Protective relays with Ethernet network to replace wiring

A typical modern protective relaying panel on which the bulk of the control wiring and all of the electromechanical auxiliary relays once used for protection have been replaced by optical fiber Ethernet connections and logic programmed in the relays.
New Maintenance and Testing Strategies for Protection and Control

The electric utility industry has a history of thorough testing of protective relays. This has been driven by the fact that, for most of the 20th Century, relays were silent observers of the power apparatus they protected, reacting only to faults and abnormalities. Electromechanical and solid state analog relay designs could fail or drift out of calibration without any indication, leading to failures to trip or false trips later.

Utilities have managed relay performance with periodic testing and calibration programs, using intervals and testing activities based on failure experience. Many also use testing as the final confirmation of whether relays are set correctly. However, a relay may fail at any time following a test, posing a hidden system performance risk. Also, maintenance errors sometimes disable the relay. The utility is lucky if a fault does not expose the problem before the next test.

Manufacturers have promoted the ability of modern microprocessor relays to monitor internal functions and alarm for failures. The monitoring coverage even extends to some of the application circuits connected to the relay. Ac input circuits connect to A/D conversion subsystems that don’t drift and have no calibration adjustments. As manufacturers have refined successive relay generations, users have experienced improving reliability, and have also experienced the usefulness of the failure alarms. Users have extended maintenance intervals and trimmed the testing activities for these relays.

The next technical wave to impact maintenance is the use of multiplexed data communications paths between microprocessor relays in place of dedicated control wires. With serial or Ethernet connections, background heartbeat messaging monitors the entire communications path, and can alarm for failures in a way that wires cannot do.

Relay manufacturers promote these legitimate advances as keys to better and easier maintenance programs. But note these challenges to the full realization of this benefit:

- Manufacturers and users have not joined efforts to create a clear picture of exactly what is and is not covered by monitoring in a particular system design. There are gaps in the overall design for reporting failures in protection systems.
- Field maintenance technicians sometimes apply familiar old techniques to new equipment, losing the benefit. Working procedures have not kept up with technical advances.
- The industry is just beginning a concerted effort to analyze and document these monitoring and maintenance practices so that all users can benefit from guidance by the industry experts and leaders.
- Many utilities lack enterprise database systems that could support effective analysis of relay reliability, maintenance issues, operating experience, and system configuration. (the huge arrays of interacting parameters in systems of relays)

Major Action in N. America

The North American Electric Reliability Corporation (NERC) has been appointed by the US Federal Energy Regulatory Commission (FERC) and Canadian provincial government authorities to develop and enforce a broad range of standards for reliability of the bulk electric system (BES) - generally transmission above 100 kV plus key generating facilities. NERC and its eight component regional reliability organizations (RROs) are charged with auditing BES owners for compliance, and can levy fines of up to 1 MUSD per violation per day. It is no surprise that utilities are paying close attention, with massive investments in organizational compliance, documentation, and internal systems for monitoring compliance. Of interest to PACWorld readers are the protective relaying and control (PRC) series of standards available under the Standards/Reliability Standards selections on the home page http://www.nerc.com/. NERC is revising many of these standards, as well as writing new standards for previously missed issues.

This article focuses on the technical concepts behind the updating of PRC-005-1, Protection System Maintenance and Testing. The existing standard requires only that an owner of a protection system have a documented maintenance program, with a documented basis for the maintenance intervals. The owner must also have full documentation proving that the
Components of a Protection System

Protection Systems include more than relays themselves. The NERC definition is “Protective relays, associated communication systems necessary for correct operation of protective devices, voltage and current sensing inputs to protective relays and associated circuitry, station dc supply, and control circuitry associated with protective functions from the station dc supply through the trip coil(s) of the circuit breakers or other interrupting devices.”

As you can see in Figure 1, the communications path for unit or pilot protection of a transmission line is included. The battery system comprises the battery itself and its charger. The facilities to be maintained include all interconnecting wiring, auxiliary devices needed for protection, and ac or binary input sources. Circuit breakers are not included, yet the maintenance program must verify that each trip coil is actually able to trip the breaker, so breakers must be tripped as part of maintenance. Technical Reference and Frequently-Asked Questions (FAQ) documents on the NERC Project 2007-17 web page explain what components of a generating plant protection system are included – generally any component that is intended for protective tripping of the generator itself. PRC-005-2 also covers underfrequency load shedding (UFLS) schemes, undervoltage load shedding (UVLS) schemes, and special protection systems (SPSs).

Methods for Verification

The standard focuses on what to accomplish in maintenance tests, as compared to all other types of testing activities. Development and type tests, product evaluations, factory and site acceptance tests, and commissioning tests all confirm design suitability and functioning of the installation. For maintenance testing, equipment in service is periodically tested only to find failed components, damage, change of calibration, or accidental configuration changes.

What might fail or change between periodic maintenance tests depends on the equipment generation. In electromechanical and analog solid state relays, the only way to find failures or drift is to test the performance of each section. By contrast, microprocessor based products tend to work as designed and set, observably healthy, until there is a clear failure that is easy to spot or is self-alarmed by the failed unit. In maintenance tests, it is not necessary to reverify an element that can’t change or fail independently. While a Zone 2 distance relay on an electromechanical panel can fail or drift and needs periodic testing, for a multifunctional microprocessor relay, it is only necessary to determine that it is measuring its ac inputs properly, is able to close its trip contact, and is set as intended. There is no further benefit in checking all the distance zone boundary points to make sure they didn’t move. They can’t move around in this type of relay. If the problem is incorrect application or incorrect settings, no amount of extra maintenance testing will show the problem.

We have discussed maintenance tests, but often an invasive test by a human technician is neither required nor a good idea. A more general concept is maintenance verification – knowing by any means that there are no failures that the maintenance test was aimed at finding.

Maintenance Approaches

Time Based Maintenance (TBM): TBM is the modern term describing the familiar testing of protection system performance on a periodic time schedule. The TBM interval is based on experience, varies with the type of component, and may range from months to years. Sometimes, verification is achieved through natural operations. TBM can include review of recent power...
system events near the particular protective relaying terminal. Operating records may prove that specific protection scheme components have performed within specifications - the maintenance test time clock can be reset for those components.

All maintenance verification is really time based, but we categorize the following two newer variations of TBM separately as fundamentally new approaches.

**Condition Based Maintenance (CBM):** CBM is used with equipment whose integrity and performance can be observed passively – the component is periodically testing itself as it performs its protection job. Frequently reported results from self monitoring demonstrate that the component is operational. This is not a lazy or less rigorous verification. For the verified parts, the maintenance verification is better than that of TBM testing. In particular, we may learn of a failure in seconds rather than years, with reduced risk of human error induced problems.

Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included in the self diagnostics. Most but not all of the internal components of a microprocessor relay are monitored. Self-monitoring may include the ac signal inputs and analog measuring circuits; processors and memory for measurement, protection, and logic; trip circuit continuity monitoring; and communications signal monitoring. For those components, failure detection programs generate alarms and inhibit operation to avoid false trips.

Certain internal components such as trip output relay driver circuits and contacts have not been equipped with self-monitoring, so they must be periodically verified by testing or by observation during a natural event.

**Performance Based Maintenance (PBM):** PBM establishes maintenance intervals from analysis of historical TBM failure rates for a statistically significant population of similar components. This requires systematized gathering and analysis of test results. If a population has very low failure findings in ongoing maintenance tests, the maintenance interval is extended while keeping acceptably low failure rates. Even when low failure rate experience is used to justify extended time intervals, infrequent TBM must be continued to discover any increase in failure rates requiring return to a more frequent program.

### Verifying the Protection System in Sections

We must verify that the whole protection system is working. Each portion is either monitored or must be periodically tested.

We can test the entire protection scheme as a single unit, from voltage and current sources to breaker tripping. Such an end-to-end test may require personnel at multiple sites and an outage of all the tested facilities. A practical alternative is to divide the protection system into segments or portions which may be tested or monitored individually. The boundaries of the verified sections must overlap to insure that there are no gaps. To be technically valid, a maintenance program should be supported by documentation showing how the verified protection system includes much more than just the relays.
system segments overlap.

We can combine TBM testing by technicians, TBM by observation of natural events, CBM, and PBM time extensions into an efficient hybrid maintenance program. A protection system may be divided into any number of overlapping sections with a different maintenance methodology for each segment.

While human testing may be needed to prove some protection system components, human error is a documented cause of failures and misoperations. Keeping human hands off of equipment is better if monitoring verifies that equipment is functioning. Monitored components are verified during every second with all the assurance that could be achieved by a manual off-line test.

**Example of Verifying or Testing in Overlapping Zones**

Figure 2a shows an example of how the overlapping of self-monitoring and testing is accomplished in a unit or pilot line protection system based on microprocessor line relays. It demonstrates monitoring gaps that must be covered by periodic testing or by observation of natural operations. The figure shows transmission line protection carrier blocking directional comparison unit or pilot relaying. Verification takes advantage of the self-monitoring features of microprocessor line relays at each terminal. The example assumes that the user has the following arrangements in place:

- Each relay has a data communications port serving a remote control center
- The relays have internal self-monitoring functions that report failures via data communications or alarm contact
- The relays report loss of dc power, and the relays or the battery chargers report the voltage and ground isolation of the dc battery supply
- The CT and PT inputs to the relays are used for calculation of metered values of volts, amperes, and phase that are reported by data communications. EMS computers or maintenance personnel compare ac measurements to those from a redundant set of line protection relays not shown in the figure, or to readings from other corresponding signal sources nearby. Agreement of these metered values to within relaying accuracy continuously verifies instrument transformers, wiring, and analog signal input processing of the relays
- Breaker state indications are verified in the same way as in (4). Open state must also be consistent with absence of current in the line
- The trip coil monitor (TCM) reports continuity of the closed breaker trip circuit from the dc supply bus through the trip coil
- Each on-off carrier set has an automatic checkback test unit. Since checking carrier is normally off, the checkback test runs several times a day to verify the entire channel between relay panels

We must verify that the whole protection system is working.

These monitoring features plus the checkback test comprise automatic verification of all the protection system elements that experience tells us are the most prone to fail. But, is this complete verification of the protection system?

The large dotted boxes of Figure 2b show portions of the line protection system that are verified by monitoring via the features just listed. These segments are not completely overlapping. Furthermore, the shaded boxes show parts that are not verified within each segment:

- TCM verifies the continuity of trip coils and circuits, but this does not assure that the circuit breaker can actually trip if the trip coil should be energized
- Within each line relay, the trip circuit is energized by the contacts of a small telephone-type “ice cube” relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. Today’s relays do not monitor the processor output, driver circuit, or ice cube relay coil or contacts. These components are critical for tripping the circuit breaker. The contacts are not rated for continuous trip current, and sometimes suffer hidden damage from tripping of sluggish, binding circuit breaker mechanisms
- The checkback test of the carrier channel does not verify the connections between the line relay internal microprocessor and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, and wiring

The first two verification gaps are closed by initiating breaker tripping **through each protective relay trip output** at a convenient time, from
the relay front panel, or via SCADA. Trip the breaker through each of the two trip coils separately for a valid test. Testing of the relay-carrier set interface requires that each relay keys its transmitter, and that the other relay indicates reception of the carrier. This is observed from relay or DFR records during naturally occurring faults, or by a manual test.

Users and manufacturers who understand these principles will find new opportunities to extend the coverage of monitoring and reduce human maintenance work. In the example, if the checkback test were programmed in the relay logic, the checkback test keying would pass from relay logic processor at one end all the way to the corresponding processor at the other end. This includes the relay-to-carrier wired connections at both ends. The monitoring gap is completely eliminated.

**Measurement and Control via Data Communications**

The Figure on page 38 shows a typical modern protective relaying panel on which the bulk of the control wiring and all of the electromechanical auxiliary relays once used for protection have been replaced by optical fiber Ethernet connections (orange and blue fibers to ports on back of relays) and logic programmed in the relays.

In order for two microprocessors to exchange a trip command over a data communications channel, every component between those processors must be working. To monitor the path, processors exchange no-action messages at a heartbeat rate. By using signal level or message bit error checks, and checking of message time tags, the receiving processor can alarm for degradation in the data channel even before complete failure occurs.

A wired tripping connection cannot be monitored so effectively. Monitored communications can use periodic data messages programmed in a vendor’s proprietary serial data exchange protocol, or via IEC 61850 GOOSE messages on an Ethernet local area network as Figure 3 shows. The subscribing relay alarms for a failure if it does not see GOOSE packets it expects every second.

**Setting Management’s Role in CBM**

Microprocessor relays do not require testing or calibration of each setting. However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. New relays have thousands of setting and configuration parameters that are critical to protection system performance. Monitoring does not check measuring element settings.

To minimize risk of setting errors after commissioning, the user must enforce strict settings data base management, with periodic verification (manual or automatic) that the installed settings are correct. A good settings management process compares field settings with a controlled archive that features access authorization, and settings production, update and version management. Relay unit replacements and firmware version updates can impact correctness of settings and must be controlled along with the settings. Ideally, the same controlled archive also serves as the database for relay coordination studies. In this way, erroneous settings will show up as apparent misbehavior in a coordination study. See the IEEE Power System Relaying Committee Working Group C3 Report, “Processes, Issues, Trends and Quality Control of Relay Settings,” December 2006.

**(PBM) Performance Based Maintenance Implementation**

In the approach developed by the NERC drafting team, the user starts with a statistically valid sample of about 60 products of one type from one manufacturer to apply PBM. Multiple users can aggregate their populations of like devices operating in similar service conditions – for example, a group of generation owners can associate to develop data for a merged population of generator protection relays, where

**New relays have thousands of settings and configuration parameters that are critical to protection system performance.**
each individual owner does not have 60 units.

If the TBM results show a problem discovery rate of less than 4% with the normal intervals, it is permissible to extend to test long intervals such that only 5% of the population is tested every year, if this extension would not cause the testing problem discovery rate to exceed 4%. This is equivalent to a maintenance interval of 20 years! TBM at a rate of at least 5% per year is always required to insure discovery of problems that arise with time, like deterioration failure of components. The program requires complete maintenance records and annual analysis of results.

**Other Features of NERC Standard PRC-005-2**

A copy of the draft NERC PRC-005-2, Protection System Maintenance makes it easier to follow the explanations below – find it at [http://www.nerc.com/files/standards/Protection_System_Maintenance_Project_2007-17.html](http://www.nerc.com/files/standards/Protection_System_Maintenance_Project_2007-17.html). The maintenance program approaches explained here are summarized in terse requirements that focus on a set of three tables with device attributes, maintenance intervals, and activities:

- **Table 1(a) – Level 1 monitoring (no monitoring)** – Pure TBM. For each type of protection system component, the table specifies maintenance activities, and absolute maximum allowed time intervals. Users should schedule shorter intervals to insure compliance in the face of unexpected delays. It is always acceptable to use TBM tests and to keep detailed records if a user prefers this familiar approach. For electromechanical relays and auxiliaries, and analog solid state devices, this is the only available choice. Specific requirements make it easier to know exactly what to do than was the case under PRC-005-1
- **Table 1(b) – Level 2 monitoring (partial monitoring)** – Extended intervals and reduced testing with help from CBM. The table lists required monitoring attributes of eligible components at the top and with specifics for each component type. Almost all microprocessor relays qualify. For such relays with monitored alarms the maximum maintenance time interval is 12 years, as compared to 6 years in Table 1(a). The activities are greatly trimmed – check relay unit and I/O instead of full functional and calibration checking. Unmonitored components such as trip outputs must still be tested. The alarming path itself must also be tested.
- **Table 1(c) – Level 3 monitoring (full monitoring)** – Components whose performance is fully monitored list an interval of “continuous” – these do not require periodic maintenance testing as long as the component attributes meet the specific technical requirements in the table. Alarming paths from the fully monitored protection system components to a site where failure response action is taken must also themselves be fully monitored. The owner needs to document the system design to justify the Level 3 claim. Certain components, such as batteries, are not eligible for full monitoring and always require some periodic attention. However, performance monitoring of these parts (such as a battery cell impedance monitoring) can extend intervals and simplify activities.

**Industry Evolution towards Full Condition Monitoring**

With today’s microprocessor relays and data communications for control messaging among the relays, a protection system design can be almost entirely self-monitoring and requires very little technician testing -- as little as occasionally confirming that the relay can trip the breaker via control center operator commands. In North America, manufacturers need to help users with application maps that users can include in a documentation package for NERC compliance auditing. The maps should show what the user must do in application design to achieve the expected condition monitoring. The vendor supplied monitoring map combined with the user’s design standards support the claim that periodic testing is not required. Records of actual self-alarmed failures and the organization’s repair responses further bolster the audit documentation. This is a good system for managing a protection system performance with minimum testing anywhere in the world, not just where NERC standards govern. Once manufacturers and the industry understand the nature of the technical requirements and the solutions, they will find ways to close more of the gaps that still exist.

A few examples:

- The authors believe that it is possible to design trip output circuits whose ability to issue a trip command can be monitored
- One manufacturer recently introduced power line carrier sets that communicate via IEC 61850 GOOSE with the transmission line relays for unit protection of the transmission line. With a GOOSE heartbeat, the unit protection scheme that can be fully self-monitoring
- Manufacturers are developing new alternative auxiliary power supply systems that don’t use electrochemical batteries – for example, a flywheel based energy storage system whose operation can be fully monitored

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**Figure 3:** The designer of this installation reduced wiring cost by connecting only the bus relay to the trip coil of this breaker.