PG&E 500 kV Protection Standard Design and Development

Davis Erwin, Rafael Pineda, and Monica Anderson
Pacific Gas and Electric Company

Eric Udren
Quanta Technology, LLC

Jordan Bell and Neal Jones
Schweitzer Engineering Laboratories, Inc.

Revised edition released October 2014

Originally presented at the
41st Annual Western Protective Relay Conference, October 2014

PG&E 500 kV Protection Standard Design and Development

Davis Erwin, Rafael Pineda, and Monica Anderson, *Pacific Gas and Electric Company*
Eric Udren, *Quanta Technology, LLC*
Jordan Bell and Neal Jones, *Schweitzer Engineering Laboratories, Inc.*

***Abstract*—Pacific Gas and Electric Company (PG&E) owns an extensive 500 kV series-compensated transmission line network. The availability of this network is critical to serving Northern California loads and regional power transfers from the Pacific Northwest to Southern California. PG&E identified the need to replace aging solid-state relay systems with modern, more reliable microprocessor-based relay systems to improve the 500 kV transmission network reliability and availability.**

This paper describes the development of the new PG&E 500 kV transmission line and breaker protection standard, with a focus on the practical aspects of the design. The paper includes the motivation and triggers for embarking on the project, challenges encountered, and lessons learned during the design effort. The final design standard addresses single points of failure, ease of testing, functional integration, and end-of-life replacement. The design was validated with a prototype prior to field deployment. The deployment stage, relay setting development, model power system testing using the Real Time Digital Simulator (RTDS®), and field installation are discussed. The intent of the paper is to present how PG&E redesigned the protection system from the ground up.

I. Introduction

This paper details the scope of a Pacific Gas and Electric Company (PG&E) 500 kV transmission line protection design created to address the replacement of relays used for line protection, breaker failure, and reclosing. It discusses why the project was initiated, design considerations to minimize single points of failure (SPF), deficiencies in previous line relaying designs, building and use of a prototype, modeled power system testing, and lessons learned during the implementation.

This project addressed 17 of the 23 500 kV lines within the PG&E system. The relay replacements were prioritized by an evaluation of the health and age of the existing protection schemes, clearance availabilities, annual budget constraints, and coordination with neighboring utilities.

II. History, Performance of Legacy Protection Systems, Benchmark Study, and Relay Selection

Prior to 2009, the PG&E 500 kV transmission lines were protected by a fleet of aged, mostly analog, solid-state protection systems that were a challenge to maintain, understand, and monitor. There were 23 lines protected by 20 different scheme designs of mixed generations. Electronic relays with no failure alarming or data reporting capability left the system exposed—they misoperated for system faults on a number of occasions. These performance shortfalls led to a 2007 double-line outage on a single 500 kV path. The corridor was out of service for nearly 8 hours. Fortunately, no customers lost service during this event, but the highlighted risk was troubling. A major capital investment was needed to replace the obsolete protection systems with newer designs aligned with present industry standards. Nonetheless, PG&E system protection engineers and managers faced a challenge in making the business case to PG&E executive management due to competition from other capital investment projects.

To begin the process, the PG&E System Protection Engineering Department commissioned a formal study project, conducted from 2008 through 2009, to document the drivers and technical requirements for a redesign of the 500 kV transmission line protection for the entire PG&E network in accordance with a single new design standard.

Early in the project, the PG&E project team conducted a major benchmark study of the extra-high voltage (EHV) protection practices of 20 major North American utilities. Questionnaires, telephone calls, and personal interviews were conducted by protection experts who were independent of PG&E and device manufacturers. The goal was to collect detailed information on unique protection features and requirements related to each utility EHV system. Interview discussions captured device and design preferences, fleet demographics, specific protection functions and logic, redundancy approaches, the use of single or multiple manufacturers, creation processes and cycles for protection design standards, reliability experiences, data collection and analysis processes, performance management, and performance results. An extracted list of the best practices of these 20 utilities influenced the direction of the entire PG&E design standard development process, as described in this paper.

Other 500 kV redesign study project steps are described in the following subsections.

A. Investigation of the Control Buildings and Wiring Situations for All PG&E 500 kV Substations

The project team visited a sample of substations to assess the condition of the wiring, the layout, and the opportunity for the installation of new relays in available building space. PG&E was already using drop-in replacement protection and control (P&C) buildings of a standard design with new field wiring for switchyards of 230 kV and below. However, in the 500 kV substations, large concrete control buildings with generous unused panel space on the main floor and cavernous basement space with access for switchyard cable entry and connections invited the installation of new relays in the existing buildings. Some substations had relatively new switchyard wiring; all had newly installed automation equipment that still had most of its asset life remaining. The new automation equipment had been installed to support control center consolidation efforts. The consolidation was completed one year prior to the beginning of the relay replacement effort. The project team elected to install replacement relay panels in the existing buildings with the new automation systems.

B. Internal PG&E Surveys

Internal PG&E surveys were conducted regarding the existing line protection. The team used meetings and field visits to gather experiences to factor into the new design standard. The team interviewed engineers, field operations personnel, and maintenance personnel about their encounters with the old protection systems. The survey gathered critical observations on problems with existing P&C architecture, failure events, and the challenges of identifying assets being maintained and operated in light of inconsistent design, layout, and labeling of devices. The variety of confusing configurations had caused human errors and misoperations on multiple occasions, which were understandable in light of the specific issues the team identified.

C. Study of Recent Relay Operating Experiences

An additional internal study was made of specific operating principles, relay performance experiences, technical challenges, and the successes of corrective actions for 500 kV relays then in service from various manufacturers. The results guided the development of the requirements for replacement protection systems.

D. Development of a Standard Protection Philosophy Underlying a New 500 kV Line Protection Standard

The team first developed an industry roadmap for EHV P&C, documenting new device trends, PG&E line protection application experiences, experiences with existing relays, and where the industry was going in light of the benchmark study results. The study included analysis and recommendations on specific protection schemes and methods, leading to the concept of having current comparison and directional comparison schemes combined at each location. The study developed performance requirements and specifications for the new relays to be selected. The design philosophy included specific details such as breaker control, breaker failure protection, and reclosing design, the implementation of which is discussed later in this paper.

Specific pilot schemes and logic selections were evaluated with consideration for the tradeoff between dependability and security. The study defined high requirements for the redundancy and availability of alternate protection systems in light of past communications failures and maintenance challenges. Two pairs of redundant relays were specified for each terminal. Pilot and transfer tripping communications channel interfacing concepts were created to take full advantage of modern synchronous optical network (SONET) channels with IEEE C37.94 interfacing [1], thus eliminating separate transfer tripping panels.

E. RTDS Modeling of the PG&E Network

The section of the PG&E 500 kV transmission system with the most challenging protection requirements was modeled in PSCAD® and validated for correspondence to real-world observations. The PSCAD model was tested and then transferred to the Real Time Digital Simulator (RTDS®) implementation for use in testing the performance of prospective relay types and schemes as well as for analysis of setting requirements and issues.

F. Initial Manufacturer Selection

With design requirements in hand, the team selected six manufacturers whose devices were to be evaluated. Manufacturers individually presented their offerings and addressed team questions, leading to the selection of a specific list of devices to test in detail.

G. Extensive Testing of Candidate Devices Using the RTDS Laboratory and the PG&E System Model

Manufacturers of prospective devices engaged with the project team during RTDS lab testing to ensure fair and uniform comparisons as well as to address observed performance and setting issues.

H. Comparative Evaluation and Selection of Devices

The project team created a weighted evaluation matrix that included RTDS test results, device features, compliance of devices with protection philosophy principles (described in Subsection D), and company evaluation criteria. This process led to the selection of two devices and two manufacturers from the multiple offerings of the six manufacturers evaluated.

I. Development of a High-Level Standard Line Protection Terminal Design

In this phase, the project team created a prospective panel design and layout that incorporated the selected relays into the design requirements developed in the prior work. Salient features, described in more detail in later sections of this paper, include the following:

- Two standardized redundant cabinets for each line terminal with two physically separated protection systems on each (one current differential system and one directional comparison system). This provides a total of four redundant protection systems.
- Two manufacturers. One standard device from each manufacturer is used in each cabinet.
- Relaying communications systems and interfacing for directional or current comparison and transfer tripping. IEEE C37.94-to-SONET multiplexers or power line carrier (PLC) sets are included in a separate cabinet for the lines using PLC communications for the directional comparison schemes.
- Clear, consistent labeling and marking principles for minimizing human errors.

- Physical separation of individual protection systems for easy servicing or replacement of a single system in isolation from the others.
- A wiring and terminal block design that supports full replacement of any one of the four protection systems with minimal line outage and minimal disruption of the remainder of the systems at that line terminal.
- Standardized breaker and bay control relays that are separate from the line protection relays to support uniform single-pole tripping and reclosing, breaker monitoring, and straightforward relay and breaker maintenance procedures.
- Design for practical North American Electric Reliability Corporation (NERC) compliant maintenance, including opportunities to use microprocessor-based relays and data communications systems for self-monitoring and the resulting condition-based maintenance time extensions and testing simplifications.
- Survey results from PG&E stakeholders incorporated into the standard design requirements. When the study results were later presented within PG&E, those stakeholders expressed heartfelt appreciation that their experiences and needs were being acted upon.

J. Development of the Implementation Strategy

The project team documented the business case to obtain PG&E executive management support for the capital investment to replace the protection systems on 17 of the 23 500 kV lines. A major factor in the business case adoption was the mitigation of the risk of a major outage due to the operational problems experienced with the existing fleet of old relays. The team developed a practical time scale of approximately seven years for the completion of the project, with a prioritized replacement ranking of the existing installations.

K. Planning the Creation of a Permanent Standard Development Laboratory

Before field deployment, new standard panel designs must be configured in a laboratory for an assessment of performance and functional issues, including hands-on vetting of physical and user-interface features in trials by field and maintenance personnel. The laboratory facility ensures short- and long-term project success by helping project teams and device manufacturers to fine-tune designs while avoiding costly development and design corrections in the field. Once a standard design is deployed in substations, it is then critically important to keep a permanent lab setup that replicates field installations for use in the testing of new firmware, revised settings and logic, or updated replacement devices. The permanent lab is also used to replicate field operations or misoperations for analysis, and for hands-on training of new personnel. The following section describes PG&E experiences with vetting of the first standard panel designs in the permanent laboratory.

III. 500 kV Transmission Line Protection Design

The PG&E 500 kV transmission system is series-compensated and the lines are designed for single-pole tripping and reclosing. Series compensation presents challenges to traditional protection coordination, so a minimum of one level of communications-assisted protection is necessary for a line to remain in service. This ensures instantaneous protection for 100 percent of the protected line and prevents miscoordination with adjacent lines.

When considering the new design maintenance requirements and ensuring immunity to SPF, an assessment is made of the limitations of the existing infrastructure. A decision is made whether to address limitations within the design scope or to create the new design to withstand the failures of the existing infrastructure. The extent of the scope is a decision based on cost, budget, outage requirements for construction, and resources. These are common considerations for establishing any design scope.

First, the telecommunications infrastructure was evaluated. The PG&E 500 kV system uses two diverse digital routes to achieve the necessary communications dependability. Prior to the construction of the second digital route (completed before this redesign effort), a PLC was used to provide a diverse route to the single digital circuit. Two diverse digital paths were considered sufficient, and the redesign scope did not include modifications or additions to the telecommunications infrastructure. Furthermore, the new design retained the PLC feature and replaced tuners, transceivers, and wave traps where necessary. Three distinct communications routes provide a reliable infrastructure to ensure 500 kV line availability during multicontingency events in the telecommunications infrastructure.

Second, the current and voltage instrumentation were evaluated. Many PG&E 500 kV breakers only include two bushing-mounted current transformers (CTs). Two CT sources were considered sufficient for the design. The addition of a third CT would have yielded marginal reliability benefits and detrimentally impacted the symmetric design strategy. Furthermore, the new design maintained the physical summation of one CT circuit in the yard rather than installing a new conduit to wire each breaker contribution separately to the new line relays. If independent breaker CTs had been brought to the control room, the relays could have performed the summation mathematically and taken advantage of algorithms such as CT saturation detection and integrated breaker failure in the line relays. This approach would have provided marginal benefits at a large expense and, thus, was not used in the new design. PG&E 500 kV breakers are equipped with 3000:5 taps on C1200 class CTs and evaluation of fault duties, present and future, showed minimal exposure to CT saturation. Unlike previous designs, separate half taps from the coupling capacitor voltage transformer (CCVT) were brought into all new line relays. In order to mitigate secondary transient phenomena witnessed in past operation investigations, it was also decided to replace most unshielded control and instrumentation wiring with shielded wiring.

The new design can withstand SPF of telecommunications infrastructure, a CT, or a CCVT. The design meets NERC Order No. 754 inquiry descriptions [2]. The basic instrument transformer connections and telecommunications route and equipment are shown in Fig. 1 and Fig. 2.

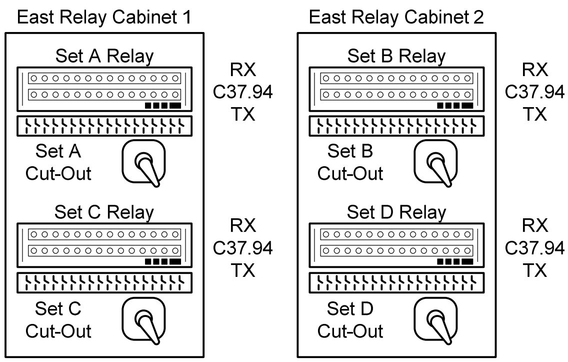

Fig. 1. Single Line Terminal

At each end of the line there are four relays—two relays in each of two relaying cabinets. Cabinet 1 contains the Set A and Set C relays while Cabinet 2 contains the Set B and Set D relays. The two cabinets are each wired to a different CT circuit and different CCVT secondary circuit. All line relaying cabinets are designed to be electrically identical. The cabinet contains two relays, each from different manufacturers with different operating principles. The Set A and Set B relays are current differential, and the Set C and Set D relays are directional comparison in a permissive overreaching transfer trip (POTT) scheme.

Each relay has four standard setting groups, as shown in Table I and described in the following subsections.

TABLE I
STANDARD SETTING GROUP DETAILS

Group Number	Group Features
1	Pilot and direct transfer trip (DTT) (normal operating group)
2	Nonpilot (no DTT)
3	Stub bus
4	Nonpilot (extended Zone 1 distance)

A. Group 1: Sets A and B

Current differential elements and DTT functions are enabled. Instantaneous neutral directional overcurrent, neutral time overcurrent, and switch on to fault elements are also enabled. Distance elements are disabled when the communications channel is healthy. If the communications channel fails, distance elements are automatically enabled, with the Zone 1 and neutral instantaneous elements not time-delayed. While in Group 1, the relays are immune to any voltage source (line CCVT) failures or anomalies and power swings.

B. Group 1: Sets C and D

POTT and DTT functions are enabled. Ground time overcurrent, distance elements, and switch on to fault elements are also enabled. The instantaneous ground directional overcurrent element is disabled. (The instantaneous neutral overcurrent element is not used because an internal relay algorithm drives a three-pole trip).

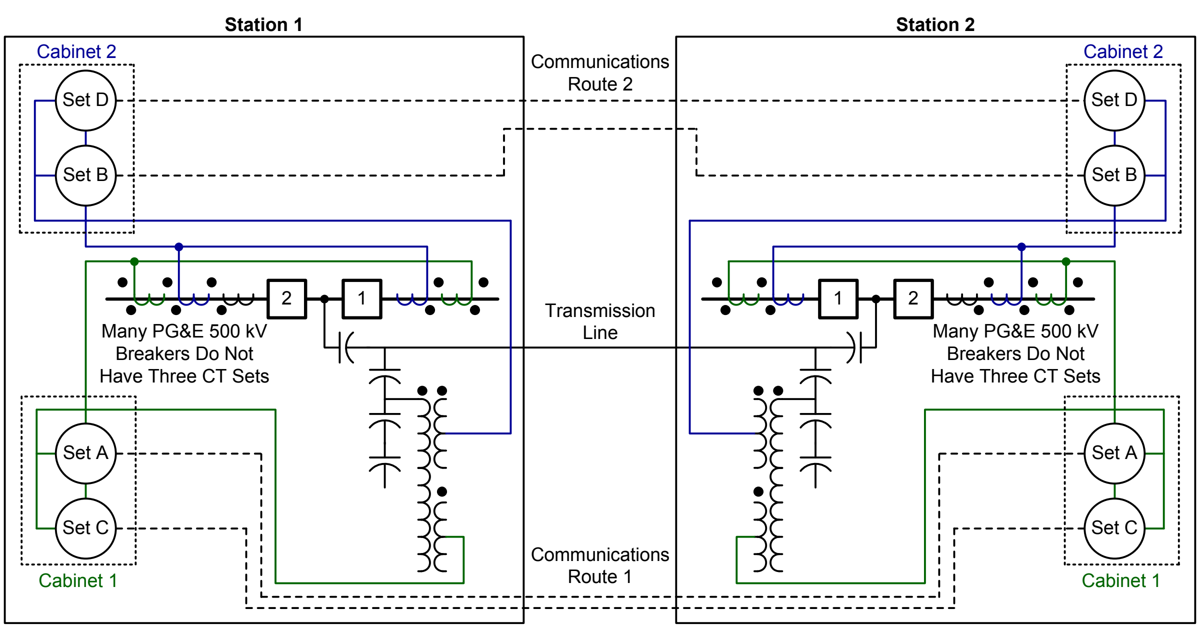

Fig. 2. Simplified Telecommunications and Relay Cabinet Design

C. Group 2: Sets A, B, C, and D

Communications-assisted elements and DTT are disabled (differential elements for Set A and Set B and POTT elements for Set C and Set D). Distance, instantaneous neutral/ground overcurrent (only on Set A and B), neutral/ground time overcurrent, switch on to fault, and instantaneous neutral/ground directional overcurrent elements are enabled. This nonpilot setting group is used for special setups, as dictated by the PG&E system protection team. The Zone 1 and neutral/ground instantaneous elements are delayed if and only if the line pole select switch is set to the single-pole mode.

D. Group 3: Sets A, B, C, and D

Only the nondirectional phase instantaneous overcurrent element is enabled. This setting group is available for conditions where the line disconnect is open (potential source is on the line side of an open disconnect) and either or both of the line circuit breakers are closed.

E. Group 4: Sets A, B, C, and D

This setting group is used in conjunction with Setting Group 3. Setting Group 4 is used for the other end of the line that is not in stub bus. This setting group is also used as a special setup for the remote ends of the generation export lines in the event that the line is used to block load or energize a generator step-up transformer using a remote substation source. The relay elements are identical to Setting Group 2, with the exception that the Zone 1 phase and ground distance elements are extended to overreach the remote bus (Zone 1 reach is set identically to Zone 2). Also, series capacitor restraint compensation on Zone 1 distance elements is disabled. Sensitive phase and ground overcurrent elements are enabled to trip for loss-of-potential conditions.

F. Relay Configuration

The CCVT connections to the differential relays are used for fault location and as backups to the distance elements in Setting Group 1 that are only enabled upon channel failure. In this manner, it is possible to take advantage of a NERC PRC-023-1 loadability exclusion [3]. Voltage inputs allow the use of charging current compensation algorithms, but these were not used. The feature was not necessary to achieve differential pickup values more sensitive than PG&E setting guidelines. Because the differential relays do not require a voltage instrumentation source for proper operation, the line relay package as a whole can withstand the loss of a CCVT and still provide the minimum necessary line protection.

The line protection cabinets have no cross wiring and any necessary common points are wired in a different location in the control room. In this manner, there is flexibility for end-of-life replacement considerations with minimal invasive electrical isolation requirements. Future replacement efforts will require minimal line outages. One cabinet adequately provides the necessary line protection functionality.

The design provides the following benefits:

- Complete redundancy (i.e., immunity to SPF).
- One design (all cabinets are identical).
- Symmetry and simplicity.
- Maintenance and outage flexibility.
- Simple operation and maintenance.
- End-of-life replacement with a minimal line outage requirement.

DTT is a standard feature on PG&E 500 kV lines. If a protection relay operates three-pole at one terminal, it serves no benefit for the line to remain energized from the other terminal (no tapped loads or generation). DTT is also required to trip the remote source in the event of a breaker failure condition at the local substation. In past designs, the DTT scheme was composed of separate telecommunications equipment external to the line relays. Because the legacy DTT design used the same telecommunications equipment and route as the legacy line relays, no benefit in dependability was gained by this configuration. Removal of the equipment provided benefits by limiting the exposure to failures caused by additional equipment, testing, and asset management (including settings).

The new 500 kV design removed the external DTT equipment and integrated the DTT feature into all four line protection relays. The conceptual logic implementation can be seen in Fig. 3. Fig. 3 also depicts the use of a single-phase permissive algorithm. This is an important consideration when applying a POTT scheme on double-circuit tower lines to allow for correct single-pole tripping for a cross-country fault [4]. Cross-country faults are a legitimate concern for double-circuit towers.

Each of the four relays is physically wired to trip both coils of the breaker. For the total package of four relays, there are 72 wires total required for single-pole tripping and single-pole breaker failure initiation.

IV. Breaker Control Design

PG&E made the decision to not integrate the breaker failure protection within the EHV line protection relay in order to keep a clear demarcation of these different functions. Therefore, the breaker failure relay became a subset of the breaker. On the EHV system, it is a documented operational practice that the breaker failure relay must be in service when the breaker is closed. For operational simplicity, a single breaker failure and reclosing relay per circuit breaker was implemented. The breaker failure and reclosing relay is not redundant. This relay also provides other breaker features described later in this section.

In order to minimize the possibility of misoperations, the overreaching elements are based on the protected line characteristics and, therefore, are not intended to overreach the remote lines or transformers. As a result, the EHV line settings do not provide remote breaker failure backup for faults along the entire element at the remote substation. Due to

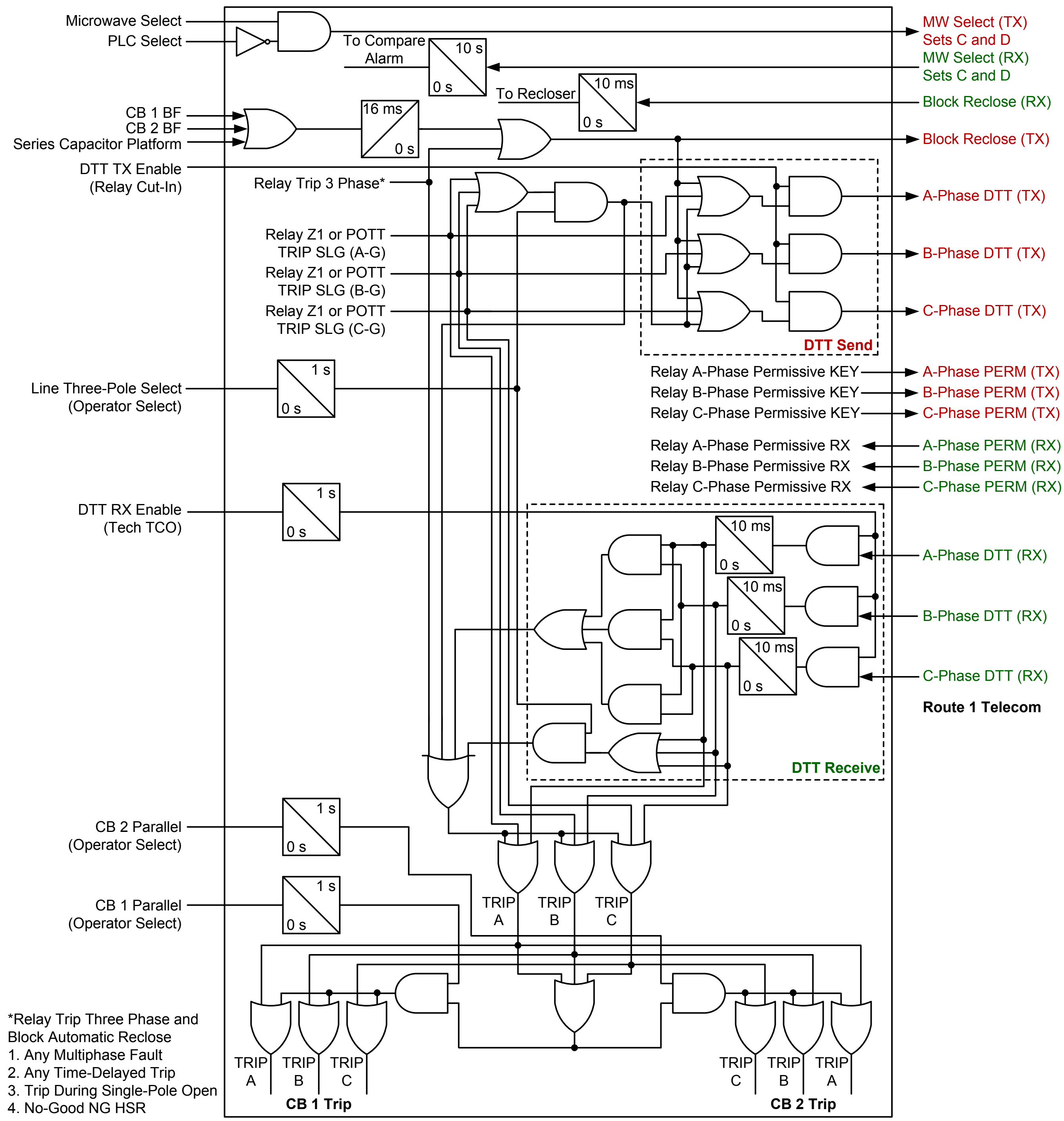

Fig. 3. DTT Integration Into Line Relays (Custom Relay Logic)

this line setting philosophy, a DTT feature must be in service to clear remote breaker failure events. The relay reach required to see all possible faults on a remote element, such as those beyond a transformer, might not be possible. Even if possible, it would jeopardize coordination and loadability requirements.

All substation configurations for the 500 kV system are breaker-and-a-half or ring-bus topologies, and each line breaker is designed for single-pole tripping.

When developing the design for the breaker control, some of the following criteria were considered:

- Uniform design that could be applied to either breaker-and-a-half or ring-bus schemes.
- Consistent interconnection from the breaker relaying to the terminal relaying package (terminal can be either a line, bus, or transformer).
- Standard design for varying configurations, such as bus-to-line, bus-to-transformer, line-to-line, line-to-transformer, line-to-bus, transformer-to-line, and transformer-to-bus configurations.

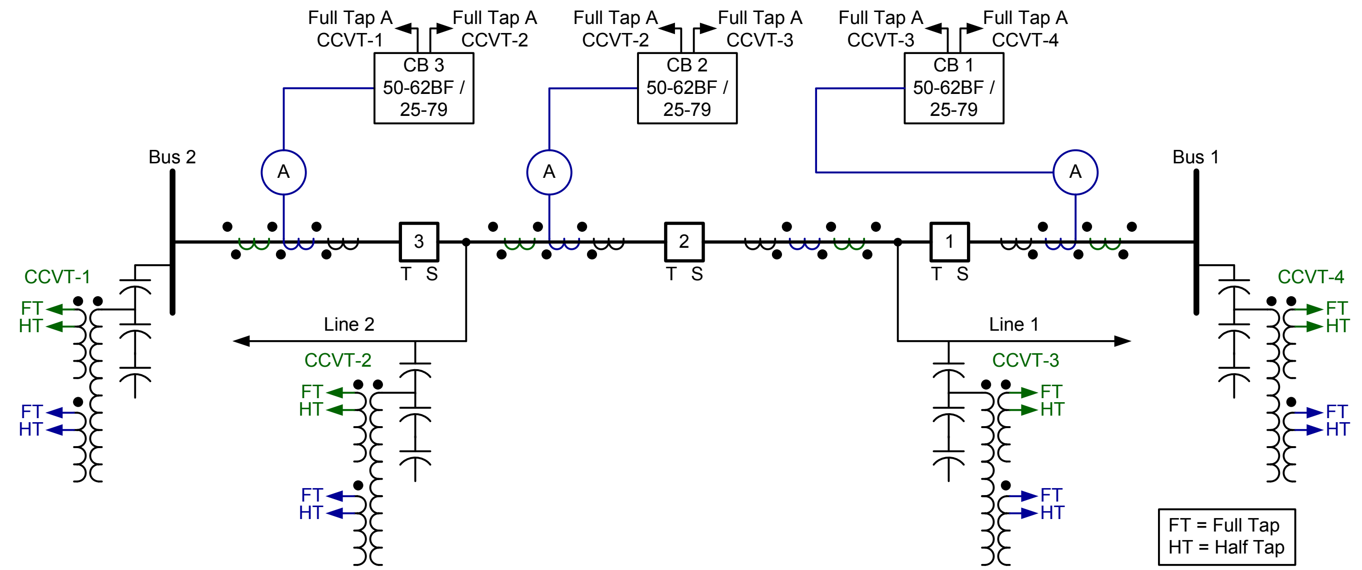

Fig. 4. Breaker-and-a-Half Breaker Relay Configuration

- A single relay per breaker for breaker failure, reclosing, and other breaker functions.
- Reduced number of required auxiliary devices, such as steering diodes and auxiliary tripping relays.
- Accounting for bay functions, such as reclosing interlocks and dc monitoring.

The breaker design is illustrated in Fig. 4. Each relay has dedicated I/O for each side of the breaker. To aid in maintaining consistency in application and standard settings, half of the I/O is designated as S (Bus 1 side) and the other half as T (Bus 2 side). A similar convention can be followed for a ring bus, where all of the S sides are on the same side of the breaker when rotating around the ring. When following this convention, the result is that each terminal has dedicated, standard I/O. The internal logic and operator switch contact assignments are standard for each terminal (as shown later in Fig. 6).

The breaker control was designed to have the features described in the following subsections.

A. Breaker Failure Detection

The breaker relay provides independent pole breaker failure protection (A-, B-, and C-Phases) as required for single-pole operation. Breaker failure detection has two different algorithms for current detection or breaker seal detection (for faults where current detection may not be available, such as a trip with breaker failure initiation from the transformer mechanical protection). There are two separate relay inputs for breaker failure initiation to choose which algorithm to invoke, as shown in Fig. 5.

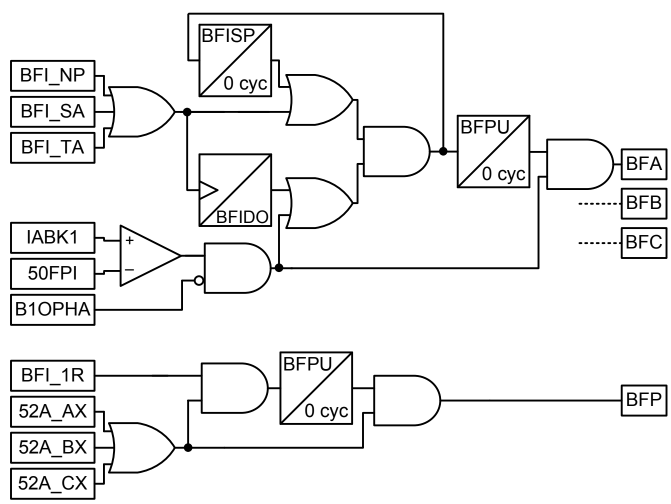

Fig. 5. Custom Breaker Failure Logic

B. High-Speed Reclosing

Each breaker relay provides high-speed reclosing (HSR) for its respective breaker. Because there are two breakers per line, the design needs to account for the sequencing of the closing of both breakers. For a line terminal, only one breaker performs HSR and, upon successful HSR, the other breaker parallels it. The breaker that is selected for HSR is the lead breaker and the other breaker is the follow breaker. A feature select switch provides both relays with the desired operator setup for the lead and follow breakers. For further operator setup, a separate single-pole or three-pole (1P/3P) selection switch is provided. This switch allows the line to be set up in either a single-pole or a three-pole mode.

The breaker selected to lead recloses in 0.5 seconds if a single-line-to-ground (SLG) fault occurs on the line and the 1P/3P switch is in the 3P position. The HSR occurs in 1 second if an SLG fault occurs on the line and the 1P/3P switch is in the 1P position. The reclose time is longer when a single-pole trip takes place to account for arc extinction.

If the breaker is selected to be the follow breaker, then the relay automatically parallels the breaker. The breaker closes in 12 seconds if there is voltage present on both sides of the breaker and all synchronism requirements (voltage magnitudes, phase angle, and slip frequency) are met.

For the three breakers on a breaker-and-a-half bay, there are further interlocks for HSR when the middle breaker is selected as the lead. In this mode, HSR is only allowed if the third breaker associated with the adjacent line or transformer is closed. This interlock is required because the relay settings do not account for the loss of the substation source.

C. Pole Disagreement

The design provides pole disagreement monitoring and tripping using the breaker control relay. Furthermore, PG&E has a variable pole disagreement timer. The following are the two conditions for pole disagreement:

- For any three-pole trip or any breaker closing event (manual or automatic), the pole disagreement timer trips the breaker for a pole discordance time of 20 cycles.
- For a single-pole trip operation, the pole disagreement timer is extended to trip the breaker for a pole discordance time of 90 cycles.

The previous philosophy called for a single relay in the breaker cabinet. It was supposed to be set at 90 cycles, but the setting was not always set properly or documented in the relay setting database for setting management queries. This feature was included in the breaker relays to implement the variable timers and for greater setting asset control. This addition helps prevent problems that occurred previously in which the line protection tripped on directional ground overcurrent upon a breaker closing prior to pole-disagreement tripping.

In addition, for line relay single-pole tripping, the resultant ground current can be quite high during the pole-open condition. In order to account for this higher ground current, the line relay element shifts to a different time dial for ground overcurrent tripping.

D. Trip Coil and DC Health Monitoring

The relay monitors each trip coil on each phase (six trip coils) when the breaker is closed. The relay monitors the breaker failure dc and the bay reclosing dc. The relay provides an alarm if either dc is outside of a specified tolerance.

E. Remote Manual Close Synchronism Supervision

The relay provides an output for supervision of the remote close command. It closes under all conditions other than a dead line or dead bus and to parallel it must meet the synchronizing requirements previously described.

V. Operation Interface, Integration, and Monitoring

When considering the functional implementation of the new design, a cautious approach was used to determine which features would be integrated into the relays. In order to avoid the failure of any relay affecting the remaining protection and operational features, most external control interfaces were left as discrete devices. Only relay setting group selection and digital circuit or PLC selection were integrated into the applicable relays. The operator setup interface switches for circuit breakers and lines are shown in Fig. 6.

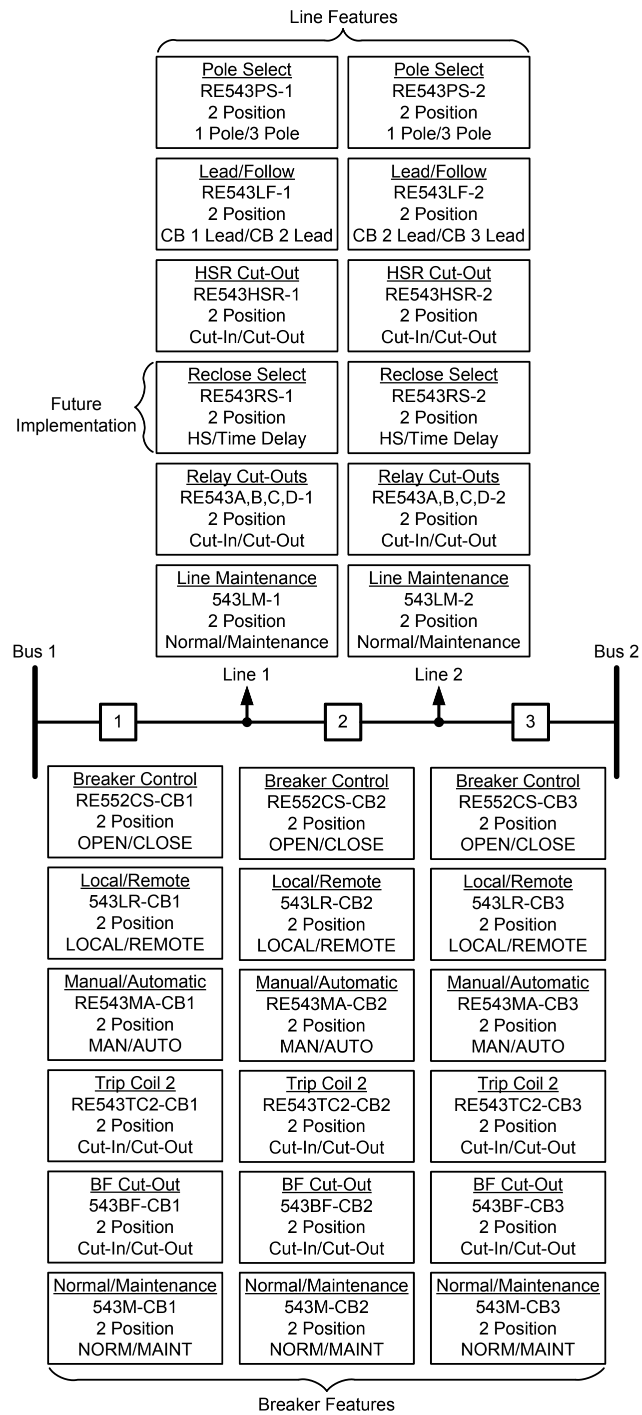

Fig. 6. Operator Interface Switches

Except in very special circumstances, the dc control design eliminates auxiliary relays. This approach moves the system closer to the ideal of achieving fully monitored protection.

The sequence of events (SOE) reporting for each line relay is programmed to capture channel failure and channel normal conditions. To preserve SOE data for all relays (line and breaker), special attention was given to eliminating the logging of chattering elements. In this manner, SOE can reveal channel availability data spanning months.

Additional features in the relays include the following:

- All new relays have continuous monitoring capabilities and provide supervisory control and data acquisition (SCADA), a human-machine interface (HMI), and energy management system (EMS) visibility via DNP3 over Transmission Control Protocol/Internet Protocol (TCP/IP).
- All relays have two Ethernet ports. One port is the primary and the other is a failover. If the primary Ethernet connection fails, the relay automatically switches over to the alternate port and resumes communications.
- Generic Object-Oriented Substation Event (GOOSE) messaging between relays is not implemented in any of the schemes. (Relays are compliant with IEC 61850 standards. Implementation may occur at a later date.)

VI. Prototype

PG&E management funded prototype panels and testing with the belief that the initial feedback and changes would save money in the long run by avoiding costly field changes. Before the panels were built, the schematics were reviewed several times to consider each feature in the new design. The prototype panels reflected the complete line package for each terminal and the additional panels at each end for the two circuit breakers adjacent to the line. The circuit breaker panels consisted of the breaker failure and reclosing relay and control switches. An HMI, remote terminal unit (RTU), and breaker simulators were also installed.

The line relays were connected through the same communications systems (digital microwave and backup PLC channel for the POTT relays) as the field installations. All equipment that was planned to be installed in the field was installed in the prototype system to allow for complete testing. The prototype panels were placed in a laboratory, which contained channel impairment equipment to take advantage of communications system testing for bit error rate, channel asymmetry, SONET resynchronization, and channel delay. The channel alarms were then set based on preprogrammed channel impairment levels.

The validation consisted of testing and reviewing the physical panel layouts, electrical design, relay acceptance testing, relay light-emitting diodes (LEDs), relay pushbuttons, a Mathcad® setting guide, and relay setting templates. The Mathcad files provided setting philosophy guidance. The validation was used to create the Ethernet DNP3 visibility, Ethernet DNP3 control, and custom relay logic. The relay custom logic for the prototype is shown on a standard logic diagram. The relay setting database lists the standard drawing number and revision number to identify the exact custom logic within each relay. The logic diagrams were an important tool for analyzing how the system works because they allow for a fast review of the philosophy. The logic diagrams have also been used to evaluate both RTDS testing and relay event files triggered by actual system faults.

After the panels were created, field technicians performed testing of the wiring and provided feedback to improve future field implementation. The experience of the technicians was critical in providing learned recommendations for improvements. One of the recommendations was to wire a test switch for every relay input and output. This change was implemented in all field installations and is one difference that exists between the prototype and field installations.

The characteristics of one PG&E line were used as a model to create settings to verify the proposed custom logic, settings, and physical design. Protection engineers spent several weeks testing the system. IEEE standard COMTRADE files obtained from previous RTDS tests were used for secondary injection into the prototype line relays. The results of this testing led to changes in the custom logic and settings. These final setting files became the templates for all field installations. The field technicians then returned and completed all functional testing and validated the test plans to be used for all field installations.

Once the standard was rolled out and applied at several locations, the validation panels were used for training the operators and other technicians. They were also used for several additional tests by protection engineers. For the first short-line application, the POTT relays were replaced with line differential relays. The same steps used for the original validation were used again for the validation of the line differential system. From this testing, the design was changed for all future 500 kV lines to include all line differential relays and replace distance POTT relays. These new Set C and Set D differential relays have custom logic that can be used for all of the installations with the selection of either POTT or line differential protection by setting variables to on or off in the custom logic. The logic diagrams also list the differences in protection settings for the application of either line differential or POTT protection.

VII. RTDS Testing

The industry has moved from applying dependable protection schemes to applying secure protection schemes as a result of decreased operating margins on transmission paths. Overtripping on the PG&E series-compensated 500 kV lines can impact system stability and lead to serious regulatory and monetary consequences. The PG&E 500 kV system is a major path for bulk electric power flow between the hydroelectricity-rich Pacific Northwest and heavy load centers in the Southwest.

PG&E used the RTDS platform to develop an accurate real-time model of the entire series-compensated 500 kV system to prove line relay settings and to challenge the relays with tens of thousands of external and internal faults. This paper does not discuss in depth how the relays were initially set or tested. For more information, refer to papers [5], [6], [7], and [8].

For each terminal of the line, the differential relay set of one manufacturer and the POTT distance relay set of the other manufacturer were tested. The results of the testing were automatically tabulated in a spreadsheet for each relay and analyzed.

Out-of-section and in-section fault results were reviewed to ensure that there were no relay trip outputs for the out-of-section faults and correct single-pole or three-pole trip outputs for the in-section faults. Where anomalies were observed, the RTDS model was checked for proper fault scripting and accurate system modeling and configuration. The next step was to check relay settings for adjustments, or additions or modifications of logic, to address the anomaly. In some cases, it was necessary to contact the relay manufacturer to request support, which resulted in a simple solution or a more involved relay firmware upgrade. The implementation of a relay firmware upgrade triggers a rerun of all testing to ensure that the anomaly has been addressed without creating new anomalies. In some cases the issue was with the custom relay logic and it had to be updated and retested.

Once all anomalies were addressed in the manner described, the test results were tabulated using charts and graphs. An example series-compensated line is shown in Fig. 7. The analysis charts that follow are based on this simplified one-line diagram.

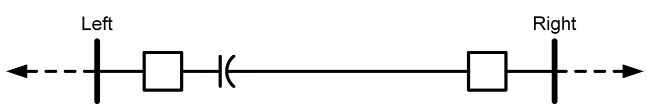

Fig. 7. System One-Line Drawing

The graph in Fig. 8 describes the relay Zone 1 reach from each terminal of a 500 kV line, with series compensation located at the left terminal only. Line potentials are connected on the line side of the series capacitors. The left terminal with the series compensation has complete Zone 1 coverage for up to 70 percent of the line. The right terminal looking into the series capacitor is limited to Zone 1 coverage for only the first 15 percent of the line before the relay series compensation logic [9] inhibits Zone 1 operation. This illustrates the importance of maintaining at least one level of high-speed protection at all times because the Zone 1 coverages do not overlap.

The graph in Fig. 9 shows the maximum (worst-case) operate times for the Zone 2 element at each terminal of the 500 kV line described previously. The right terminal looking into the capacitor displays a steady increase in the worst-case Zone 2 pickup time that tops out at 28 milliseconds (1.7 cycles) near the remote terminal. The left terminal displays slow operate times for faults at 25 percent of the line and beyond that does not follow a steadily increasing trend.

Note that for the left terminal there are two 0.1 percent listings. These are from the fault locations on both sides of the series capacitor in the model. The Zone 2 element reaches are critical for the operation of the POTT scheme.

Fig. 8. Zone 1 Distance Coverage Along the Line

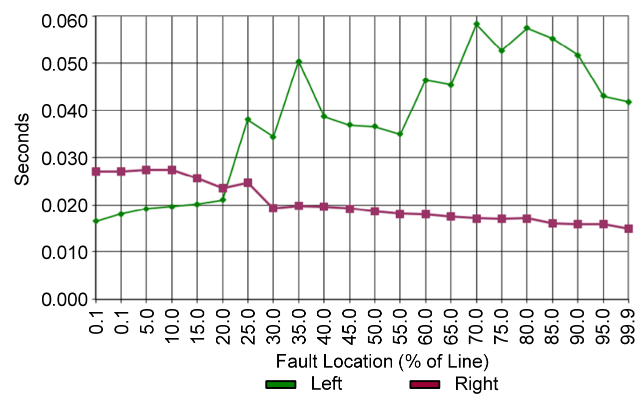

Fig. 9. Zone 2 Maximum Assertion Time for Faults Along the Line

Fig. 9 shows the worst-case operate times, which are only a small subset of the total faults. Analysis of the relay response revealed that the slow Zone 2 operations were from the subtransients of the series capacitor and the heavy mutual coupling. The mho ground and phase impedance loops [10] were oscillating enough for the first few cycles that the proper fault could not be selected. Once the transients subsided, the relay was able to make the proper decision and operate. The takeaway from this was that there were no failures to trip, only a handful of slow operations.

Due to the small exposure and coverage by the line differential protection, these occasionally slow operations of the distance relays were determined to be acceptable responses and no further changes were required in settings or firmware. In addition, looking at the average operate times revealed a relay response in line with the expectation of a steadily increasing relay operate time from close-in to remote faults.

Fig. 10 describes the average speed at which the Zone 2 element asserted at each terminal of the 500 kV line described previously. The left terminal with series compensation has subcycle performance up to 50 percent of the line while it ramps up to a 25 millisecond (1.5 cycle) assertion time near the remote bus. The right terminal looking into the line series compensation displays a subcycle assertion time up to 80 percent of the line and holds steady at 17 milliseconds (1 cycle) near the remote bus.

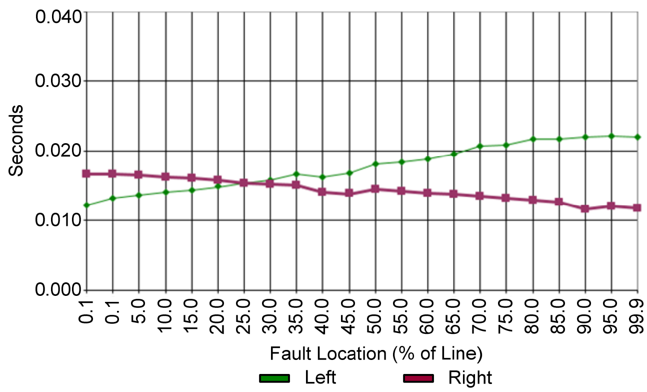

Fig. 10. Zone 2 Average Assertion Time for Faults Along the Line

A review of the line differential protection testing includes the proper response for each fault, backup element assertions, and Zone 1 coverage. A more detailed review of the differential protection is not required because coordination of the distance elements between both terminals is not necessary for proper scheme operation.

VIII. Field Deployment

After full RTDS testing of the proposed settings at the factory is completed, the settings are converted to field settings using existing written instructions to facilitate the process. For example, multiple load groups are not required for RTDS testing, backup distance elements are normally only enabled when the line differential channel is not functional but for RTDS testing are always enabled, and outputs are varied for RTDS testing for proper data collection. Field technicians perform full site acceptance testing per testing documents.

To aid in the understanding of the system, a description of operations and logic diagrams is provided. From the RTDS testing, which includes thousands of tests for both in- and out-of-section faults, 14 tests are run to test the communications channels and relay settings. Satellite communications are used to synchronize the two terminals to start the fault simulation with 2 seconds of prefault current at the same time. Eight out-of-section faults are run first and then six in-section faults are run. They include three-phase, phase-to-ground, and phase-to-phase faults. The tests are also run on one of the POTT relays with a PLC selected as the communications channel. Note that DTT is isolated for this testing in order to view the relay targeting based on the fault without the DTT masking the pilot operation and associated targets.

For POTT channels, channel delays are expected to be less than 1 cycle. The delay is determined during the field testing. For line differential communications channels, asymmetry is critical because PG&E does not employ IRIG-B timing at each terminal to correct for channel asymmetry. This decision was made to avoid having the Global Positioning System (GPS) antenna and clock become critical to the protection system, which would have required the IRIG-B clock and antenna alarms to be treated in the same critical manner as a relay alarm. Channel asymmetry throughout the PG&E system is expected to be less than 3 milliseconds and channel delays are expected to be less than 1 cycle.

PG&E uses locked bandwidth channels on the digital microwave system for line differential channels. If either the transmit (TX) or receive (RX) path is lost, no switching is made because this would result in the transmit and receive paths following different channels, which could introduce greater channel asymmetry. The Set A and Set B relays use fully redundant communications paths, and therefore the loss of one path is not expected to have any effect on the other path.

With the PG&E design, the Set A and Set B line differential relays pick up the channel asymmetry alarm from a loss of the GPS signal, but this does not lead to any overtripping. If the channel asymmetry alarm is picked up on both the Set A and Set B line differential relays, it is a result of the GPS not being functional because the Set A and Set B channels are fully redundant with no SPF.

On one of the differential channel installations, the microwave channels were not properly configured and the channel delays exceeded the relay calculation range. As a result of this communications issue, the field commissioning procedure was updated to calculate the transmit route time and the receive route time. In order to calculate the channel transmit route time and receive route time, the calculation is made from the quantities provided by the line differential relays. The relays provide the following:

- Round-trip channel time (T), which is the total time of transmission from one relay to the other end and its return path for the round trip.
- Channel asymmetry (ΔT), which is the time difference between the transmit and receive paths calculated by using the GPS clock information from both ends.

The transmit route time from the left terminal transmitter to the right terminal receiver is $\frac{1}{2}(T + \Delta T)$. The receive route time from the right terminal transmitter to the left terminal receiver is $\frac{1}{2}(T - \Delta T)$.

IX. Lessons Learned

It is inevitable that, even in the most organized and planned project, deficiencies will arise and require appropriate attention. The items in the following subsections were evaluated to determine the urgency of modifying the previous installations. Ways of addressing these unanticipated challenges included wiring changes, custom logic changes, relay firmware upgrades, and setting changes. The following subsections discuss some of the challenges encountered and how they were addressed.

A. Prototype Implementation

Even though the team thought that there was ample feedback from field personnel, certain details were still missed, and the field design accounted for the identified prototype deficiencies. Because the deviation between the prototype and field installation was slight, the prototype was not retrofitted to account for the differences. Instead, a setting template conversion process was created to exchange settings between the field and prototype installations (for example, I/O mapping).

B. Relay Firmware Upgrades

Occasionally, manufacturers issue device advisories that describe relay deficiencies. In most cases, these deficiencies can be corrected by firmware upgrades. A relay firmware upgrade was initiated as the result of an issue found during RTDS testing. Updates to previously installed relay packages must be evaluated because they require field testing and possible RTDS testing.

C. Non-Assertion of Reclose Block for Evolving Faults

The same type of evolving fault was run with different transition times between the single-phase fault stage and the multiple-phase fault stage (See Table II). During the testing, it was found that the relay responded differently with regard to reclose blocking. To address the issue, changes in the current differential relay were made, and the final custom logic is as shown in Fig. 11.

TABLE II
EVOLVING FAULT RECLOSE BLOCK OPERATIONS

Time to Evolve From Single-Phase-to-Ground Fault to Multiphase Fault	Single-Phase-to-Ground Trip Result	Multiphase Trip Result	Reclose Result
2 cycles	Single-pole trip	Three-pole trip	Reclose block
3 cycles	Single-pole trip	Three-pole trip	No reclose block
12 cycles	Single-pole trip	Three-pole trip	No reclose block

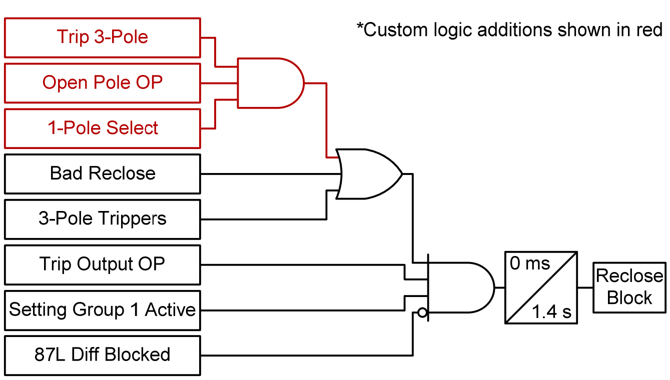

Fig. 11. Updated Custom Logic for Reclose Block for Evolving Faults

D. Simplified DNP3 Mapping

The relays were originally programmed with a large DNP3 map. This resulted in the RTUs being overloaded and the technicians performing testing being overwhelmed by the requirement to test each point. Furthermore, system operators only required a small subset of the original points list to adequately manage the system. The points list was reduced to their required list.

E. Single-Pole Tripping for Switch on to Fault

During manual RTDS testing, it was found that single-pole tripping was taking place for an end-of-line switch on to fault. To correct this anomaly, setting changes, Mathcad template changes, and custom logic changes were made. The logic shown in Fig. 12 enables distance elements for a certain period of time following breaker closing.

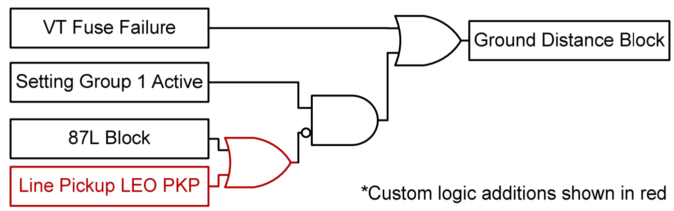

Fig. 12. Correct Single-Pole Trip for End-of-Line Switch on to Fault

F. Additional Zone When Required Line Setting Reaches Through Remote Transformers

While creating the settings for one of the longer lines with three remote transformers, it was found that the required distance reach picked up for low-side faults on the transformers. While the present PG&E philosophy is to install dual bus differential protection on all 230 kV buses, many 230 kV buses have only a single set of bus differential relays. For the loss of a single bus differential relay, the line settings required further delay to coordinate with the transformer high-side time-delayed clearing. Therefore, an additional zone was added in order to allow faster clearing for as much of the line as possible before picking up for faults on the low side of remote transformers.

G. Reclosing Issue With Existing Breaker Failure Logic

The full system review of PG&E breaker failure, HSR, and line protection practices and their interdependency was not considered because the subtlety of their interaction was not known. One of the line differential relays in the new design, with existing legacy breaker failures and HSR practices, led to the overtripping of a bus due to a false breaker failure operation for a permanent line fault. The original legacy PG&E breaker failure logic, as shown in Fig. 13, starts the breaker failure protection when the *BF Initiate* input is picked up and seals it in for the duration of the *Control Timer*. After the programmed *BF Timer* (8 cycles for PG&E) has elapsed, if current is detected the relay issues a BF Trip and the bus and/or adjacent circuit breakers are tripped and locked out.

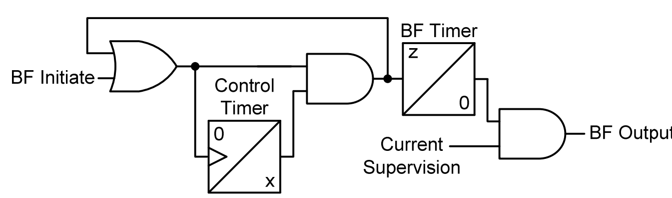

Fig. 13. Original PG&E Breaker Failure Logic

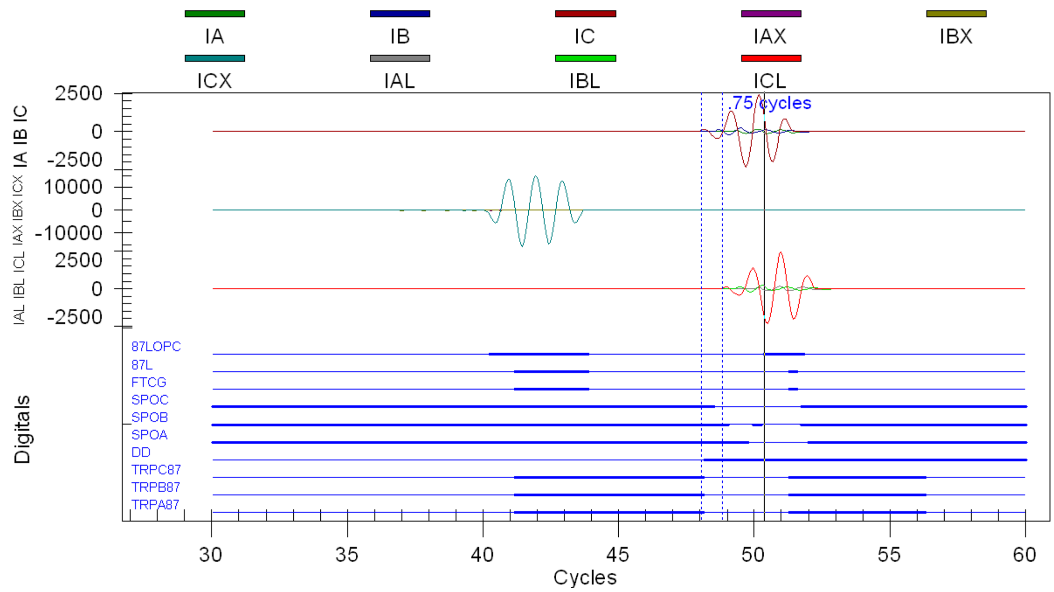

Fig. 14. Line Differential Relay Event Report

With this existing breaker failure logic, if the following three conditions exist simultaneously, a false breaker failure trip will be initiated:

- Tripping and *BF Initiate* when the circuit breaker is open and there is no local current.
- The existing PG&E logic, which allowed the *BF Timer* to start timing without local current supervision.
- Reclosing into a permanent fault after the timer has timed through several cycles, leaving not enough time for the circuit breaker to properly open before initiating breaker failure.

At PG&E, HSR is initiated from the line relays for SLG faults. It takes place 30 cycles after the trip when three-pole trip is selected and 60 cycles after the trip when single-pole trip is selected.

After the new system was employed with the new line differential relays, a permanent SLG fault occurred and the line was properly cleared at both terminals. The remote end reclosed about 8 cycles before the local end, tripped, initiated breaker failure at the local end, and started the local *BF Timer*. When the local end reclosed, the timer had already been timing for around 7 cycles. The *BF Timer* expired before the breaker cleared the fault, which resulted in a false breaker failure operation. The cause of the false breaker failure operation was that the breaker failure initiated and started timing when the local circuit breaker was opened (because of the reclosing at the remote terminal) into a permanent line fault with a line differential scheme that did not require local current or disturbance in order to issue a trip.

The relay event report shown in Fig. 14 shows the reclosing at the remote end (ICX current), local tripping and breaker failure initiation by the differential element, clearing at the remote terminal (current goes to 0), local reclosing (IC current), and local tripping (current goes to 0). Although the circuit breaker was properly opened to clear the fault, the breaker failure also picked up and tripped all adjacent circuit breakers because the *BF Timer* had elapsed when local current was flowing during the reclosing of the local end into the permanent fault.

Although the HSR times had drifted from the anticipated values, it was not possible to reclose both ends at the exact same time. It was investigated whether the relays could be altered to initiate trip only with local current or disturbance, but this was not possible. Therefore, in order to keep the HSR in service, PG&E studied, tested, and implemented breaker failure logic to include current supervision logic to supervise *BF Initiate* and have it present for the duration of the *BF Timer*. In addition, to accommodate non-current-initiated trips (e.g., those from a circuit breaker in a breaker-and-a-half configuration shared by the line transformer position, DTT, or special protection systems or remedial action schemes), the breaker failure logic has provisions to incorporate an option for circuit breaker auxiliary 52a status supervision to start *BF Initiate*.

The Western Electricity Coordinating Council (WECC) was queried to investigate breaker failure practices, and from this query it was found that the vast majority of utilities are moving forward with requiring breaker failure initiation and fault detection to initiate breaker failure for the duration of the *BF Timer*. The team also reviewed the IEEE breaker failure protection standard for guidance [11].

Shown in Fig. 15 is the new PG&E breaker failure logic, which supervises breaker failure initiation with local current and stops the *BF Timer* if the current drops out.

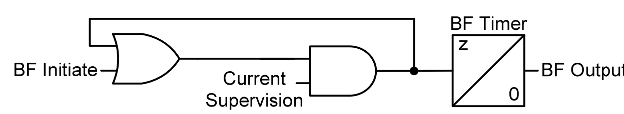

Fig. 15. New PG&E Breaker Failure Logic

The new logic provides a secure solution to correct for overtripping. One accepted consequence of choosing this secure method is that there may not be dependable breaker failure operate times.

X. Conclusion

This paper lists the important aspects of a relay replacement project from the scoping stage through field deployment with the challenges encountered along the way. The diagram in Fig. 16 is a simplified process flow chart of each step discussed in this paper.

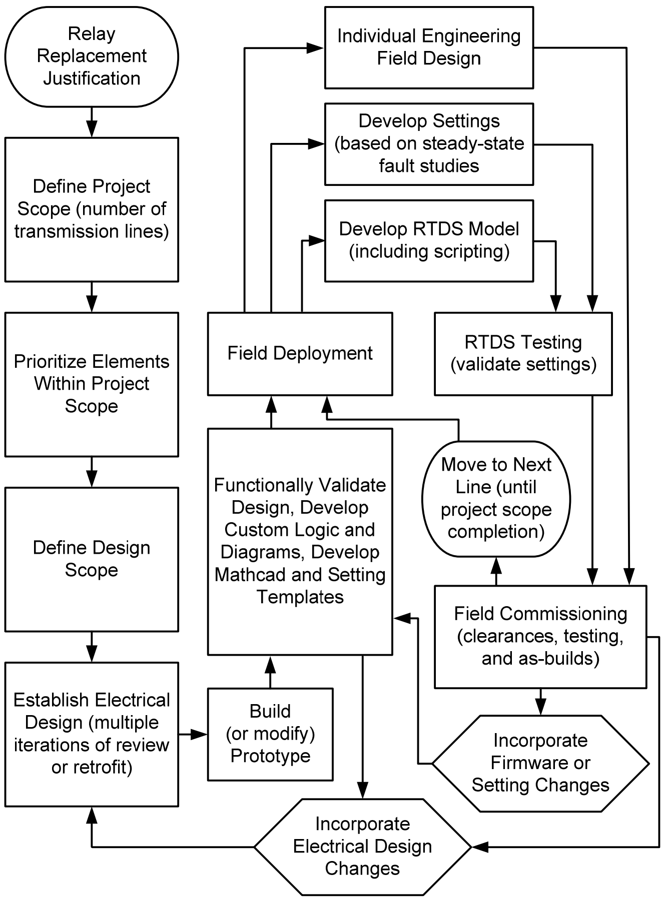

Fig. 16. Process Flow Chart

XI. References

[1] IEEE Standard C37.94-2002, IEEE Standard for N Times 64 Kilobit Per Second Optical Fiber Interfaces Between Teleprotection and Multiplexer Equipment.

[2] NERC Order No. 754. Available: http://www.nerc.com.

[3] NERC Standard PRC-023-1 – Transmission Relay Loadability. Available: http://www.nerc.com.

[4] S. Watanasiriroch, M. Best, and S. Turner, "An Application of Relay-to-Relay Logic Communications for Single Pole Tripping," proceedings of the 4th International Conference on Advances in Power System Control, Operation and Management, Hong Kong, China, November 1997.

[5] F. Plumptre, M. Nagpal, X. Chen, and M. Thompson, "Protection of EHV Transmission Lines With Series Compensation: BC Hydro's Lessons Learned," proceedings of the 62nd Annual Conference for Protective Relay Engineers, College Station, TX, March 2009.

[6] G. Corpuz, K. Koellner, J. Bell, S. Rajan, A. Somani, and M. Thompson, "Series-Compensated Line Protection Challenges in the CREZ Region," proceedings of the 67th Annual Conference for Protective Relay Engineers, College Station, TX, March 2014.

[7] D. Erwin, M. Anderson, R. Pineda, D. A. Tziouvaras, and R. Turner, "PG&E 500 kV Series-Compensated Transmission Line Relay Replacement: Design Requirements and RTDS® Testing," proceedings of the 64th Annual Conference for Protective Relay Engineers, College Station, TX, April 2011.

[8] D. Erwin and F. Karchemskiy, "An Automated Fault Study Application," proceedings of the 36th Annual Western Protective Relay Conference, Spokane, WA, October 2009.

[9] H. J. Altuve, J. B. Mooney, and G. E. Alexander, "Advances in Series-Compensated Line Protection," proceedings of the 62nd Annual Conference for Protective Relay Engineers, College Station, TX, March 2009.

[10] E. O. Schweitzer, III, and J. Roberts, "Distance Relay Element Design," proceedings of the 46th Annual Conference for Protective Relay Engineers, College Station, TX, April 1993.

[11] IEEE Standard C37.119-2005, IEEE Guide for Breaker Failure Protection of Power Circuit Breakers.

XII. Biographies

Davis Erwin received his BSEE and MSEE in 1997 and 1998, respectively, from New Mexico State University. Davis is a registered professional engineer in California and has been with PG&E system protection since 1999, primarily supporting 500 kV system projects and Special Protection Schemes.

Rafael Pineda received his BSEE in 1990 from California Polytechnic State University, San Luis Obispo. Rafael is a registered professional engineer in California and has been with PG&E since 1991. He is currently supporting 500 kV system protection projects and Special Protection Schemes. He is a member of the WECC Relay Group.

Monica Anderson received her BSEE in 1988 from the University of California, Davis. Monica is a registered professional engineer in California and has been with PG&E system protection since 2003. Previously, she worked at Western Area Power Administration, First Energy Corp., and Puget Sound Energy.

Eric Udren has 45 years of experience in the design and application of protective relaying. He works with major utilities to develop new substation protection, control, communications, and remedial action scheme designs. Eric is an IEEE Life Fellow and Chair of the Relaying Communications Subcommittee of the IEEE Power System Relaying Committee. He is a U.S. Technical Advisor for IEC relay standards and is a member of IEC TC 57 WG 10, which develops IEC 61850. Eric serves on the NERC System Protection and Control Subcommittee (SPCS) and the NERC Protection System Maintenance Standard Drafting Team developing NERC Standard PRC-005-2. He has written and presented over 90 technical papers and book chapters and has 7 patents. He currently serves as Executive Advisor with Quanta Technology, LLC of Raleigh, NC, with his office in Pittsburgh, PA.

Jordan Bell received his BS degree in electrical engineering from Washington State University and joined SEL Engineering Services in 2008 as a protection engineer. He performs event report analysis, relay settings and relay coordination, fault studies, and model power system testing using a Real Time Digital Simulator.

Neal Jones received his BSEE and MEEE in 2004 and 2008, respectively, from the University of Idaho. Neal is a registered professional engineer in several states and has been with SEL Engineering Services Protection since 2009, providing custom control designs and conducting protection studies for clients varying from utility to industrial sectors. He is currently the protection group manager. Previously he worked at Dashiell Corporation and Georgia Transmission Corporation.