVO.

Table 2 – Count of Modifications to Device Controllers

Device Controller	On Initial 4 Banks [12 circuits]	On Dinuba Bank 1 [2 circuits]	Circuit Conditioning
Capacitor Controller	52	14	
Line Regulator Controller	9 (3 sets)	18 (6 sets)	15 (5 sets)

Second, the substation transformer LTC controllers required modification to enable VVO to control the LTC via SCADA. Modifications were made to all five LTC controllers involved with the VVO Pilot.

Third, the capacity of field telecommunications needed to be expanded to deploy VVO. Adding a substantial number of capacitor and line regulator controllers to SCADA was anticipated to increase field message traffic. PG&E assessed the capacity of the field telecoms systems in Fresno Division, calculated the expected communications bandwidth needed to support VVO, and concluded that installing a low elevation antenna at a PG&E facility in Fresno was needed to accommodate the increased message traffic that would accompany VVO.

3.2.4 *Field Modifications to Improve VVO Performance*

A key learning from utility benchmarking interviews was that making certain physical modifications to circuits (i.e., conditioning, defined below) could enhance VVO benefits.

Following VVO commissioning in July and August 2015, PG&E began to evaluate opportunities to perform primary and secondary conditioning. Primary and secondary conditioning are defined as follows for the context of modifications assessed and performed for the VVO Pilot:

- Primary conditioning entailed:
  - Phase load balancing
  - Relocating and adding new line regulators and capacitor banks
- Secondary conditioning entailed:
  - Service transformer replacement

- o Secondary reconductoring
- o Secondary redesign
- o Installation of novel, power electronics to regulate voltage and reactive power

PG&E performed engineering and economic assessments to identify what primary and secondary conditioning scope would be cost-effective in enhancing VVO benefits. After performing this analysis, PG&E implemented the following primary conditioning scope:

Table 3 – Primary Conditioning Scope on Banks Selected for VVO

Bank	Circuit	Primary Conditioning Actions
Airways Bk 1	1101	Install 1 new regulator, relocate 1 capacitor
	1102	Install 1 new regulator, relocate 1 capacitor, phase load balance
	1103	None
Pinedale Bk 1	2101	Install 1 new regulator, phase balance
	2102	Install 1 new regulator
	2103	None
Barton Bk 3	1114	None
	1115	Phase load balance
	1116	Phase load balance
Woodward Bk 2	N/A	No Primary Conditioning
Dinuba Bk 1	1102	Regulator actions on the Dinuba circuits were pursued for operational reasons (i.e., to enable VVO operation) rather than conditioning to improve operation.
	1104	

PG&E prioritized executing on primary conditioning opportunities before scoping secondary conditioning. This prioritization was based on the following principle. Primary conditioning influences a large number of customers' voltages, and thus increases VVO's ability to reduce voltage whereas secondary conditioning impacts a smaller group of voltages, and is thus best used to address outlier low or high voltages that impede VVO's ability to effectively optimize voltage. PG&E identified four locations that were optimal for secondary conditioning. These four locations on Barton Bank 3 showed strong potential of being cost-effective in enhancing VVO performance. Secondary conditioning at these four locations involved upgrading service transformers, reconductoring and reconfiguration of secondary networks to reduce voltage drop.

Beyond making physical modifications to circuits, PG&E evaluated how novel power electronics hardware[21] on the secondary system could enhance VVO benefits. PG&E's investigation of novel electronics found that although these devices do show promise of enhancing VVO performance by raising low voltages, constructability issues and costs challenged the viability of these products on PG&E's system in the current timeframe. As an example, some of PG&E's poles have insufficient space or loading capacity to locate these power electronics where they are needed. Additionally, Smart Inverters offer similar functionality to the novel power electronics. PG&E focused attention on investigating customer-sited Smart Inverters to potentially enhance VVO's benefits as Smart Inverter adoption will be mandatory in California beginning in September 2017.[22]

3.2.5 *Design, Build, and Use SmartMeter™ Voltage Visualization and Analysis Prototype Tool*

The voltage measurements from SmartMeter™ devices were leveraged to measure the effectiveness of VVO on all five pilot banks. By analyzing SmartMeter™ voltage measurements for all customers served by the pilot banks, PG&E was able to gain two insights. First, PG&E could monitor the data to ensure that any Rule 2 violations were not caused by VVO commands issued by the VVO software. Second, PG&E could use the voltage data to better analyze how VVO performs on a bank-by-bank and vendor-by-vendor basis.

In early 2015, PG&E did not have an enterprise platform for data visualization and analysis that the VVO Pilot could use. After developing requirements for a tool to visualize and analyze SmartMeter™ voltages on VVO pilot banks, PG&E built a prototype tool to support the needs of the VVO pilot. This prototype tool, called the VVO PAT, presented various data (e.g., SmartMeter™ voltages, location of distributed PV generation, service transformer capacity and connectivity). The tool allows for a user to visualize and analyze various data streams.[23] In late 2016, Smart Inverter data was integrated into the PAT. This allowed engineers to evaluate the impact of Smart Inverters on distribution system voltages during the 14-week Smart Inverter Field Trial (discussed in detail in *Section 3.2.9* below). The PAT offers a range of levels for evaluation, from performing local, detailed (i.e., micro) level analysis of individual customer SmartMeter™ voltages, to bank-level (i.e., macro) analysis of thousands of service points. The PAT was used on a nearly daily basis to evaluate the effectiveness of VVO software settings in driving VVO's

[21] In the past few years many vendors have begun marketing power electronics that can assist with voltage and reactive power control to improve power quality and drive CVR.
[22] CPUC Rule 21 requires Smart Inverter autonomous functionality for all new inverters beginning in September 2017.
[23] Screen shots of this tool are included in Section 4.1 (Project Achievements).

benefits. The PAT was designed for the scope of the VVO pilot project and as a prototype, it was not designed to be scaled to analyze larger areas of PG&E's system after pilot completion.

3.2.6 *VVO software Installation, Integration, Configuration, and Commissioning*

PG&E obtained VVO software from two vendors, and then implemented the needed systems integration to enable both vendor solutions. Prior to turning VVO on in the field, PG&E performed a series of system readiness tests to ensure that systems were exchanging the necessary information for VVO to perform as expected. In parallel, PG&E Customer Relationship Managers proactively communicated with customers prior to VVO commissioning in the field. PG&E determined that proactively informing a small set of customers about the VVO pilot was the best method to engage customers and mitigate the risk of VVO adversely impacting customer experience. PG&E spoke with customers that connect directly to the primary (i.e., who own their own service transformers) to verify the variable tap settings.

Once system readiness testing, proactive customer outreach, and training of key stakeholders was complete, and the SmartMeter™ voltage visualization and analysis tool (i.e., PAT) was ready, PG&E began commissioning VVO on a bank-by-bank basis, beginning in June 2015. Commissioning took approximately two weeks per bank, and involved a series of tests to ensure that VVO behaved as expected. Table 4 below lists the dates of completion of VVO commissioning, which marked the start of the operational period of VVO on each bank.

Table 4 – Commissioning Complete Date by Bank[24]

Banks	Date Commissioning Completed
Airways Bank 1, Pinedale Bank 1	7/13/15
Barton Bank 3, Woodward Bank 2	8/10/15
Dinuba Bank 1	1/29/16

3.2.7 *Operate VVO to Support M&V Protocol*

After VVO was declared operational, PG&E began manually alternating days of enabling and disabling VVO following the M&V protocol that is described in Section *4.2 – Pilot Project Metrics.* Enabled and Disabled VVO days are referred to as "constituted in service days" and "constituted out of service days," respectively. The purpose of M&V is to quantify the energy savings and demand reduction achieved by VVO. PG&E contracted a third party to perform the analysis of the data collected through the M&V period. The results of the third-party M&V analysis are shown in *Section 4.2 – Pilot Project Metrics*.

[24] Note that all circuits on each bank began commissioning on the date listed.

Additionally, PG&E engineers periodically used the PAT to evaluate VVO's performance and make settings changes in VVO software as needed to facilitate voltage compliance and deliver the benefits associated with voltage reduction.

3.2.8 *Test and Field Trial Software Enhancements to Improve VVO Performance*

After VVO was commissioned on the initial four banks, PG&E began working with the two pilot vendors to understand what software enhancements would be available over the remainder of the VVO Pilot. Of these available enhancements, PG&E then evaluated which were of interest based on their ability to improve VVO benefits. PG&E discussed requirements with software vendors and tested multiple iterations of software updates in the lab environment at ATS prior to implementing software enhancements in the field.

One particularly beneficial software enhancement featured the use of a solar irradiance forecast in the VVO algorithm. This solar irradiance input enabled VVO's algorithm to predict voltage variation due to changes in distributed PV generation output. This enhancement allowed for VVO to better anticipate these PV-related voltage variations and take appropriate action before their occurrence in order to prevent Electric Rule 2 violations. As PG&E customer adoption of distributed PV generation increases overtime, algorithms like VVO must account for voltage variation driven not only by load, but also by DG.

3.2.9 *Test and Field Trial Smart Inverters to Improve VVO Performance*

After commissioning VVO in the field, PG&E began testing the use of Smart Inverters to incrementally improve VVO's ability to deliver CVR benefits. As DERs are becoming more prevalent on today's electric grid, there is increasing importance in understanding how these resources can support and improve grid operations and efficiency. Traditionally, distributed solar PV systems were interconnected via conventional inverters operating at unity power factor (only outputting real power and no reactive power), unless the interconnection study requested operation of the inverter at a non-unity power factor operating mode. In September 2017, use of advanced (i.e., "Smart") Inverters to connect PV to the distribution system will become mandatory in California.[25] Smart Inverters are expected to have a variety of capabilities, including the ability to supply and absorb reactive power. With this ability to provide reactive power, Smart Inverters have the potential to support local voltage and power factor on the grid. Given these complementary capabilities of Smart Inverters, PG&E sought to test whether they could provide incremental improvements to the VVO. This local control can be done through various

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[25] CPUC Rule 21 requires Smart Inverter autonomous functionality for all new inverters beginning in September 2017.

Smart Inverter modes, which include fixed power factor configuration or autonomously controlling the reactive power output based on the local voltage.[26]

In early 2015, PG&E began scoping work to understand how Smart Inverters can improve VVO benefits. This scope was created to answer three key questions:

1. What are the appropriate Smart Inverter Volt-VAR and Power Factor autonomous settings that help VVO support high DG penetration and deliver Conservation Voltage Reduction (CVR)?
2. What Smart Inverter Volt-VAR and Power Factor autonomous settings provide stable conditions[27] among inverters in close electrical proximity?
3. What analysis techniques can quantify the impact that Smart Inverters have to deliver CVR benefits, and how can the marginal benefit of Smart Inverters be quantified?

To answer these questions, PG&E performed analysis, lab testing, and a 14-week field trial. Due to the absence of software that can efficiently determine the optimal set points for Smart Inverters, and thus enable closed loop control of a small fleet of Smart Inverters, PG&E's Smart Inverter control philosophy was to operate Smart Inverters with "Engineer in the Loop Control." This means PG&E engineers determined and issued Smart Inverter autonomous functionality set points. Engineers then observed the resulting voltage impact from Smart Inverter settings changes to ensure that this did not have an adverse impact on voltage and cause any Electric Rule 2 violations.

Lab Testing of Smart Inverters

Through lab testing Smart Inverters, PG&E aimed to evaluate how various autonomous functions would perform under normal and abnormal grid conditions. PG&E tested Smart Inverter autonomous functionality on both a component (one device) level, as well as on a group (multiple devices) level. Testing activities performed in the ATS lab testing environment included:

- Performance of individual inverters under normal operating conditions
- Performance of individual inverters under grid disturbance conditions
- Performance of individual inverters under outage scenarios
- Performance of multiple inverters in close electrical proximity

[26] The autonomous control of reactive power based on local voltage is commonly referred to as Volt-VAR control for Smart Inverters.
[27] In early 2015, PG&E observed many utilities, vendors, and other parties discussing the need to evaluate how inverters would interact out of concern that inverters could "fight" (i.e., counteract) each other in a way that results in additional wear and tear on inverters.

- Communication capability of Smart Inverters

PG&E lab tested Smart Inverters manufactured by five vendors. Testing multiple Smart Inverter products secured PG&E's option to field trial inverters best suited to drive learnings. By the conclusion of testing, PG&E had vetted a variety of Volt-VAR autonomous settings for use in the Smart Inverter Field Trial.

During the testing of multiple inverters on the same secondary system, oscillations in reactive power output of Smart Inverters were observed under large secondary side load disturbances when Smart Inverters were operated in a Volt-VAR operating mode with aggressive VAR-Volt slope. As a result, the decision was made to only operate Smart Inverters in the field with Volt-VAR curve slopes where 100% change in reactive power is required in no less than 2-V range.

<u>Smart Inverter Field Trial</u>

The field demonstration explored opportunities to leverage the autonomous Smart Inverter functions to support VVO performance by:

1) Maintaining secondary voltages of all smart inverters served from a common service transformer within Electric Rule 2 limits in support of VVO operations;
2) Reducing secondary voltage levels in support of CVR; and
3) Reducing service transformer losses and voltage drop by providing VAR support on the secondary side of the service transformer.

The execution of the Smart Inverter Field Trial had the following stages:

- **VVO bank selection for Smart Inverters deployment:** Woodward Bank 2 was chosen based on its high penetration of distributed PV generation.

- **Selection of Smart Inverter Locations and Aggregator:** PG&E entered into contract with a Smart Inverter aggregator to provide PG&E with a Smart Inverter monitor and control platform, to install Smart Inverters at customer locations in Fresno, and to support the field trial. The aggregator installed 21 Smart Inverters at 12 customer locations for a total of 104 kilovolt-ampere of Smart Inverter capacity. PG&E worked with the aggregator to identify the optimal locations for Smart Inverters, targeting a mixture of low and high voltage locations. Targeting these locations enabled PG&E to evaluate how well the application of different Smart Inverter settings could compress the voltage profile of a secondary network.

- **Obtain increased voltage and power quality monitoring in the vicinity of the Smart Inverters:** PG&E reprogrammed SmartMeter™ devices in the vicinity of Smart Inverters to provide voltage and loading data every 5 minutes. PG&E also installed Power Quality Meters (PQM) to evaluate the aggregate voltage and power factor impacts on secondary networks where Smart Inverters were installed.

- **Adjust Smart Inverter power factor and Volt-VAR autonomous control settings:** Various combinations of Volt-VAR curve settings were created for the field trial in order to assess the secondary system performance under various system conditions. The aim was to identify the combinations which yielded the most favorable results. After testing the functionality of the aggregator's Smart Inverter monitor and control application, PG&E adjusted Smart Inverter autonomous settings to observe and understand how different settings impact voltage. PG&E began operating Smart Inverters in the field in September 2016, and ran through the end of November 2016.

- **Perform exploratory M&V to quantify the local impact of Smart Inverters on voltage:** Limited field investigations have occurred that quantify the impact of adjusting Smart Inverter Volt-VAR and power factor settings on voltage. Unlike VVO M&V protocols, there are no established industry methods for performing Smart Inverter related M&V. M&V is one of the foundational methods for determining how to leverage Smart Inverters as part of VVO in order to enhance benefits. PG&E implemented two types of M&V, namely Statistical and Power Flow M&V. Statistical M&V applies statistical techniques to infer the impact of Smart Inverter reactive power control settings on secondary system voltage. Power Flow M&V applies power flow modeling techniques to estimate the impact of Smart Inverter reactive power control settings on the primary and secondary voltages. The results of these M&V approaches are discussed in *Section 4.3 – Pilot Lessons Learned.*

3.2.10 *Collect SmartMeter™ Interval Voltage Data to Forecast Benefits of Wide-Scale Deployment*

In mid-2015, PG&E began the planning that would enable utilizing SmartMeter™ voltage data to forecast the CVR benefits of a wide-scale deployment of VVO. PG&E believes that the analysis of systemwide SmartMeter™ voltage measurements was the best method of forecasting the total potential benefits of a wide-scale VVO deployment. SmartMeter™ voltage measurements inform the potential range for voltage reduction, and thus with an assumed CVRf, improve the calculation of potential CVR benefits. Although these benefits can be calculated via power flow modeling, the model is less accurate than the actual field measurements.

PG&E initiated the collection of interval voltage data[28] from approximately one million SmartMeter™ devices (approximately 20% of PG&E's installed stock of meters). The VVO Pilot team engaged engineers across PG&E to identify what meters to initiate voltage data collection from. Approximately 500,000 meters were allocated to collect voltage data to be used for VVO benefits forecasting. Approximately 500,000 meters were allocated to collect voltage data on circuits with high levels of distributed PV generation, and on circuits with known voltage issues.

PG&E began storing collected voltage data for these one million identified meters in November 2015. PG&E began evaluating these data in early 2016 to develop the methods used to forecast the benefits of a wide-scale deployment of VVO. These methods are discussed in *Section 5.3 – Cost-Benefit Analysis*.

[28] Interval voltage data means that every time the SmartMeter™ records energy consumption, that a voltage measurement is recorded as well. For single phase (primarily Residential) customers, this results in a voltage measurement every 60 minutes. For poly phase (primarily Commercial and Industrial) customers, this results in a voltage measurement every 15 minutes.

4 Pilot Project Results and Lessons Learned

This section of the report begins by discussing the overarching project achievements from the VVO Pilot. It continues by discussing the results of each of the metrics (described in *Section 2.5*) and highlighting the key lessons learned across various guiding criteria of the pilot (as identified in *Section 2.4*). It concludes by presenting recommendations for other utilities as they consider piloting and/or deploying VVO and additional learnings the VVO Pilot uncovered.

4.1 Project Achievements

This section highlights the key achievements of the VVO Pilot.

Delivery of Conservation Voltage Reduction

Through implementing a day on/day off operating schedule, PG&E collected data to enable the M&V of VVO's CVR benefits. The quantified benefits show that VVO can deliver energy savings, line loss reduction, and peak demand reduction, thereby driving customer savings. The pilot results show that while not all banks in PG&E's service territory are likely to be good candidates for VVO, when a bank with the appropriate characteristics is selected using the right approach, VVO can deliver substantial benefits and deliver a B/C Ratio above 1.0. For example, a deployment of VVO to banks similar to Woodward Bank 2 is expected to yield a B/C Ratio above 1.0.

Driving Initial Learnings Around How Smart Inverters Can Increase VVO Benefits

PG&E collaborated with a Smart Inverter aggregator to drive the early adoption of Smart Inverters at 12 customer locations on Woodward Bank 2. Through this pilot, PG&E became one of the first U.S. utilities to operate VVO and Smart Inverters on the same circuits. The Smart Inverter field trial demonstrated that Smart Inverters can adjust customer voltages using autonomous power factor and Volt-VAR curve functions, and thus can potentially improve VVO's ability to deliver cost-effective CVR. Additionally, the importance of Smart Inverter siting in order to provide potential improvements to VVO operation and benefits was discovered. Specifically, in order for Smart Inverters to enhance VVO benefits, the Smart Inverters must be located at or adjacent to the customer premises experiencing voltages that are constraining VVO's operational range.

Leveraging PG&E's SmartMeter™ Devices to Create Additional Benefits

As part of the VVO Pilot, PG&E significantly increased the frequency of voltage data capture from SmartMeter™ devices. More granular voltage reads enabled better VVO operations in five ways:

1) Utilize more advanced VVO control software algorithms that required more granular data in order to function
2) Better evaluate the performance of VVO

3) Better forecast the potential benefits of a wide-scale deployment
4) Address previously unknown voltage issues
5) Make settings changes to capacitors to improve voltage profiles

Beyond these grid engineering and operational benefits, SmartMeter™ devices yielded two additional benefits. Frequent voltage reads through VVO also tested the ability of PG&E's communications infrastructure to accommodate the increased network traffic. Beyond understanding voltage collection impact on network traffic, PG&E determined how to cleanse and condition the raw voltage data to extract value from the over 5 billion SmartMeter™ voltage measurements that had been collected through the pilot.

Demonstrating Soft Benefits of Enhanced Monitoring and Control

PG&E implemented novel approaches to visualize and analyze new data collected through the VVO Pilot. This included the use of a tool that visualized data collected from SCADA devices, and a second tool to visualize SmartMeter™ voltage data.[29] Beyond using these tools to monitor VVO solution performance and to make necessary changes to VVO software settings, PG&E used these tools to proactively identify and correct voltage issues not associated with VVO *before* a customer called to report an issue. The VVO pilot developed approaches that PG&E could use in the future to increase proactive issue resolution. Through proactively resolving voltage issues, PG&E's workforce could perform more planned instead of unplanned work, which could result in improved customer satisfaction and operational efficiency. Figure 3 and below demonstrate an instance of proactive issue resolution performed during the VVO pilot. Figure 3 is a screenshot from the PAT, showing the voltage reads over a 6-hour period on July 3, 2015 across the customer-level SmartMeter™ devices on a specific service transformer. In the line graph at the bottom of the screen, the orange line represents one outlying customer experiencing low voltages relative to the rest of the customers downstream of the same service transformer.

Figure 4 shows a "click down" of this specific customer's voltage readings over the time series between July 7 through July 19, 2015. Upon recognizing this customer's outlying voltage band through a routine periodic assessment of the voltage data, a Troubleman was assigned to investigate the issue. After establishing the root-cause, the Troubleman repaired the service drop to the customer on July 14, 2015.

[29] The tool used to visualize SmartMeter™ voltage data was called the Performance Analysis Tool, and is discussed in Section 3.2.5.

Figure 4 demonstrates that the replacement of the service drop adequately resolved the voltage issue as the voltage levels after July 14 are within Electric Rule 2 limits. This was all performed before the customer called to report a problem that PG&E would have diagnosed as a voltage issue.

While this example was generated by work performed by the VVO Pilot, VVO is not necessary to deliver this specific benefit. Collecting more granular SmartMeter™ voltage data and using the right tools to drive insight and action is needed. While the VVO pilot was able to demonstrate this benefit via the prototype PAT, substantial investment would be needed to develop a tool in order to achieve insights at wide scale.

Figure 3 – Performance Analysis Tool – Interface Demonstrating Outlier Voltage

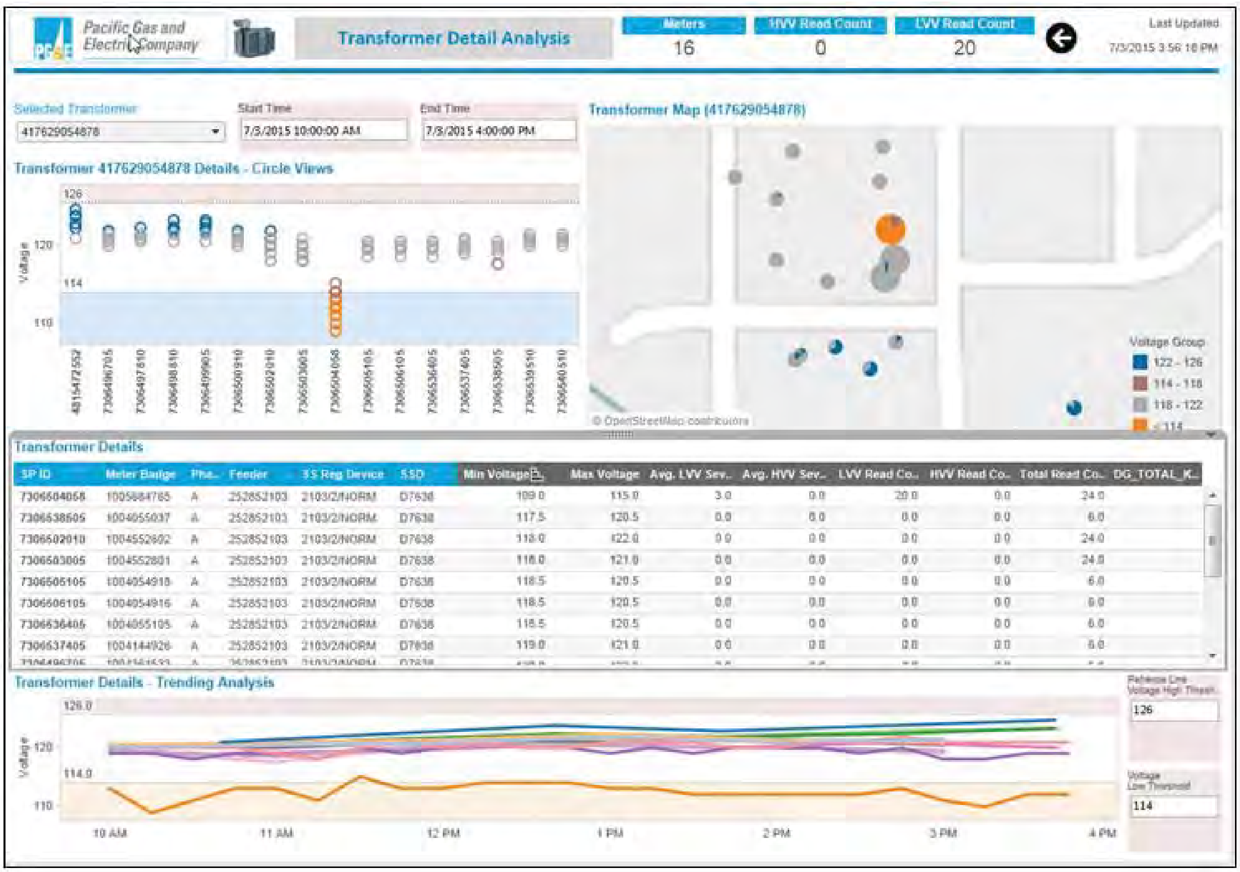
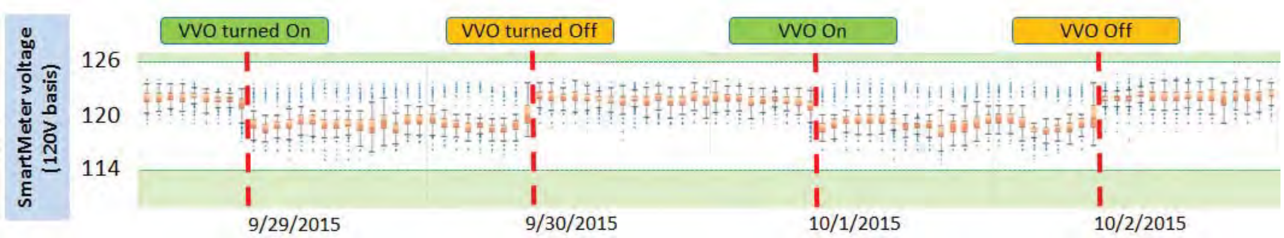


Figure 4 – Performance Analysis Tool – Service Drop Replacement Corrects Voltage Issue

In addition to the micro (i.e., granular to the service transformer and customer level) voltage analysis shown above, the PAT also enabled macro level (i.e., all customers served by a bank, circuit, or downstream of a line regulator or capacitor) voltage analysis.

Figure 5 below shows a time series plot of the distribution of SmartMeter™ voltages on Pinedale Bank 1, overlaying when VVO was turned on and off in accordance with the M&V approach. This plot indicates that VVO had a visible impact on the distribution of voltages, with the box and whisker plots lowering when VVO was on, and rising when VVO was off.[30]

Figure 5 – Time Series Plot of SmartMeter™ Voltage Distributions on One VVO Bank



4.2 Pilot Project Metrics

This section of the report first discusses the VVO M&V methodology. It then reports on the performance of the VVO pilot across the regulatory, technical and industry metrics described within *Section 2.5 – Metrics*.

[30] This is an illustrative analysis meant to show the variety of visualization approaches used.

4.2.1 *VVO Benefits Measurement and Verification Metrics*

Measurement &Verification Approach

The VVO Pilot employed a *VVO Day On/VVO Day Off* Benefits M&V approach for the operationalized VVO systems on all five banks (14 circuits). A "day on/day off" benefits M&V approach scheduled VVO systems to be on for 24 hours and then off for 24 hours, switching at approximately 0730 on each day of the pilot period. This allowed for comparison between "on" days and "off" days. The "off" day measurements acted as a *control* against which to measure the VVO performance (i.e., *treatment*) on the "on" days. Thus, roughly 50% of the hours measured in the test period were planned for *control* measurements and 50% were planned for VVO *treatment* measurements.

PG&E began tracking all technical performance metrics after commissioning VVO solutions on two banks on July 13, 2015, on two banks on August 10, 2015, and the one remaining bank on January 29, 2016. PG&E chose to evaluate VVO performance seasonally to understand how VVO performance changes with seasonal changes in customer behavior and energy usage. Table 5 below shows dates of the six M&V seasonal periods.

Table 5 – Pilot M&V Season Definitions

Period	M&V Season	Start	End
1	Summer 2015	13 July 2015	15 September 2015
2	Autumn 2015	16 September 2015	30 November 2015
3	Winter 2016	1 December 2015	15 March 2016
4	Spring 2016	16 March 2016	31 May 2016
5	Summer 2016	1 June 2016	15 September 2016
6	Autumn 2016	16 September 2016	26 November 2016

Following a competitive Request for Proposal (RFP) process, PG&E selected a third-party consultant to perform the VVO pilot M&V. The final M&V results calculated by the consultant are shown below. A detailed description of the statistical methods used to perform the M&V calculations are discussed in the consultant's final report.

4.2.2 *Performance on Benefits Measurement & Verification Metrics*

The metrics and figures shown in Sections 4.2.2.1 through 4.2.2.5 are from the M&V performance report produced by the third-party consultant. For the purposes of the discussion in this section, referring to a substation's name will reflect the overall bank performance (i.e., multiple circuits), and referring to a specific circuit refers to circuit-specific performance. The following metrics are quantified in this section by bank:

1) Percent change in voltage reduction (%ΔV)
2) Percent change in energy consumed (%ΔE)
3) Change in energy consumed (MWh)
4) Percent change in reactive power demand (%ΔQ)
5) Percent change in real power (%ΔP) demand at CAISO system peak days
6) Weighted Average Voltage Reduction Factor (CVRf)

The figures shown in Sections 4.2.2.1 through 4.2.2.5 show detailed results by bank of the first five metrics above by period (i.e., season) and provide the cumulative weighted average value of the 6th metric. By comparing the results of each of these metrics, PG&E arrived that the following takeaways:

1. **Heavily loaded circuits performed less well than moderately loaded circuits:** Airways and Barton exhibited average peak loading of 89% of circuit capacity across the six circuits sourced from the two banks, with the most heavily loaded circuits exhibiting peak loadings of 105% and 92% of capacity, respectively. In contrast, the Pinedale and Woodward circuits exhibited peak loading of 86% and 60%, respectively. Additionally, Pinedale and Woodward experienced more consistent voltage reduction performance across test periods.
2. **Loading percentages and measured voltage reductions directionally affirm benefits forecast approach of voltage reduction potential:** The measured loading percentages and achieved voltage reductions directionally affirm the SmartMeter™ voltage data based approach to determining voltage reduction component of the benefit computation. Higher loading levels will generally result in greater circuit voltage drop, reducing the voltage reduction that may be achieved by VVO.
3. **There is differing performance amongst VVO vendors in reducing line losses:** Differing algorithms between the two pilot vendors drove differences observed in Reactive Power Demand Reductions between banks with one vendor (Airways and Pinedale) and banks with the second vendor (Barton, Dinuba and Woodward). One vendor's algorithm objective function considered reactive power impacts from capacitor switching. This allows the algorithm to reduce line losses through power factor improvements. These results are shown in the percent change in reactive power demand metric (%ΔQ). In August 2015, when VVO went live on the Barton and Woodward banks, the applicable vendor's algorithm objective function focused on the voltage impact of capacitor switching, and not the power factor implication. In July 2016, PG&E implemented a software update to this vendor's product which incorporated reactive power impact into the algorithm's logic. This updated vendor algorithm had a beneficial impact on VVO's ability to reduce line losses through power factor optimization.

4. **Measured CVRf from M&V is within bounds used for VVO benefits forecasting:** The VVO pilot circuits exhibit a CVR factor that align with the 0.6 to 0.8 range used in the PG&E deployment-scale benefits forecast. Across all test periods and pilot banks (excluding Dinuba),[31] the weighted average CVRf was 0.7.

The M&V consultant's methods compute CVRf regardless of the voltage reduction achieved. In cases of small voltage changes (e.g., less than 1% reduction in voltage), this can result in widely varying CVRf across different test periods. PG&E developed an approach to discount CVRf derived from small magnitude voltage changes by computing a CVRf Weighted Average (weighed based on ∆V%). This approach computed a weighted average of CVRf, utilizing the magnitude of the voltage change as the weighting factor.[32] The rationale for discounting CVRf derived from small voltage changes is that the small changes in voltage can result in large magnitude CVRf that are more likely a result of "noise" than representing a causal effect of voltage on energy.

Operational Challenges Impacting M&V Results

PG&E experienced a number of challenges during VVO operations that either resulted in lower solution up-time or limited VVO's ability to reduce voltage. Table 6 below shows the scheduled on-days per period and the "full-on" and "partial-on" days achieved per bank for each period. The days which are "full-on" are days where VVO was engaged for the full 24-hour period with no disables interrupting the operation of VVO. "Partial-on" days are any day where VVO is engaged for less than the fully-scheduled time. Days where VVO was scheduled to be operating, but did not operate at any point during that day are not listed in the table. The Summer 2015 test period is not listed due to the limited data available due to mid-period go-live dates and the initial challenges with keeping VVO engaged at the beginning of the pilot.

[31] Dinuba is excluded as it is not considered a candidate for driving CVR, but to understand the ability of VVO to perform on long, complex distribution circuits.

[32] For example, a CVRf derived from a 0.1% change in voltage would be given one tenth the weight of a CVRf for a different period derived from a 1.0% change in voltage.

Table 6 – Scheduled, Full, and Partially VVO On Days Per Bank, Per Season

	Days	Autumn 2015	Winter 2015/2016	Spring 2016	Summer 2016	Autumn 2016
	On Scheduled	38	53	38	54	36
Airways	Full On	22	31	35	40	34
	Partial On	11	19	3	8	3
Barton	Full On	34	45	9*	27**	29
	Partial On	1	8	3*	5**	1
Pinedale	Full On	14	47	30	35	32
	Partial On	22	7	6	11	4
Woodward	Full On	15	47	38	34+	25
	Partial On	2	4	1	1+	3
Dinuba	Full On	NA	22	35	42	24
	Partial On	NA	2	0	10	5

Table 6 Notes:

* In Spring 2016, VVO lost communication with the Barton LTC for 76 days resulting in only 9 days of valid on-day data out of the 33 days in which VVO was engaged for the full 24-hour period. This prevented the LTC from being able to reduce voltage during VVO On Days. This led to key learnings about the need for improved alarms and changes in pilot processes for ensuring communications reliability.

** In Summer 2016, VVO regained communication with the Barton LTC on June 27, 2016 followed by one week of commissioning a software enhancement resulting in 27 days of valid data out of the 36 days which VVO was engaged for full 24-hour period.

\+ In Summer 2016, the Woodward LTC was stuck for 27 days resulting in 34 days of valid on-day data out of the 42 days in which VVO was engaged for the full 24-hour period. This prevented the LTC from being able to reduce voltage during VVO On days.

4.2.2.1 Performance of Metrics on Airways Bank 1

Table 7 shows the performance of Airways Bank 1 across five M&V Metrics. As Table 1 listed, Airways has three 12-kV circuits with the following characteristics:

Circuit	% Loaded	Total Circuit Length [miles]	Longest Circuit Length, *From Substation to Furthest Device* [miles]	Customer Classification [Residential/Commercial/ Industrial/Agricultural]	Bank 2016 Load Forecast [MW]	% DG/ Load
A-1101	105%	46.4	4.3	95% / 1% / 3% / 1%	36	22%
A-1102	98%	57.4	7.5	84% / 2% / 13% / 1%	36	29%
A-1103	82%	32.0	3.2	48% / 10% / 39% / 3%	36	16%

Results on Airways show less effective voltage reduction [%ΔV] when compared to the more lightly loaded Pinedale and Woodward, with achieved voltage reductions often less than 1% in magnitude, potentially leading to normal changes in circuit load being incorrectly attributed to VVO voltage impacts. Airways experienced only marginal changes in energy consumed, which is aligned with the small changes in voltage. Additionally, in the first three periods after go-live, over a third of the on-days achieved by Airways were cut short due to technical challenges. Some of these challenges were addressed in mid-October 2015, and the rest were addressed in early February 2016. The small changes in voltage suggest VVO will effect limited energy and peak demand impacts and that a significant portion of the energy impacts may be spurious and not a result of VVO. This is particularly true in Summer 2016 in which the voltage impacts did not exceed a 1% reduction. The CVRf showed a wide range of values, particularly in the Summer 2015, Autumn 2015 and Summer 2016 periods when the lowest voltage reductions were seen, likely introducing significant error (as discussed in Section 4.2.2 above). Airways exhibits a significant reduction in reactive power demand [%ΔQ] as a result of the vendor's algorithm. The weighted average of CVRf over the pilot period was 0.25. The Percent Change in Real Power Demand [%ΔP] at CAISO System Peak Days varies across the three circuits, yielding an average 1% CAISO peak reduction for the bank as a whole.

Table 7 – Airways Bank 1 M&V Metrics Results

Period	Airways Bank	Voltage Reduction [%ΔV]	Energy Reduction [%ΔE]	Energy Conserved [MWh]	Reactive Power Reduction [%ΔQ]	Real Power Demand Reduction on CAISO 1-in-2 Peak Day Scenario [%ΔP]
Period 1 Summer 2015	**Bank**	**0.4%**	**-0.4%**	**-20**	**64%**	
	A-1101	0.0%	-0.9%	-14	72%	
	A-1102	1.0%	0.6%	10	45%	
	A-1103	0.1%	-1.0%	-17	77%	
Period 2 Autumn 2015	**Bank**	**0.7%**	**0.3%**	**23**	**60%**	
	A-1101	0.3%	0.2%	3	65%	
	A-1102	1.2%	1.2%	31	47%	
	A-1103	0.3%	-0.5%	-11	72%	
Period 3 Winter 2016	**Bank**	**1.1%**	**-0.1%**	**-4**	**50%**	
	A-1101	1.0%	-0.2%	-4	66%	
	A-1102	1.4%	0.0%	0	19%	
	A-1103	0.9%	0.0%	0	70%	
Period 4 Spring 2016	**Bank**	**1.3%**	**0.9%**	**46**	**53%**	
	A-1101	1.2%	2.3%	32	64%	
	A-1102	1.6%	1.6%	30	32%	
	A-1103	1.2%	-0.8%	-16	60%	
Period 5 Summer 2016	**Bank**	**0.6%**	**-0.4%**	**-57**	**59%**	**1.0%**
	A-1101	0.2%	-0.7%	-28	45%	1.4%**
	A-1102	1.0%	-0.3%	-16	31%	1.5%
	A-1103	0.4%	-0.3%	-13	78%	0.1%**
Period 6 Autumn 2016	**Bank**	**0.7%**	**1.1%**	**74**	**63%**	
	A-1101	-0.1%	1.2%	20	69%	
	A-1102	2.0%	2.5%	60	34%	
	A-1103	0.0%	-0.3%	-6	76%	

**results above based on M&V Measurements between 7/13/15 and 11/26/2016*

***not statistically significant*

4.2.2.2 Performance of Metrics on Pinedale Bank 1

Table 8 below shows the performance of Pinedale Bank 1 across each test period and over five benefit M&V Metrics. As Table 1 listed, Pinedale has three 21-kV circuits with the following characteristics:

Circuit	% Loaded	Total Circuit Length [miles]	Longest Circuit Length, *From Substation to Furthest Device* [miles]	Customer Classification [Residential/Commercial/ Industrial/Agricultural]	Bank 2016 Load Forecast [MW]	% DG/ Load
P-2101	86%	40.7	7.1	49% / 5% / 46% / 0%	60	15%
P-2102	80%	46.5	5.1	76% / 5% / 19% / 0%	60	14%
P-2103	47%	20.7	3.1	37% / 15% / 48% / 0%	60	10%

Results on Pinedale showed fairly consistent voltage reduction [%ΔV] across the test periods, especially when compared to heavily loaded banks (Airways and Barton). Pinedale exhibited consistent percentage change in energy consumed for the Summer 2015 and Autumn 2015, with a reduction in the percentage of energy consumed in later periods, but maintaining consistency over this second group of test periods. This “step change” in computed percentage energy reduction between the first two periods and the final three periods is due to many (over half) of the “on” days in the Summer 2015 and Autumn 2015 periods being shortened as a result of in the first two periods by VVO automatically disabling due to a bad meter at the substation. The premature disabling of VVO inflated the percentage energy reduction providing the appearance of greater overall savings when lesser percentage savings would be experienced if operated continuously. This meter was replaced in early November 2015 resolving the issue, enabling unabbreviated VVO run time, increasing the sample size of VVO on days. The weighted average of CVRf over the pilot period was 0.80. Pinedale exhibits a significant reduction in reactive power demand [%ΔQ] due to the vendor’s algorithm. Pinedale exhibits a reduction of demand (Percent Change in Real Power Demand [%ΔP]) at CAISO System Peak Days both at the individual circuit and bank level.

Table 8 – Pinedale Bank 1 M&V Metrics Results

Period	Season	Pinedale Bank	Voltage Reduction [%ΔV]	Energy Reduction [%ΔE]	Energy Conserved [MWh]	Reactive Power Reduction [%ΔQ]	Real Power Demand Reduction on CAISO 1-in-2 Peak Day Scenario [%ΔP]
Period 1	Summer 2015	**Bank**	**1.3%**	**1.5%**	**56**	**72%**	
		P-2101	1.3%	1.4%	21	68%	
		P-2102	1.5%	2.6%	29	81%	
		P-2103	1.0%	0.7%	7	58%	
Period 2	Autumn 2015	**Bank**	**1.8%**	**2.0%**	**131**	**57%**	
		P-2101	1.3%	2.3%	60	-102%	
		P-2102	2.2%	2.8%	54	88%	
		P-2103	1.7%	0.9%	17	64%	
Period 3	Winter 2016	**Bank**	**1.7%**	**0.9%**	**114**	**49%**	
		P-2101	1.4%	0.8%	45	-21%	
		P-2102	2.0%	1.1%	42	86%	
		P-2103	1.5%	0.7%	27	46%	
Period 4	Spring 2016	**Bank**	**1.6%**	**0.7%**	**57**	**51%**	
		P-2101	1.3%	0.7%	23	0%	
		P-2102	1.9%	1.3%	28	85%	
		P-2103	1.4%	0.3%	6	46%	
Period 5	Summer 2016	**Bank**	**1.2%**	**0.6%**	**101**	**49%**	**1.2%**
		P-2101	0.7%	0.1%	7	13%	0.8%**
		P-2102	1.4%	0.7%	35	74%	1.7%
		P-2103	1.4%	1.4%	60	54%	1.0%**
Period 6	Autumn 2016	**Bank**	**1.2%**	**0.9%**	**73**	**32%**	
		P-2101	1.0%	1.0%	36	-101%	
		P-2102	1.5%	1.2%	29	81%	
		P-2103	0.8%	0.4%	8	19%	

**results above based on M&V Measurements between 7/13/15 and 11/26/2016*

***not statistically significant*

4.2.2.3 Performance of Metrics on Barton Bank 3

Table 9 shows the performance of Barton Bank 3 across five Benefit M&V Metrics. As Table 1 listed, Barton has three 12-kV circuits with the following characteristics:

Circuit	% Loaded	Total Circuit Length [miles]	Longest Circuit Length, *From Substation to Furthest Device* [miles]	Customer Classification [Residential/Commercial/ Industrial/Agricultural]	Bank 2016 Load Forecast [MW]	% DG/ Load
B-1114	85%	24.5	2.9	75% / 5% / 20% / 0%	32	2%
B-1115	92%	44.9	6.0	74% / 5% / 20% / 0%	32	8%
B-1116	73%	22.7	5.4	46% / 6% / 48% / 0%	32	3%

Results on Barton showed consistent voltage reduction [%ΔV] over the Autumn 2015 through the Spring 2016 periods with significantly reduced realized voltage reduction voltage reduction during the more heavily loaded Summer 2016 test period. Additionally, in the Spring/Summer of 2016, VVO lost communication with the Barton LTC resulting in a combined total of 33 on-days lost between the two periods and resulting in particularly poor data set in Spring 2016 for Barton. This reduced data set is evidenced by the inconsistency between the Spring and Summer 2016 results when compared with other test periods. The weighted average of CVRf over the pilot period was 0.95. Barton exhibits no more than a 13% change in reactive power demand [%ΔQ] for any of the test periods/circuits due to the VVO software vendor's algorithm. Pertaining to Percent Change in Real Power Demand [%ΔP] at CAISO System Peak Days, all three Barton circuits show real power increases when modeled under CAISO peak conditions indicating limited potential reduction at CAISO peak for the Barton bank.

Table 9 – Barton Bank 3 M&V Metrics Results

	Barton Bank	Voltage Reduction [%ΔV]	Energy Reduction [%ΔE]	Energy Conserved [MWh]	Reactive Power Reduction [%ΔQ]	Real Power Demand Reduction on CAISO 1-in-2 Peak Day Scenario [%ΔP]
Period 1 Summer 2015	**Bank**					
	B-1114					
	B-1115					
	B-1116					
Period 2 Autumn 2015	**Bank**	**1.3%**	**1.1%**	**56**	**4%**	
	B-1114	1.2%	0.8%	15	-11%	
	B-1115	1.4%	2.4%	34	12%	
	B-1116	1.5%	0.4%	7	9%	
Period 3 Winter 2016	**Bank**	**1.5%**	**1.1%**	**98**	**-10%**	
	B-1114	1.5%	1.0%	27	-5%	
	B-1115	1.6%	1.0%	35	-9%	
	B-1116	1.5%	1.2%	35	-15%	
Period 4 Spring 2016	**Bank**	**1.7%**	**4.0%**	**52**	**-13%**	
	B-1114	1.7%	2.9%	11	13%	
	B-1115	1.8%	1.8%	9	0%	
	B-1116	1.7%	7.1%	32	-76%	
Period 5 Summer 2016	**Bank**	**0.4%**	**-1.4%**	**-121**	**-33%**	**-1.3%**
	B-1114	0.3%	-1.5%	-43	-53%	-1.0%**
	B-1115	0.4%	-2.0%	-64	-7%	-2.1%
	B-1116	0.4%	-0.6%	-14	-38%	-0.8%**
Period 6 Autumn 2016	**Bank**	**1.9%**	**1.7%**	**88**	**-17%**	
	B-1114	1.8%	1.5%	24	-37%	
	B-1115	2.0%	1.6%	31	-3%	
	B-1116	1.9%	2.1%	33	-14%	

**results above based on M&V Measurements between 8/10/15 and 11/26/2016*

***not statistically significant*

4.2.2.4 Performance of Metrics on Woodward Bank 2

Table 10 shows the performance of Woodward Bank 2 across five Benefit M&V Metrics. As Table 1 listed, Woodward has three 21-kV circuits with the following characteristics:

Circuit	% Loaded	Total Circuit Length [miles]	Longest Circuit Length, *From Substation to Furthest Device* [miles]	Customer Classification [Residential/Commercial/ Industrial/Agricultural]	Bank 2016 Load Forecast [MW]	% DG/ Load
W-2104	56%	38.7	6.2	48% / 4% / 46% / 1%	58	25%
W-2105	60%	33.4	3.4	84% / 7% / 9%/ 0%	58	16%
W-2106	54%	24.5	5.5	66% / 2% / 30% / 2%	58	35%

Woodward was by far the most lightly loaded (on a percent of capacity basis) of the pilot circuits and as a result exhibited largest and most consistent voltage reductions of those experienced with the pilot banks. Aligning with the larger voltage reductions, Woodward exhibited greater absolute energy reductions compared to other banks in non-summer test periods, with the exception of Summer 2016 in which results were impacted by the stuck LTC. The weighted average of CVRf over the pilot period was 0.82. Woodward exhibits on marginal changes in reactive power demand [%ΔQ] due to the VVO software vendor’s algorithm. In Summer 2016, the Woodward LTC tap stuck for a total of 27 days resulting in a loss of eight on-days for the period limiting the data from which the peak demand reduction could be developed. As a result of the small set of data from which to compute the Percent Change in Real Power Demand [%ΔP] at CAISO System Peak Days, a statistically significant result was not obtained.

Table 10 – Woodward Bank 3 M&V Metrics Results

		Woodward Bank	Voltage Reduction [%ΔV]	Energy Reduction [%ΔE]	Energy Conserved [MWh]	Reactive Power Reduction [%ΔQ]	Real Power Demand Reduction on CAISO 1-in-2 Peak Day Scenario [%ΔP]
Period 1	Summer 2015	**Bank**	**2.4%**	**0.0%**	**0**	**17%**	
		W-2104	2.5%	-0.1%	-4	23%	
		W-2105	2.3%	-0.4%	-7	4%	
		W-2106	2.4%	1.2%	12	19%	
Period 2	Autumn 2015	**Bank**	**2.9%**	**2.2%**	**201**	**5%**	
		W-2104	3.0%	2.3%	111	15%	
		W-2105	2.9%	1.9%	50	-24%	
		W-2106	2.9%	2.7%	40	4%	
Period 3	Winter 2016	**Bank**	**2.9%**	**5.5%**	**453**	**-3%**	
		W-2104	2.9%	2.9%	98	9%	
		W-2105	2.9%	8.7%	280	-25%	
		W-2106	2.9%	4.6%	74	-1%	
Period 4	Spring 2016	**Bank**	**2.6%**	**1.3%**	**62**	**-24%**	
		W-2104	2.4%	1.2%	25	-26%	
		W-2105	2.7%	1.1%	21	-30%	
		W-2106	2.6%	1.9%	16	-14%	
Period 5	Summer 2016	**Bank**	**2.1%**	**-0.4%**	**-42**	**-38%**	**0.8%****
		W-2104	2.0%	-0.1%	-5	-25%	0.3%**
		W-2105	2.1%	-0.8%	-27	-39%	0.8%**
		W-2106	2.0%	-0.5%	-10	-61%	1.8%**
Period 6	Autumn 2016	**Bank**	**2.7%**	**3.9%**	**172**	**-147%**	
		W-2104	2.4%	3.6%	63	-133%	
		W-2105	3.0%	3.4%	55	-106%	
		W-2106	2.5%	5.4%	53	-278%	

**results above based on M&V Measurements between 8/10/15 and 11/26/2016*

***not statistically significant*

4.2.2.5 Performance of Metrics on Dinuba Bank 1

Table 11 shows the performance of Dinuba Bank 1 across five Benefit M&V Metrics. As Table 1 listed, Dinuba has two 12-kV circuits with the following characteristics:

Circuit	% Loaded	Total Circuit Length [miles]	Longest Circuit Length, *From Substation to Furthest Device* [miles]	Customer Classification [Residential/Commercial/ Industrial/Agricultural]	Bank 2016 Load Forecast [MW]	% DG/ Load
D-1102	102%	45.9	4.9	57% / 10% / 25% / 8%	23	1%
D-1104	93%	114.5	8.5	24% / 4% / 11% / 61%	23	34%

Results on Dinuba Bank 1 showed significant variation in voltage reduction between the circuits, with Dinuba 1102 regularly showing greater reduction than that on 1104. This is expected as Dinuba 1102 serves mostly Residential customers in a small community, and Dinuba 1104 serves a large area of mostly Agricultural customers. The weighted average of CVRf for both circuits over the pilot period was -0.02. Dinuba's observed Percent Change in Real Power Demand [%ΔP] at CAISO System Peak Days was not statistically significant.

The pilot results show that circuits like Dinuba 1104 are poor candidates for implementing VVO to achieve CVR benefits. The complexity[33] and load characteristics of Dinuba drive the poor CVR performance. The challenge of operating VVO on circuits as complex as Dinuba validates PG&E's belief that VVO should be deployed on banks with shorter, less complex circuits. Operating VVO on Dinuba also showed the challenge posed by large agricultural loads near the end of a circuit. These loads can be large and exhibit significant "step changes", causing the LTC or immediate upstream line regulator to tap up and resulting in an increase in all other customers' voltages. In a VVO deployment, PG&E would need to understand that the loading behavior and circuit impedance characteristics for customers at the low end of a bank's voltage distribution could adversely impact VVO's ability to deliver CVR benefits.

[33] See Tables 1 and 2 for data that compare Dinuba from other piloted banks. Dinuba has eight sets of line voltage regulators, making it the most complex bank piloted.

Table 11 – Dinuba Bank 1 M&V Metrics Results

		Dinuba Bank	Voltage Reduction [%ΔV]	Energy Reduction [%ΔE]	Energy Conserved [MWh]	Reactive Power Reduction [%ΔQ]	Real Power Demand Reduction on CAISO 1-in-2 Peak Day Scenario [%ΔP]
Period 3	Winter 2016	**Bank**	**1.7%**	**1.1%**	**21**	**-26%**	
		D-1102	1.9%	1.3%	14	-25%	
		D-1104	0.7%	0.8%	7	-27%	
Period 4	Spring 2016	**Bank**	**1.4%**	**1.6%**	**85**	**-40%**	
		D-1102	1.6%	1.2%	29	-71%	
		D-1104	0.3%	1.9%	56	4%	
Period 5	Summer 2016	**Bank**	**0.3%**	**-1.2%**	**-122**	**3%**	**0.1%****
		D-1102	0.3%	-0.5%	-26	3%	0.2%**
		D-1104	0.1%	-1.8%	-95	4%	0.0%**
Period 6	Autumn 2016	**Bank**	**0.4%**	**-1.7%**	**-75**	**-64%**	
		D-1102	0.2%	0.1%	1	-53%	
		D-1104	1.1%	-3.6%	-76	-76%	

**results above based on M&V Measurements between 1/29/16 and 11/26/2016*

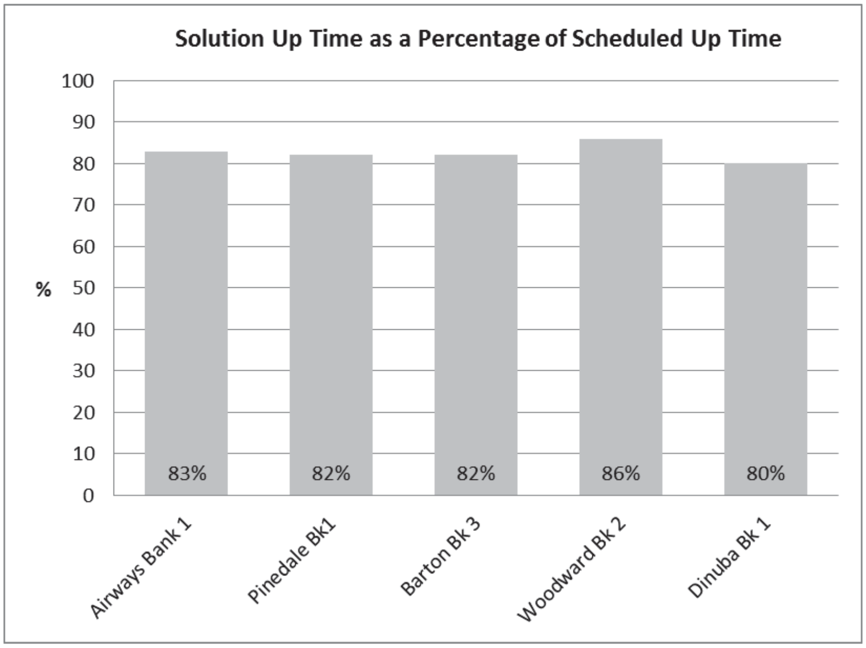
***not statistically significant*

4.2.3 *Solution Up-Time Metrics*

4.2.3.1 Solution Up-Time Metric

As Figure 6 below shows, all five banks within the VVO pilot achieved at least an 80% Solution Up-Time Percentage. This 80–86% range of Up-Time performance was calculated across the full test period (from operationalization of VVO on each Bank to October 16, 2016).

Figure 6 – Observed Solution Up-Time Percentage
Across Full Trial Period of Each Bank

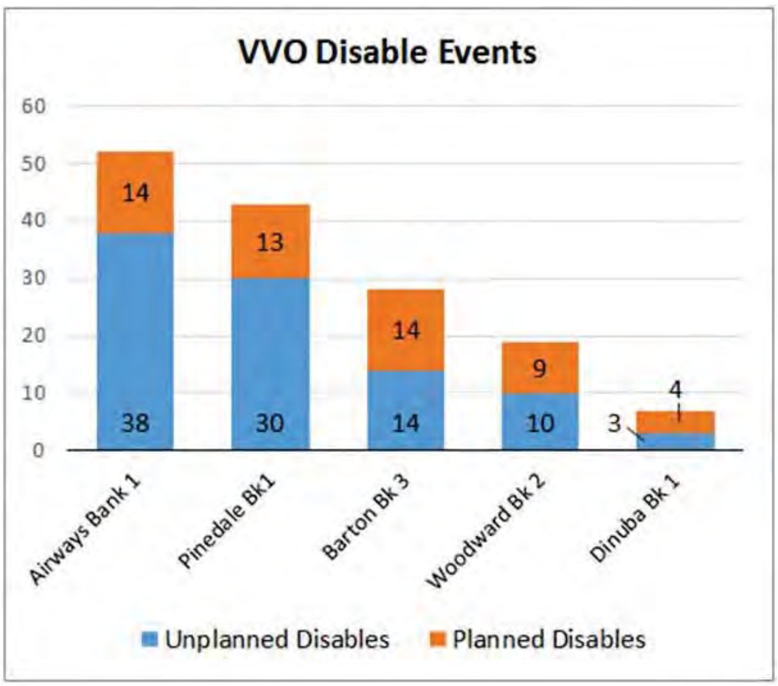


4.2.3.2 Planned and Unplanned Disables Impacting Solution Up-Time Performance

As described in *Section 2.5 – Metrics*, the hours in which VVO was not operating when scheduled to be operating are split into two types—unavailable hours due to *planned* disables and unavailable hours due to *unplanned* disables. In order to better understand the root causes of non-performance in VVO Up-Time metric, PG&E tracked the counts of disable events between these two categories. The primary reason for planned disables affecting the Up-Time metric is due to circuit reconfiguration; PG&E anticipates that the majority of downtime resulting from planned disables can be mitigated through the addition of auto-reconfiguration functionality, which would require VVO to be integrated with the DMS. Unplanned disables typically pertained to outages, abnormal circuit configurations and issues with VVO settings, reverse power flow and communications. Auto-reconfiguration functionality would sufficiently mitigate down-time experienced as a result of outages and abnormal circuit configurations. However, the majority of unplanned downtime during the pilot was a result of issues with reverse power flow, and communication issues. Over the course of the pilot, the pilot team resolved existing issues with VVO settings on pilot banks. Updates to vendor software addressed down-time driven by reverse power flow through line voltage regulators. In future deployments, the majority of communication and equipment issues could be resolved during the initial phases of deployment. The team must plan for emergent work during the deployment to address any malfunctions that arise during installation. A major learning from the pilot is to pursue proactive monitoring of critical operating equipment early. By catching equipment issues early on in the pilot, the availability of VVO could have been greatly increased.

Figure 7 below shows the count of unplanned and planned disables of VVO over the M&V period. This count excludes disabling VVO to begin a scheduled day off for M&V purposes. Airways and Pinedale had 38 and 30 unplanned disables respectively, much greater than Barton and Woodward's 14 and 10 unplanned disables. This difference in unplanned disables on Airways was due to reverse power flow seen at the line voltage regulator for the first three periods before a work around and eventually a code patch could address the issue. The difference for Pinedale was driven by a bad meter at the substation, which caused issues until it was resolved late in the second period (Autumn 2015) by replacing the meter.

Figure 7 – Count of Unplanned and Planned Disabling of VVO



4.2.4 *SCADA Communications Health Metrics*

SCADA communications health (i.e., the availability of SCADA to monitor and control substation and line devices) is a key driver of VVO solution up-time. PG&E understood the value of healthy SCADA communications to the success of the pilot through the VVO benchmarking process as well as other internal technology projects. A combination of upfront work, continuous monitoring, and good engagement among the SCADA and VVO Pilot teams allowed PG&E to achieve minimal down time due to communications issues while operating VVO for over a year.

PG&E worked with vendors during the lab testing phase to ensure that loss of communications to less significant devices in the VVO scheme like capacitor banks, would not cause the overall system to disable, thereby improving uptime of the system while still providing the majority of benefits.

4.2.4.1 SCADA Communication Health

Figure 8 below shows the SCADA Communications Health from June 22, 2015 through August 28, 2016. SCADA Communications Health is defined as the percent of time that SCADA communications was available to substation and line devices requiring communications for VVO to operate. Communications Health was continuously monitored and calculated on a week-by-week basis.

The high availability of SCADA at the distribution, substation, and data center levels allowed for SCADA Communications Health to have a minimal impact on the overall VVO Solution Up Time. The average SCADA Communications Health for VVO distribution line devices was 99.6%, while data center and substation SCADA availability was greater than 99.9%.

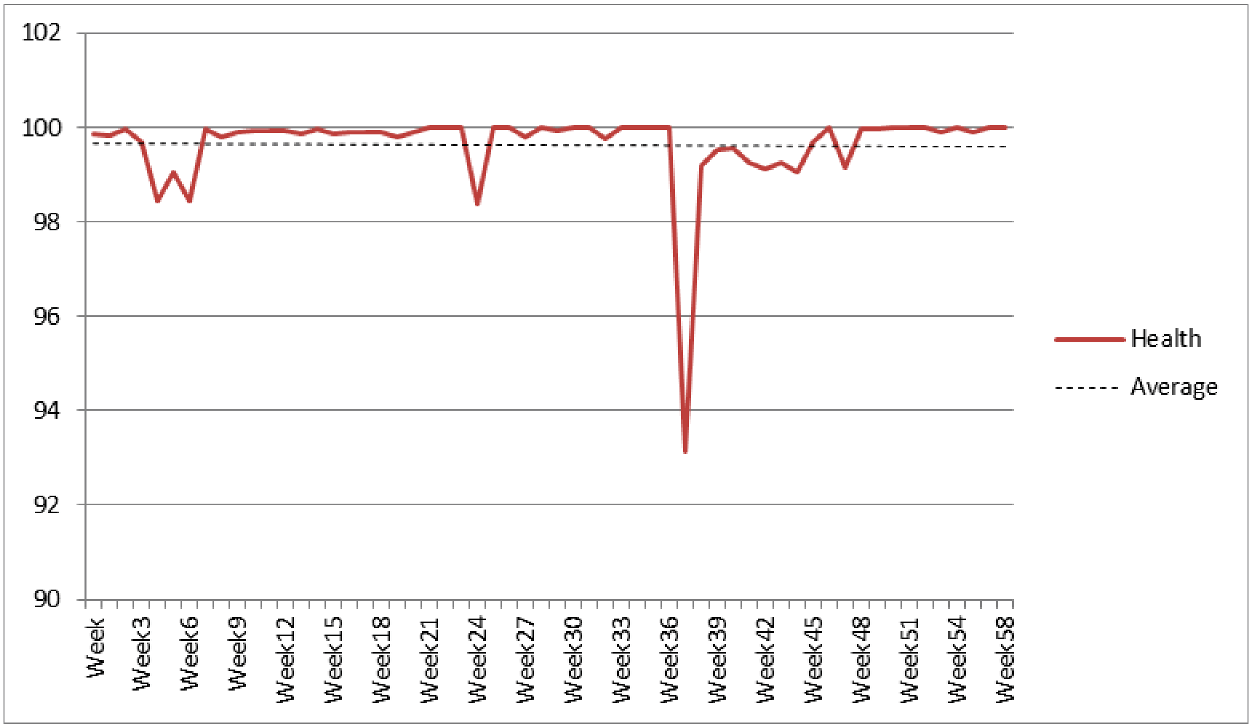
While substation SCADA availability was very high, there were occasions when the communications health to individual assets on the lines (e.g., capacitor bank, line voltage regulator) impacted VVO solution up time. SCADA Communications Health stayed above 99% for all but five weeks of the VVO Pilot, and only dropped below 98% for one week. The key drivers of the reduction in SCADA Communications Health were:

- **Weeks 5-7:** Signal strength was found to degrade on certain devices due to vegetation and new construction. Corrective actions were taken to reallocate SCADA devices to different radio channels, improving signal strength and communications.
- **Week 25:** A 22-hour outage on the mountain top master radio station affected all devices served by that station. This did not affect VVO uptime because the only VVO devices on this

station at the time were capacitors and line voltage monitors where VVO could ride-through communication losses on those types of equipment.

- **Week 38:** A 56-hour outage on the mountain top master radio station affected all devices served by that station. VVO rode-through this event on banks where only capacitors and line voltage monitors were affected. However, VVO for Dinuba disabled because it had some line regulators served by this station.

Figure 8 – SCADA Communications Health Over Time



4.3 Pilot Lessons Learned

In the section below PG&E discusses lessons learned in the following categories:

- VVO Measurement & Verification
- Use of Smart Inverters to Enhance VVO Benefits
- Value of Lab Testing VVO Prior to Field Implementation
- Solution Up-Time Dependency on Integration With DMS
- VVO Implementation Requirements
- Information Technology and Operations Technology (IT – OT) Integration
- Ability of VVO Vendor Software to Drive Benefits on PG&E's System

- SmartMeter™ Data Availability for Control Systems
- Staffing to Execute Circuit Conditioning in a Timely Manner
- Increasing SCADA Penetration to Field Devices
- Comparing VVO Programs at Other U.S. Utilities
- Screening and Selecting Banks (and Associated Circuits) for VVO Deployment
- Commissioning Process

VVO Measurement & Verification

There is not presently a standard method for performing VVO M&V in the industry. The Institute of Electrical and Electronics Engineers (IEEE) is developing P1885, the "Guide for Assessing, Measuring, and Verifying Volt VAR Control Optimization on Distribution Systems." PG&E expects that the M&V methods used by the VVO Pilot will align with the guidelines yet to be published in IEEE P1885.

PG&E contracted with a third-party consultant to perform the M&V of the VVO pilot circuits. The consultant's model utilized regression models for each hour. The model incorporated SCADA data, SmartMeter™ data, weather data, VVO operation and transition time, as well as solar potential index as a proxy for solar PV generation impacts not captured in other variables. Each of the aforementioned items was key in development of an M&V model to capture parameters influencing VVO effectiveness. The use of SmartMeter ™ voltage and energy consumption data supported breakouts of voltage reductions and energy savings by customer class.

Despite the sophistication of the model, the impact of VVO can be difficult to separate from the noise of the voltage and energy consumption data. Such impacts may be greatest during periods of high-loading conditions, and may drive the lack of statistically significant results of the Percent Change in Real Power Demand [%ΔP] at CAISO System Peak Days in some of the circuits. Further study is needed to determine whether this uncertainty in the cause of voltage and energy changes during high loading can be addressed through statistical modelling.

Use of Smart Inverters to Enhance VVO Benefits

By adjusting Smart Inverter autonomous function reactive power control operating modes and set points, PG&E was able to further drive CVR benefits under both VVO on and off operating statuses. The effectiveness of the Fixed Power Factor operating mode to drive CVR was dependent on Smart Inverter active power output, which is correlated to solar irradiance. On the other hand, Volt-VAR curve effectiveness to drive CVR depended on the curve set points selection and voltage present at the inverter terminal. Although PG&E demonstrated that Smart Inverters can enhance VVO's CVR benefits, PG&E did not have sufficient time to conclude what the optimal settings are for the Smart Inverters installed on Woodward Bank 2.

PG&E learned about the capabilities, limitations, and challenges of Statistical and Power Flow M&V approaches that aimed to quantify the incremental CVR benefit delivered by Smart Inverters. Power Flow M&V analysis included the service transformers model but not the secondary network model as part of the CYME Woodward Bank 2 model. The Statistical (regression) M&V analysis relied on voltage measurements from PQMs installed downstream of the service transformer. The PQMs provided decimal precision voltage measurements, which are more accurate than integer voltage reads values provided by residential SmartMeter™ devices.

Both Power Flow and Statistical M&V analyses showed additional voltage reduction on secondary networks with Smart Inverters, when operated in a non-unity reactive power control mode that resulted in VAR absorption. Due to the small amount and capacity of Smart Inverters on Woodward, PG&E was not able to measure Smart Inverter impact on the primary system voltage using the Statistical approach. However, the Power Flow modeling results also showed limited Smart Inverter impact on the primary voltage when Smart Inverters were absorbing VARs. Also, the Statistical model results showed that proper selection of Volt-VAR curve set points is important to optimally drive CVR benefits on circuits where VVO operates.

There is substantial additional room to learn about Smart Inverter M&V, and PG&E expects to continue to learn how to utilize Smart Inverters to drive CVR and perform M&V to quantify the enhancement of VVO benefits that may be provided by Smart Inverters through the *EPIC 2 Customer-Sited Smart Inverters* technology demonstration project.

Value of Lab Testing Prior to Field Implementation

Phase 1 lab testing allowed PG&E to test multiple VVO vendors under normal and edge case conditions in an environment built to address both operational and integration challenges. VVO solutions were initially unable to meet all PG&E's business requirements, despite having been implemented at other utilities. For example, PG&E worked with both vendors to enable the solutions to accommodate reverse power flow through line voltage regulators which were caused by high distributed PV penetration. Identifying and correcting issues in the lab prevented the issues from occurring during the Phase 2 Field Trial. Lab testing also provided a test bed for stakeholders to interact with the system in a safe environment which uncovered operational needs such as ensuring VVO vendors provided detailed actionable alarms for Operators and Engineers to help with troubleshooting. Lab testing with hardware in the loop provided value to PG&E in evaluating new equipment controllers and communication protocols, as well as ensuring VVO vendors could properly control PG&E-specific field equipment. Lab testing also allowed PG&E to evaluate edge cases, which have a low frequency of occurring but could likely have a significant impact on VVO.

Solution Up-Time Dependency on Integration With DMS

PG&E's piloted VVO solution was enabled and operating as expected 84% of the time it was scheduled to be on.[34] The piloted VVO solution architecture did not integrate to PG&E's DMS. This created challenges when moderate to major circuit reconfigurations happened as a part of regular operations and maintenance of the distribution grid. The high solution up-time was driven by prudent lab testing in Phase 1, proactive monitoring by the pilot team, and selecting banks with no major planned work. For a VVO solution to have high solution up-time, it must be able to quickly and efficiently reconfigure when the topology of the distribution system changes.[35] The most effective way to implement this at scale is by integrating VVO with the DMS (or using a VVO application that is native to the DMS platform), and enabling the VVO solution to automatically reconfigure itself when distribution topology changes happen.

VVO Implementation Requirements

By issuing and evaluating a RFI to assess the VVO software marketplace, and operating solutions from two VVO software system vendors in the lab and field environments, PG&E has gained a detailed understanding of the Business and IT Requirements to implement different VVO control algorithms at PG&E, and operational knowledge on how to implement these requirements.

Information Technology and Operations Technology (IT – OT) Integration

VVO is considered an Operational Technology, similar to SCADA. Historically, U.S. utilities have had separate communications networks for IT and OT systems, with limited integrations. Implementing VVO requires integrating systems across PG&E's IT and OT networks. The VVO pilot has yielded information about how to safely and securely integrate IT and OT systems to increase automation and efficiency on PG&E's electric distribution system. As part of the project, PG&E defined the security controls that should be in place for future projects that require integrating IT and OT systems. These controls are worth considering as requirements for the future technology implementations.

In addition, PG&E has determined how to integrate VVO software within the PG&E technology environment (e.g., SCADA software, SmartMeter™ network management software, PI historian software).

IT-OT integration challenges from the VVO Pilot are discussed in detail in Section 4.4: Technology Integration Challenges, below.

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[34] VVO was scheduled to be on and off on alternating days to collect data for M&V of VVO benefits.

[35] As discussed in Section 4.2.2.6, VVO Solution Up-Time was greatly impacted by the number of planned and unplanned disables. Circuit reconfiguration was the major reason for planned disables of VVO as some circuit reconfigurations experienced during the pilot would require a manual reconfiguration of VVO by an engineer. This manual mitigation approach is likely to be cost prohibitive for a wide scale deployment of VVO. Thus, through an automated reconfiguration capability, it is expected that VVO's Solution Up-Time could be greatly enhanced at reasonable cost.

Ability of VVO Vendor Software to Drive Benefits on PG&E's System

The VVO vendor software system marketplace is continuing to evolve and mature. PG&E has evaluated the strengths and weaknesses of different VVO software system vendors. Vendors are differentiated by their control algorithms, which consume different data and make different decisions around controlling voltage and power factor. Understanding the strengths and weaknesses of different approaches given the specific design and operating characteristics of PG&E's system can make PG&E a more effective buyer and implementer of VVO in the future.

SmartMeter™ Data Availability for Control Systems

PG&E experienced two key challenges when using SmartMeter™ voltage data in VVO controls algorithms; challenges to the reliability of VVO systems during periods of data unavailability, and challenges with the scalability of Meter Data Management Systems (MDMS) to drive operations systems. P G&E found that VVO solutions are able to cope during periods in which SmartMeter™ voltage data was temporarily unavailable due to network limitations. However, the temporary unavailability of a small number of meters can potentially have a disproportionate impact on VVO. This disproportionate impact is driven by vendor algorithms. Utilities can take two actions to mitigate these impacts. First, utilities can work with vendors to ensure VVO solutions become more resilient during data issues. Second, utilities can improve the reliability of their networks which transmit data. Specifically, they can assess the potential impacts and make investments to the networks that communicate with SmartMeter™ devices to improve the overall reliability of data availability. Both of these actions can yield improvements to VVO's performance.

On challenges with MDMS, PG&E observed how these systems, that were designed for meter-to-cash purposes, had some challenges when applied for operational needs. More granular and real time measurements required by operational systems necessitate changes to data storage, processing and delivery methodologies of MDMS. PG&E understands the limitations of existing systems to drive operational tools like VVO, and would be able to implement a solution at scale that either improves or accommodates limitations.

Comparing VVO Programs at Other U.S. Utilities

Through benchmarking VVO programs at other U.S. utilities, PG&E has compared and contrasted different VVO approaches. As VVO deployments vary by distribution system engineering and design, IT and OT architecture, and VVO control software, it is challenging to compare VVO at a high level at different utilities. Instead, a detailed and thorough understanding of these three aspects is needed to compare VVO programs across different utilities.

Screening and Selecting Banks (and Associated Circuits) for VVO Deployment

Although specific banks (and associated circuits) for a deployment of VVO have not been selected, the VVO Pilot has allowed PG&E to establish a methodology for selecting circuits for deployment. Of the 14 operating pilot circuits, the performance of VVO has varied due to the as-found condition of the circuits. Notably, phase load imbalance during summer months limited VVO performance through limiting low voltages. This process informed the value of screening potential VVO banks with SmartMeter™ voltage data to identify limiting voltages that are challenging to correct. PG&E has begun collecting frequent (every 15 minutes for Commercial and Industrial customers, and every 60 minutes for Residential) SmartMeter™ voltages from one million of PG&E's over five million electric SmartMeter™ devices. These voltage readings will allow PG&E to better select circuits for VVO deployment. These voltage data were not available in early 2014 when PG&E began selected the banks and associated circuits for the VVO Pilot. Historic voltage analysis can also be used to identify the circuit segments limiting the ability of VVO to minimize voltages and the conditioning that can be performed to enhance benefits.

Commissioning Process

A multistep commissioning process is required before letting the systems automatically operate in an unmonitored mode. Some of the best practices during the commissioning process include:

- Incorporating operating thresholds in the solution
- Generating alerts and notifications when thresholds are violated
- Failing back to known stages during failure
- Gradual ramp up/down of set points
- Operating in advisory mode with manual controls before automated controls are allowed
- Regular monitoring through operational dashboards

4.4 Technology and Integration Challenges and Recommendations

Throughout the VVO, Pilot PG&E encountered a variety of technology and integration challenges. In the section below PG&E discusses challenges experienced in the following categories:

Data Architecture/Data Analytics

VVO is a complex real-time system that needs timely updates of granular data from several sources in order to optimize results. SCADA, SmartMeter™, SCADA, solar irradiance, and Smart Inverter information and feeds are needed on VVO circuits for operation. Building a simple data model, integrating data feeds, and providing timely access to data for the project was feasible but would require an incrementally larger investment in an enterprise data platform to stage and integrate larger volumes of data for a roll out beyond the current project.

PG&E does not presently have an enterprise Analytics platform that can store, process, analyze and present the volumes of data generated by a larger roll out of VVO technology. Making the appropriate investments to acquire a big data platform and appropriate data architecture is needed for a wide-scale deployment of VVO.

Cyber Security

The VVO deployment presented many cyber security challenges driven largely by the integration of data and other non-control systems with VVO. Additionally vendor software and hardware solutions contained vulnerabilities that were identified during testing and remediated prior to deployment. The VVO team developed a comprehensive list of cyber security controls and framework to assess, secure, and remediate the vendor solutions. This was in addition to existing PG&E controls.

Having a comprehensive cyber security control framework covering network, application, and hardware will be essential to integrating VVO with other control systems like the DMS. The current framework and controls developed by the VVO Pilot will require review and update by the cyber security team to ensure controls continue to evolve with the changing threats. Vendor solutions should be designed to meet PG&E cyber security controls and standards. A large-scale VVO roll-out may also require additional investments in tools to automate monitoring, threat detection, and response.

Network

VVO leveraged existing telecommunication network capacity to monitor and control the system. Communication systems in some areas are heavily loaded and have little additional bandwidth. PG&E needed to make minor investments to increase network bandwidth in the Fresno area for the VVO Pilot. Although bandwidth and communication systems were broadly adequate for this project the introduction of new devices on a wider scale may require new investments in broadband radio technology to reduce congestion and bandwidth constraints.

For a larger scale roll-out of VVO, a complete telecommunications analysis and design will be needed for each bank where VVO is deployed and investments made where there is insufficient network capacity.

IT/OT Integration and Convergence

The electric utility industry is seeing a convergence of IT and OT. Historically, these solutions and teams have not been integrated. VVO was successfully rolled out with a closely integrated team that was dedicated for this project. The VVO project required a multidisciplinary approach for implementation including Data Scientists, Network, Cyber Security, SCADA, Application, Hardware, Engineering, and Operations teams working closely together to overcome the many challenges associated with this new technology.

As PG&E implements new Smart Grid technology, like VVO, IT and OT teams will need to be effectively organized and integrated to better plan, build, and operate this complex technology.

4.5 Industry Recommendations

The following findings of this project are relevant and adaptable to other utilities and the industry:

4.5.1 *Utility Recommendations*

<u>VVO Can Be Successful Without Integrating With DMS/OMS</u>

With sufficient attention, VVO can be effective at driving CVR benefits without an integration to a utility's DMS or Outage Management System (OMS). Although PG&E expects to integrate VVO with DMS in the future, this may not be required for VVO to be cost-effective. In addition to normal cost and benefit drivers, utility-specific distribution circuit design, operating practices, and personnel will influence if VVO can be cost-effective without DMS or OMS integration.

<u>Integrate VVO With DMS/OMS to Make Initial Setup More Efficient and Improve Up-Time When Cost-Effective</u>: A VVO System integrated within a DMS/OMS can improve solution up-time, and thus yield greater benefits.[36] Realizing that systems integration can increase costs, the value of the additional up-time may or may not outweigh the cost of the integration. Integration costs vary utility by utility, and thus this decision should be made with a clear understanding of a utility's specific estimated costs.

<u>Use SmartMeter™ Voltage Data to Forecast VVO Benefits and Evaluate VVO's Performance</u>

Unless a utility has customer phasing data throughout the system, and high confidence in the accuracy of their unbalanced load flow modeling, use of SmartMeter™ voltage reads provides the most accurate assessment of potential to reduce voltage. Where possible, analysis of SmartMeter™ voltage data provides a clear signal of the potential benefits on a utility's system, and enables choosing where VVO can provide the maximum benefit at lowest cost.

Additionally, SmartMeter™ data is key for M&V of VVO benefits, allowing evaluation of benefits at the customer level as well as savings breakdowns by customer class as SmartMeter™ data is at the premise or customer level, whereas feeder or bank level SCADA data spans all customers on a given feeder or bank.

<u>Invest in the Skillset and Tools Needed to Extract Value From "Big" Data</u>

Extracting value from SmartMeter™ data requires tools and systems that are designed to efficiently

[36] Based on Section 4.3 Pilot Lessons Learned discussion on *<u>Solution Up-time Dependency on Integration with DMS</u>*.

store and compute extremely large datasets. The skillset to leverage these tools was not widespread within engineering and operations organizations at PG&E when the VVO Pilot began perhaps because there was not a significant business need for these skills in the past. PG&E expects that there is a growing need for Data Scientists in the future, and recommends that other utilities understand the value add, and uniqueness of data science.

Invest time in Evaluating Communications System Capacity and Reliability Before VVO Deployment

Limited communication system capacity or reliability can hurt VVO Up-Time, and thus benefits. Analyzing capacity and reliability before implementing VVO allows for better Up-Time performance.

Engage Impacted Stakeholders Early On

Each utility has its own capacity to handle change brought about by pilots. Some utility systems present significant challenges to implement VVO, and thus there is a risk that working with the owners of those system will take a substantial amount of time to agree how the system can be changed/adapted to enable VVO. Depending on customer relationships, engaging specific customers with known power quality issues or with unique needs may be needed prior to implementing VVO.

Evaluate and Influence Vendors' Own Test Capabilities

PG&E observed a difference in vendors own test approaches. Evaluating a VVO vendor's own test approach and influencing it when there are perceived limitations is in the interest of the utility and the vendor. Sharing utility data with the vendor (e.g., system model, SCADA loading, SmartMeter™ loading and voltage data) can improve the vendor's tests and de-risk performance for the customer utility.

Co-Locate the Dedicated Team Working on VVO

Implementing VVO requires a mix of personnel from a utility's IT, engineering, and operations departments. Co-locating these teams can drive efficient collaboration that mitigates the risk of divergent or redundant work.

Strategically Buy Architecture Optionality to Enable Efficient IT-OT Convergence

PG&E expects that there will be more integration of historic IT and OT systems. Strategically understanding when technology and budget decisions create or eliminate optionality for future low cost, scalable integration is important.

Impact on Equipment Operations

The vendor algorithm has a significant impact on LTC, line regulator, and capacitor operations. PG&E observed significant differences between the two piloted vendors. It is important to closely follow the impact on equipment operations in the weeks following VVO commissioning. VVO software can be configured to reduce the number of operations to prevent excessive wear and tear on substation and line devices.

One VVO algorithm substantially reduced tap operations of LTCs and line regulators. For LTCs with tap operation-based maintenance, this would results in longer maintenance cycles and possibly a longer lifespan. This decrease was made even more pronounced due to issues with tap hunting caused by over sensitive voltage bandwidth base settings of this equipment. One VVO algorithm was found to slightly increase tap operations for LTCs and slightly decrease operations for line regulators by ca. 5%-15% depending on the equipment base number of operations. Both piloted VVO algorithms had mixed results for capacitors banks with both increases and decreases depending on the particular capacitor. However, neither created any significant over operation of these devices, nor would they affect the existing annual inspections of these equipment.

This shows the importance of monitoring VVO settings and impact on equipment operations.

4.5.2 *Vendor Recommendations*

Use SmartMeter™ Data in the VVO Algorithm

Both *model* and *measure* approaches[37] to VVO can benefit from use of SmartMeter™ voltage and/or loading (i.e., kWh) data in the VVO algorithm. Although there are patents in place that protect vendors' approaches to doing this, VVO performance can be improved with SmartMeter™ data.

Support for Both Voltage Reduction and Reactive Power/Power Factor Management

Vendor VVO systems should include voltage as well as reactive power, power factor, loss minimization in objective functions to enable not only voltage reduction, but also dispatch of reactive power resources (i.e., capacitor banks) to meet system operating targets.

Optimize Capacitors for Both Voltage Support and Power Factor Correction

VVO algorithms should use a balanced approach to operate capacitors for both voltage support and power factor correction to avoid potential conflicts between these objectives. PG&E encountered issues with vendors focused only on power factor correction not providing enough voltage support where needed to prevent low voltages. Conversely, vendors that focused only on voltage control for capacitors led to voltages that may have been beneficial for CVR savings, but led to undesirable power factors. A balanced approach should optimize both voltage support and power factor correction when controlling capacitors.

[37] See Appendix 9.2 (Detailed Technology Description) for discussion of *model* and *measure* approaches.

Enable Auto Configuration and Auto-Reconfiguration Capabilities

Configuring the network hierarchy and building the network topology is a time consuming process as it involves multiple primary devices like LTCs, Voltage Regulators, Cap banks, Switches, Circuit Breakers, Substation Meters and secondary devices like SmartMeter™ devices. The topology changes constantly as the switching states change, new distribution field devices and meters are installed, removed or upgraded. VVO solutions should support more automated process to configure and reconfigure the network with minimum impact to VVO solution up-time, and therefore VVO benefits.

Unless Already Done, Develop a Path Towards Integrating With a Distribution Management System

To enable Auto Configuration and Auto-Reconfiguration capabilities, VVO must be able to efficiently digest a utility's as-built and as-operated (i.e., as-switched) model. This most likely comes through an integration with the utility's DMS, and in some cases with the OMS. Developing a custom integration to a DMS is complex and costly, and therefore, will not likely be a capability that every vendor has. Therefore, designing VVO with the likelihood that a customer will seek the benefits of DMS integration is in the interest of VVO vendors, as it is likely to be a desired feature for VVO customers.

Develop Automated M&V

VVO algorithms could have the ability to automatically perform M&V, which could reduce the cost of implementing VVO, and offer utility engineers and operators more efficient insight into VVO performance on a bank by bank basis. This insight can enable vendor algorithms to better balance the potentially conflicting objectives of voltage optimization, and reactive power optimization (i.e., power factor correction).

Allow "Advisory" Mode for VVO Commissioning

Some VVO solutions do not have an advisory mode. An advisory mode allows an operator to review the VVO's recommended command, and accept the command. This could be a useful feature during VVO commissioning and as part of the change management process in order to build understanding and trust of the VVO command instructions by experienced distribution operators.

Invest significant Time to Understand What Is Unique About Certain Utilities

There are similarities and differences between different utilities. Specifically applicable to VVO are differences in the following:

- IT and OT systems: architecture and existing applications
- How distribution systems are designed and operated
- Models and data used to predict and measure how their circuits behave under different situations

- Impact that changes in industry (e.g., adoption of distribution connected solar PV) have on the distribution system

Having a good grasp on these enables a vendor and a utility to better manage expectations of each other.

Actively Participate in Smart Inverter Forums

Smart inverters present a complex opportunity to enhance VVO benefits. The more that VVO vendors participate in Smart Inverter industry forums, the more likely that vendors will offer solutions that help utilities leverage Smart Inverters to provide customer benefits.

4.6 Additional Learnings

4.6.1 *Technology Readiness Assessment*

Although VVO is still in the relatively “early adoption” phase by U.S. utilities, VVO can soon move to the “early majority” phase, effectively crossing the chasm that impedes new technology adoption.

There is sufficient vendor participation in the marketplace and general industry knowledge and experience implementing VVO that almost any utility can find a VVO system solution that can meet its needs, and obtain needed expertise to implement VVO.

The VVO Pilot demonstrated how utilities like PG&E can collaborate with forward-looking Smart Inverter aggregators to implement pilot solutions that drive learnings around how Smart Inverters can deliver customer benefits. While Smart Inverters present an opportunity to enhance VVO’s benefits, doing so at scale has not been proven, and is not straightforward. Substantial investment from utilities, research bodies, and vendors is needed for solutions to be developed that enable the cost-effective use of Smart Inverters to either drive CVR benefits by themselves, or coordinate with a VVO control of utility-owned voltage and reactive power controlling devices. California utilities are expected to be early adopters of this technology.

5 Deployment Recommendations

This section of the report presents a recommendation for the further deployment of VVO given the results and lessons learned outlined in Section 4. It concludes by presenting the results of the Cost-Benefit Analysis for the specific deployment recommendation, which was performed to verify that the expected benefits to PG&E's customers of further VVO deployment outweigh the anticipated implementation costs.

5.1 Recommended Deployment

Given the results of the VVO pilot, PG&E recommends deploying VVO to approximately 170 banks (510 circuits) of PG&E's 3,200 distribution circuits. This recommendation is driven by a benefit and cost forecast that leverage learnings from the VVO Pilot. The benefit forecast is built from an analysis of SmartMeter™ voltage and substation loading [MW] data at a bank level and the corresponding CVR benefits expected given those characteristics. This analysis produces the estimated reduction in energy consumption [MWh] and reduction in peak demand [MW] which are used to calculate the economic benefits delivered through CVR. Through performing a Cost-Benefit Analysis of a 170-bank deployment, PG&E forecasts a cumulative customer B/C TRC ratio of 1.5 to 2.7.[38] This range of anticipated B/C Ratio is favorable when compared to alternative investments in conservation and affordability, including products within PG&E's Energy Efficiency portfolio. A deployment of 170 banks is anticipated to be the quantity that will take advantage of economies of scale (i.e., spreading fixed deployment costs across banks) while achieving adequate benefits on each VVO-enabled circuit. Thus, this 170 bank deployment recommendation takes into account the diminishing benefits expected from each incremental bank. At a 170-bank deployment scale, the expected average annual reduction in energy consumption [MWh] equates to approximately 80,000 tons of CO_2 emissions reductions per year.[39] This is equivalent to the CO_2 emissions associated with a 4-mile stretch of railway cars filled with coal to be burned for energy production or the offset of the annual electricity consumed by 11,000 homes in the U.S.[40]

The timing of the recommended 170-bank deployment depends on the timing of PG&E's completion of an upgrade of the base systems and technologies upon which VVO relies. VVO should be deployed after PG&E has the necessary foundational systems in place, specifically a Distribution SCADA system that is integrated

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[38] This is based on the external public forecast of Avoided Costs for Energy and Capacity as published in August 2016.

[39] This was calculated based off the Climate Registry's official 2014 Emissions Factor of pounds of CO_2 emissions/MWh for PG&E's System Average Electricity Delivered.

[40] The conversion of tons of CO_2 Emissions to other Equivalencies was performed utilizing the EPA's Greenhouse Gas Equivalencies Calculator [https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator].

with a DMS. While the VVO pilot showed that PG&E is able to implement VVO with its current Distribution SCADA and DMS systems, improvements to these foundational systems can reduce the costs of deploying VVO and additionally, improve the benefits of VVO. During the VVO Pilot, PG&E was able to achieve a cumulative up-time that ranged from 80%-86% between the five pilot banks. This was achieved due to two characteristics of the pilot design. First, a high number of dedicated project personnel oversaw field operations. Second, the VVO team selected pilot banks that had little planned work that would require taking VVO out of service for extended periods. Both of these factors would not be present in a wide-scale deployment, which could potentially result in VVO solution up-time dropping. Building VVO from an integrated DMS and SCADA can enable VVO to automatically reconfigure settings when the topology of the distribution system changes. This auto-reconfigure capability is expected to increase the percent of time that VVO remains operational with more efficient intervention and oversight from operators and engineers. These auto-reconfigure capabilities are needed to achieve a solution up time of 94% that is assumed in the deployment benefits analysis.

Once Distribution SCADA and DMS foundational capabilities are deployed, and if at that time the re-forecasted B/C Ratio of VVO deployment is favorable relative to alternatives, PG&E recommends pursuing VVO deployment. PG&E has not set a “hurdle rate” for B/C Ratio for VVO Deployment at this time. Through ongoing dialog with the CPUC and California Energy Commission (CEC) regarding how to achieve SB 350 energy conservation targets,[41] PG&E anticipates that more definitive criteria for setting the “hurdle rate” will be established for evaluating these programs. In the meantime, PG&E recommends continuing to operate VVO on the four of the five piloted banks, keeping VVO operating on Airways, Barton, Pinedale, and Woodward, but turning VVO off on Dinuba. For the four banks that would continue operations, PG&E would continue to perform M&V of the benefits. Doing so will enable PG&E to learn more about how the benefits of VVO are affected by the continuing adoption of DERs, and provide information to refine CVRf assumptions in a refreshed B/C Ratio forecast. PG&E does not recommend continuing operations on Dinuba because VVO has not proven to deliver CVR benefits, and no additional field data on VVO performance needs to be collected to obtain any other learnings on Dinuba.

Prior to deploying VVO, PG&E would reassess the industry with vendor research, utility benchmarking, and a competitive RFP process. When selecting a vendor, PG&E would consider:

[41] SB 350 requires that the California State Energy Resources Conservation and Development Commission to establish annual targets for statewide EE savings and demand reduction that will achieve a cumulative doubling of statewide EE savings in electricity and natural gas final end uses of retail customers by January 1, 2030; and that the CPUC establish efficiency targets for electrical and gas corporations consistent with this goal.

- The understanding of the piloted vendors' respective approaches.
- The need for updates and changes to the VVO business requirements, IT requirements, and the corresponding solution architectures that PG&E developed to implement the VVO Pilot. The changes should aim to ensure a solution up-time of over 94%.[42]
- Learnings from the challenges and opportunities of implementing an On-line Power Flow as part of the EPIC Distributed Energy Resource Management System (DERMS) technology demonstration project. Some VVO solutions are driven by an On-line Power Flow. The EPIC DERMS project will be PG&E's first use of an On-line Power Flow. PG&E can use learnings from this demonstration to understand what effort is needed to operate an On-line Power Flow driven VVO algorithm.
- The potential increased benefit and cost of integrating a third-party's VVO system software into PG&E's DMS, and what this does to the expected B/C Ratio of implementing VVO.

As industry continues to develop methods and tools to determine how to operationally leverage Smart Inverters to deliver customer benefits, PG&E should consider evaluating if Smart Inverter adoption is occurring on banks and circuits at the right locations to drive benefits, and if the tools exist to cost-effectively deliver the benefits. In addition, PG&E may evaluate if there are tools that are capable of coordinating Smart Inverters with a VVO control software that controls utility devices. As PG&E evaluates industry advancements that seek to automate the use of Smart Inverters at large scale, PG&E will develop deeper understanding regarding whether using Smart Inverters are a cost-effective means of achieving greater CVR benefits relative to VVO as it exists today.

5.2 Alternatives to Recommended Deployment

If future B/C Ratio forecasts of VVO deployment are not favorable relative to alternative investments in conservation and affordability available at that time, and if other methods to accommodate DER growth are more effective than VVO, then VVO should not be deployed. As market and operating conditions change over time, PG&E should reassess the optimal scale of VVO deployment given refreshed B/C Ratio results. PG&E could consider deploying an alternate scale of VVO that shows a greater than 1 B/C Ratio.

5.3 Cost-Benefit Analysis

Of VVO's three benefits streams (CVR, Enablement of DER Penetration, Enhancement of Grid Monitoring & Control), only CVR benefits are tangible enough to be economically valued at this time. Given the uncertainty in the assumptions pertaining to DER enablement and enhancement of grid monitoring and control, PG&E elected to make a conservative valuation of VVO benefits by excluding these two benefit

[42] PG&E's deployment business case assumes a 94% solution up-time.

streams from the Cost-Benefit analysis. VVO's CVR-specific benefits include reduced energy consumption (MWh), reduced line losses (MWh), and reduced demand (MW). These are the same benefits that DSM programs such as Energy Efficiency deliver. Thus, PG&E applied the TRC framework, which is the same Cost-Benefit Analysis methodology used to evaluate EE programs, to measure the value of VVO.

The calculated B/C is the ratio of the discounted lifetime benefits to the discounted lifetime costs. In valuing the recommended VVO deployment, PG&E evaluated high and low performance scenarios. The key assumptions and differences in these scenarios are summarized in Table 12 below.

Table 12 – Cost-Benefit Assumptions and Results for Low and High Effectiveness Scenarios

Assumption	High Effectiveness Scenario	Low Effectiveness Scenario
CVR factor	0.8 in year 1, deflates on average 1% per year for remaining useful life	0.6 in year 1, deflates on average 1% per year for remaining useful life
Useful Lifetime	20 years	15 years
Source of Avoided Cost Forecasts	Energy and Environmental Economists (E3)	Energy and Environmental Economists (E3)
Discount Rate	7%	7%
Annual Escalator to Account for Inflation	2.5%	2.5%

The results of the low and high scenarios of the recommended VVO deployment demonstrated a range of 1.5-2.7 B/C Ratio, respectively:

Effectiveness Scenario	Discounted Lifetime Costs	Discounted Lifetime Benefits	Lifetime	B/C **Ratio**	B/C Ratio *(Excluding Avoided Cost of Capacity Benefits)*
High	$177M	$472M	20 yrs.	**2.7**	2.5
Low	$194M	$286M	15 yrs.	**1.5**	1.4

The 1.5 – 2.7 range in B/C Ratio included the benefits achieved through *both* Avoided Cost of Energy Consumed and the Avoided Cost of Capacity (associated with the Reduction of Demand during CAISO Peak). Due to some circuits lacking statistical significance in the Pilot's M&V results pertaining to the percent change in Demand during CAISO Peak (as discussed in Section 4.2), PG&E has also calculated the B/C excluding the benefit of Avoided Cost of Capacity. This B/C Ratio ranges between 1.4 and 2.5 from the Low to High scenario. Thus, even without the Capacity benefits, the B/C Ratio is favorable for a 170-bank deployment.

The remainder of this section will continue by discussing the methods of estimating costs, estimating benefits, and performing sensitivity analysis around calculated B/C Ratio.

5.3.1 *Cost Estimates*

This section provides an overview of the methodology PG&E applied to estimate the costs of VVO deployment.

Cost Categories

Table 13 below lists the five major cost categories associated with VVO deployment. These costs are modelled based on the recommended deployment of VVO to 170 banks. The costs are segmented into two types:

- Multi-Year Installation & Commissioning: These are mainly capital costs pertaining to activities similar to the Phase 2 activities discussed in Section 3.2.1 through 3.2.6. These are modelled as a 3-year program starting in year 1.
- Ongoing Annual Operations and Maintenance Costs: These are the estimated annual expense costs pertaining to operations and maintenance (O&M) activities, similar to the Phase 2 activities discussed in Section 3.2.7.

Table 13 – VVO Deployment Estimated Costs

Category	Description	Multi-Year Installation & Commissioning Cost *(Capital and Expense Costs Incurred in Years 1 – 3)*	Ongoing Annual Operations & Maintenance Expense Costs *(Year 4, Escalated Thereafter Per Year of Useful Life)*
IT Applications (Including VVO Software and Security)	Build and maintain systems integrations required to run VVO solution.	$6.5M	$1.3M
IT Infrastructure	Physical servers that host the VVO solution. End-to-end communications from field devices to servers that run VVO software.	$15.0M	$0.26M
Electric System Modifications	Replacing capacitor and line regulator controllers, upgrading LTC controllers, and enabling communications with required devices.	$71.4M	$0.0
Deployment Team	Dedicated engineering team to oversee deployment, commissioning, and operations of VVO. Development of operating procedures and implementation of change management. SCADA and LTC specialists outside of core team also included for Ongoing O&M in year 4.	$4.8M	$2.2M
Overheads		$19.6M	$0.53M
Total		**$117.5M**	**$4.3M**

<u>Variable and Fixed Costs</u>

Approximately 75% of costs for VVO deployment are variable, and the remaining 25% are fixed. The fixed costs, by nature, do not change significantly with each incremental bank deployed.

Examples of fixed costs are:

- <u>IT Applications:</u> The design, implementation, and maintenance of systems integration required to deploy VVO.
- <u>Deployment Programmatic Costs:</u> The development of operating procedures, training guides, and tools to manage the deployment and operation of VVO.

Examples of variable costs are:

- <u>Electric System Modifications:</u> The cost to replace capacitor bank controllers scales linearly with the number of capacitor controllers replaced.

- VVO Software Licensing: VVO software licensing agreements are normally structured on a per bank or per circuit structure, making the cost of VVO software scale with the size of the deployment.

Discounting of Costs

Estimated costs are discounted at 7% in line with the TRC methodology to calculate a Total Discounted Lifetime Cost.

5.3.2 *Deployment Benefits*

The economic benefits calculated for VVO only include the hard benefits associated with the avoided energy and generation capacity procurement costs delivered through CVR. The economic value of these benefits is generally calculated for each forecast year as follows:

Equation 1 – Avoided Cost of Energy

$$\begin{aligned}&\boldsymbol{Avoided\ Cost\ of\ Energy\ Procurement}\ [\$]\\&\quad= \boldsymbol{Energy\ conserved\ by\ VVO}\ [\boldsymbol{MWh}] \times \boldsymbol{Value\ of\ Conserved\ Energy}\ [\$/\boldsymbol{MWh}]\end{aligned}$$

Equation 2 – Avoided Cost of Capacity

$$\begin{aligned}&\boldsymbol{Avoided\ Cost\ of\ Generation\ Capacity}[\$]\\&\quad= \boldsymbol{System\ Coincident\ Peak\ Demand\ Reduction\ Achieved\ by\ VVO}\ [\boldsymbol{MW}]\\&\quad\times \boldsymbol{Value\ of\ Avoided\ Generation\ Capacity}\ [\$/\boldsymbol{MW}]\end{aligned}$$

The values of conserved energy ($/MWh) and the values of avoided generation capacity ($/MW) per forecast year were provided by public (i.e., E3) forecasts for the low and high scenarios. These values vary year-over-year. Public forecasts utilize system-level annual average values for conserved energy and capacity value.

The annual energy conserved by VVO (MWh) and system coincident peak demand reduction (MW) achieved in each forecast year by VVO are estimated as follows:

Equation 3 – Energy Conserved Through VVO

$$\boldsymbol{Energy\ Conserved}\ [\boldsymbol{MWh}] = \boldsymbol{CVRfactor} \times \boldsymbol{Avg.\ Annual}\ \%\Delta\ \boldsymbol{in\ Voltage}$$

Equation 4 – Peak Demand Reduction Achieved Through VVO

$$\begin{aligned}&\boldsymbol{Peak\ Demand\ Reduction}\ [\boldsymbol{MW}]\\&\quad= \boldsymbol{CVRfactor} \times \%\Delta\ \boldsymbol{in\ Voltage\ at\ CAISO\ System\ Forecasted\ Peak\ Demand}\end{aligned}$$

The methods used to determine CVRf, % Average Annual Change in Voltage, and % Change in Voltage at System Peak are discussed below.

Estimated CVR Factor

The CVRf for year 1 of the high- and low-effectiveness scenarios was informed by the CVRf as measured at other VVO pilots at U.S. utilities[43,44] and in PG&E's VVO Pilot (as presented in Section 4.2.1). A deflation rate of the CVRf is applied for each subsequent year after year 1. This is based on the assumed trend of increased customer adoption of more efficient loads, such as light-emitting diode lighting, which would reduce CVRf over time. PG&E analyzed the CEC's End Use Load Forecasts and multiple studies[45,46] that measure the CVRf of different end loads to produce a forecast of CVRf over the potential lifetime of VVO. PG&E estimated that the appropriate annual CVRf deflation rate was roughly 1% per year (differing slightly each year given the forecasted technology adoption trends).

Annual Average Percent Change in Voltage

PG&E leveraged voltage data collected from over 500,000 SmartMeter™ devices to forecast the potential voltage reduction VVO can deliver. Analyzing these voltage measurements alongside bank-level loading data allowed PG&E to understand the relationship between bank loading and voltage reduction potential.[47] PG&E collected voltage reading from SmartMeter™ devices across 33 banks. In combining this voltage data with the loading data along each banks over a time period, PG&E was able to assess the distributions of voltage at any given loading level for each of the 33 banks.

Figure 9 demonstrates this process illustratively on one sample bank of how voltage data at particular loading levels was collected and built into distributions. Through assessing the voltages observed within the 1st percentile of the Voltage distributions, PG&E was able to calculate each bank's specific average annual voltage reduction potential.

[43] EPRI Green Circuit Distribution Efficiency Case Studies, October 2010, page x, cites CVRf generally range from 0.6 to 0.8

[44] National Assessment of CVR: Preliminary Results from DOE's CVR Initiative, September 2014, page 22 shows range of CVRf measured at VVO pilots across the U.S.

[45] *Single-Phase Nonlinear Power Electronic Loads: Modeling and Impact on Power System Transient Response and Stability*, Matthew Rylander, PhD Dissertation, University of Texas at Austin, May 2008.

[46] "Impacts of Voltage Reduction," IEEE PES General Meeting 2014, Tom Short, EPRI, July 2014.

[47] Voltage reduction potential was defined as the difference between the lowest 0.75% percentile voltage, and 115 V (on a 120-V basis). A 115-V lower limit was used instead of 114 V to build a safety factor and conservatism into the voltage reduction estimate.

Figure 9 – Illustrative Voltage Reading Distribution Given Loading on Bank

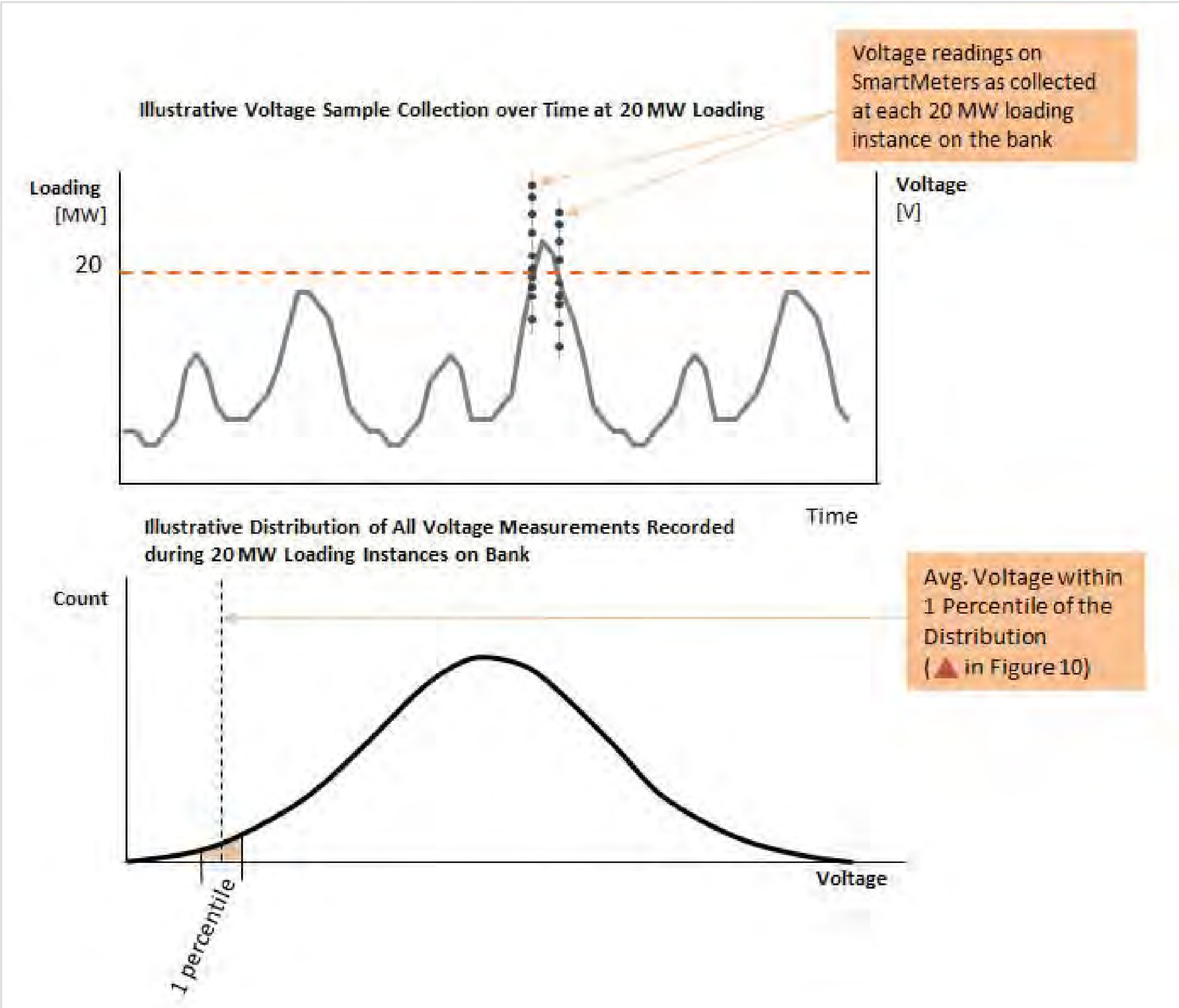

Figure 10 below illustrates the observed negative relationship between bank loading and voltage reduction potential for one bank. PG&E calculated this relationship for 33 banks where the MW loading data quality was sufficient to enable efficient analysis.[48] Based on this analysis, PG&E assumed an Annual Average Percent Change in Voltage of 3% for all forecasted years. This value was extrapolated to a wider set of banks that were considered for deployment.

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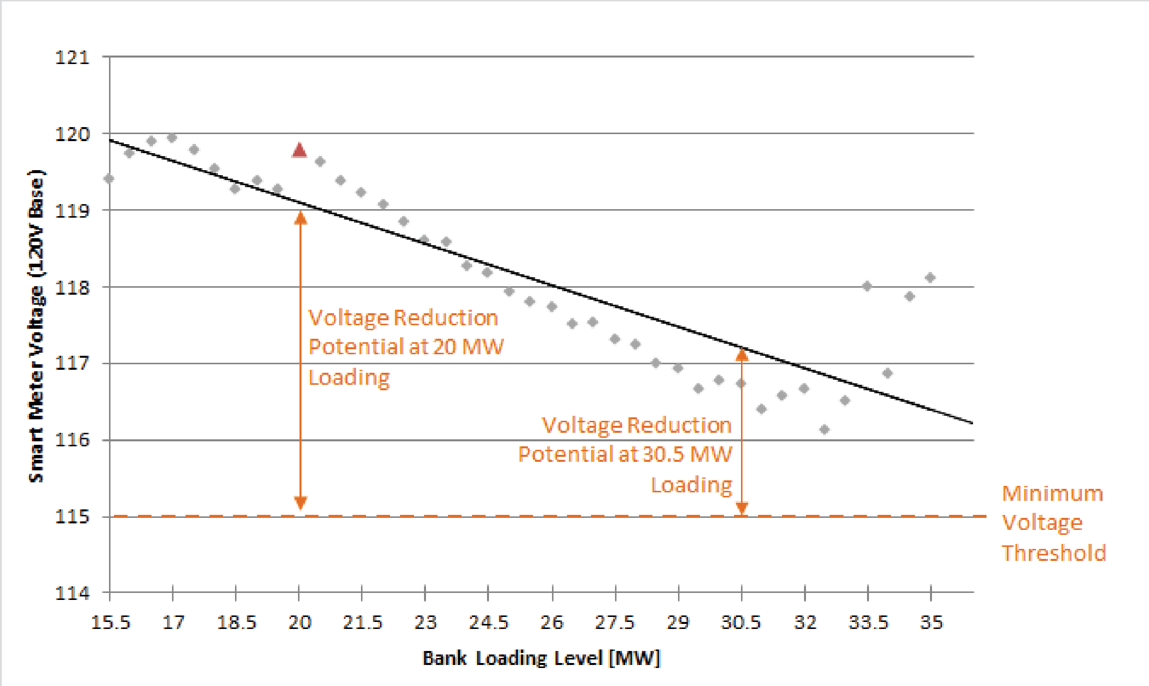
[48] Missing bank level MW data and instances of large and frequent load transfers resulted in reducing the set of banks that PG&E could analyze for this assessment.

Figure 10 – Observed Relationship Between SmartMeter™ Voltages and Bank Loading (MW)

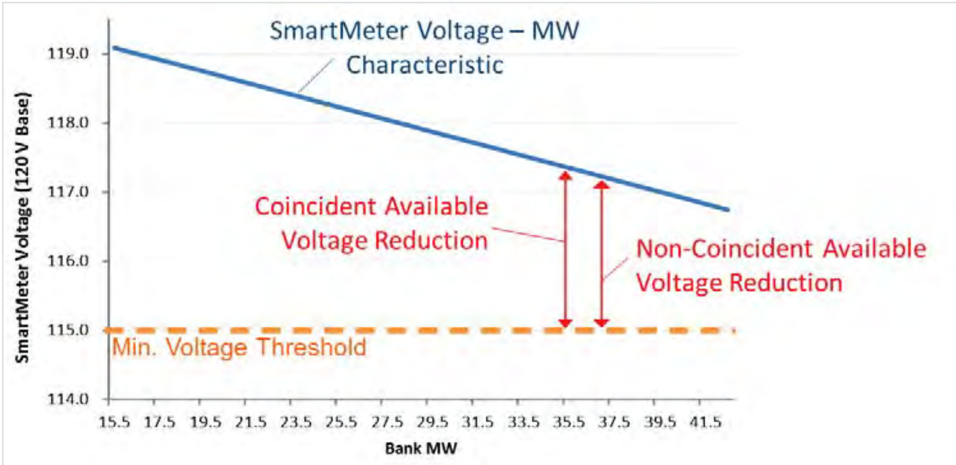
On one sample Bank of the 33 Banks studied



<u>Percent Change in Voltage at CAISO System Peak Demand</u>

PG&E used the SmartMeter™ voltage and bank loading relationship for 33 banks to understand VVO's ability to reduce voltage during CAISO system peak loading conditions. Figure 11 below illustrates how a bank's peak load can be non-coincident with CAISO load. PG&E evaluated the loading on the 33 studied banks during the 2015 CAISO coincident peak and determined each bank's ability to reduce voltage during the CAISO coincident peak. Based on this analysis, PG&E assumed the Average Percent Voltage Reduction at CAISO Peak Demand is 1.6%. This value was extrapolated to a wider set of banks that were considered for deployment.

Figure 11 – Illustrative Evaluation of Voltage Reduction Potential at CAISO Peak Loading



Resulting Percent Change in Energy and System Peak Demand

The preceding three paragraphs detail the assumptions for CVRf, Average Annual Percent Change in Voltage for Energy and Average Annual Percent Change in Voltage for CAISO Peak Demand. Given these assumptions, the Average Percent Change in Energy and Average Percent Change in Demand in the B/C Model are as follows:

Table 14 – Resulting Percent Change in Energy and System Peak Demand

Benefit Scenario	CVRf	%△ in Voltage, *for CAISO System Peak*	Avg. %△in Peak Demand	Avg. %△ in Voltage, *for Energy*	Avg. %△ in Energy Consumed
Low Benefit Case	0.6	1.6%	**0.81%**	3.05%	**1.53%**
High Benefit Case	0.8	1.6%	**1.04%**	3.05%	**1.97%**

These are the average values as calculated over the service life of the VVO system given the benefit scenario.

Comments on Excluded Benefit Streams From Benefit/Cost Calculation

As mentioned previously, the benefits anticipated from DER Enablement and Enhanced Grid Monitoring and Control were excluded from this economic analysis. This is due to the lack of an accepted methodology for quantifying and valuing their benefits economically at this time. In principal, VVO will enable further DER deployment through increasing a circuit's hosting capacity. By reducing the overall voltage across the circuit, VVO increases the range of voltage rise possible before triggering a Rule 2 violation (i.e., voltage levels above 126 V on a 120 V basis). After VVO is deployed on a bank, the additional benefit of increased DER hosting capacity on that bank can be achieved at zero marginal cost. Additionally, the benefit of enhanced Grid Monitoring and Control through the visibility VVO provides will be achieved without additional incremental cost.

5.3.3 *Sensitivity Analysis*

PG&E explored the B/C Ratio's sensitivity to the scale of deployment, and to bank-specific benefit and cost forecasts. For simplicity, PG&E assumed that for a deployment to 350 banks (1/3 of PG&E's system), that banks will exhibit relatively consistent voltage reduction characteristics. However, each bank's ability to delivery energy and demand reduction is driven by the peak loading and load factor[49] on the banks. On costs, each banks' variable cost to implement VVO is driven by the number of line devices (i.e., line voltage regulators, and capacitor banks) that require new controllers to be installed. Applying the principle that candidate banks have a bank-specific benefit and cost, PG&E developed a model that rank ordered banks from high to low B/C. This model calculates the cumulative B/C Ratio of VVO deployment to a variable number of banks, with the objective of calculating the maximum achievable B/C, and thus recommending the scale of a VVO deployment. Factoring in the spreading of fixed costs among a larger deployment, the B/C Ratio of VVO deployment rises as the number of banks increases from a small size deployment. As deployment continues to the next bank with a smaller bank-specific B/C, the cumulative B/C eventually reaches a maximum. PG&E's present analysis shows that the maximum B/C from VVO deployment is achieved on the order of 170 banks, which is approximately 15% of PG&E's distribution system.

5.3.4 *Considerations for Future Benefit/Cost Evaluations of VVO*

The present forecasted B/C Ratio indicates that VVO can be a cost-effective means of driving conservation and affordability. However, it is important that PG&E update this B/C Ratio as needed to account for changes in key assumptions, notably:

- The role of Smart Inverters in enhancing VVO benefits. California and Arizona utilities, DER providers, and other third-parties are evaluating how Smart Inverters can support VVO. While Smart Inverters have the capability to enhance VVO benefits, there is presently not a commercially off the shelf available system that incorporates Smart Inverters into VVO schemes.
- Forecasted unit costs of avoided energy procurement ($/MWh) and avoided generation capacity procurement ($/MW). The forecasts of these avoided unit costs have changed substantially since 2011, and additional changes will influence the forecasted benefits of VVO.

In addition to these changes, PG&E can further improve the accuracy of the B/C forecast by collecting and analyzing additional SmartMeter™ voltage data. PG&E's present benefits forecast performed a detailed study on approximately 3% of PG&E's system (33 banks), and extrapolated this to a larger scale.

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[49] Load factor is the ratio of average loading to peak loading.

If PG&E expands SmartMeter™ voltage collection, the benefit forecast will be informed by a larger sample size and be less impacted by extrapolation assumptions.

Lastly, future updates to VVO B/C evaluations will consider the cost-effectiveness of VVO to alternative investments in conservation and affordability, notably EE programs.

6 Pilot Financials

Total project spend for the VVO project is ~$33.6 million, more than $4 million under the total approved budget of $37.8 million. Details of project spend by phase are illustrated in Table 15 below.

Table 15 – Pilot Project Spend by Phase in Thousands of Dollars

	Phase 1	Phase 2	Total
	2013 & 2014	**2015 & 2016**	**2013-2016**
Capital	$7,492	$21,600	$29,092
Expense	$4	$4,462	$4,466

All values in thousands – figures above based on Actual spend through November 2016, and forecasts for December. Total Administrative spend over life of the project was 2% of project costs.

7 Next Steps

7.1 General Rate Case

Aligning with the recommendations discussed in Section 5, PG&E plans to reforecast the benefits and costs associated with a VVO deployment when additional data become available, and when key inputs to the business case change. The re-forecasted benefits and costs will inform to what extent PG&E will include VVO in the 2020 – 2022 GRC forecast.

7.2 Technology Transfer Plan

The VVO systems put in place on 12 distribution circuits for the VVO Pilot will continue to be operated in 2017.

7.3 Dissemination of Best Practices

PG&E presented results, lessons learned, and best practices from the VVO Pilot at many industry conferences across the U.S., which are listed below.

Event	Location	Date
EMS Users Conference	Indianapolis, IN	September 21-22, 2015
DistribuTech	Orlando, FL	February 9 - 11, 2016
iPCGRID (Innovations in Protection and Control for Greater Reliability Infrastructure Development)	San Francisco, CA	March 30 - April 1, 2016
EUCI Volt/VAR Regulation and Optimization Conference	Denver, CO	April 18 - 19, 2016
IEEE Power & Energy Society – SF Chapter Monthly Meeting	San Francisco, CA	April 21, 2016
EPRI and Sandia PV Systems Symposium	Santa Clara, CA	May 10, 2016
IEEE Power & Energy Society General Meeting	Boston, MA	July 18 - 20, 2016
Edison Electric Institute T&D Metering and Mutual Assistance Meeting	Bellevue, WA	October 3, 2016
EPRI Distribution Operations Interest Group October 2016 Meeting	Walnut Creek, CA	October 18 - 19, 2016

PG&E was mindful that because of the Smart Grid Investment Grants, many other U.S. utilities had previously piloted VVO and some large IOUs had already begun VVO deployments. PG&E's presentations provided an emphasis on new learnings achieved by PG&E's VVO Pilot that either hadn't been implemented by other utilities, or where so few utilities were in the process of implementing that there was a strong appetite at various conferences for different utilities to present the results and lessons learned from their initial explorations into new aspects of VVO. PG&E's common net new learnings presented at the above conferences fell into four key categories:

- Operating VVO on circuits with high penetrations of distributed solar PV generation;
- Modeling, lab tests, and field trials of Smart Inverters to understand how Smart Inverters can enhance VVO's benefits;
- Use of advanced data analytics approaches to understand the impact of distributed solar PV generation on voltage in the presence of VVO; and
- Use of SmartMeter™ voltage data visualization approaches to understand and enhance VVO's performance and proactively address voltage issues (not related to VVO) before customers call to notify PG&E of a problem.

8 Conclusion

The VVO Pilot drove many beneficial PG&E firsts. Achievements of the VVO Pilot resulted in it being one of three recipients of PG&E's 2016 *Margaret Mooney Award for Innovation*.

PG&E successfully piloted VVO on 14 distribution circuits. Upon completing the pilot, PG&E established that a VVO system can be cost-effective solution for enhanced voltage regulation on a portion of the circuits on PG&E's distribution grid. Specifically, VVO offers a customer B/C TRC ratio of 1.5 to 2.7, making it an attractive means of driving conservation and affordability. PG&E expects to continue to assess VVO's benefits as more SmartMeter™ voltage data are collected, and as the value of avoided energy procurement and generation capacity change over time. The VVO pilot has left PG&E with the knowledge and toolkit to more efficiently reforecast the benefits and costs of a VVO deployment in the near future. PG&E is considering deploying VVO after DMS and SCADA are integrated, as this provides an important foundation for VVO to be efficiently operated with high solution availability to drive benefits.

VVO delivers benefits that align with California energy policy and PG&E's strategic goals:

- PG&E successfully drove initial learnings about how Smart Inverters can be used alongside VVO. Through that process, PG&E can frame future technology demonstrations that will enable utilities and DER providers to work together to determine how to make the use of Smart Inverters cost-effective.
- PG&E demonstrated the soft benefits of enhanced monitoring and control, and drove unprecedented visibility into the grid edge through the collection and analysis of SmartMeter™ voltage data. The VVO pilot demonstrated how the collection and analysis of SmartMeter™ voltage data by engineers and algorithms, such as VVO, can deliver additional benefits to PG&E's customers.

The VVO pilot drove significant learnings that PG&E has shared with industry via presentations at a variety of conferences and via this report.

9 Appendix

9.1 List of Acronyms

Acronym	Term
ATS	Applied Technology Services
CAISO	California Independent System Operator
CVR	Conservation Voltage Reduction
CVRf	Conservation Voltage Reduction Factor
DER	Distributed Energy Resource
DG	Distributed Generation
DMS	Distribution Management System
EPIC	Electric Program Investment Charge
EV	Electric Vehicle
FLISR	Fault Location, Isolation, and Service Restoration
GRC	General Rate Case
IEEE	Institute of Electrical and Electronics Engineers
IT	Information Technology
M&V	Measurement & Verification
MDMS	Meter Data Management System
LTC	Load Tap Changer
OT	Operational Technology
PAT	Performance Analysis Tool
PQM	Power Quality Meters
PNNL	Pacific Northwest National Labs
PV	Photovoltaic
RFI	Request for Information
RFP	Request for Proposal
SCADA	Supervisory Control and Data Acquisition
SI	Smart Inverter
SPI	Solar Potential Index
TRC	Total Resource Cost
VAR	Volt-Ampere Reactive
VVC	Volt VAR Control
VVO	Volt VAR Optimization

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