Benefits of using IEC 61850 messages for testing conventional protection schemes

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Abstract

One of the most common questions posed when considering digital systems based on IEC 61850 technology is how to test protection elements and a digital system as a whole. Test provisions in IEC 61850 are plentiful and elaborate and are covered broadly in industry publications. This paper instead focuses on the ability to use IEC 61850 messages for testing conventional commonly deployed copper-based protection schemes. It discusses implementation and usage of this approach and summarizes its benefits.

1. Introduction

To verify a new design, protection scheme, or a new relay variant, protection engineers are challenged with running thousands of test cases. Typically, a real-time power system simulator, such as real-time digital simulator (RTDS) is used with the relays, connected as hardware in the loop to simulate various faults and power system conditions. This process takes an enormous amount of time and effort. For each of the thousands of test cases performed for line protection, fault records must be retrieved in COMTRADE format, from all line terminals, and time aligned for proper analysis.

Testing approach based on IEC 61850 messages instead of copper connections to test equipment simplifies the overall testing process, saves enormous amount of time, and eliminates the need for manual time alignment of the event records. These are valuable benefits for protection engineers and field technicians.

It should be noted that the method leverages the existing IEC 61850 technology to make relay testing more efficient. Numerous relay types and makes, constant shortage of staff, regular and emergency, sometimes simultaneous testing needs with added high time pressure are the key drivers for more efficient testing. A common test setup re-configurable without any time-consuming rewiring simply by changing Ethernet connections and loading new configuration files to the relays is a solution discussed in this paper.

This testing method has been used by BPA for several years for RTDS testing and commissioning testing of relays. BPA test setups and test cases for line protection and transformer protection are discussed in this paper to explain method's operation, challenges and benefits.

2. The concept of using IEC 61850 message to test conventional protection schemes

Let us start from clarifying that the test concept discussed in this paper does not introduce any new IEC 61850 features, but rather applies the IEC 61850 technology, as known today, to simplify and accelerate relay testing, while making it more detailed and efficient.

A general simplified diagram for conventional relay testing is shown on Figure 1. A conventional test set or power system simulators can be used. While not shown on the diagram for simplicity, various breaker simulators are also commonly used, including those using IEC 61850 messages.

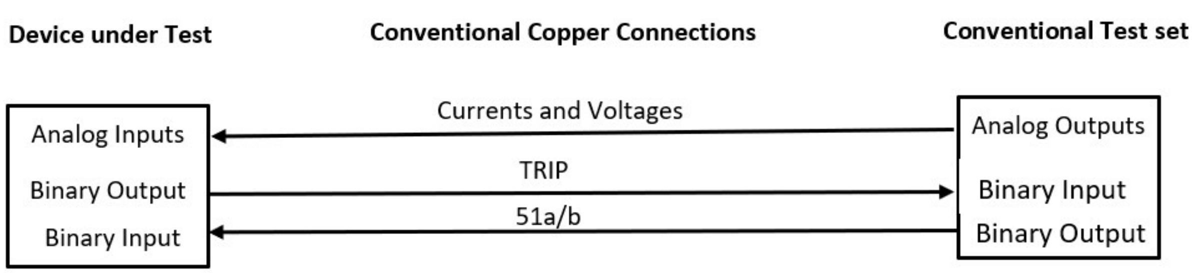

Figure 1. A general simplified diagram for conventional relay testing

The main idea of the IEC 61850-based testing is to replace the conventional copper connections by communication-based connections and provide signal exchange using IEC 61850 messages. As copper connections depend on hardware availability and generally take a long time to make, the use of communication-based signals instead offers simplification, more detailed data for analysis and a much-desired time savings among other benefits.

The first step in incorporating communication-based signal exchange is converting conventional copper binary signals to data points in IEC 61850 Generic Object-Oriented Substation Event (GOOSE) messages. In this step a single Ethernet-based connection replaces multiple copper connections for binary signals. In addition to simplified connectivity, very importantly, not only signals connected to the relay's hardware outputs, but internal relay logic signals can be shared as well. A conceptual diagram for this first step is shown on Figure 2.

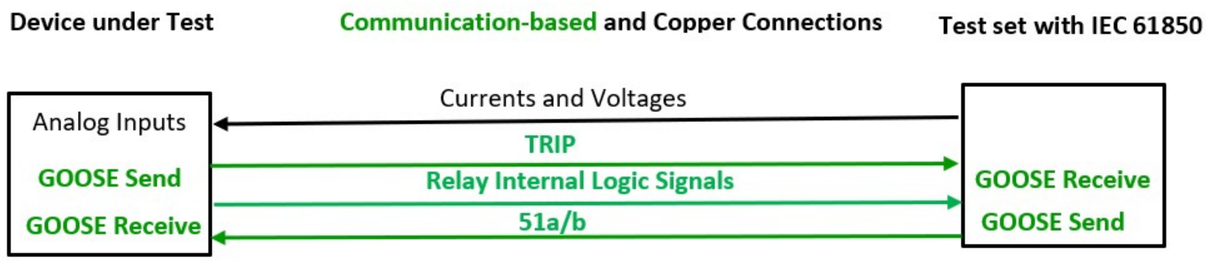

Figure 2. Converting binary signals to IEC 61850 GOOSE messages

The obvious requirements for this step are that both the relays and tests sets support IEC 61850 GOOSE messages and communication cables or network are available. All devices as well need to be configured correctly to exchange (or publish and subscribe in IEC 61850 terms) proper binary signals. Ethernet network with GOOSE message exchange is commonly referred to as IEC 61850 station bus. Once GOOSE communication is established, various tests can be performed for setup verification and main operation of the conventional protection schemes. Binary signals in GOOSE messages essentially replicate relay's hardware contacts and append internal relay logic signals to assist with analysis. As most relays available today support GOOSE message, they can be tested using GOOSE messages for binary signals and conventional copper connections for analog data.

To compare performance and timing of the binary signals (e.g. trip signals) sent over conventional copper wires with same signals communicated as bits in GOOSE messages various industry demonstrations and studies were performed. One testing and analysis done as a part of a multi-utility project conducted by Electric Power Research Institute (EPRI) showed that signals transmitted over a communication link are actually faster than those sent over copper wires. More details on this project can be found in [1].

Generally, GOOSE trip signals transmissions are expected to have an up to 3 millisecond transmission delay within a substation and up to 10 millisecond transmission delay between substations. The 3-millisecond delay is comparable with delays introduced by relay hardware output contacts themselves: some can operate in 1 millisecond while most operate in 4 milliseconds. So, in terms of operating speed, communication-based signals actually may be faster. The timing for hardware asserted trips will differ slightly from the timing for the same signals received in GOOSE messages. This difference was found to be marginal per the initial assessment done by Bonneville Power Administration to quality this testing concept.

A more important consideration is communication network availability and performance to provide a reliable and timely trip signals' delivery. To address this transmissions and processing of Layer 2 GOOSE messages should be prioritized over processing of other non-critical network traffic, if present. Lab testing can apply dedicated Ethernet switches that are not serving any other applications. Commonly, dedicated switches are used for GOOSE communication at IEC 61850 station bus level.

The second step in incorporating communication-based signal delivery is converting analog conventional copper connections to transmission of digital samples of measured currents and voltages using IEC 61850-9-2 sampled value (SV) technology. A diagram for this step is depicted on Figure 3.

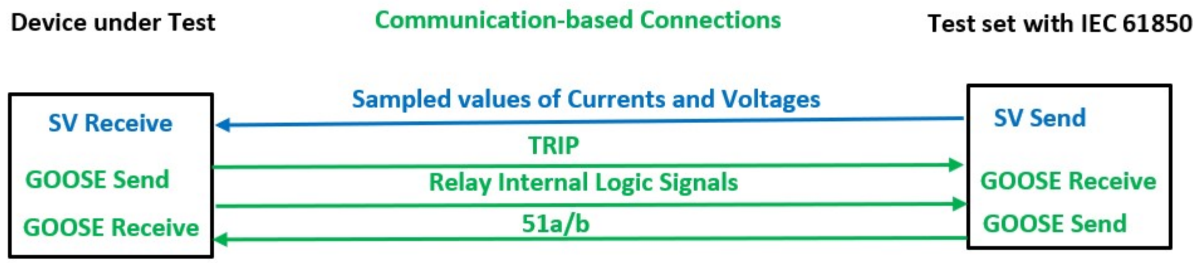

Figure 3. Converting analog signals to IEC 61850 SV messages

These sampled values transmissions as well use Ethernet-based communication and can be sent over the same communication ports as GOOSE messages. However, more often than not a separate communication network with dedicated Ethernet switches, commonly referred to as IEC 61850 process bus, is deployed. For this step the relays and test sets need to support IEC 61850-9-2 sampled values. The most common message format for a single SV stream contains 4 currents and 4 voltages (3 phases and 1 neutral each), as specified by the UCA IEC 61850-9-2 Light Edition (LE) Implementation Agreement [2]. Digital samples of analog measurements can be transmitted as 80 or 256 samples per power system cycle. Other frame structures and sample transmission rates are specified in newer IEC standards on dynamic merging unit behavior.

Both GOOSE and SV transmissions require available and reliable communication for data exchange. Like GOOSE, sampled values data is put into Layer 2 frames and their transmissions and processing can also be prioritized. It should be noted that, understandably, to transmit digital data samples of analog measurements SV streams requires much more network bandwidth. Each IEC 61850-9-2LE stream with 80 samples per power cycle sends continuous data at approximately 4Mbits/s, and each IEC 61850-9-2LE streams with 256 samples per power cycle sends continuous data at approximately 13Mbits/s.

In addition, SV data streams rely greatly on a very accurate samples synchronization, with accuracy down to ± 1 microsecond. For samples to be received correctly, SV senders (known as publishers) need to be synchronized with SV receivers (known as subscribers). No synchronization to the absolute time, such as Universal Time Coordinated (UTC) is necessary, only an accurate second transition at which sample count is zeroed is needed. Figure 4 shows the required synchronization between an SV sender and an SV receiver.

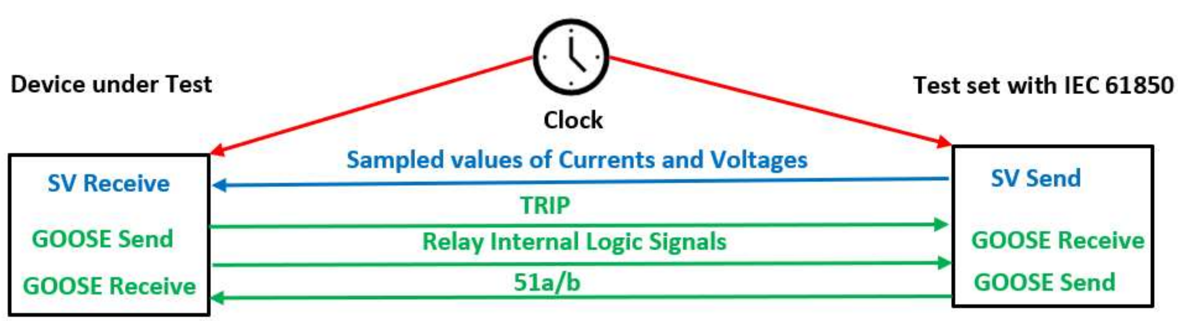

Figure 4. Samples synchronization concept between an SV sender and an SV receiver

The UCA IEC 61850-9-2LE Implementation Guideline [2] specifies a single time synchronization method: an optical 1 pulse per second (1PPS) signal. This is the only method used by all devices compliant to the IEC 61850-9-2LE specification. Other time synchronization methods of SV data exist, including an Ethernet-based time distribution using Precision Time Protocol (PTP). The use of base PTP profile for power industry applications, specified in joint development standard IEC/IEEE 61850-9-3, has been included as a synchronization method into newer IEC standards on dynamic merging unit behavior.

As multiple sampled values streams can be supported and transmitted over the same communication ports and networks (some relays can receive up to 8 SV streams), this ability dramatically increases testing capabilities. A diagram for relay testing with multiple SV stream transmissions is shown on Figure 5. As discussed later in this paper, a transformer differential protection with five (5) 3-phase current streams was tested using this method by Bonneville Power Administration (BPA). This would not have been possible using any conventional test gear!

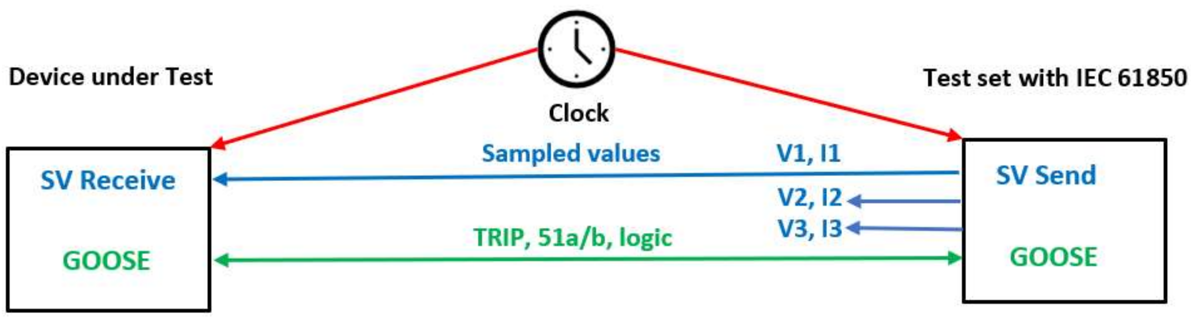

Figure 5. Relay lab testing with multiple SV streams, e.g. for transformer differential protection

Testing with multiple SV streams also enables line protection testing for multiple terminal lines. One SV stream can be sent to a relay configured to operate at line terminal 1, and another SV stream can be provided to the relay configured to operate at line terminal 2. Complete operation of line protection schemes can be fully tested in a single lab location, as discussed later in this paper. A communication channel simulator can be used to emulate channel delay and inject errors, if desired. A diagram for lab testing of 2-terminal line protection scheme is depicted on Figure 6.

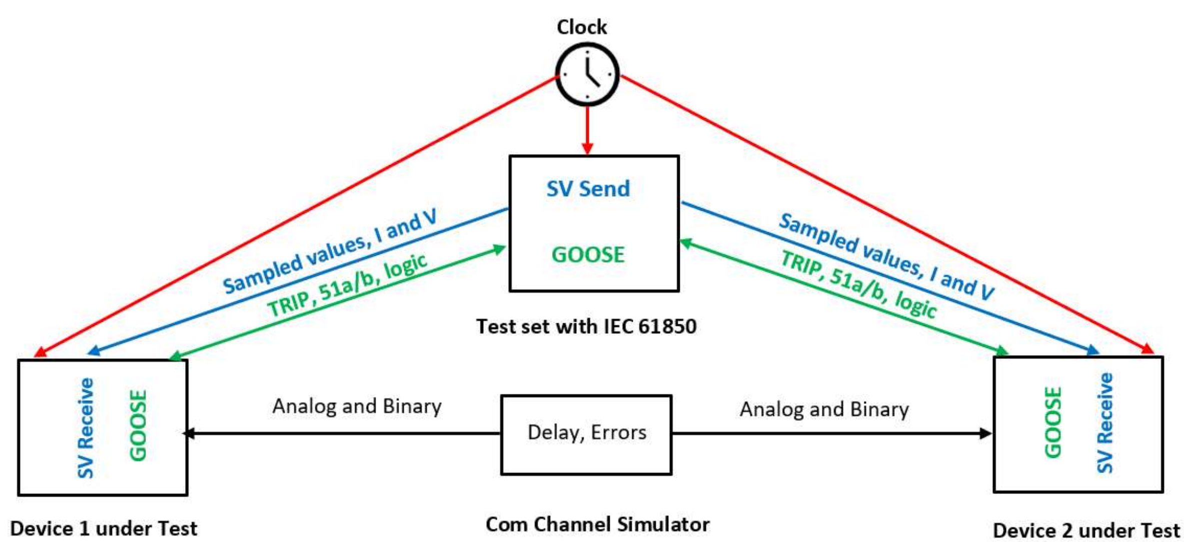

Figure 6. Relay lab testing with multiple SV streams, e.g. line current differential protection

It should be noted that the use of a single test set brings at least 2 advantages: (1) synchronized data transmissions for both line terminals, as these are produced by the same test equipment, and (2) a common display with signals from both terminals, this also eliminates the need for cumbersome time-alignment of multiple event records. Also note that synchronization to the absolute time, such as UTC, is not required, as long as all devices use the same common and accurate time base.

Now, let's consider if the discussed testing concept could be useful for field testing. For transformer protection testing the same setup as shown earlier on Figure 5 can be used at the stations in the same way as it is used in the lab. This brings little benefit as a new test setup will be required for each station.

For line differential protection testing where operation and personnel at each line end is expected, again, all copper signals can be replaced by communication-based signals, and a new test setup will be needed each time for each station. Figure 7 shows relay field testing example for 2-terminal line current differential protection testing. In this field testing case, a real communication channel is used instead of a simulated one, and clocks at both line terminals are synchronized to the same absolute time over a Global Navigation Satellite System (GNSS), such as Global Positioning System (GPS).

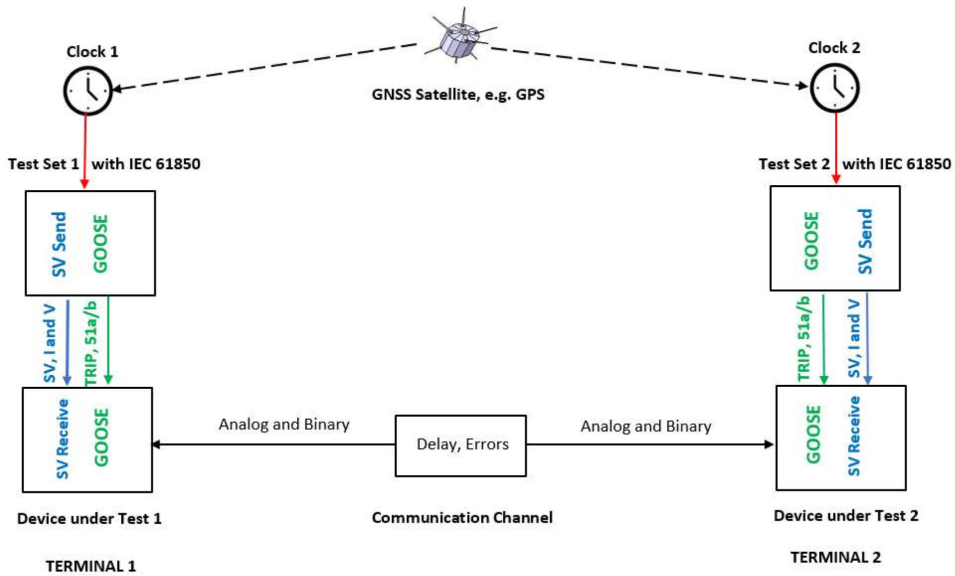

Figure 7. Relay field testing example for 2-terminal line protection

However, by considering a possibility of remote testing as a viable future option, one can identify a number of advantages for using an established lab test setup for remote relay testing in the field. A diagram depicting a remote relay testing idea for 2-terminal line protection is shown on Figure 8.

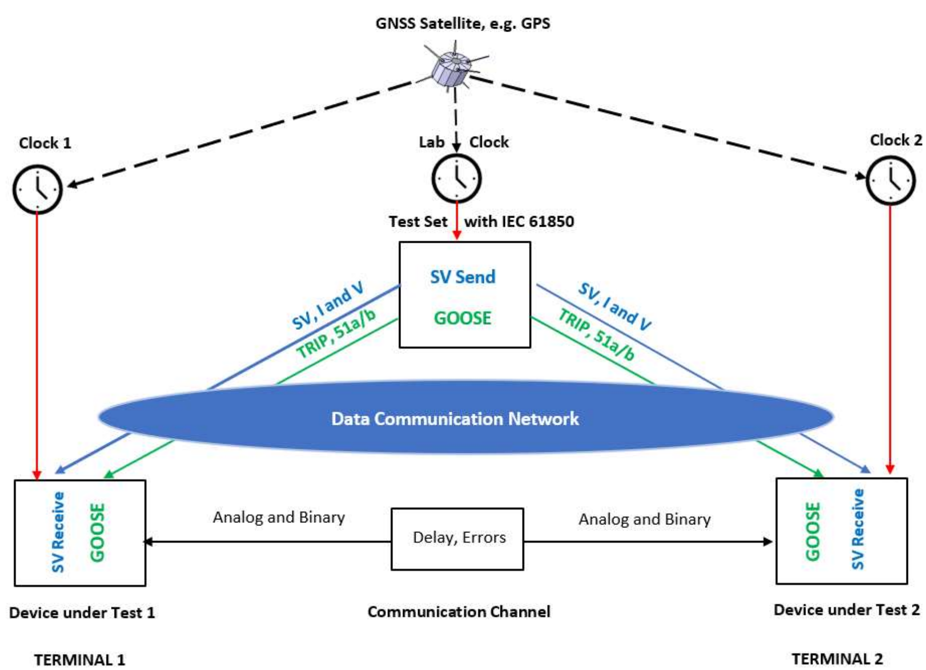

Figure 8. Remote relay testing idea for 2-terminal line protection

One can observe that possibilities of using this remote testing idea will depend highly on the availability and reliability of the communication network, preferably a dedicated network or dedicated bandwidth, between the lab location and the stations. If an available and reliable network would be available, the use of the same testing concept can be expanded beyond the lab use to the field over the whole power system, while keeping all the advantages of the reconfigurable test setup with test gear in the lab and devices under test in the field.

Let's back to the first initial step that is to replace conventional copper connections with communication-based signal exchange. One can imagine how much time it takes to re-wire relay terminals, reconnect a test gear, and compare it with time needed to re-connect (plug or un-plug) Ethernet cables. Figure 9 shows provides pictures of both hardwire relay terminals and communication ports for reader's reference. While an optical port with ST connector is shown on the picture below, other types, such as LC connectors (un) pluggable even faster can be used.

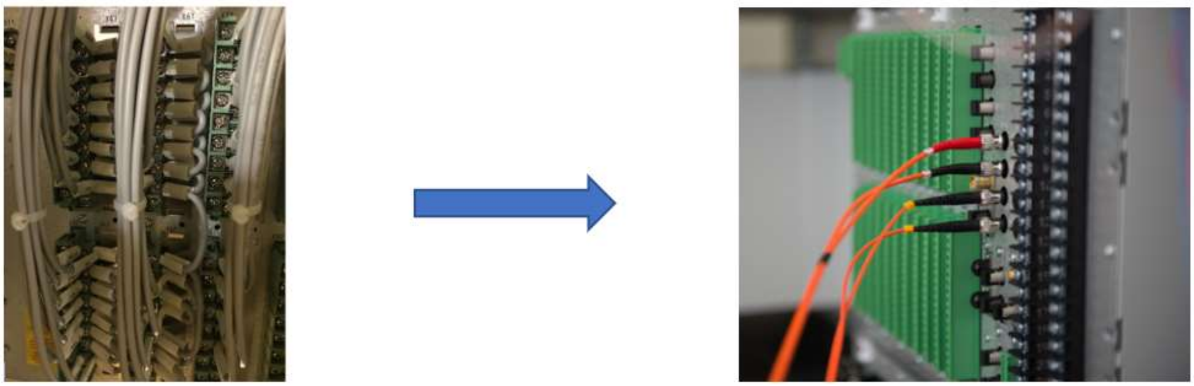

Figure 9. Replacement of conventional copper wires by optical Ethernet connections

In addition to reconnecting communication ports relays and test equipment need to be (re) configured properly for a given test. Communication and synchronization also have to be established for reliable operation and testing. These actions replace all the steps required for a conventional test setup.

The next session shares how the described testing concept has been applied by Bonneville Power Administration's for relay RTDS testing in their laboratory. The paper continues with BPA testing results, lessons learned and plans for further applications of this testing approach.

3. Relay RTDS testing at BPA's laboratory

Bonneville Power Administration (BPA) uses RTDS testing for complicated protection applications in the power system. Descriptions of BPA power system and protection use could be found in industry publications. Line protection details can be found in [3]. Transformer protection details are summarized in [4].

Main test setup used with IEC 61850 GOOSE messages is shown on Figure 10.

The three main steps of this testing method are:

(1) setting the relays at all line terminals to publish time-synchronized GOOSE messages with digital signals of interest (trips, permissive, alarms, and internal logic), and to subscribe to RTDS simulation signals (breaker position and reclose enable),

(2) configuring the RTDS to subscribe to GOOSE messages published by the relays, and to publish GOOSE messages with breaker position and reclose enable

(3) generating a single time aligned COMTRADE file.

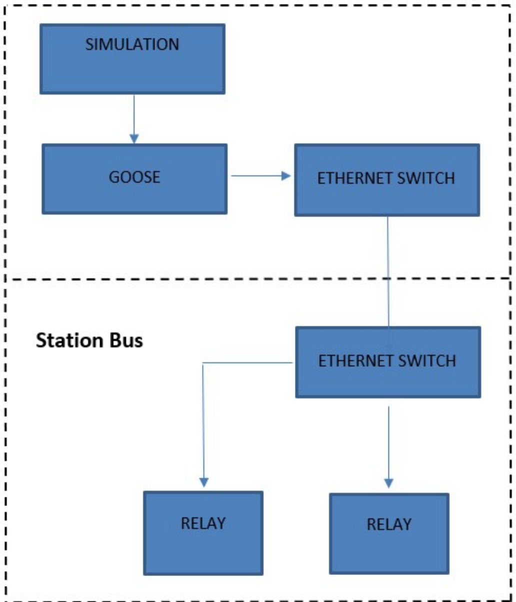

Figure 10. Test setup with GOOSE messages

It should be noted that GOOSE messages not only allow sending of relay hardware binary input/output signals without wiring them to RTDS, but also provide visibility of the internal relay logic signals that are most valuable when resolving operational issues with specific protection elements and settings. Thus, this method is also highly useful for re-creating and resolving operational issues expeditiously.

Initially, analog signals were injected conventionally via copper connections, but as testing and confidence level progressed, these physical copper connections were replaced with IEC 61850-9-2 Sampled Value (SV) streams. Moving to sampled value streams opened yet other testing horizon: 5 streams, i.e. 5 3-phase currents and 5 3-phase voltages, were successfully generated and used for transformer protection testing. This would have been a rigorous requirement for most conventional test gear. Test setup with sampled values is shown on Figure 11, it includes communication and time synchronization.

RTDS was used for power system simulation, GOOSE and SV publishing/subscription and event analysis. RTDS test setups are shown on Figure 12 and 13.

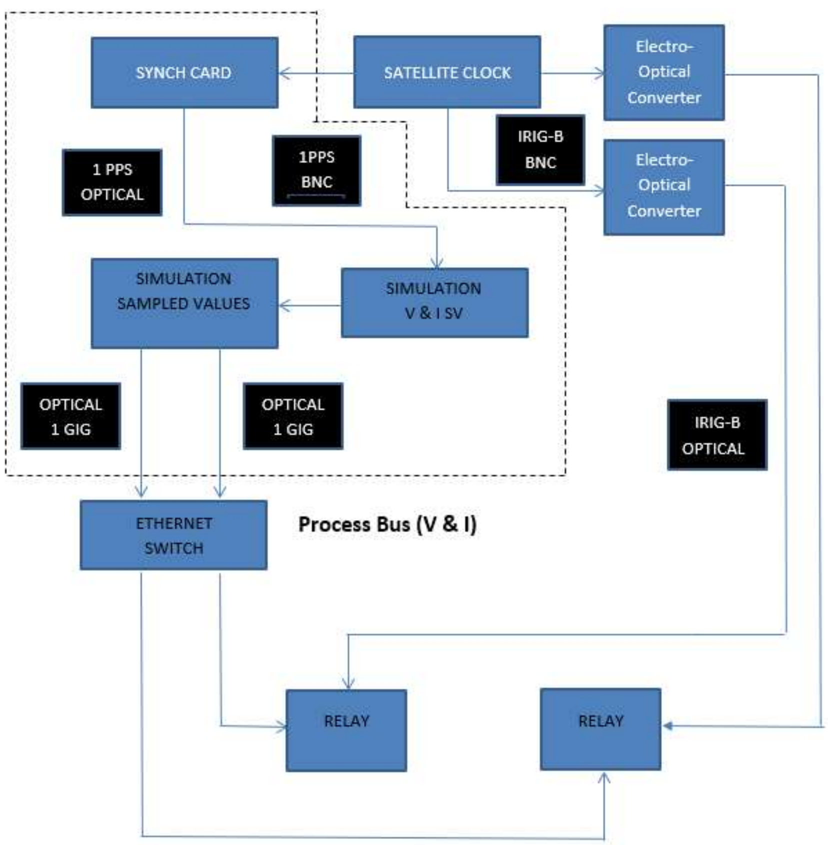

Figure 11. Test setup with sample values, including communication and time synchronization

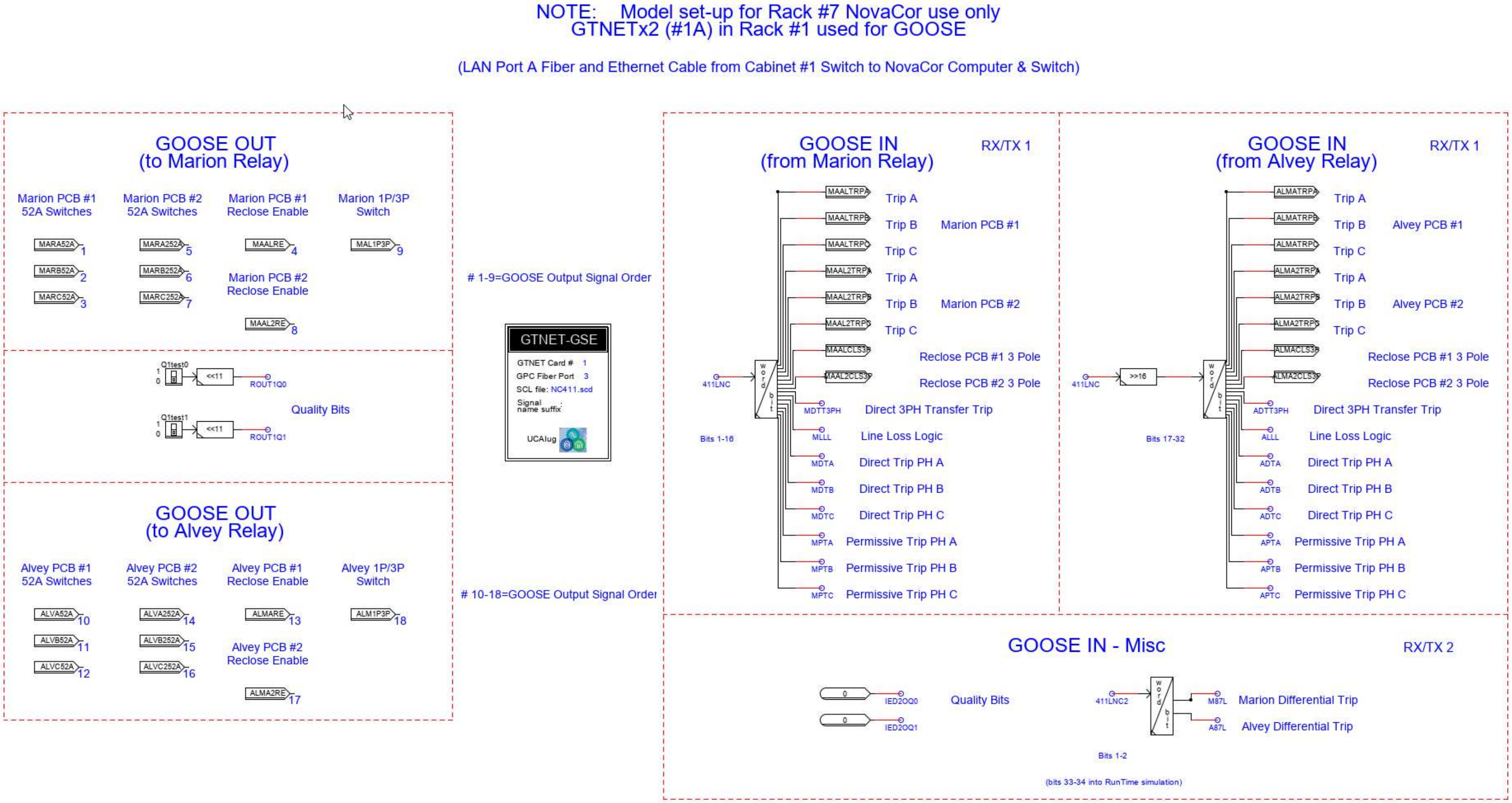

Figure 12. RTDS test setup with IEC 61850 GOOSE messages

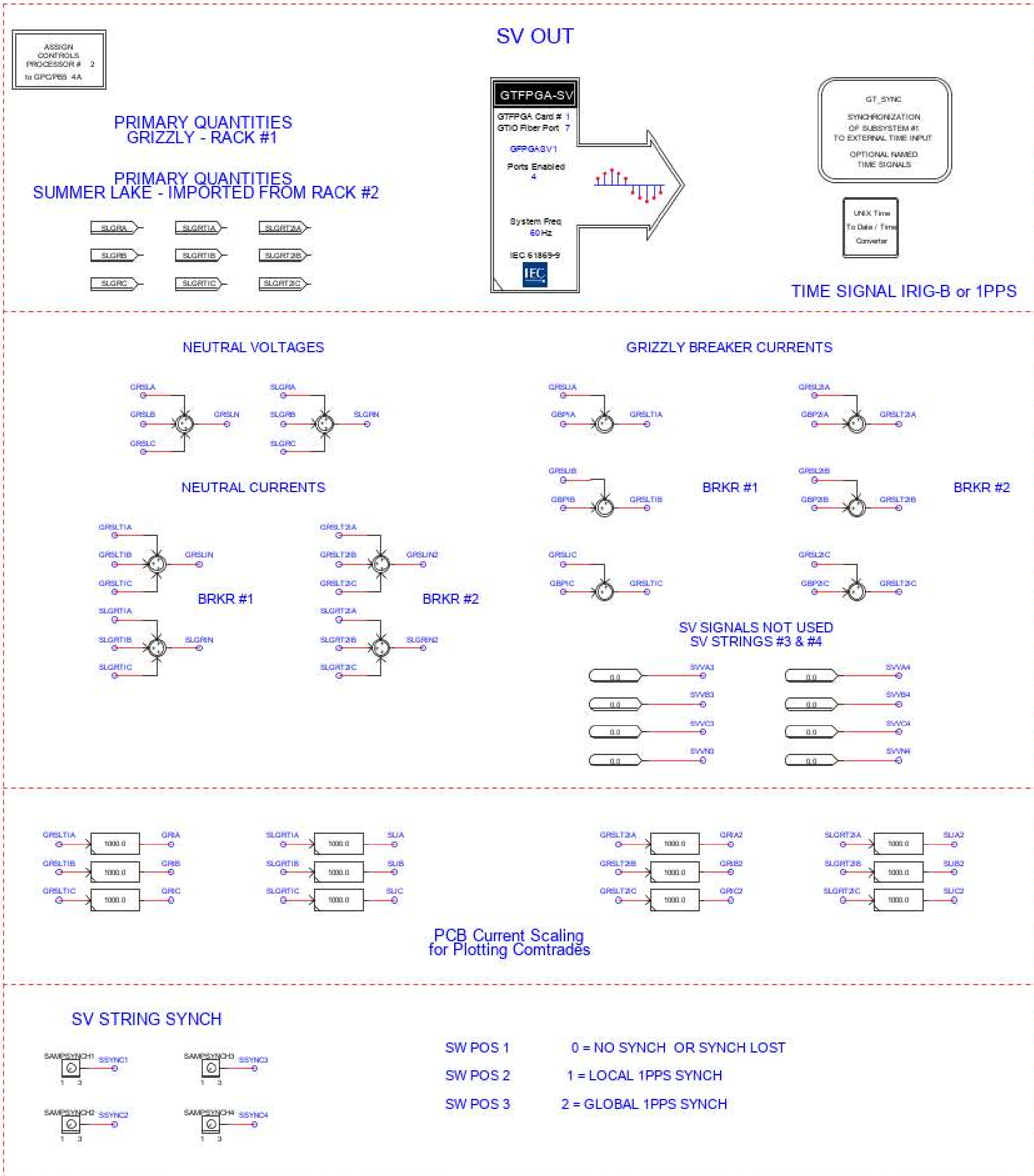

Figure 13. RTDS test setup with sampled values

BPA’s laboratory with RTDS test setup is depicted on Figure 14, RTDS and relay racks are shown.

Figure 14. BPA’s laboratory with RTDS test setup

Dedicated Ethernet switches for IEC 61850 station and process bus connectivity are shown on Figure 15.

Figure 15. Station bus and Process bus connectivity

Clocks and communication channel simulator installed in the BPA’s laboratory are pictured on Figure 16. Interestingly, an optical 1PPS synchronization was augmented by optical IRIG-B interface that brings both the precise UTC second transitions as well as the actual time information in frames transmitted once a second. Communication channel emulator mostly provided channel latency for the RTDS tests performed.

Figure 16. Laboratory clocks and com channel simulator

One of the benefits of the proposed and used test method is that all injected AC signals and received digital signals can be shown on the same RTDS plot in an oscilloscope-like view and in high resolution for analysis. RTDS screens and a screen capture of an RTDS plot are shown on Figure 17.

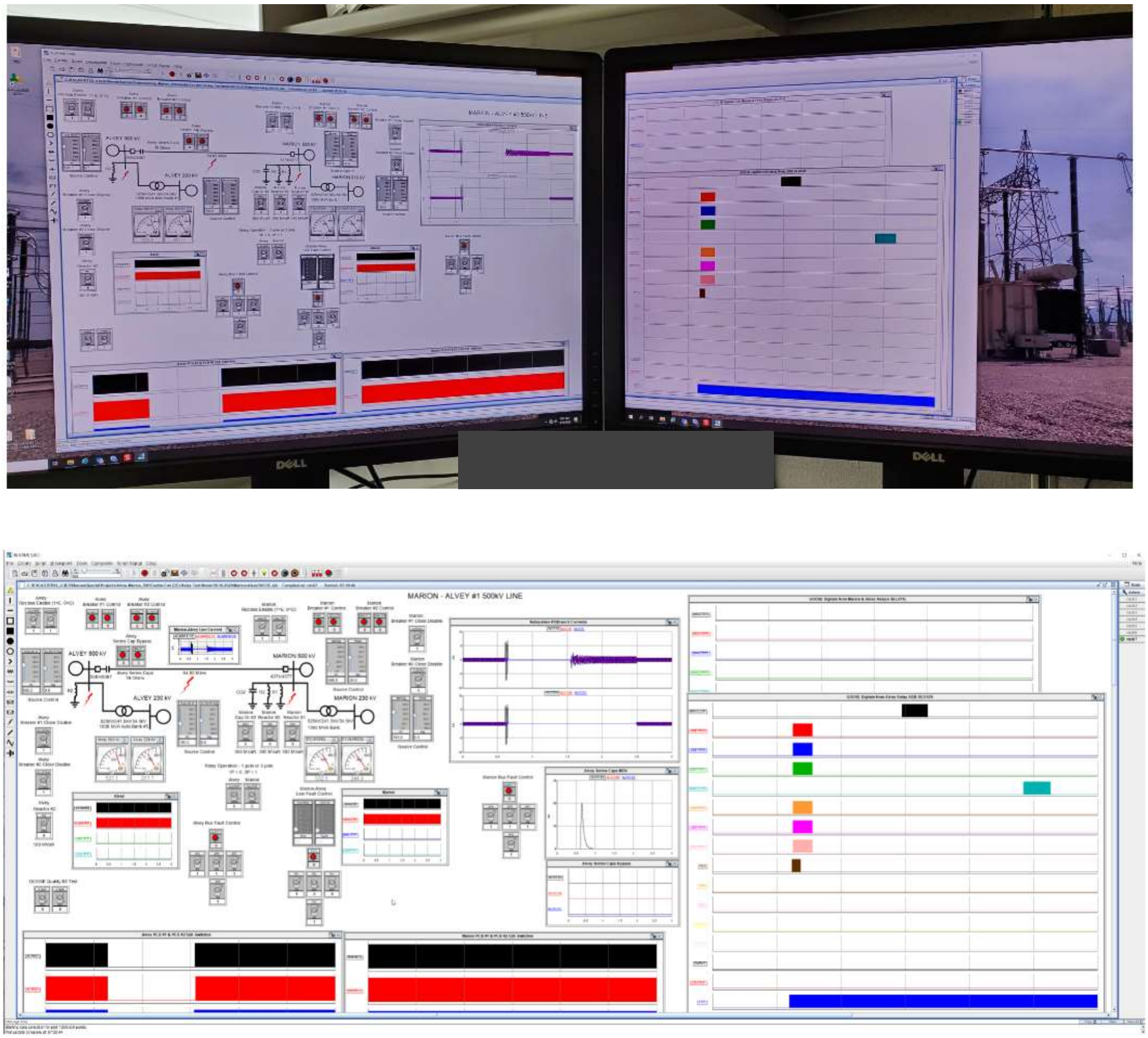

Figure 17. RTDS screens and a screen capture of an RTDS plot

These plots, also called an RTDS Human Machine Interface (HMI), are used in the next session that describes line protection and transformer protection testing.

4. BPA testing and results

Six test cases are included below to illustrate the use of testing method and obtained results. Test cases include three line protection faults, two transformer protection faults and one line protection commissioning test. All have shown numerous benefits of this testing method and led to various learnings.

A. Line protection testing

Single pole protection schemes, particularly on BPA 500kV series compensated intertie lines provide some of our greatest protection challenges. The protection schemes are comprised of single pole line differential relays that are operating in parallel with single pole distance relays. These relays must operate for all internal faults, but they must also be secure from mis–operations during fault clearing on adjacent lines and buses. Line differential relays are very good. For the most part they do not operate on load, system swings, and for sub-harmonic oscillations. The problem with line differentials is that they do not provide backup protection for out of zone relays, and that they need to cut themselves out of service for failures such as for time sync errors and for communications failures. Line differential relays need to have backup protection that remains in service when the differential cuts itself out. Single pole distance relays are part of the overall protection scheme. The distance relays operate in parallel with the line differential relays and remain in service at all times, even without communications.

The distance protection is comprised of single pole zone 1 elements, phase segregated permissive tripping elements, single pole direct tripping, and backup three pole direct tripping. The phase segregated permissive elements are instantaneous over-reaching elements that are set for permissive tripping. Each phase keys a permissive signal. Single pole permissive tripping occurs when one phase detects a fault, keys a permissive signal to the associated phase at the remote terminal. The faulted phase will trip when a permissive signal for the faulted phase is received from the remote terminal. Echo back tripping is enabled. Echo back tripping returns received permissive signal back to the sending terminal when a weak source terminal does not detect the fault. This prevents a weak terminal from blocking proper single pole tripping if the remote terminal properly detects the fault. The remote terminal will trip single pole when the permissive signal is received and it will send a direct trip for the faulted phase to the weak terminal, which trips single pole. The line will then reclose as normal. The goal is to minimize to the greatest extent backup three pole tripping that de-energizes the line and blocks reclosing when the relays can be set to operate single pole with reclosing.

Example 1: Mid-line phase to ground fault.

This series of tests is for an upgrade to the distance elements to improve the performance of the standalone distance protection. A permissive transient detector was added in parallel to the standard permissive distance elements. This element does not operate on load, system swings, or for subharmonic oscillations, and can be given more sensitive settings than the distance relay blinders. The transient detector also operates faster than the distance elements. This element required a complete series of fault tests. The relay must operate properly for all types of faults at various locations; internal faults, external faults, and for faults on parallel lines. Three load levels were run; light load, medium load (normal load), and heavy load. All fault combinations were run; AG, BG, CG, AB, BC, CA, and 3G.

When one considers the total number of faults that needed to be run for this element the number is very large. Knowledge in real time when any fault had a mis-operation can save considerable time during testing. The RTDS was set up to give a real time display. The RTDS has COMTRADE plot capture capability so any fault can be quickly saved when needed. In the future this real time capability can be extended to automated analysis, but initially an efficient manual way was used to identify problems in real time without running 100 faults only to realize that fault #4 had a problem.

The RTDS plot was set up to monitor line currents and voltages at both ends of the line, the distance element starters (permissive send) at both ends of the line, the received permissive signals at both ends of the line, the single pole trip signals at both terminals, and the differential trip signals. The operation of the distance relay was compared to the operation of the line differential to be sure it will operate properly when the line differential has an issue and disables itself. The RTDS plot also allows for both terminals to be compared in the same display. The elements are expected to operate properly for each fault, but they also must operate in the expected times. These comparisons are directly made on the plot.

The Example 1 fault is a typical mid-line A phase to ground fault with successful reclosing. This event indicates proper permissive operation at both terminals. The starters at both terminals picked up and keyed permissive signals to the remote terminals. When the signals are received these elements would have tripped. The differential element actually tripped first for this fault.

Mid Line AG

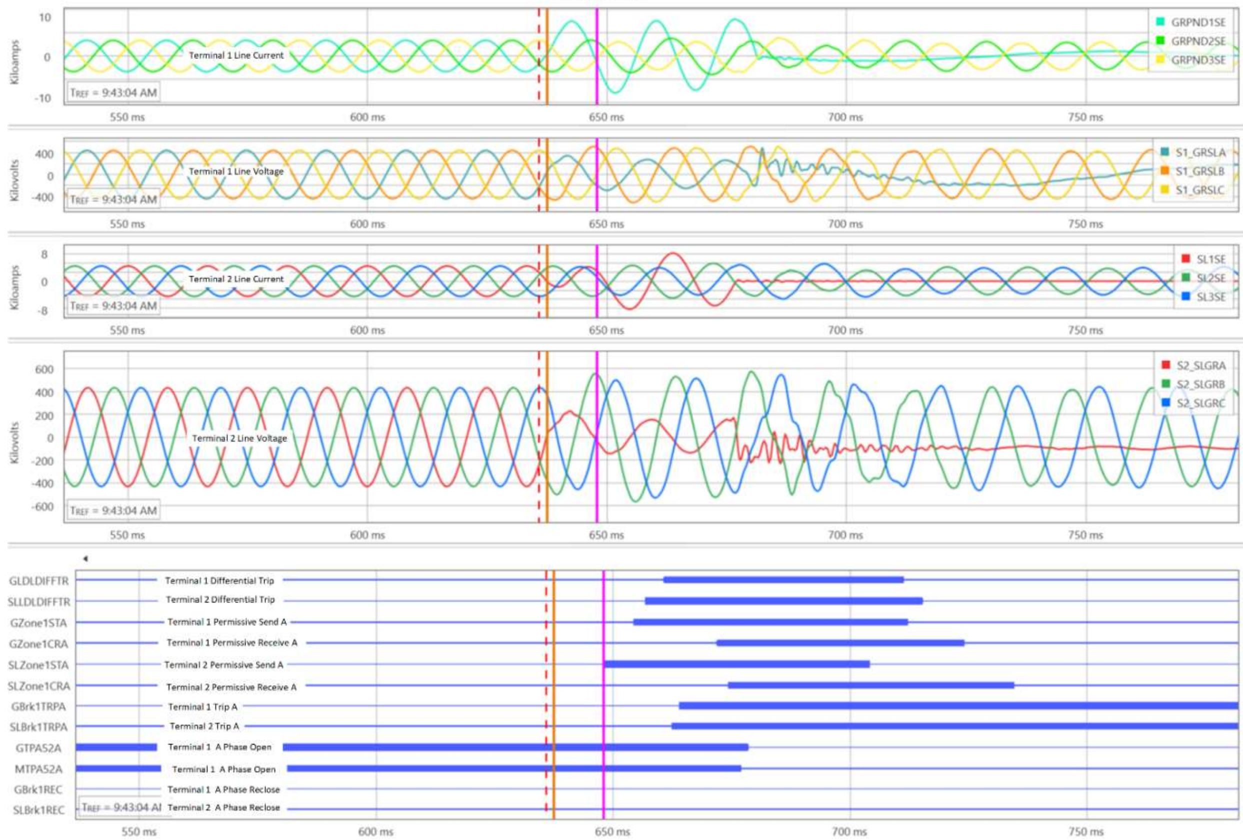

Figure 18. RTDS HMI plot for the midline phase to ground fault, Example 1.

Example 2: Mid-line phase to ground fault with 300-ohm fault impedance.

Line differential relays can have very sensitive settings and can operate properly for ground faults with considerable fault resistance. Ground distance relays on the other hand are limited by the blinder settings. To overcome this problem the addition of the transient detectors can allow for more ground resistance coverage when the differential relay is cut out.

The Example 2 fault is a mid-line fault with 300 ohms of ground resistance. This fault resistance is near the limit of the transient detector sensitivity with BPA settings. This transient detector has two limits: minimum current change and minimum voltage change. It is expected that the strong source terminal will reach its minimum voltage change as the fault resistance increases and the weak source terminal will reach its minimum current change as the fault resistance changes. This test will determine which happens first. It can be seen that the strong source receives its permissive signal before it transmitted a permissive signal. This is an echo back at the strong source. The distance relay at the strong source did not operate for this event. The weak source relay properly detected the fault and sent its permissive signal. Notice also that the differential relay operated properly. It can be concluded that the distance relay can operate properly for ground fault resistances up to about 300 ohms when the differential is not available. The differential will operate for ground fault resistances exceeding 400 ohms with BPA current settings.

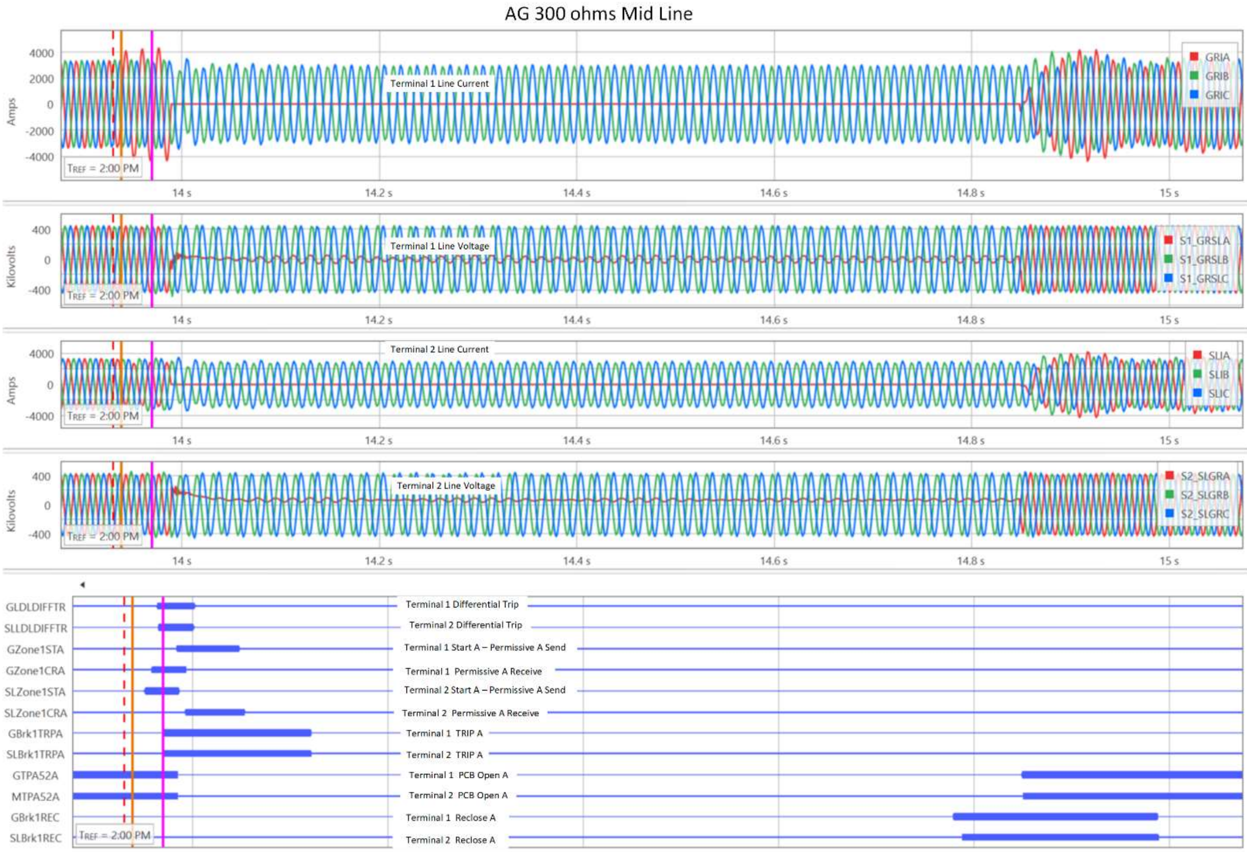

Figure 19. RTDS HMI plot for midline phase to ground fault with 300 Ohm fault impedance, Example 2.

Example 3: 3-Phase Bus Fault

A line protection relay will have relatively low magnitude fault currents for a fault on a substation bus that is essentially a line end fault with the terminal closed. On other hand if the fault is moved to the line side of the breaker the fault current magnitudes will approach the magnitude of a bus fault. This wide fault current range is time consuming for current amplifiers if current ranges need to be changed. The relay under test has sampled values capability and was tested using sampled values. This is a case where we needed to change amplifier ranges as we moved the fault from one side of the breaker to the other. Switching to sampled values corrected this problem.

The below bus fault was a proper operation of the phase segregated permissive tripping logic. The remote terminal detected the fault as a forward fault and keyed permissive on the faulted phases. The local terminal received the permissive signals but did not trip because the fault was a reverse fault.

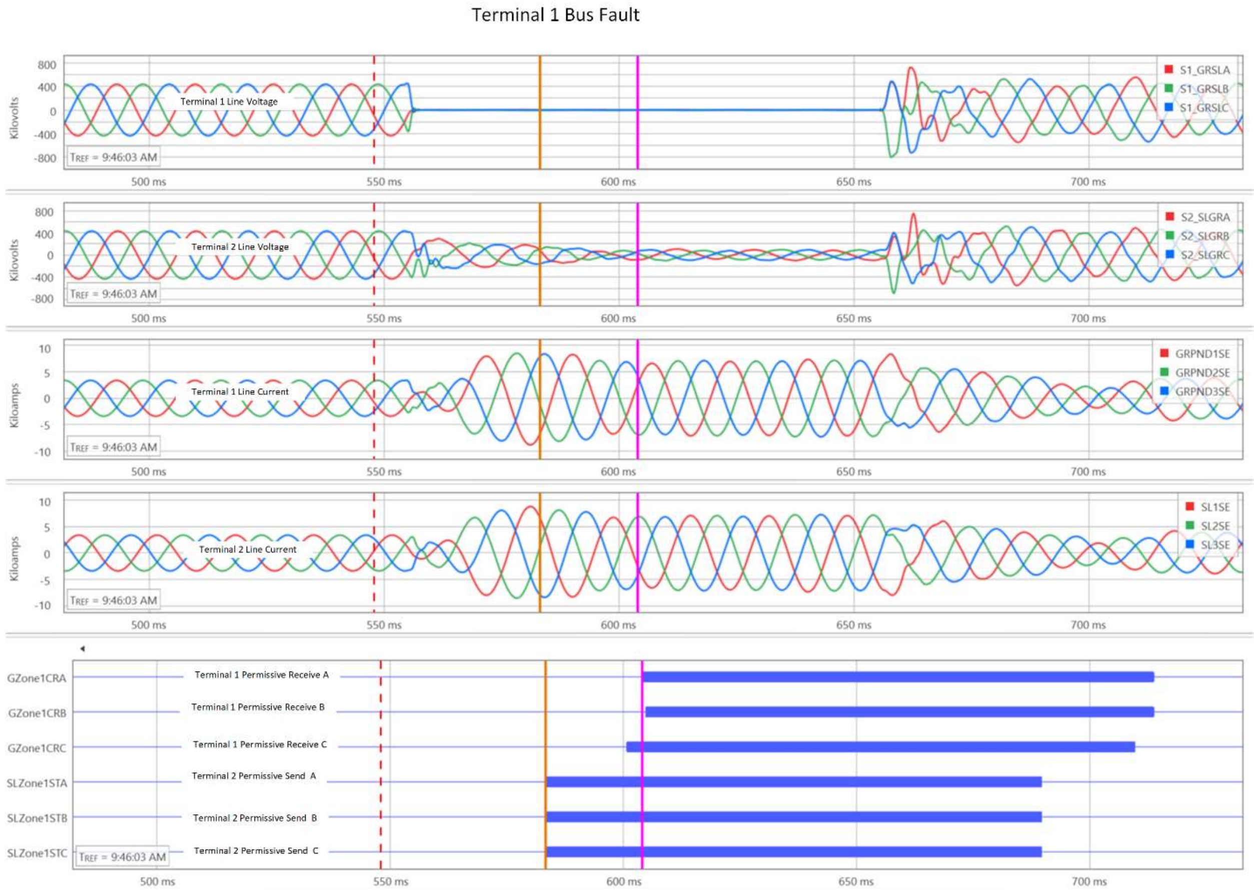

Figure 20. RTDS HMI plot for the 3-phase bus fault, Example 3.

B. Transformer protection testing

Many larger MVA rated transformers in BPA are comprised of three single phase auto banks with a tertiary winding that is bussed as a delta. These transformers are installed in ring buses, 1 ½ breaker buses, main bus / auxiliary bus arrangements, or any combination. The bus differential zone of protection is often from the high side breakers to the low side breakers. This arrangement will protect all of the bus work to the breakers, but it will also overlap the bushings such that a bushing failure will not damage or bypass a CT and cause a protection problem. The bus differential relay therefore needs to accommodate current inputs for up to 5 breakers plus a neutral CT. It also needs to trip up to 5 breakers plus an LOR. On transformer terminated lines it also needs to send a trip to the remote terminal. The bus differential relay has inputs for primary and secondary side potentials for the voltage-based elements and for metering, and it has a zero-sequence voltage input for delta tertiary ground fault protection.

The transformer differential relay under test has up to 8 merging unit inputs, each with four voltages and four currents. The relay is using 16 currents and 7 voltages. These AC quantities were assigned to 5 merging unit inputs. The RTDS test AC quantities were assigned to 5 associated merging units. A very large mass of wires, amplifiers, and D/A converters were replaced with a pair of optical fibers.

Microprocessor-based relays are very flexible. That adds detail to the settings, which increases the possibility of human error. The RTDS model was set up to test settings for the larger, more complex applications that have auto banks with delta tertiary windings. The model can apply internal and external faults including turn to turn faults and turn to ground faults. Buses and breakers are also modeled.

This group of tests was set up to test settings and the operation of the main differential protection with different winding configuration settings, clock number settings, zero sequence current subtraction filters, and test the restricted earth fault (REF) element.

For internal faults the main or restrained differential element is often initially blocked by the harmonic blocking elements. Even though the differential usually picks up very quickly, tripping is blocked until the harmonic blocking elements drop out. The restricted earth fault element does not need harmonic blocking and can therefore output a faster trip. The following example depicts this operation. The REF element tripped significantly faster than the restrained differential.

BPA has been actively updating older circuit breakers for some time. With the newer, faster breakers BPA has been able to significantly reduce the number of catastrophic tank failures for transformer internal faults. Transformer and shunt reactor differential relays must operate as fast as possible to allow the breakers to trip in time to prevent tank ruptures and fires when internal faults occur.

These example faults were from a battery of tests that had two goals. On our more complicated transformers we were having settings questions for various winding and CT configurations. Microprocessor based relays perform internal calculations for specific configurations. Deviations from the internal relay expected configurations in an actual application can cause confusion. One setting question, for example involved differences in winding configuration settings and phase shift settings for current transformers that are located inside of a delta winding compared to settings for the same winding when the CTs are located outside of the delta. These same applications also cause confusion when applying zero sequence current subtraction. We used these results to verify and update our setting criteria for these special cases. We were also tracking the performance of the differential elements and the restricted earth fault element.

Example 4: Internal fault

This internal fault shows the improvement in the differential trip time when the REF element trips without harmonic supervision. Lots of tests were performed to make sure the REF element settings are correct (i.e. not too sensitive) and the element does not mis-operate.

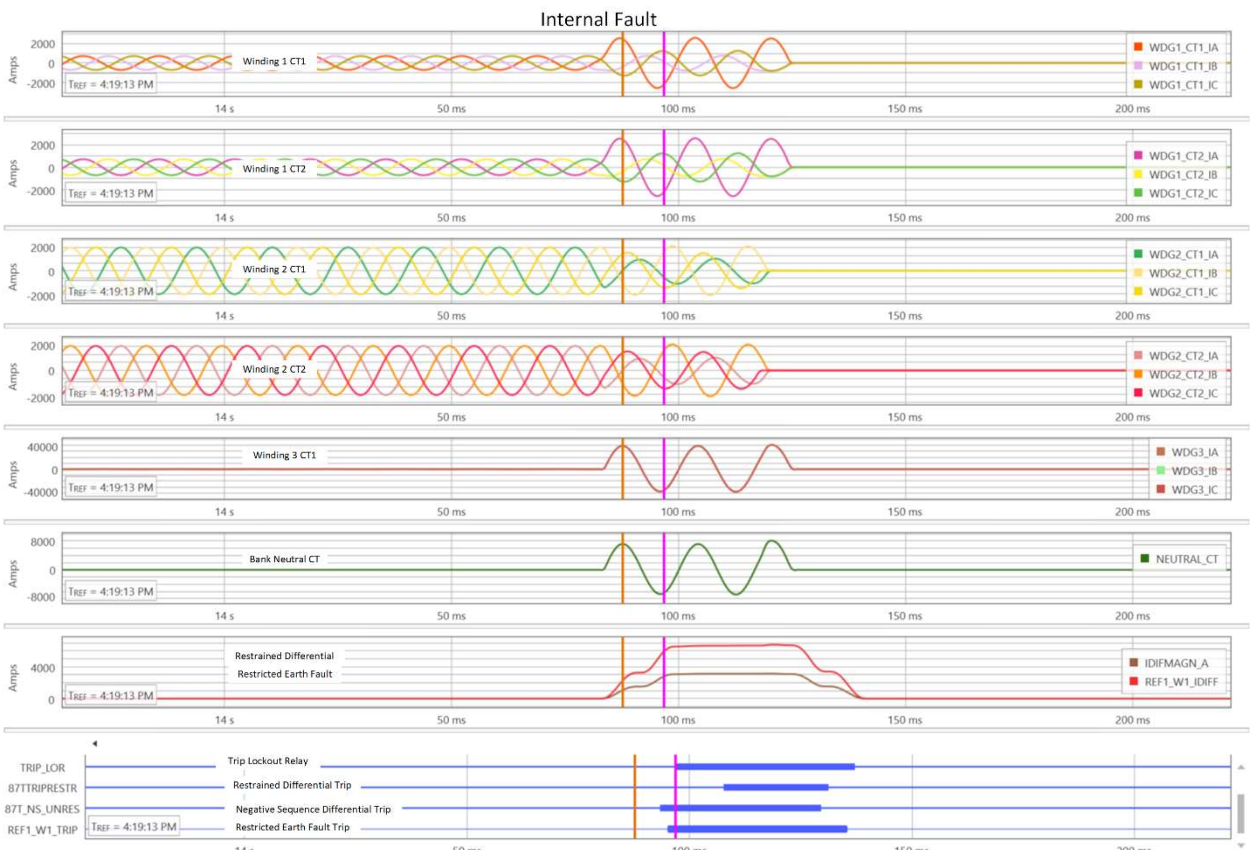

Figure 21. Fault record for the transformer internal fault, Example 4.

Example 5: External Fault

The relay must be secure from mis-operation during external faults. In this case it can be seen that a backup over current relay picked up and started a timer. The bottom traces show that the restrained differential elements summed to a very low value while the REF differential summed to zero. This is a correct operation for an external fault.

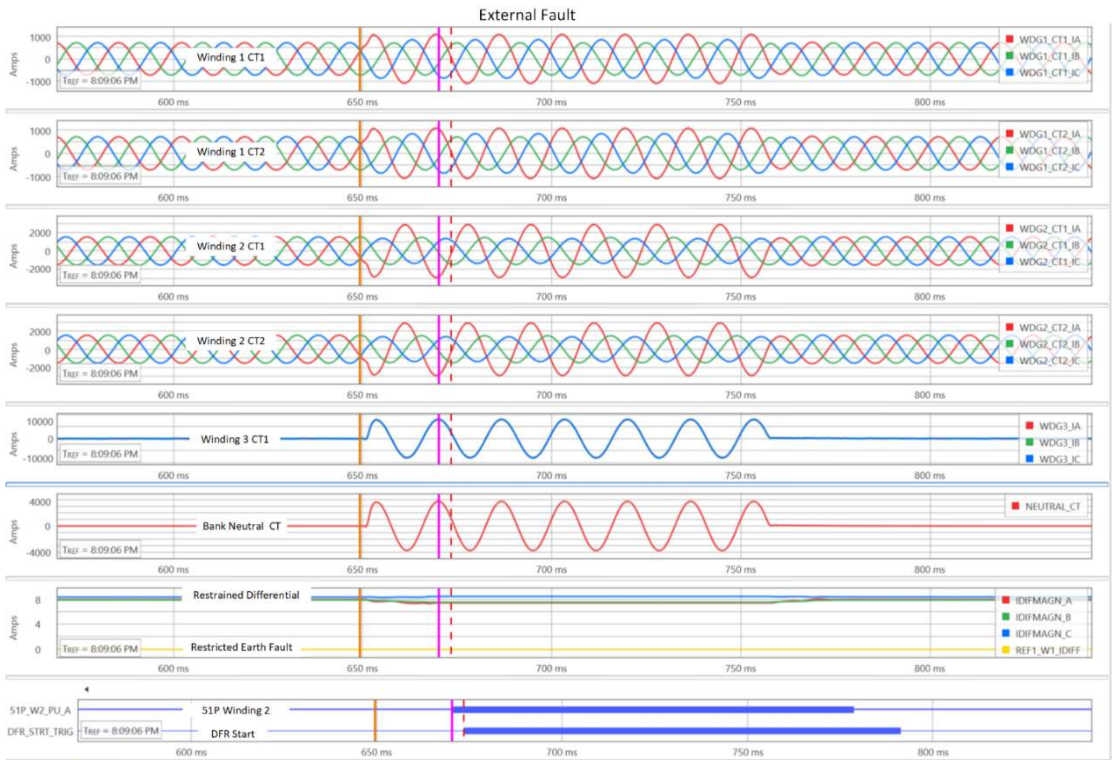

Figure 22. Fault record for the transformer external fault, Example 5.

C. Commissioning Test

This Example 6 shown on Figure 23 is from two operational logic issues that were discovered in the field during commissioning tests of two 500kV line relays.

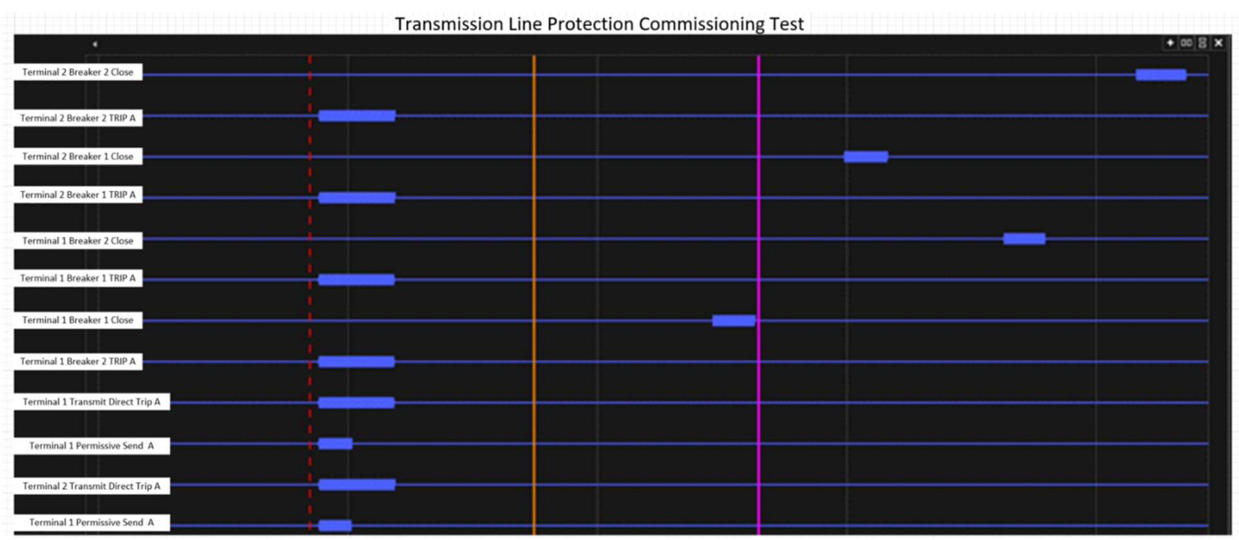

Figure 23. RTDS HMI plot for the transmission line protection commissioning test, Example 6.

Commissioning testing is end-to-end testing. During commissioning tests faults at specific locations are played into the relays and specific outputs are recorded in the test record. Trip outputs, communications output bits (direct trip send and permissive send), reclose commands, backup remote trip transmit, and remedial action transmit bits all are required to operate in specific order for the various faults. The test record documents that the correct signals operate for each test fault, and signals that were not supposed to operate did not operate.

The RTDS plot was set up such that commissioning test bits from both terminals were sent to the RTDS HMI such that they were compared on the plot in real time. The RTDS test first simulated the problems that were reported in the field. Logic corrections were applied to the relays and the faults were re-run to verify the problems were corrected, and also to verify that no other logic was affected. Figure 10 is an example of a correct operation for an A phase to ground fault with reclosing. The correct signals operated and there are no unexpected elements operating.

5. Benefits and Challenges

There are several benefits to using digital communications for testing rather than hard wires.

1) Much quicker set up that allows for much quicker switching from one test to another. It is not uncommon for more than one test project to be waiting in line for testing. It was found that this test method has fewer components and test failure modes.
2) RTDS HMI plots can be saved as COMTRADE screen captures that can be played in the field test sets.
3) The real time display from both terminals allows for much quicker determinations of correct and incorrect operations. The plot can be used to accurately measure times and magnitudes for quick analysis. Testing personnel is more focused on the problem that is being analyzed when there is no need to sort through information that is not pertinent to the task.
4) Sampled values replace numerous amplifiers. Relays can be tested with all current and voltage inputs and run more realistic models. There is also no need to maintain calibrations for D/A converters and current and voltage amplifiers.
5) Data on the RTDS HMI plot can have relatively high sample rates for a better resolution of the event data. COMTRADE plots can be down sampled as needed.
6) Once a Substation Configuration Description (SCD) file is tested for a specific relay it can be saved for future use. There is no need to wire and re-wire test set to perform quick testing in emergencies.
7) The RTDS HMI plot can be set up to view most of protection and logic functions in a relay. Specific elements of interest can be sent to the RTDS HMI plot.

One of the challenges faced during testing is that IEC 61850 technology is more detailed at the end user level than it should be. It was noted that too much time can be spent with small details.

6. Conclusions

BPA has been using the RTDS power system simulator HMI as a breaker simulator and to analyze specific protection logic functions for several years. This has been successful for the most part. Even with growing learning pains considerable time was saved during testing, particularly when more than one device needs testing at nearly the same time. The most important result so far is actually for the future. BPA has made a commitment to pursue future automation and protection schemes using IEC 61850. BPA engineers and technicians are already starting to test relays using IEC 61850 GOOSE messages and, in the future, when available using sampled values. The relays that were tested with the RTDS test set are being set up in preparation for that future. The needed GOOSE receive signals are added for the IEC 61850 breaker simulators. In the figure this test method can also be used for new firmware verification. BPA sees the standardization of datasets structure, content, and system configuration as the natural next steps.

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