END to END TESTING

A PRACTICAL PROCESS TO PREPARE AND PERFORM PROTECTION SYSEM SCHEME TESTS

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Intro

Utilities today are investing in new and upgraded protective relaying schemes on existing and new transmission lines and equipment as they improve their systems. The new schemes are leveraging new technology to improve the speed of operation, improve reliability and improve data gathering. Other beneficial features are present that were never available before.

As relays have become more powerful and featured, relay test methods have needed to change also. Dynamic scheme testing has been advocated for many years as the best method to measure relay performance, but was beyond the reach of most utilities due to the hardware requirements. Testing a communication assisted line protection scheme was very challenging until the release of the GPS system to public users. Today the biggest obstacles to transmission line scheme testing are all related to money and planning. The technical issues that made it so difficult have been resolved.

Planning a scheme test needs a degree of organization to simplify the process and make test time efficient.

The first time my utility performed an End-End test on a transmission circuit, we tried to simulate all the possible system configurations that might occur. A full day was spent with a protection engineer running simulated faults modeling many different system configurations, and then several more days were spent putting together the test programs and test routines. In all we had generated almost 70 scenarios to test. In the end, when it came to actually performing the test, we only ran a subset of those tests due to time constraints, and the similarity of the test values to each other. Hind sight told us that the job of the field tester was not to prove the relay functioned correctly, but rather to verify that the system functioned as intended.

Our philosophy has changed from verifying the relay works, to now verify overall scheme functionality. If we run a zone 1 fault, we expect to get the response for zone1. Zone 2 would again get just the response. We don't need to check exactly where Zone 1 transitions to Zone 2. Or Zone 2 to Zone 4. If the fault is outside of the line, does the relay block operation. Some people may advocate more tests, such as high impedance faults, but these can be done in a laboratory too satisfy their engineering curiosity.

History

Protection engineers have always wanted to reduce the damage and stress caused by faults on their systems. Fast clearing time is the best method to achieve this and the challenge to get fast clearing but secure operation has been an ongoing battle. Today we are practically limited by the speed of the circuit breaker (2 cycle) and the decision making time of the protective relay (1-2cycle). If the fault is beyond the line section, in order to provide securit , time delay is added, hoping that another circuit breaker closer to the fault clears first. This is stepped zone protection and is almost universally applied to mid length and longer lines. The first zone is set to reach anywhere from 60-80 percent of the line length, the second zone 80 to 125% of the line and so forth. Doing this with electromechanical relays required separate devices for either one phase(3 zones) or each zone(3 phases). Thus there was an economic limit to multi-zone protection. Rarely did schemes with more than 3 zones of stepped zone protection get used.

If the reach of Zone 1 was set to 75%, This meant that the line was really only protected for 50% of it length with high speed operation because the 25% at each end of the line was Zone 2 from the remote line terminal.

To deal with this coverage problem, some form of communication with the remote terminal was needed to determine if that terminal also sensed the fault or if it was outside the line. Various communication paths were developed that used either the line itself (carrier), telephone systems (FSK or voltage signaling) or microwave carrier. Many various protection logic schemes were devised to incorporate these communication channels depending on the type of carrier and communication security. All these analog schemes were using analog signals to represent digital data. But it was typically only sending 3 bits of data and this could be handled with tones representing the digital states. The common element in all the schemes is the need for a reliable communication path between the line terminals.

Schemes had terms like POTT, DCB, and PUTT are labels placed on the schemes to explain how they work. For example POTT – Permissive Overreaching Transfer Trip – uses the Zone 2 element to send a signal to the remote terminal. If it also sees a zone 2 fault, the fault is within the line and both terminals trip. (one end probably also saw Zone 1)

Testing these schemes was very difficult. It required a separate communication link between the line terminals that could synchronize the application of fault currents to each terminal. Not impossible, but very custom and costly. Most of us just accepted that manually sending and receiving tones or voltages was all we could do to test communication schemes and the inherent delay in the communication circuit was the best we could do. If we got high speed clearing, that was a bonus. As electric system became more heavily loaded, the need to clear faults asap to maintain stability reached higher levels of importance. The ability to generate a time synchronized ac current was very cumbersome and not available outside the larger laboratories.

Things changed dramatically with the introduction of digital relays, computer controlled current sources and Satellite Based Time standards (GEOS and GPS). We could now get a time reference that was within microseconds anywhere on earth. We could generate time synchronized voltages and currents to inject into relays separated by large distances. We could get time stamped event reports from the relays or other fault recording equipment to show what the replays did. Relays even evolved to a point where they now communicated digitally with each other with analog data to provide current state at the line terminal.

Hardware –

Current Sources - Modern relay testing equipment vendors have been selling test sets capable of time synchronized testing for about 15 years. The hardware to do this is a synthesized voltage and current source that can trigger on a set time. The synchronizing time signal comes from a GPS receiver, either in the test set or externally. Software applications typically sends the test parameters to the test set and records the response time. Capabilities vary in the software, some offer very flexible scripting languages, while other are restricted to canned routines the manufacturer has designed. In newer test sets, the test software might be built into the test sets and the interface is a web interface.

One important requirement is time synchronicity between the test sets used at each terminal. The test set/software combo should be tested for this before a test is started if there is any doubt. A difference of 10 usec is enough to begin affecting test results. This might be the case if the manufacturer or model of the test sets differs. It has also been found between different firmware versions from the same manufacturer. Simply locate the test sets next to each other and run the current and voltages into a digital fault recorder or even a digital relay and initiate a fault. Some software packages will allow adjusting the Test start time by an offset if necessary.

Breaker Simulators - During the test development phase, especially for new schemes, the number of breaker operations can be very high, and could put a circuit breaker above the maintenance parameters. This is especially true of oil breakers. Some would argue that it's good to exercise the breakers, others caution against many unnecessary operations. Using a breaker simulator, we can limit the number of operations and can adjust the operation parameters of the breaker, i.e. slow them down to emulate a slow breaker trip. The breaker simulators we have found useful have time delay built in too emulate an actual 3 cycle breaker, and can be slowed down to a 5 cycle if desired. Thy can also be turned into a slow breaker that takes about 20 cycles to trip. This enables testing the breaker failure functions in the relays without removing test leads.

If using a breaker simulator – always bypass it and use the actual breakers for at least one trip/close cycle from the relays during the testing.

Optional Equipment

An accessory that might be useful when testing at power plants where line of site to GPS satellites is blocked is a GPS clock emulator. This maintains a GPS timing signal for several hours after being synched to a GPS satellite.

Test Plan

Testing benefits from a well thought out test plan that is documented. This will contain the setup connections, the fault currents that will be supplied for each fault scenario, relay response that is expected, and pass/fail criteria. An Excel spreadsheet is adequate for this and a specialized software is not necessary. Excel may be able to format data to the format the test software needs. This prevents data transcription errors that are common when large amounts of data are entered.

KISS – there is a vast amount of data and parameters when doing relay testing so it is important to keep things as simple as possible but still adequately test the relay scheme. One way we found to simplify out testing was to split it into 2 different components. The first part is what we called single ended testing. We ignore the communication circuits and test the relays at both ends of the line as stand alone devices

Single Terminal Testing

We can test reclosing schemes, check inputs and outputs, backup protection and trouble shoot settings without the complication of the communication channel and the costs of personnel standing by at the remote terminal(s). This allows us to also check interfaces to SCADA systems and operate circuit breakers. The single terminal test always proceeds the End to End test. Many times we can use the same technician(s) to do both ends of the line if a second technician has limited availability.

One relaying scheme that does not lend itself to a single ended test is a line current differential scheme. It relies on the communication channel and cannot be fully tested single ended since loss of the communication channel takes it out of service. But if the comm channel is working, it can be tested by injecting current at one end only. Some utilities use redundant line current differential schemes only, others will use stepped zone protection using transfer tripping to backup line current differential.

End to End (E2E) – Some use the term E2E to cover the entire commissioning process. If the entire process is broken down to smaller components, E2E is just the fault tests that confirms operation of the communication aided tripping. Test that don't involve the communication channel do not need to be repeated since they have already been run in the single ended tests. Since we are testing reliability and security, we use in zone faults, out of zone faults, loss of potential test, and breaker failure. The total number of tests is around 12. If there is line current differential, a series of test is performed with it enabled, then a series of tests (using the same faults) is performed with the current differential disabled.

Line Current Differential vs Impedance – Short lines do not have enough impedance to allow impedance relays to be secure from overreach. Current differential schemes were devised to protect these lines. Knowledge of the currents at the other end was necessary. If the line was short enough, the CT secondary's were looped to both ends and a current differential was used. If the distance was further(> 2000 ft), some type of pilot wire scheme was used. Today in the digital realm, we can measure the currents or charge digitally locally and send the data to the other end(s) via the communication path. It provides 100% line coverage securely. Current differential is very simple in concept and to set but very difficult to test. It requires getting the phase relationship and timing exactly the same at each end of the line. With impedance relays, the communications are just digital control signals. The error between the waveforms could be a few milliseconds and the test would pass. With a line current differential relay, the timing error between ends needs to be less than about .25 milliseconds or a false trip can occur. This is where using test equipment from different manufacturers or generations could cause problems. It's best the check the timing error before going to the field to test.

When the line protection has Line Current Differential and Impedance protection, we disable the 87 protection, test the Impedance function first and then repeat the test with the 87 enabled and impedance disabled. This way we can see both functions. When both are enabled, the 87 usually operates first.

Relay Settings – We do not test to the settings, but to the system. As long as the system fault modeling tool (Aspen, Cape, EasyPower) is updated, it is used to generate all the faults cases used in the tests. If you don't know how to use these programs or don't have access to them, you can calculate numbers based off settings. Some of the test software packages have a fault simulator that will take the line parameters and generate fault values based on these numbers. When we first investigated these tools, the system source impedance was difficult to determine and influences the test values. We prefer to use actual fault study values.

The settings define CT and PT ratios, names, id's, relay scheme used, etc. It's important to review the settings to see if there is reclosing, the number of zones, and anything that might be special.

Fault selection

Faults are created in each zone of protection for both multiphase and line to ground faults. More cases are created for single ended tests since we locate faults outside of the line more. You may reuse some of these for the E2E tests but find it easier to just regenerate new faults when preparing the E2E portion of the test. Data transcription errors at this point are common and this is where copy/paste is to be encouraged. Cape and Aspen both can output test files sometimes in the format that is directly used by the test software (SS1 files, comtrade). Excel can also be used to reformat / reorder the values for input to the relay test program. Our relay test program then has generic routines that are matched up to the fault data. All this is can be done without typing one voltage or current value. The use of macros in Excel does some of this automatically. Manual copy/paste does the rest.

Rolling phases of faults for single phase fault tests. Older digital relays may have had an ADC (analog digital converter) for each analog input, but typically today, they all use a common ADC or DSP (digital signal processor) chip. They can multiplex the data to the ADC or the DSP can have multiple analog inputs. These still are treated as separate paths. A three phase metering check or single phase to each channel must be done. If that is satisfactory, then the need to rotate phases for single phase faults is not necessary. If the scheme has electromechanical relays, then this is essential.

Which Faults to create for E2E Tests –

Here is my short list:

NERC Load tests

5% Line – 3 phase

5% Line – 1 Line-Ground

95% Line – 3 phase or P-P

95% Line – 1 Line-Ground

Local bus fault – 3 phase

Local bus fault – 1Line-Ground

Remote bus fault – 3 Phase

Remote bus fault – 1 Line-Ground

50% Line – 3 phase

50% Line – 1 Line-Ground

SOTF – Switch onto Fault

Breaker Failure at each end

LOP tests

Phase-Phase faults can be substituted for 3 Phase faults in any of the cases. The 1 Line – Ground faults can be any phase, and preference is to rotate the phases. You do not need to perform a line to ground test for each phase at each fault location.

Additional Faults for Single Ended Tests – these are the additional faults we use for a single ended test.

Phase-Phase faults

Zone 3 (Reverse Faults) – 25% of reverse direction

Zone 4 – Second Bus in forward direction

Zone 5 – if used – forward direction

Additional test routines that check functionality

NERC emergency loading

Reclosing -

Single shot

Multi-shot

Lockout

Switch onto Fault – use any Zone 2 faults

Synch Check conditions

Breaker Failure

Loss of Potential

Expected Results – A list of the expected relay targets and elements should be part of the test plan. The labels should be accurate to the type of relay for sequential event reports (SER), but targets can be listed more generically… ie Z2PT element versus – A, B & C Zone 2 targets. Outputs that are to be expected may be listed the first time they appear. They can be left off in subsequent tests. Communication bits should always be listed. There are techniques that can search a SER report and match to the expected results to determine pass and fail conditions. This is a very advance technique and should look for just the unique items to reduce the plan setup time. I personally would prefer a manual check box for pass/fail. This would reduce the number of repeated tests, just to get a pass for the test.

Acceptance criteria - to pass a test, the relay scheme must do two things, perform the intended function and do it in the expected time. The intended function is the correct relay elements pickup and correct signals are sent and received. The correct time is the measured time from fault initiation to breaker 52A opening. (some will use the trip output, but this does not account for breaker time) If the test plan has listed the critical expected elements, a simple search of the SER or event report is made. The measured operate time is recorded by the relay test set. The tolerance in the time measured defaults to 5%, but this requires setting the expected time accurately. Larger tolerance could be used if time are more generic, rather than specific. Ex – expected operate time is 5 cycles. If the tolerance is set for 5%, this in only 4.95 cycles to 4.05 cycles for a range. In practice, anywhere from 3.5 to 6 cycle could be acceptable and this is about a +- 25% tolerance.

For a communication assisted protection scheme, we are striving to get high speed clearing for all faults. Thus the only thing of interest is to see the difference between a direct trip and a communication (Zone2) trip at the local terminal.

There are others times of interest when a single ended test is run. When these tests are performed, we actual measure the Zone 2, Zone 3, Zone 4, and Zone5 time delays if elements are used and all the back up overcurrent times. Switch onto Fault is analyzed, reclosing delays are measured, Synchronizing is checked, Breaker failure is confirmed. All these do not need to be repeated during a E2E tests.

Reporting – The reporting requirements depend on how you gather data for NERC audits. At the base level, the testing software has the raw data of the test and depending on how sophisticated the software is, it may have full documentation of results, or simply be the driver of the test set. If data is gathered in a spreadsheet such as the test plan manually, the tester will fill this out as they go. If you attest to a master database, then the data is uploaded later.

Commissioning – New relay protection schemes must go thru the full Single Ended/E2E sequence before they are placed in service. This starts the calendar for relay maintenance intervals

Maintenance – Protection packages that are part of the bulk electric system (BES) must have a minimum level of maintenance checks done on a time based interval. NERC does allow other performance based intervals to be used, but few are using them because of the administrative overhead associated with them. Some utilities are performing the E2E tests as their maintenance tests to satisfy the NERC requirements. If this is the case, the test plan needs to be attached to the relay maintenance record for access at a later date. A smaller number of faults needs to be run since you are only verifying functionality of communication signals and outputs. Test plans do evolve over time though and don’t count on running the exact same old plan again in 6 years without checking it for updates. During maintenance tests, the breakers can be used rather than simulators. If primary and backup relay systems are tested, this will be about 20 operations on the breaker. Because the test routine has ideally been run and debugged during commissioning, the setup time will be about equal to the test time.

Settings Modification – Design Changes – Setting changes present the greatest dilemma for determining if a single ended or E2E test needs to be repeated. If the physical wiring is changed, this will usually warrant a single ended test to be done again. If setting changes are made that significantly alter pickup values or change logic within the relay, this will also warrant a single ended test. If the logic changes affect the communications channels, then an E2E tests is indicated. If the settings changes slightly alter pickup values, but do not change logic then neither test would be performed, just a verification of the value is entered and an element test for pickup.

Testing with Load Current – Prefault loading conditions can be chosen to emulate real world conditions or just some nominal load condition. A fault scenario (out of zone) can be generated that uses the maximum fault impedance in Cape or Aspen and this should give a system load flow (if loads are turned on). A preset value can also be used that is calculated by hand. The advantage of the later is that a definite value can be picked. This case is used to verify connection of the relay test set and relay metering scaling.

The issue to be determined is whether to have load current added to the fault current during the faults. This is feature on Aspen and Cape when the fault files are generated. I don’t use this feature because of the confusion it creates for low magnitude faults. The programs vector-ally adds the load values to the fault values. The vector angles may not be what you intended to see particularly if the load flow is out of the line. It’s easier to inspect the results and debug routines if load current is only used before the faults.

Communications – Efficient testing relies on reliable and intelligible voice communications between the line terminals. We have tried phone bridges, two way cell phones, speaker phones on PSTN, and radios but still struggle with reliable & audible voice. What seems to work best is cell phones with headsets. This filters out some of the noise and raises the volume of the cell phone. But batteries go dead on cell phones and wireless headsets, no cell reception in remote areas or buildings, other calls come in, can't do multiparty (conference calls), phone bridges take some setup time and preplanning or unavailable for the requested hours. We have tried using WebEx audio conferencing. And some have tried to use the protection communication circuits embedded in the protection circuit. I have even resorted to a boom box attached to a cell phone.

Other Applications – A similar test method can be developed for other equipment in substations.

Transformer differential schemes can be tested using time synchronized sources when the number of windings is three or more. Many times neutral CT's are present and these would require moving leads or addition current channels. We have tested a transformer that required 15 current channels. With modern test sets, this was 3 test sets. Since software is not designed to handle this many from 1 computer, we had 3 computer/test set combinations and Satellite synched them or distributed the same clock signal to all test sets in parallel. The test plan appears to be similar to a line test. Aspen/Cape generate the test currents and the spread sheet massages these to send to the appropriate CT input of the relay.

High Voltage Bus Differentials are another scheme that is fairly easy to apply this test technique. Modern bus protection relays can have as many as 21 current inputs. We have applications that have used all these, but these are three phase setups. If we have more than 21 inputs required, we use 3 relays and use single phase inputs. Then the number of inputs needed drops. The fault cases we use are single phase faults on the bus and then on each of the transmission lines. Walk the fault around to each line. The metering tests are probably the most important when setting up this test. We also do primary current injection for new busses using the relay test sets. Use fault resistance to limit fault currents within the test set capabilities.

Low Voltage Bus Differentials – Lower cost protection is applied to distribution class busses. A high impedance relay is used. This sums all the feeder positions with the transformer position. This type of test benefits from a static primary injection tests rather than the dynamic tests. The purpose is to make sure CT's are connected correctly to the right phase and with correct polarity. Again the test is done with the relay test set and a custom test routine.

Common Pitfalls when testing - There can be many different reasons a test fails. We have experience all the following.

- Satellites can't lock on – either due to poor southern exposure line of sight, metallic interference or unable to distance to get antenna outside. Using a GPS simulator works, but these will go out of synch after 6-8 hours and need to be resynched.
- Wrong test case or waveform used at one terminal. This is readily apparent with 87 tests.
- Pre-fault delays differ between ends or the software has a delay time offset that is not correct. This may not be a problem for zone protection with transfer trip but is deadly for line current differential.
- Disable switch left in incorrect position.
- Breaker or Breaker Simulator was not closed

- Relays not receiving IRIG signal – the clock signal for the relays is different from the test setup usually. The relay needs to be on the same time base for accurate comparison of results. It does not affect the operation, but does affect analysis.

- Test lead falls off – with the jumble of test leads between test paddles, test switches, test sets and simulators, it's easy for a lead to come off. Test paddles are known to develop bad connections.

- Test Switch - Paddle not wired to a standard – this trap is easy to walk into because we all have standards but this might be unique installation. Always check the test switch labelling or schematic to verify the connections.

- CT backwards/rolled – this means that the metering test was either not interpreted correctly or it had wrong numbers (phase angles). Internal faults have same phase angles, external faults have 180 deg angles and same magnitudes.

- Fault cases not getting correct results – since the values come from a Power System simulation program, is the system model correct for the system under test, are the right results linked to the correct test case. These are all problems the test engineer / protection engineer will need to answer.

- Relay failure – we have actually had relays fail during testing, sometimes it's just 1 input or output. If no spare exists, moving to another input/output is possible to complete testing, but the replay needs to be repaired. When the relay comes back, do you need to repeat the E2E tests? The E2E does not need to be repeated, but the single ended test should be done.

Reports – Reporting the results from relay commissioning can vary depending on company policy, the BES status of the terminals, and whether you are a contractor for a utility or employee. Most transmission lines that will be E2E tested will fall under NERC auditing rules. At present, inspectors expect to find a commissioning test plan, a confirmation that the plan was done when relays were placed into service, and your ability to access the results. Recent audits have even asked for some of the results. Newer relay test software can manage the test plans, collect the test results and archive them for later retrieval.

If a report is required as part of a contract – more extensive record keeping must be done. We don't routinely download event records from the relay if operation is as expected as evidence by the SER entries. This saves a lot of time, but a contractor may be expected to capture each event record from the relay for each successful fault test. For schemes with 87 & Transfer Trip with redundant relays, that's at least 40 event records and test records. Keeping these all separated and identifying them becomes a nightmare that requires capture and labeling as you go. Trying to do this after the test would not be advised.

Return to Service – Final Settings

One of the intents of E2E and Single Ended testing is to test the actual settings that will go into service. It is therefore important to avoid making changes to accomplish the tests. If any settings must be adjusted as a result of the testing, then these must be communicated back to the protection group, both for approval and record keeping. If a consultant is used to provide settings, then his job is not done until he sends final as tested settings to the customer.

Removing all test equipment, restoring all open test switches, slide links, lifted wires, jumpers seems trivial but many misoperations have occurred because links or switches were closed out of order.

Time Requirements

Much discussion has compared the efficiency of E2E testing against element testing. There is really no fair comparison since they are different kinds of tests. A well done element test on a complicated relay may take two days. It might take the same amount of time to do an E2E tests.

Our standard protection schemes uses redundant protection using identical relays. The longest we ever have taken is 3 days for the single ended test and two days for E2E test. More typically we can complete the single ended test in a long day and the E2E in a normal shift day (if we don't have to set up equipment). The first relay will take 80% of the time and the second relay, 20%. At it's best, tests can be run every two minutes and we have finished the second relay in less than 1 hour. If we have to retrieve event reports, this interval runs about 4 minutes.

There have been people stating that E2E testing only takes 4 hours to perform. That may be true of just that piece of commissioning, but with all the other things we check, we still ask for a full 5 days to commission a new package after the wiring is checked out.

Conclusion

Relay commissioning using advanced simulation of fault conditions gives a better measure of relay performance than single element testing practices of the past. In light of NERC requirements of commission activities and ongoing maintenance activities it is an important part of a utilities protection system assurance programs. Technician knowledge of why and how to perform single ended and end to end test using dynamic faults is key to correct performance of this type of testing. Relay performance is verified after each test so that completion of the tests with expected results is the best method currently available for a reasonable cost to assure protection will function as desired.

Biography

Rick Asche has worked for Portland General Electric for almost 40 years. During that time he has had positions in Distribution Engineering (4 years), Substation Maintenance (33 years) and now is in the Protection Group as a field testing engineer. He has worked with most of the protection apparatus used in distribution, transmission and power plant systems. He has been a key contributor to new technology application at PGE and has overseen the application of new test techniques. He has developed applications for capacitor control that are unique in the industry that combine his knowledge of electronics, AC drive systems, Power quality and logic control to improve power quality for customers and reduce var flow within the PGE system. He has authored papers presented at the Doble conference, lectured at the Hands on Relay School several times in the 25 years he has been on the HORS steering committee. He teaches courses on voltage regulation and new technology at PGE. As a test engineer, he works directly with relay technicians to oversee tests and develop test plans for protection schemes. Hobbies include biking, Karaoke, animated Christmas lighting and electronics. He is a registered professional engineer in Oregon.