PG&E 500 kV Series-Compensated Transmission Line Relay Replacement: Design Requirements and RTDS® Testing

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

Demetrios A. Tziouvaras and Rick Turner
Schweitzer Engineering Laboratories, Inc.

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PG&E 500 kV Series-Compensated Transmission Line Relay Replacement: Design Requirements and RTDS® Testing

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***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 six transmission lines requiring immediate replacement of faulty solid-state relay systems with modern, more reliable microprocessor-based relay systems to improve the reliability and maintain maximum availability of the 500 kV transmission system.**

This paper describes the PG&E design philosophy of the 500 kV transmission line relay systems and the protection challenges of series-compensated transmission lines operating in single-phase tripping and reclosing modes. In addition, the paper describes the relay system settings considerations and their validation using a Real Time Digital Simulator (RTDS®). The paper demonstrates the analysis of RTDS results and the benefits derived during the engineering and commissioning stages of the project.

I. Introduction

Existing solid-state relay systems that protect the Pacific Gas and Electric Company (PG&E) critical series-compensated transmission lines have reached the end of their useful life. Several of these relay systems were taken out of service because of misoperations and relay failures discovered during routine testing. The misoperations and failures were caused by faulty solid-state components. Because the failing solid-state relay systems were no longer supported by the manufacturer, repair and support were not possible. In addition to the challenges resulting from relay failures, the legacy solid-state relay systems were designed to emphasize dependability over security. In the present environment, where the transmission system often operates near its designed capacity, the PG&E system cannot tolerate overtripping.

Taking these relay systems out of service severely impacts the reliability and availability of the 500 kV network. Clearances on the remaining in-service equipment are much more difficult to obtain, and any additional transmission line relay system failures could force 500 kV lines out of service in order to comply with North American Electric Reliability Corporation (NERC) reliability standard requirements. In addition, NERC could impose substantial monetary fines on PG&E if critical 500 kV lines are forced out of service.

PG&E identified six transmission lines requiring immediate replacement of faulty solid-state relay systems with modern, more reliable microprocessor-based relay systems. The relay systems applied to protect these critical transmission lines must be high speed, very reliable, secure, and capable of protecting series-compensated lines while operating in three- or single-phase tripping and reclosing modes.

The relay replacement was considered an emergency project and had to be completed in a short time period, which restricted any consideration of implementing new protection design philosophies. The existing PG&E line protection design was maintained on five of the six lines in this project. The sixth line required special consideration because of its unique configuration and is not addressed in this paper. To expedite the schedule, only the relays were replaced, and the existing telecommunications equipment was used. Because of the urgency of this project, PG&E obtained engineering services from the relay manufacturer for engineering design, Real Time Digital Simulator (RTDS®) modeling, and testing. The relay manufacturer created the settings for the first line using fault study data provided by PG&E. The relay manufacturer also provided PG&E with a template for creating the settings for the other lines. Besides helping with the creation of settings, the template provides a convenient method to check and document the settings and associated fault study data.

Fig. 1 shows the project flow diagram. The RTDS model, design prints, and relay settings using a steady-state fault model were created in parallel. RTDS testing requires the completion of the relay settings and development of the model. The final system was installed and field commissioning tests were completed in order to place the relays in service.

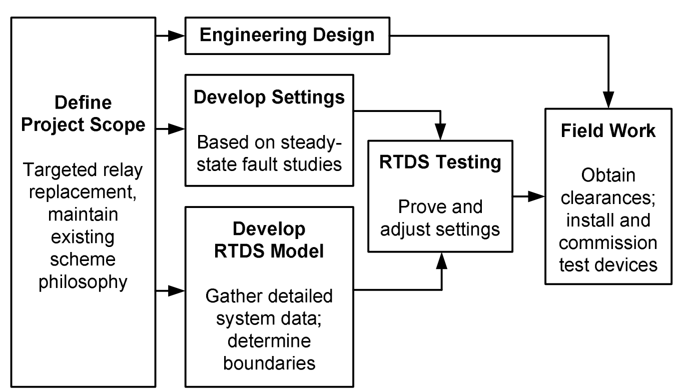


Fig. 1. Relay replacement project flow diagram

The goal of this paper is to share the lessons learned during testing of the 500 kV relay systems using the RTDS and the practical steps taken to install the new line relays. This unique testing approach has many advantages over traditional methods of testing and verifying settings of transmission line protection systems. Traditional protection testing methods are limited in their ability to predict the response of protective relay elements to actual system fault conditions. The RTDS represents the power system under more realistic conditions so that the relay system response can be evaluated under conditions that closely match actual fault conditions.

This paper describes the types of tests selected to verify the relay settings and the reasons behind the test selection. It also discusses the analysis of the RTDS test data and the tools used to expedite the data analysis. This paper discusses the results of this analysis and a case study that shows the importance and benefits of this testing approach.

II. 500 kV Transmission Line Protection Design Requirements

The existing line protection philosophy requires four separate relay systems installed on each line terminal, as shown in Fig. 2. The Set A relay utilizes high-speed protection over a microwave system and is normally selected for tripping. The Set B and Set C relays utilize power line carrier (carrier) for high-speed protection, with the carrier switchable between the two relays. The relay that is connected to the carrier is also selected for tripping, while the relay that is not connected to the carrier is disabled from tripping. The Set D relay is normally disabled from tripping. When the Set D relay is enabled for tripping, it only provides a time-delayed three-pole trip and no high-speed reclosing. The Set A, B, and C relays, if selected for single-pole operation, trip single pole for single-phase-to-ground faults and provide high-speed reclosing. If selected for three-pole operation, these relays trip three pole for all faults and only provide high-speed reclosing for single-phase-to-ground faults.

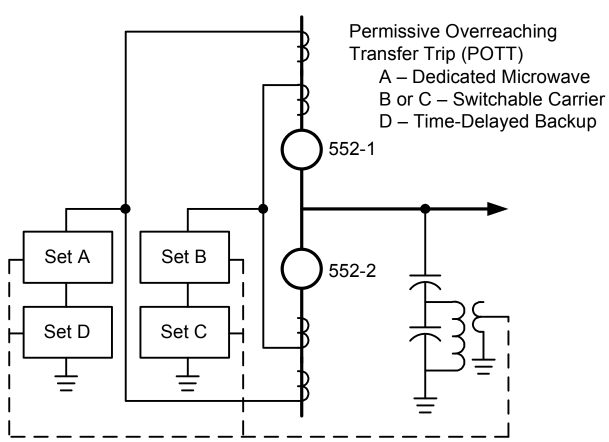


Fig. 2. Typical 500 kV line protection

The relay failures occurred on the Set B and Set C solid-state relays. The failed relays were replaced with two identical microprocessor-based relays that provide series-compensated line protection and single-pole tripping operation. Permissive overreaching transfer trip (POTT) protection is selected in the relays for high-speed protection over the existing carrier system, which is switchable between the two relays.

The PG&E 500 kV lines require at least one level of high-speed protection to be in service at all times; otherwise, the line must be forced open. In addition to stability concerns, high-speed clearing is required for all line faults because of coordination concerns. Terminals looking into series compensation have reduced Zone 1 reach. As a result, the coordination of the overreaching elements of adjacent lines is compromised. Security is of utmost concern in the PG&E system; therefore, the system is maintained in a configuration that mitigates the potential for overtripping.

III. Series-Compensated Line Protection Challenges

Series capacitors influence the magnitude and the direction of fault currents, which, in turn, influence the magnitude and phase angle of voltages measured at different points in the network. This has an impact on the performance of protection functions where operation depends on the magnitude and phase angle properties of measured voltage and current. Other phenomena like voltage and current inversion at the relay location, subharmonic frequency oscillations, series capacitor metal oxide varistor (MOV) protection, and series capacitor bypassing controls can influence the performance of different protection functions.

Numerous technical papers discuss the challenges of series-compensated line protection [1] [2] [3] [4] [5]. Reference [1] presents in great detail the problems associated with series compensation, and [1], [6], and [7] provide settings recommendations for distance and directional elements applied in series-compensated lines. In this section, we briefly review the most important issues of series-compensated line protection.

Voltage inversion is a phenomenon that affects distance and directional element discrimination. A voltage inversion is a 180-degree change in the voltage phase angle. For elements responding to phase quantities, voltage inversion can occur for a fault near a series capacitor if the impedance from the relay to the fault is capacitive rather than inductive. In general, phase relays that utilize voltage information from the line side of the series capacitor correctly declare the fault direction for faults on the protected line. Relays measuring the voltage from the bus side of the capacitor, with respect to faults on the protected line, can incorrectly declare the fault direction.

Voltage inversion can also occur in negative- and zero-sequence networks if the impedance behind the relay location is capacitive. A negative- or zero-sequence voltage inversion can affect directional discrimination of voltage-polarized directional elements that respond to sequence quantities.

Fig. 3 shows the voltage and current phase relationship for a bolted three-phase fault in front of the series capacitor.

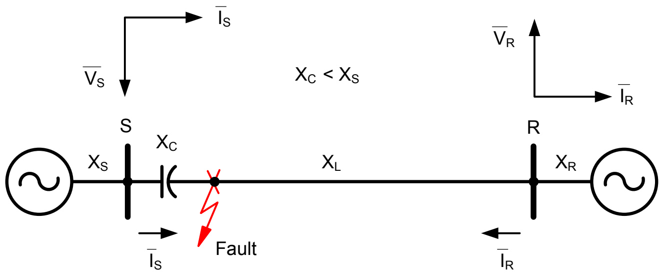


Fig. 3. Voltage inversion at Bus S on a series-compensated line

In Fig. 3, the voltage applied to the relay at Bus S is 180 degrees out of phase from what would be considered a normal fault voltage on an uncompensated system. In addition, a point farther back into the system (to the left of Bus S) experiences zero voltage and could impact the operation of relay systems on adjacent transmission lines, even though those lines might not be series compensated.

Series capacitors introduce errors in the impedance that distance elements estimate. The series capacitor modifies the line impedance that the relay measures. Furthermore, subharmonic frequency oscillations cause the impedance estimation to oscillate. The impedance estimation depends on the state of the capacitor protection. The effect of series capacitors on distance elements is more severe for line-end capacitors than for midline capacitors. Line-end capacitors not only affect distance estimation but also affect directional discrimination because of voltage inversion. Midline capacitors do not affect directional discrimination unless the capacitive reactance X_C is greater than half of X_L.

Memory polarization, which uses prefault voltage to enhance relay directional discrimination, solves the voltage inversion problem and the zero-voltage, three-phase fault problem for mho and directional elements responding to phase quantities. In a memory-polarized mho element, the relay uses a combination of prefault and fault voltage information when the memory is active. When the memory expires, the relay uses only fault voltage information. Memory action needs to be time-limited to avoid relay errors for system disturbances in which prefault and fault voltages are out of phase with each other [8].

In series-compensated lines, the polarization memory should be long enough so that the mho elements consistently pick up until the fault clears, the capacitor protection spark gap flashes, or the MOV conducts to clear the voltage inversion. For the worst (slowest) fault-clearing time, we want a long memory. While directional integrity and overreach are important issues, the viability of the directional comparison scheme logic is equally important. Additional transient blocking logic may be necessary to provide adequate security against undesired operations where directional integrity cannot be maintained for slow-clearing faults. Relays using memory polarization, especially those using positive-sequence memory polarization, are very secure and do not require special logic.

For an internal fault, a current inversion occurs on a series-compensated line when the equivalent system at one side of the fault is capacitive and the equivalent system at the other side of the fault is inductive. The current flows out of the line at one terminal, which is referred to as current outfeed. For most bolted high-current faults, the series capacitor protection spark gap or MOV bypasses the series capacitor. Current inversion is a rare event for these faults. However, for high-resistance faults, the low fault current prevents the capacitor from being bypassed and creates the conditions for a current inversion.

Current inversion can also occur in negative- or zero-sequence networks. Current inversion affects directional, distance, phase comparison, and differential elements responding to phase or sequence component quantities. Fig. 4 depicts the condition required for a phase current inversion. The currents are approximately 180 degrees out of phase, rather than in phase, for this internal fault.

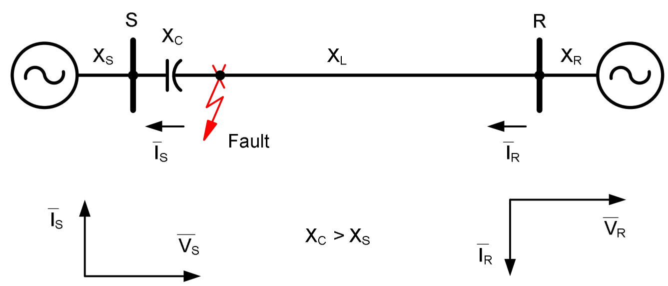


Fig. 4. Current inversion on a series-compensated line

Series capacitors introduce subharmonic frequency oscillations in power system currents and voltages, which are not common in noncompensated systems. These subharmonic frequency oscillations can cause a delayed increase of fault currents, delayed operation of spark gaps, and delayed operation of protective relays. Subharmonic frequency transients can also influence the correct operation of distance protection functions by increasing the operating time of distance elements and causing an overreach of Zone 1 instantaneous distance elements, resulting in an undesired line trip.

Fig. 5 shows a transmission line with 50 percent series compensation (i.e., the series capacitor reactance equals 50 percent of the positive-sequence line reactance). For the fault location in the figure, the underreaching Zone 1 distance element at Bus S should not operate. Intuitively, we would expect that an 80 percent Zone 1 setting of the compensated impedance ($X_L - X_C$) would be an appropriate reach setting. However, the series capacitor and system inductance generate subharmonic frequency oscillations that can cause severe overreach of the Zone 1 distance element.

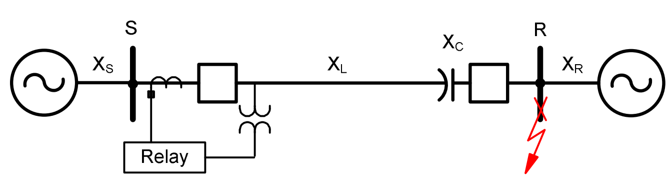


Fig. 5. Series-compensated line with a fault at the remote bus

Fig. 6 shows the spiraling impedance resulting from a subharmonic frequency transient [1]. The circle represents the steady-state characteristic of a Zone 1 mho element set with a 2.5-ohm reach. This setting represents a best estimate to prevent Zone 1 overreach for a remote bus fault based on the steady-state impedance. As we can see from the impedance plot, the apparent impedance magnitude decreases to a value well below 2 ohms secondary, which is lower than the compensated line impedance. Immediately after fault inception, the impedance trajectory passes through the Zone 1 mho element characteristic. As the transient decays, the impedance spiral decreases until it reaches a steady-state value after a number of cycles (dependent on the system characteristics). There are three options to avoid Zone 1 operation during the subharmonic frequency transient:

1. Introduce a Zone 1 time delay, which is not recommended.
2. Further reduce Zone 1 reach settings, and use RTDS zone margin batch testing to validate that the impedance spiral does not cause a Zone 1 element overreach.
3. If the capacitor is in front of the relay, enable the relay function that blocks the Zone 1 element for a fault beyond the capacitor [9].

Compared to the third option, the second option provides faster tripping for close-in faults, at the expense of reduced security for faults beyond the capacitor.

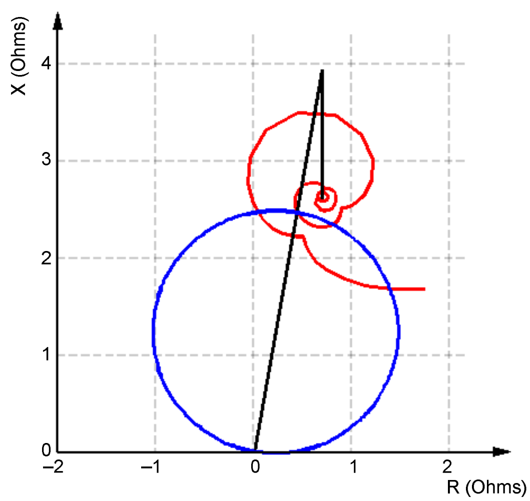


Fig. 6. In series-compensated lines, distance elements can overreach because of the impedance oscillation caused by subharmonic frequency transients

Proper setting of the Zone 1 elements includes not only the reach setting of the elements but also the pickup setting of any overcurrent elements that supervise the Zone 1 distance element. The settings required for the Zone 1 distance elements are determined by the following factors:

- Series capacitor location
- Capacitor and line impedances
- Location of instrument transformers
- Type of capacitor protection
- Protective level of the capacitor protection

To prevent Zone 1 distance element overreach, relay logic detects when a fault occurs beyond a series capacitor [9]. The relay blocks the Zone 1 element until the series compensation logic determines that the fault is between the relay and the series capacitor.

Subharmonic frequency oscillations could also affect relay elements based on superimposed components. A relay system misoperation tripped a PG&E 500 kV line after an external line-to-ground fault was cleared at high speed [2]. Subharmonic modulation of voltage at any relay location is a function of the local source impedance magnitude. There is no guarantee that a relay resetting from a reverse decision will see the highest voltage changes. A relay resetting from a forward decision could see higher subharmonic voltage changes, which could lead to a longer resetting time in relation to the reverse resetting time of the relay at the remote end of the line.

Another misoperation occurred when the same relay tripped three pole for single-line-to-ground faults [2]. In other instances, while in three-phase tripping mode and set to block autoreclosing on multiphase faults, the same relay blocked autoreclosing on a line-to-ground fault. The cause of these undesired operations was the loss of phase selection because of higher-than-anticipated subharmonic frequency transient current in one of the healthy phases. Operation of the third $\Delta I_{ph\text{-}ph}$ relay element, after the operation of the other two $\Delta I_{ph\text{-}ph}$ elements, was the basis for loss of phase selection following a correct initial phase selection.

As noted previously, subharmonic frequency transients that occur on series-compensated networks can cause an overreach of Zone 1 distance elements and misoperation of directional or superimposed component elements. Therefore, relay settings in series-compensated line applications must be verified using transient testing in an RTDS environment. The relays that caused the misoperations were tested extensively using open-loop transient testing with data obtained from a transient power system model using the Electromagnetic Transients Program (EMTP) [2]. The deficiencies in the relay design were not uncovered during transient testing because the EMTP simulation was terminated 10 cycles after an external fault was cleared. However, the in-service relay misoperated 18 cycles after the successful clearing of an external fault. Open-loop testing using EMTP runs for a limited amount of time and requires certain assumptions, such as relay operating time. On the other hand, closed-loop testing, such as connecting the RTDS to the actual relays, simulates the power system continuously in real time and provides voltages and currents to the relays under test until the user stops the test.

IV. Relay Settings Considerations and Criteria

The initial relay settings were developed from the steady-state solutions of the short-circuit base case. The relay settings require verification using RTDS testing because these lines are subjected to severe transients, due to series compensation, that cannot be modeled with a steady-state short-circuit program.

Multiple steady-state fault study base cases were used to calculate the relay settings. Each steady-state fault study base

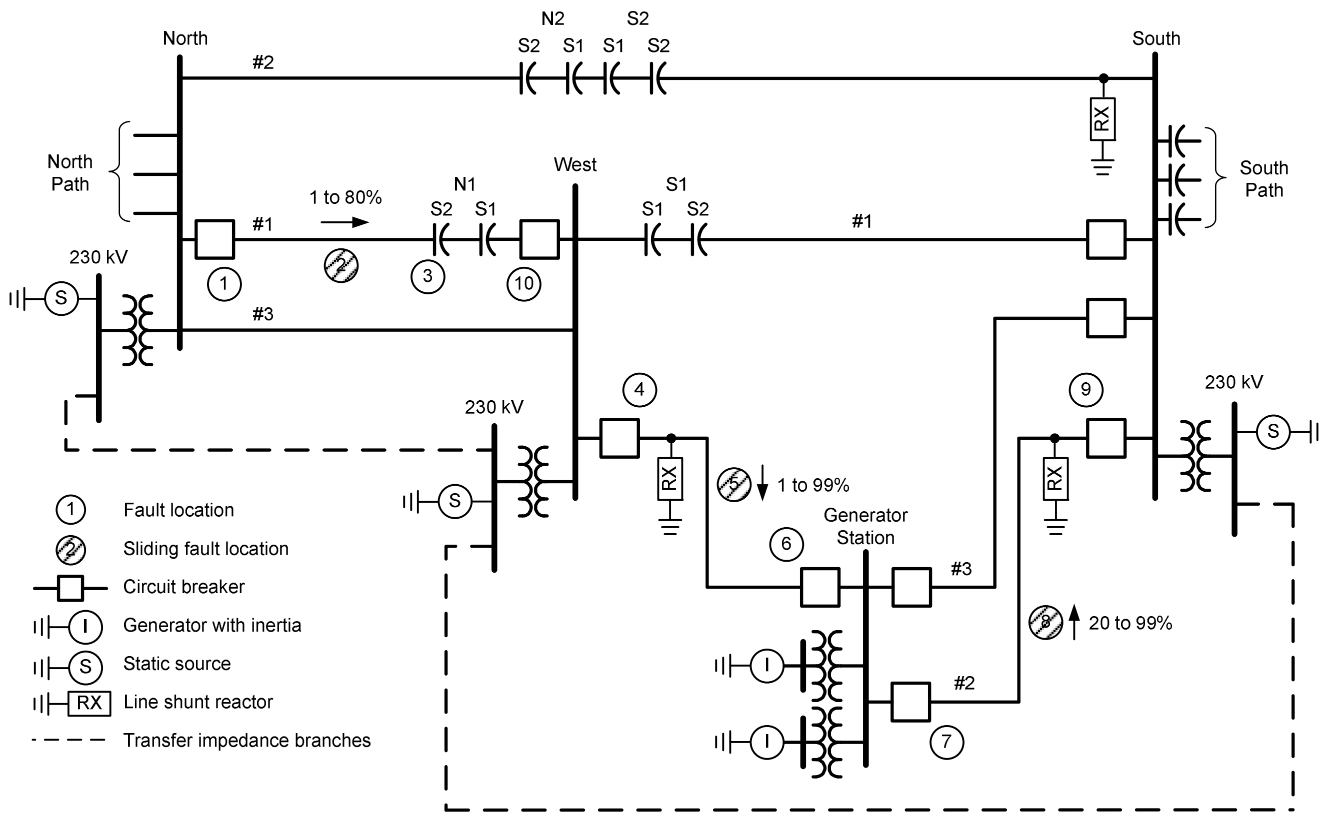


Fig. 7. Southern portion of the PG&E 500 kV system

case was configured with a particular system contingency, such as a generator or step-up transformer bank outage, along with variable configurations of the series capacitors. Each of the fault study base cases represents a legitimate, operating system configuration. Once a particular base case was selected, additional single-contingency outages were examined, using a program that sequentially removes one system component at a time, performs the study, and creates a text file containing the fault values. An automated Microsoft® Excel® workbook was used to read the text files and organize the data to determine the minimum and maximum values used to set all protective relay elements [10]. As mentioned previously, the cases were determined by applying all of the possible bypass combinations on the neighboring series capacitors. Once the minimum and maximum values were determined for the West – Generator Station line, the cases showing the largest minimum and maximum fault current and impedance values were used to create additional cases with a single Generator Station out-of-service generator and with a single de-energized Generator Station step-up transformer bank, because a generator can be offline for extended periods.

As shown in Fig. 7, there are four series capacitor bypass combinations and, therefore, 16 separate cases were used to test the West – Generator Station line relays.

Fig. 8 shows the cases created to test the West – Generator Station line relays. The minimum and maximum values from the analysis of all of these cases with further N – 1 outage contingencies were used for setting the line relays.

Fault Data

Case	South Path	North – South	North – West	West – South
1				
2				BP
3			BP	
4			BP	BP
5		BP		
6		BP		BP
7		BP	BP	
8		BP	BP	BP
9	BP			
10	BP			BP
11	BP		BP	
12	BP		BP	BP
13	BP	BP		
14	BP	BP		BP
15	BP	BP	BP	
16	BP	BP	BP	BP

*BP – bypassed capacitors

RB at West Bus

5D Case 5 with generator station Unit 2 offline
9D Case 9 with generator station Unit 2 offline
12D Case 12 with generator station Unit 2 offline
13D Case 13 with generator station Unit 2 offline
12T Case 12 with generator station Bank 2 out
13T Case 13 with generator station Bank 2 out

RB at Generator Station

2D Case 2 with generator station Unit 2 offline
4D Case 4 with generator station Unit 2 offline
12D Case 12 with generator station Unit 2 offline
16D Case 16 with generator station Unit 2 offline
2T Case 2 with generator station Bank 2 out
4T Case 4 with generator station Bank 2 out

Fig. 8. Cases created to test the relays on the West – Generator Station line

Analysis of the fault studies resulted in lower apparent impedance values for faults beyond the capacitors on the North – West and South – West lines than for the West bus faults as seen by the Generator Station line relays. However, lower impedance values were not used for the Generator Station relay settings because the relay has a function that blocks Zone 1 for a fault beyond a capacitor. This logic was turned on with a capacitor setting equal to the highest capacitive reactance value connected to the West bus. We rely upon the series compensation relay logic to block Zone 1 tripping, when required. The West settings for the West – Generator Station line also utilize the series compensation line logic, but with the logic to block for faults beyond the capacitor turned off. This allowed us to set the Zone 1 element to the desired sensitivity and be secure during voltage inversions that may occur during faults on neighboring series-compensated lines.

The relays were initially set using the minimum and maximum calculated steady-state fault values with the following PG&E criteria. The criteria for distance protection include the following:

- Enable phase distance Zone 1, and set it for 80 percent of the worst-case minimum reach to the remote bus.
- Enable ground distance Zone 1, and set it for 80 percent of the worst-case minimum reach to the remote bus.
- Enable phase distance Zone 2, and set it for 130 percent of the worst-case maximum reach to the remote bus. The relay settings must accommodate emergency line loading, as defined by NERC PRC-023-1.
- Enable ground distance Zone 2, and set it for 130 percent of the worst-case maximum reach to the remote bus.
- Enable phase and ground distance Zone 2 elements to trip with a 15-cycle time delay.
- Set reverse phase and ground distance elements used in the POTT scheme to coordinate with remote overreaching Zone 2 distance elements.
- Enable out-of-step blocking logic on all relays.

The PG&E criteria for overcurrent elements include the following:

- Disable all instantaneous phase overcurrent elements (directional or not) to prevent tripping on recoverable system swings, with the exception of switch-onto-fault (SOTF) and loss-of-potential (LOP) protection.
- Disable instantaneous ground overcurrent elements. These elements were initially enabled and set with a conservative margin (130 percent) for the worst-case out-of-section fault. However, RTDS testing revealed timing issues with high-speed reclosing and had to be disabled.
- Enable ground time-overcurrent tripping for worst-case remote bus faults or line-end faults (highest contingency current) to trip in 15 to 25 cycles.
  - Use two distinct ground overcurrent curves for enhanced sensitivity, and switch between the two curves for anticipated single-pole conditions and actual open-pole conditions.
  - Set ground time-overcurrent elements to coordinate during single-pole trip conditions.
  - Use the emergency current rating to calculate the highest expected ground current during a single-pole tripping condition. (The dual ground overcurrent curves allow coordination with the breaker pole disagreement timers set for 20 cycles.)
- Set the ground time-overcurrent pickup (on both curves) for 50 percent of worst-case minimum ground fault current for a remote bus fault.

The PG&E criteria for POTT include the following:

- Use Zone 2 phase distance, Zone 2 ground distance, and forward ground overcurrent elements for the forward POTT keying and tripping.
- Disable the forward ground overcurrent element during open-pole conditions.
- Use reverse Zone 3 phase distance, reverse Zone 3 ground distance, and reverse ground overcurrent elements for the reverse-blocking POTT.

Secure echo back logic was developed using relay programmable logic instead of the more dependable scheme available as an option in the relay. The custom echo logic was preferred because none of the involved terminals demonstrated weak-infeed characteristics. As shown in Fig. 9, the echo back logic is supervised by all poles being open. Three-pole open supervision, as opposed to single-pole open supervision, prohibits echo keying for out-of-section faults that can occur during single-pole open conditions. To enable echo keying, the three-pole open condition must be present for 10 cycles. This ensures that there is no inadvertent echo keying during three-phase pole opening for normal fault-clearing events. The feedback loop ensures that the 4-cycle echo pulse only occurs once per 10-cycle period. This helps avoid the possibility of an echo “ping pong” effect.

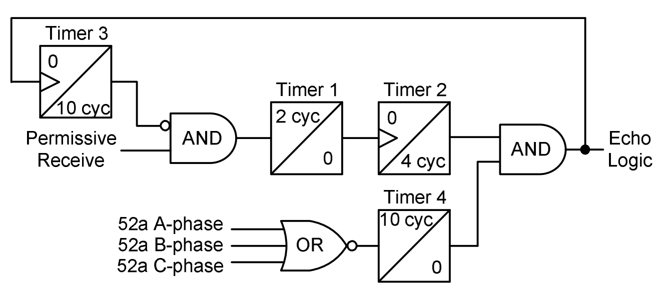


Fig. 9. Echo back logic

V. RTDS Modeling

To generate the transient data needed to test the response of protection systems applied to series-compensated lines, we must accurately represent the electrical and electromechanical characteristics of the different power system components, including their frequency dependence. The RTDS, which was used for the transient testing described in this paper, performs digital power system simulation in real time. The RTDS computes the power system simulation in discrete time steps, which are in the order of 50 to 80 microseconds. The actual time required to solve the network model is a function of the network size and the available RTDS hardware.

The study of electromagnetic transients often requires detailed modeling of large power systems. Although it is desirable to model a large portion of the power system in great detail, this requires a prohibitive amount of computer resources. Therefore, it is common practice to represent only a small, detailed portion of the system area under study and represent the remaining system with an equivalent network. This was the case with the PG&E 500 kV system, where several RTDS models were developed to accommodate the testing of the six transmission lines involved in the emergency relay replacement project.

One of the most important aspects of transient modeling is to obtain a reduced network from a large power system that we can model in detail in the RTDS. In the transient model, we retain the line under test, all adjacent lines, series capacitors, line reactors, shunt capacitors, step-down transformers, and nearby generators. The retained power system elements are explicitly modeled using their physical properties. Thévenin equivalent sources and transfer impedances at least one bus away from the line under test complete the model. Transfer impedances are modeled using distributed parameter line models and can exist at various voltage levels. Likewise, the equivalent sources can exist at various voltage levels. It is very important that the reduced model produce the same power flows and steady-state fault currents as the original power system model. Prior to performing any tests, the load flow and short-circuit fault currents are compared to the steady-state models to validate the transient RTDS model.

Another important consideration in the development of the transient model is the number of operating conditions during relay testing. We need to consider the line loading, including such things as different load flow levels and direction. Additionally, we need to examine strong and weak system sources, considering contingencies that affect either the positive- or zero-sequence source impedances (i.e., out-of-service parallel line and nearby out-of-service generators and transformers).

Finally, it is necessary to properly model the power system components and their controls, including their frequency dependence. In the PG&E 500 kV transient model, we modeled the following in great detail:

- Series capacitor protection using MOV or thyristor-protected series capacitors (TPSCs), depending on the series capacitor bank type and its damping circuits.
- Series capacitor bypass breakers and their controls, including high-MOV energy bypass, high-MOV current bypass, line relaying transfer trip bypass, and capacitor reinsertion.
- Single- and three-pole reclosing controls for the line under test and adjacent lines.
- Single- and three-pole breaker controls for the line under test and adjacent lines, including preinsertion resistors and point-on-wave closing.
- Capacitive voltage transformers.
- Shunt reactors and capacitors.
- Distributed parameter transmission line models.
- Generator step-up and 500 kV/230 kV autotransformers.
- Source and transfer impedances.
- Realistic relay operation for faults on adjacent lines.

VI. RTDS Testing

Transient testing of 500 kV relay systems has been an integral part of the PG&E protection application philosophy since 1984 [2]. The main reason for this is the realization that the transient response of relay systems differs considerably from what we can deduce from steady-state analysis and testing. Another reason is the desire to validate the performance of relay algorithms in series-compensated networks. Transient testing of relay systems is also used as a means to validate the applied settings and verify relay accuracy. As discussed previously, it is nearly impossible to determine relay settings using steady-state short-circuit programs in a system that contains nonlinear elements (MOVs), unbalanced impedances caused by asymmetrical series capacitor gap bypassing, decaying low-frequency transients, and other system transients that could influence the dependability and security of line protection.

Many relay performance improvements were realized over the last 25 years by using transient model power system data to test the relay systems and by analyzing all extra-high-voltage (EHV) relay trips for correct operation [2]. These performance improvements were realized by working closely with relay manufacturers to test, identify certain shortcomings, and improve the relay systems.

Forty years of operational experience with series-compensated line protection allowed PG&E to confirm the need for transient model power system testing. Initially, transient testing was performed using analog simulator technology at the relay manufacturer facility. Later, this evolved to computer-based simulation with EMTP and open-loop transient waveform playback into the relay systems using voltage and high-current dc-coupled amplifiers. Computer simulation makes it easier to develop models and change the power system configurations to test more scenarios. However, the biggest limitation of computer simulation is that it is not a closed-loop testing environment, where action of the protection and control system under test directly affects the power system [11]. The difficulties of using the open-loop transient simulation methods limited the thoroughness of the testing in the past.

Today, RTDS technology allows us to combine the ease of computer-based power system modeling and simulation with the closed-loop testing environment of an analog model power system simulator. The RTDS provides breaker status contacts and analog currents and voltages directly to the relays under test. Likewise, the relays provide trip and close signals directly to the RTDS. Operationally, it is as if the relay is connected to the actual power system. Other contacts from the relays are connected to the RTDS to monitor the relay performance and collect data. The following relay elements are monitored to assist in analyzing their performance:

- Reclose block and initiate
- Zone 1 phase or ground distance pickup
- Zone 2 phase or ground distance pickup
- POTT
  - Forward ground overcurrent pickup
  - Key permissive
  - Receive permissive
  - Reverse element pickup
- Series compensation block Zone 1
- Out-of-step blocking (if utilizing this feature)

The first tests validate the transient model and verify proper connections between the relays and the RTDS. This is accomplished by verifying the power flow, comparing the three- and single-phase fault duties to the steady-state model, and verifying that the relays read proper current and voltage.

Next, selected tests validate the initial relay settings. The most challenging faults are selected to determine if any relay settings changes are required prior to performing automated tests via the scripting tools. Examples of the tests include the following:

- Verify relay operation for SOTF, LOP, and a fault during the open interval of a single-pole trip.
- Apply ground faults with varying fault resistance at the zero-sequence center of the line to determine the relay sensitivity. The zero-sequence center is the point where both ends contribute the same $3I_0$ current.

Relay event reports are retrieved for faults of interest to further review and verify proper relay operation.

To minimize the set of tests that require reevaluation, the tests should be performed in the following order:

1. Verification of RTDS model (comparison of fault conditions).
2. Verification of relay analog readings during steady state.
3. Manual tests for extreme conditions (using weak and strong source base cases).
4. External fault scripted tests.
5. Internal fault scripted tests.

The scripting tools allow us to automate fault simulation and data collection. We can run thousands of test cases in a relatively short period of time. Other computer software analysis tools, such as Excel, allow us to analyze the large amount of test data generated during the simulation and transient relay testing. In addition, accurate computer-based protection algorithm models that run in Mathcad® or MATLAB® indicate how close the relay response is to a boundary or threshold. These computer relay models provide us with a better understanding of the relay response, help us adjust relay settings if necessary, and provide us with greater confidence that the relay will perform acceptably while in service.

The scripting tools allow an order of magnitude more testing than traditional EMTP-simulated testing. For example, in each of the two previous PG&E 500 kV relay replacement projects, 100 tests were run to verify relay settings on each line. For this project, one week was allocated to the RTDS for each line, and over 5,000 fault simulations were run on each line to verify the settings. Given the magnitude of data captured during the tests, it was necessary to create automated methods to detect undesirable relay responses and verify proper relay element coordination.

The automated tests run overnight to maximize the effectiveness of the testing. The number of tests to perform must be calculated to determine how much time they require. The calculation involves the number of power flow cases, contingencies, fault locations, fault types, and fault inception angles. As an example, a test involving four contingencies, ten fault locations, and all ten fault types at three different fault inception angles results in 1,200 simulations. Table I shows the calculation of the number of automated tests to be completed for one script in order to determine the time required for testing.

TABLE I
FAULTS FOR ONE SCRIPT

Power Flow Cases	4
Fault Locations	10
Fault Types	10
Fault Inception Angles	3
Total	(4 • 10 • 10 • 3) = 1,200

For some cases, there was a potential for overreach when the source behind the terminal under test was weakened by removing the strongest source. The overreach with a weak source was unexpected because it was not observed during steady-state analysis.

The actual Zone 1 reach setting was not reduced because the original setting of 80 percent provided adequate margin to ensure no overtripping for out-of-section faults.

Fig. 10 shows a Mathcad plot of the mho element calculation during an out-of-section fault. The upper dashed line indicates the Zone 2 reach, and the lower dashed line indicates the Zone 1 reach.

Fig. 10 shows that the Zone 1 element did not operate for the fault.

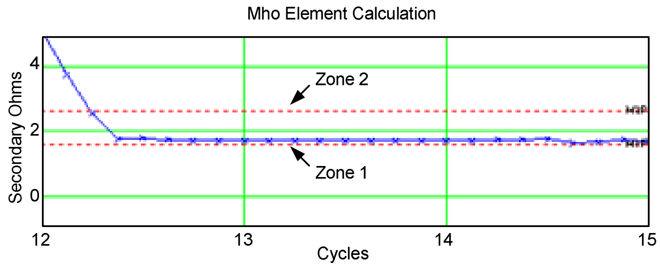


Fig. 10. Mathcad plot showing the phase-to-phase mho element calculation

VII. Analysis of RTDS Test Data

The relay instantaneous tripping elements, overreaching elements, reverse-blocking elements, permissive send, and permissive receive were mapped to relay output contacts. These contacts were wired to digital inputs on the RTDS and captured as discrete points, along with the analog voltages and currents, in a COMTRADE (Common Format for Transient Data Exchange) file. The operating time relative to fault inception of the points was also captured as a matrix within a space-delimited ASCII (American Standard Code for Information Interchange) file. A different ASCII file was created for each fault location within each particular base case selected for the testing. Fig. 11 shows a portion of an example ASCII file.

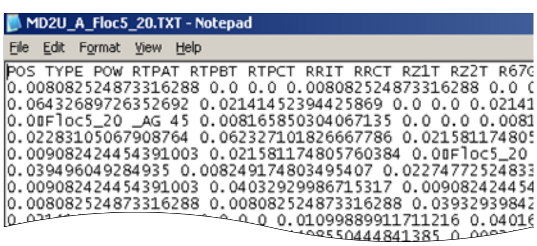
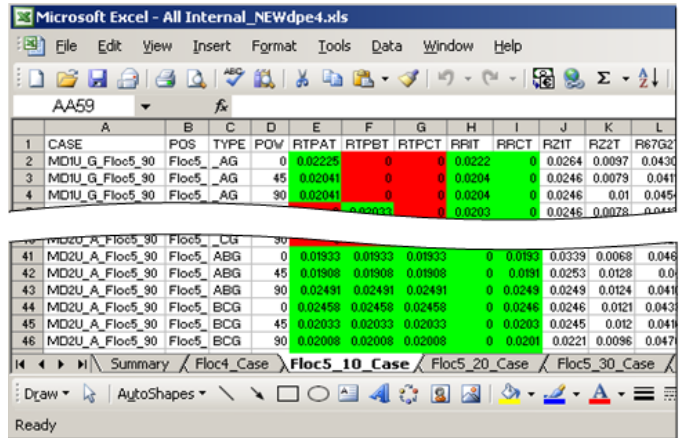

```
MD2U_A_Floc5_20.TXT - Notepad
File Edit Format View Help
POS TYPE POW RTPAT RTPBT RTPCT RRIT RRCT RZ1T RZ2T R67G
0.008082524873316288 0.0 0.0 0.008082524873316288 0.0 0
0.06432689726352692 0.02141452394425869 0.0 0.0 0.02141
0.0Floc5_20 _AG 45 0.008165850304067135 0.0 0.0 0.0081
0.02283105067908764 0.062327101826667786 0.02158117480
0.009082424454391003 0.021581174805760384 0.0Floc5_20
0.039496049284935 0.008249174803495407 0.022747725248
0.009082424454391003 0.04032929986715317 0.0090824244
0.008082524873316288 0.008082524873316288 0.0393293984
0.0 0.0 0.010998899117112160.0401
```

Fig. 11. ASCII file containing relay element assertion timing

An Excel workbook was created to automatically assist in the analysis of the vast quantity of data captured by the RTDS. The workbook contains a Visual Basic® macro to import the ASCII files, conditionally format cells for quick viewing of results, and create graphs to illustrate the coordination and trip times of the relaying systems.

Two major categories of fault simulations were performed—those internal and external to the line under test. Fig. 12 shows an example of a worksheet for the internal fault relay response.



	A	B	C	D	E	F	G	H	I	J	K	L
1	CASE	POS	TYPE	POW	RTPAT	RTPBT	RTPCT	RRIT	RRCT	RZ1T	RZ2T	R67G2
2	MD1U_G_Floc5_90	Floc5_	_AG	0	0.02225	0	0	0.0222	0	0.0264	0.0097	0.0430
3	MD1U_G_Floc5_90	Floc5_	_AG	45	0.02041	0	0	0.0204	0	0.0246	0.0079	0.041
4	MD1U_G_Floc5_90	Floc5_	_AG	90	0.02041	0	0	0.0204	0	0.0246	0.01	0.045
41	MD2U_A_Floc5_90	Floc5_	ABG	0	0.01933	0.01933	0.01933	0	0.0193	0.0339	0.0068	0.046
42	MD2U_A_Floc5_90	Floc5_	ABG	45	0.01908	0.01908	0.01908	0	0.0191	0.0253	0.0128	0.0
43	MD2U_A_Floc5_90	Floc5_	ABG	90	0.02491	0.02491	0.02491	0	0.0249	0.0249	0.0124	0.041
44	MD2U_A_Floc5_90	Floc5_	BCG	0	0.02458	0.02458	0.02458	0	0.0246	0.0246	0.0121	0.043
45	MD2U_A_Floc5_90	Floc5_	BCG	45	0.02033	0.02033	0.02033	0	0.0203	0.0245	0.012	0.041
46	MD2U_A_Floc5_90	Floc5_	BCG	90	0.02008	0.02008	0.02008	0	0.0201	0.0221	0.0096	0.047

Fig. 12. Internal fault relay response worksheet

Fig. 12 displays the worksheet that includes the relay response times for faults at 10 percent of the line for all the operating scenarios that were considered. All internal faults should result in the relay providing a trip output. Conditionally formatted cells indicate relay tripping action (green) and nonaction (red). Because the relay trips single pole for internal single-line-to-ground-faults, the red cells indicate no tripping events for the nonfaulted phases. For internal faults, predictable color patterns appear in each worksheet for easy verification of proper relay action. At the bottom of each worksheet, several preconfigured graphs illustrate important data results. Fig. 13 displays two of these graphs. The top graph displays the relay operating time as a function of faulted phase(s), and the bottom graph is a histogram of Zone 1 operations. This particular histogram shows that four base cases were considered with 30 faults each. In total, there were 120 Zone 1 operations out of 120 faults at 10 percent of the line from the generator terminal.

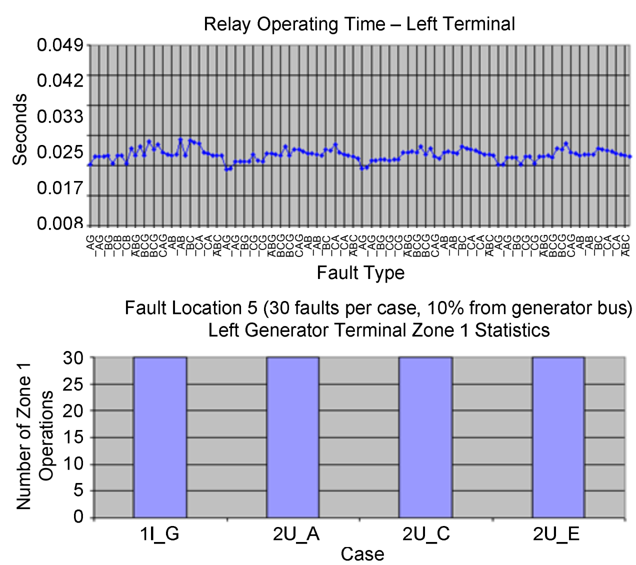


Fig. 13. Internal fault relay response graphs

Fig. 14 shows the internal fault summary worksheet, which gathers the results of the individual worksheets. The formulas in the worksheet calculate the results of the Zone 1 elements for each line terminal as a percentage of all faults simulated at each location. The histogram graph displays the effect of the right (West) terminal adjacent line series capacitors on the Zone 1 reach of the left (Generator Station) terminal. Combined together, it is clear that the Zone 1 elements provide overlapping high-speed line protection.

Summary of Internal Zero-Impedance Sliding Faults

Fault Location	Number of Cases Considered	Faults Per Case	Total Faults	Total Zone 1 Operations (Right Terminal)			Total Zone 1 Operations (Left Terminal)		
	#	#	#	% from West Bus	#	%	% from Gen Bus	#	%
Floc4	4	30	120	100%	0	0.00%	0%	119	99.17%
Floc5_10	4	30	120	90%	0	0.00%	10%	120	100.00%
Floc5_20	4	30	120	80%	118	98.33%	20%	120	100.00%
Floc5_30	4	30	120	70%	120	100.00%	30%	40	33.33%
Floc5_40	4	30	120	60%	120	100.00%	40%	0	0.00%
Floc5_50	4	30	120	50%	120	100.00%	50%	0	0.00%
Floc5_60	4	30	120	40%	120	100.00%	60%	0	0.00%
Floc5_70	4	30	120	30%	120	100.00%	70%	0	0.00%
Floc5_80	4	30	120	20%	120	100.00%	80%	0	0.00%
Floc5_90	4	30	120	10%	120	100.00%	90%	0	0.00%
Floc6	4	30	120	0%	120	100.00%	100%	0	0.00%
Total	N/A	N/A	**1320**	N/A	**1078**	N/A	N/A	**399**	N/A

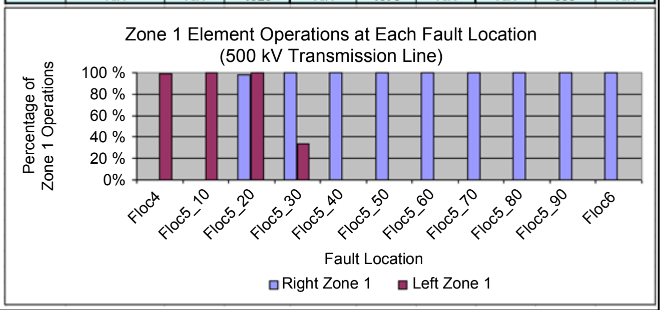


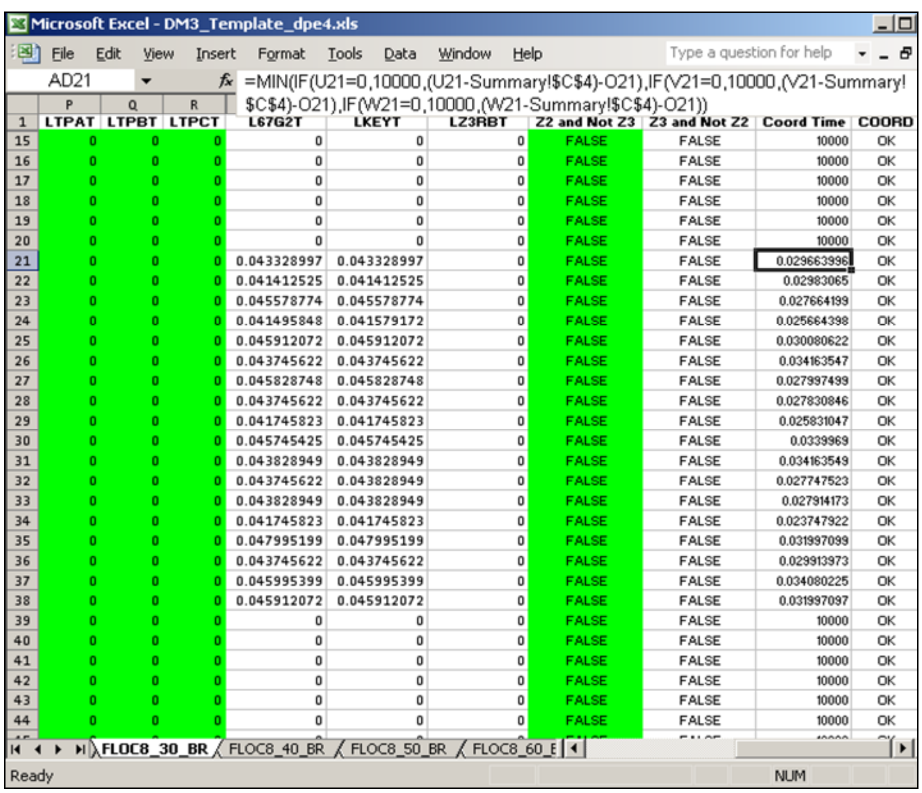
Fig. 14. Internal fault summary worksheet

The Excel workbook used for evaluating out-of-section faults is constructed similar to the one used for evaluating internal faults. Relay performance for faults behind the left (Generator Station) and right (West) terminals is evaluated. Along with verifying that no trip events occur, proper coordination of forward-overreaching elements and reverse-blocking elements is verified.

There is one worksheet per fault location. Within the worksheet, the columns contain formulas and conditionally formatted cells to automatically evaluate each fault for the following:

- Overreaching element assertion of one terminal without an assertion of the reverse-blocking element at the other terminal.
- Reverse-blocking element assertion without an assertion of the forward-overreaching element at the other terminal. (This condition is considered normal and gives the engineer quantifiable information to evaluate the relative sensitivity between the two terminals.)
- Calculation of the time difference to ensure proper coordination between the reverse-looking elements at one terminal and the forward-reaching elements at the other terminal.

Fig. 15 shows an example of the fault location data. The figure shows the conditionally formatted cells (green) that indicate there was no relay trip event, as well as a column that verifies there was no assertion of the overreaching elements of one terminal without the assertion of the blocking elements at the other terminal.


Microsoft Excel - DM3_Template_dpe4.xls

File Edit View Insert Format Tools Data Window Help

AD21 =MIN(IF(U21=0,10000,(U21-Summary!$C$4)-O21),IF(V21=0,10000,(V21-Summary!$C$4)-O21),IF(W21=0,10000,(W21-Summary!$C$4)-O21))

	P	Q	R							
1	LTPAT	LTPBT	LTPCT	L67G2T	LKEYT	LZ3RBT	Z2 and Not Z3	Z3 and Not Z2	Coord Time	COORD
15	0	0	0	0	0	0	FALSE	FALSE	10000	OK
16	0	0	0	0	0	0	FALSE	FALSE	10000	OK
17	0	0	0	0	0	0	FALSE	FALSE	10000	OK
18	0	0	0	0	0	0	FALSE	FALSE	10000	OK
19	0	0	0	0	0	0	FALSE	FALSE	10000	OK
20	0	0	0	0	0	0	FALSE	FALSE	10000	OK
21	0	0	0	0.043328997	0.043328997	0	FALSE	FALSE	0.029663996	OK
22	0	0	0	0.041412525	0.041412525	0	FALSE	FALSE	0.02983065	OK
23	0	0	0	0.045578774	0.045578774	0	FALSE	FALSE	0.027664199	OK
24	0	0	0	0.041495848	0.041579172	0	FALSE	FALSE	0.025664398	OK
25	0	0	0	0.045912072	0.045912072	0	FALSE	FALSE	0.030080622	OK
26	0	0	0	0.043745622	0.043745622	0	FALSE	FALSE	0.034163547	OK
27	0	0	0	0.045828748	0.045828748	0	FALSE	FALSE	0.027997499	OK
28	0	0	0	0.043745622	0.043745622	0	FALSE	FALSE	0.027830846	OK
29	0	0	0	0.041745823	0.041745823	0	FALSE	FALSE	0.025831047	OK
30	0	0	0	0.045745425	0.045745425	0	FALSE	FALSE	0.0339969	OK
31	0	0	0	0.043828949	0.043828949	0	FALSE	FALSE	0.034163549	OK
32	0	0	0	0.043745622	0.043828949	0	FALSE	FALSE	0.027747523	OK
33	0	0	0	0.043828949	0.043828949	0	FALSE	FALSE	0.027914173	OK
34	0	0	0	0.041745823	0.041745823	0	FALSE	FALSE	0.023747922	OK
35	0	0	0	0.047995199	0.047995199	0	FALSE	FALSE	0.031997099	OK
36	0	0	0	0.043745622	0.043745622	0	FALSE	FALSE	0.029913973	OK
37	0	0	0	0.045995399	0.045995399	0	FALSE	FALSE	0.034080225	OK
38	0	0	0	0.045912072	0.045912072	0	FALSE	FALSE	0.031997097	OK
39	0	0	0	0	0	0	FALSE	FALSE	10000	OK
40	0	0	0	0	0	0	FALSE	FALSE	10000	OK
41	0	0	0	0	0	0	FALSE	FALSE	10000	OK
42	0	0	0	0	0	0	FALSE	FALSE	10000	OK
43	0	0	0	0	0	0	FALSE	FALSE	10000	OK
44	0	0	0	0	0	0	FALSE	FALSE	10000	OK

FLOC8_30_BR / FLOC8_40_BR / FLOC8_50_BR / FLOC8_60_E

Ready NUM

Fig. 15. Fault location data

At the bottom of each worksheet, a graph plots the coordination time between the reverse-blocking elements and the overreaching permissive element. The coordination times are graphed as a function of the faulted phase, and the results look very similar to the graphs shown in Fig. 13.

Fig. 16 shows an example of the external fault summary worksheet, which compiles all of the information from each individual worksheet and displays a table of results.

	Several Cases (Behind Left Terminal)										
	FLOC 8 10%	FLOC 8 20%	FLOC 8 30%	FLOC 8 40%	FLOC 8 50%	FLOC 8 60%	FLOC 8 70%	FLOC 8 80%	FLOC 7 CI Right	FLOC 9 CI Left	TOTAL
1	30	30	30	30	60	60	60	60	60	30	450
2	0	0	0	0	0	0	0	0	0	0	0
3	0.02466	0.02758	0.0305	0.03133	0.01675	0.00283	0.003	0.00342	0.00042	0.02366	0.00042
4	2	12	12	12	23	23	37	30	0	2	153

	Several Cases (Behind Right Terminal)										
	FLOC 8 10%	FLOC 8 20%	FLOC 8 30%	FLOC 8 40%	FLOC 8 50%	FLOC 8 60%	FLOC 8 70%	FLOC 8 80%	FLOC 7 CI Left	FLOC 9 CI Right	TOTAL
1	90	90	90	90	60	60	60	60	60	90	750
2	0	0	0	0	0	0	0	0	0	0	0
3	0.00358	0.02375	0.02191	0.02375	0.02366	0.02183	0.022	0.01817	0.00175	0.00017	0.00017
4	27	19	13	13	4	2	1	0	0	0	79

Fig. 16. External fault summary worksheet

There are two tables in the summary worksheet. One table displays the results of the relays for faults behind the left (Generator Station) terminal, and the other table presents the results for faults behind the right (West) terminal. A column is created for each fault location, with four rows of data for each column. The rows represent the following data:

1. Number of faults at each location.
2. Conditionally formatted cell that counts the number of instances where the overreaching elements at one end of the line asserted and the reverse-blocking elements at the other end did not.
3. Minimum coordination time between the reverse-blocking elements at one end of the line and the remote overreaching elements at the other end.
4. Number of faults where the reverse-blocking elements asserted and the remote-end overreaching elements did not.

Automated methods for detecting undesirable relay actions are essential when working with the RTDS. Because scripted fault scenarios are generally performed during evening hours, it is important to quickly evaluate the relay performance each morning, prior to beginning subsequent testing scenarios. If a problem is detected that requires a modification of relay settings, an assessment needs to be performed to determine if previous tests need to be rerun.

VIII. Field Testing and Commissioning

To verify the adequacy of the design, relay settings, relay analog-to-digital conversion, and compatibility with the telecommunications infrastructure, it is essential to perform a small subset of tests in the field before the relays are placed in service. About 15 end-to-end, clock-synchronized tests were performed on each line using RTDS-derived COMTRADE files. Two seconds of prefault simulation data were added to the COMTRADE files to avoid LOP assertion.

IX. Conclusion

Presently, RTDS testing is the best available transient testing method to verify relay settings on 500 kV series-compensated systems. The testing helps improve the reliability of the protection systems and increase familiarity with the relays. It also provides greater insight into the power system and its behavior during faults.

Allow a minimum of one week per line for RTDS testing to perform all required tests, verify relay settings, and explore any possible problems. The testing should be carefully thought through to ensure all pertinent conditions are examined, maximize the number of runs, and minimize the number of repeats due to settings changes.

RTDS testing allows the relays to experience more faults than they would see in a lifetime of operation. Specific faults that have caused problems in the past can be fully explored to ensure the relays perform properly for that scenario. Faults that are expected to cause problems can also be fully examined. As an added bonus, the RTDS testing provides COMTRADE files that are available for field commissioning and routine time-scheduled, end-to-end, clock-synchronized tests. The RTDS model can also be used for future project work.

Transient testing of EHV series-compensated line protection relay systems has been part of the PG&E protection application philosophy for the last 25 years. Many relay performance improvements were realized during this time by working closely with relay manufacturers to test, identify certain shortcomings, and improve the performance of line protection systems.

X. References

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XI. 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 Pacific Gas and Electric Company system protection since 1999, primarily supporting 500 kV system projects and special protection schemes.

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 Pacific Gas and Electric Company system protection since 2003. Previously, she worked at Western Area Power Administration, FirstEnergy Corp., and Puget Sound Energy.

Rafael Pineda received his BSEE in 1990 from Cal Poly State University, San Luis Obispo. Rafael is a registered professional engineer in California and has been with Pacific Gas and Electric Company since 1991. He currently supports 500 kV system protection projects and special protection schemes. He is a member of the Western Electricity Coordinating Council (WECC) relay work group.

Demetrios A. Tziouvaras received his BSEE from the University of New Mexico and MSEE from Santa Clara University. He is an IEEE Senior Member and a member of the Power System Relaying Committee (PSRC) and CIGRE. He previously worked at Pacific Gas and Electric Company, where he held various protection engineering positions, including principal protection engineer for 18 years. In 1998, he joined Schweitzer Engineering Laboratories, Inc., where he currently holds the position of senior research engineer. He holds four patents and has authored and coauthored more than 50 technical papers. He served as the convener of CIGRE working group B5.15 on “Modern Distance Protection Functions and Applications” and is a member of several IEEE PSRC and CIGRE working groups.

Rick Turner received his BSEE from the University of New Mexico. He began his career at Public Service Company of New Mexico and worked for several electric utilities. He joined Schweitzer Engineering Laboratories, Inc. in 1997, where he has held several positions. He is currently a principal engineer in engineering services. He is a member of the IEEE and an active participant of the Power System Relaying Committee (PSRC). He is a registered professional engineer in the states of Washington and California.

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