Protection System Maintenance Program Choices –
TBM, CBM, and PBM

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Introduction

In 2007, FERC Order 693 launched the development of the new NERC Protection System Maintenance Standard PRC-005-2. The new standard was to replace four legacy standards for maintenance of similar types of protection system components, and to specify maximum maintenance intervals and minimum activities for a time based maintenance (TBM) program. The NERC Standard Drafting Team, however, went beyond what FERC ordered and also included provisions for condition based maintenance (CBM) and performance based maintenance (PBM) programs. The new draft Standard was approved by NERC in 2012. On July 18, 2013, FERC issued a Notice of Proposed Rulemaking (NOPR) in which it proposed to make PRC-005-2 [1] mandatory and enforceable, along with a few new action items requesting feedback of supporting information. In October of 2013, PRC-005-2 became mandatory and enforceable. The standard includes an implementation plan that gives affected utilities years to gradually develop compliance with the new standard. It is important to be aware of the need to remain in compliance with the old program until the transition is complete for the entire fleet of protection system components.

This paper explains the relationship among the three maintenance program choices of traditional Time Based maintenance (TBM), Condition Based Maintenance (CBM) that utilizes self monitoring of newer components, and Performance Based Maintenance (PBM) that utilizes the good reliability experience with certain device types to extend testing intervals. It explains for each the testing approaches, facilities, and implementation procedure that a protection system maintenance organization can use to create the most efficient and compliant program.

Evolution and Features of NERC PRC-005-2 and Newer Versions

The North American Electric Reliability Organization (NERC) is the Federal Energy Regulatory Commission (FERC) appointed industry entity that writes and enforces reliability standards for the Bulk Electric System (BES). However, FERC exercises oversight of standards development, reviews and approves the standards, and has the statutory responsibility to direct NERC to modify the standards to conform to FERC positions. Therefore, when FERC issues directives to NERC regarding changes to filed standards or new standards, NERC is obligated to address those directives.

Combining Four Current Standards

In February 2007, FERC issued the initial order on reliability standards, Order 693, approving many of the NERC Version 0 legacy standards then in existence as mandatory and enforceable. Among those standards were:

- PRC-005-0 – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Underfrequency Load Shedding Equipment Maintenance
- PRC-011-0 – Undervoltage Load Shedding Equipment Maintenance and Testing
- PRC-017-0 – Special Protection System Maintenance and Testing (SPSs are also known as Remedial Action Schemes or RASs)

PRC-005-0 became PRC-005-1, the widely recognized and somewhat vague maintenance standard for relaying systems, with which utilities have wrestled for compliance since then.

Of the four legacy standards listed above, PRC-005-1 is the most wide-reaching. However, there is a great deal of commonality among these standards. All of these applications involve protective relays, control circuits, and current and/or voltage transformers. Most of them involve station batteries, and many involve communications circuits. FERC Order 693 thus directed NERC to look at combining these four standards into a single standard as part of the project described here.

Developing specific maintenance requirements

The existing four standards are very general - they simply say that a protection asset owner must have a maintenance program, that the owner must implement that program, and that it must fully document the
maintenance activities are actually carried out according to the program. There is no specific guidance on what the program or the maintenance records should include. In addition, PRC-005-1 required that the owner have a basis for maintenance time intervals (assuming but not stating that the program is built on testing at uniform time intervals). The lack of specificity in these old standards led to difficult auditing questions, such as “What do I need to show as an acceptable basis that justifies the testing intervals I am using in my protection system maintenance program?”

NERC records showed that PRC-005-1, of all of the mandatory reliability standards, had by far the most audit findings of non-compliance, which included financial penalties from asset owners, and extensive work to mitigate adverse findings. This was due to the complexity and number of protection system maintenance activities, and the requirement for 100% compliance for tens of thousands of protection system components in use at a typical utility. One missed item can lead to a non-compliance audit finding. NERC has also cited lack of clarity in the standard as another major factor.

In Order 693, FERC ordered NERC to “develop a modification to” these four PRC maintenance standards “through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System”. This was intended to get rid of the need of a utility to come up with its own basis or rationale for the time intervals, or to have an auditor question that rationale. That aspect of the requested changes is liberating for utility asset owners.

New features - solutions for challenges of PRC-005-1

The recently-approved PRC-005-2 addresses not only the FERC directives, but also many other issues that have caused frequent non-compliance findings for the old standard. It establishes a more specific definition of what equipment is to be included in the program; it better defines included devices in a generation plant. The time based maintenance (TBM) tables establish maximum allowed maintenance time intervals, relieving the utility from proving a basis for intervals, and specifies minimum maintenance activities in a functional way. For users who wish to take advantage of microprocessor relay technology to minimize maintenance work, PRC-005-2 condition based maintenance (CBM) features let the asset owner employ monitoring of protection system component failure reports to lengthen time intervals, even eliminating some of the testing. For those who wish to analyze favorable maintenance program results to justify a basis for longer time intervals than the standard specifies, PRC-005-2 establishes a performance based maintenance (PBM) option described below. We describe these specific features in the following sections.

Which components are covered?

Which protection systems?

NERC Standards apply to the Bulk Electric System (BES). Protection Systems for BES elements must be maintained according to PRC-005-2. Responsibility for compliance falls to owners of these protection systems.

To paraphrase the NERC definition of BES in references [3] and [4]: “All Transmission Elements operated at 100 kV or higher, Real Power [Generation] resources as described [just below], and Reactive Power (var supply) resources connected at 100 kV or higher unless such designation is modified by the list shown (in a list of special inclusions and exclusions given in the definition documents [3], [4]).” Listed generation generally includes units of 20 MVA or larger, or multiple generators or distributed energy resources totaling 75 MVA or more, which connect through GSU transformers at 100 kV or above; plus black start units.

It is effective and efficient for a utility to apply the same methods as described below, and also the same management and data collection systems, to the entire relaying fleet. However, utilities that choose to apply these methods for non-BES protection systems can simplify their auditing experiences by keeping these non-BES records separately and not bringing these records into the audit of BES Protection System maintenance. They are outside the auditor’s scope of investigation.

Note that, as explained below, certain distribution protection components may be included in BES protection maintenance audits if they are part of an underfrequency or undervoltage load shedding scheme, or a special protection system (SPS or RAS) whose purpose is to protect the integrity of the BES. Maintenance requirements are relaxed for these distribution components.
**Western Protective Relay Conference - October 2014**

**Which components within a protection system?**

In development of PRC-005-2, the Drafting Team updated the official NERC definition of Protection System to include:

1. **Protective relays measuring electrical quantities** – voltages, currents, or other analog signals. At this time, mechanical sensing devices like sudden pressure relays and generator shaft vibration sensors are not included. However, FERC has directed NERC to come up with an update of PRC-005-2 that includes certain mechanical relays. That drafting work just began in the spring of 2014 and will lead to the publication of NERC PRC-005-X at some point in the near future – see just below. That will add protection components and requirements for maintaining them, but will not change the approach of PRC-005-2 described in this paper.

2. **Communication systems necessary for correct operation of protective functions.** These are usually pilot line relaying channels, but any other communications that is required for the protection to work is included. Informational or operational communications, such as those for SCADA reporting or for fault record analysis, are not included – the protection can still clear faults even when this is not working. Serial or Ethernet communications for protection and control, such as IEC 61850 GOOSE or a vendor’s serial control protocol like GE Direct I/O® or SEL Mirrored Bits®, are part of the Protection System but are normally included with the control circuitry of (5) just below.

3. **Voltage and current sensing inputs to protective relays and associated circuitry from the voltage and current sensing devices.** Note that the instrument transformer definition focuses now on the signals they deliver to protective relays with accuracy required by the protection functions. There is no concern here with physical issues of the instrument transformers themselves. Utilities used to suffer adverse audit findings from not having records of CVT insulator washing or other physical instrument transformer maintenance. The new definition narrows the scope and eliminates the issue.

4. **Station dc supply.** The station dc supply is not just the battery that was listed in the old definition – it includes the charging system and the connections that bring auxiliary power to the protection system components. This is a moderate expansion of the scope of included devices.

5. **Control circuitry associated with protective functions from the station dc supply through the trip coil(s) of the circuit breakers or other interrupting devices.** This is where one might include 61850 GOOSE or vendor serial protocol based control and status signaling, as well as wired control circuits. The power circuit breaker is not included in any NERC maintenance requirements, but this definition calls out each of the trip coils for validation. This means that each trip coil must be energized and observed to make the breaker or pole trip. With dual trip coils, each must be validated by itself.

**PRC-005-3 and -X**

The relays and other components in PRC-005-2 are those whose job is to clear faults on the BES or to protect it from threatening events or dynamic conditions (UFLS, UVLS, and SPS). Reclosing and other auxiliary functions were not included. However, more recently, FERC became concerned about the potential malfunction of certain reclosing relays.

Reclosing relays on BES transmission lines generally are applied as an operational convenience to speed up restoration after temporary faults. Other NERC transmission planning (TPL) reliability standards require that the transmission system be designed and operated so that there will be no impact if a line is permanently faulted and removed from service (reclosing reaches end of cycle, or fails to reclose). Accordingly, reclosing is not essential to the operational integrity of the BES.

The concern of FERC and NERC, however, focuses on the risk of incorrect reclosing into large generating plants comprising a major portion of the BES generation, which could lead to the loss of that generation and could trigger a cascading or widespread outage. FERC therefore asked the NERC Protection System Maintenance and Test Standard Drafting Team (PSMTSDT) to modify PRC-005-2 to include the need for identification of the few reclosing relays that could cause such a problem by undesired reclosing. The modified PRC-005-2 was also to add the testing of the security of these reclosing relays (correct restraint when electrical conditions do not justify reclosing). In 2013 the Drafting Team circulated drafts of PRC-005-3, the second phase of PRC-005 revision, which looks like PRC-005-2 except for the added identification and testing requirements for this small population of selected reclosing relays. Draft PRC-005-3 has been accepted by the industry in multiple confirmation voting cycles. It is approved by the NERC board and is undergoing final review by FERC. It is likely to become mandatory and enforceable in 2014 or 2015 – again with an implementation program of years.

Phase 3 of the PRC-005 revision cycle has been designated as PRC-005-X. This new modification of PRC-005-3 adds testing requirements for certain mechanical sensing relays like sudden-pressure or fault-pressure
relays on BES transformers, not presently in the scope of PRC-005-2. PRC-005-X development has been taking place during 2014 – at time of writing, the industry protection asset-owning stakeholders have just voted to approve the latest draft. The time frame of NERC/FERC approval and implementation is not yet defined.

To support PRC-005-X, the drafting team has added a NERC definition of Sudden Pressure Relaying - a system that trips interrupting devices to isolate the equipment it is monitoring and includes a fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of faults within liquid-filled, wire-wound equipment. It also includes control circuitry associated with the fault pressure relay.

The odd nomenclature PRC-005-X is a temporary designation because PRC-005-3 is now being modified by two drafting teams simultaneously – NERC Project 2007-17.3 (Protection System Maintenance and Testing that created the prior versions) and NERC Project 2014-01 (Standards Applicability for Dispersed Generation Resources (DGR)). Separating the changes is necessary so that the DGR Standard Drafting Team can petition government authorities for changes to the applicability part of the standard on a separate time frame from the other technical changes by the Protection System Maintenance Standard Drafting Team. The two drafting teams must coordinate to bring the separately developed changes, executed in different sections of the standard, back into a single version later.

Neither PRC-005-3 nor -X impact the approaches of PRC-005-2 for fault protection systems, as described in this paper.

Tables of maintenance intervals and activities in NERC PRC-005-2

The core of the protection system component maintenance requirements are listed in an extensive series of maintenance tables in PRC-005-2. A 2010 paper at the present conference [5] illustrated the structure of these tables – only the wording details have been edited from then to the present final version for clarity. The fundamental approach of maximum maintenance time intervals and minimum activities has been stable.

The tables present in sequence the maintenance requirements for all the categories of components of a Protection System, as we listed them above under “Which components of a protection system?” in its appended Maintenance Tables. The tables specify absolute maximum time intervals between maintenance sessions for each particular component type, considering in some cases how it is applied. Each table is structured to list the most basic time based maintenance (TBM) requirements in the top row before showing other options. Successive rows define some levels of continuous automatic self-monitoring or performance monitoring, and then give increased time intervals and reduced maintenance activities that are justified by that monitoring – leading to a condition based maintenance (CBM) program. The CBM section below gives additional design guidance for monitored systems and components.

Performance based maintenance (PBM) programs are presented in a completely different way. A PBM program for a particular type of component is built from the TBM tables via a management process for time interval extension based on reliable history, as given in Attachment A of the standard [1]. The paper section Specifics of PBM programs further below explains the subtleties of implementing such a program.

The tables in PRC-005-2 and -3 are:

- Table 1-1 – Protective Relays
- Table 1-2 – Communications Systems
- Table 1-3 – Voltage and Current Sensing Devices Providing Inputs to Protective Relays
- Table 1-4 (a) through (e) – Station dc supply, based on a series of specific battery types or non-battery technology
- Table 1-4 (f) – Maintenance reduction for dc supply systems based on monitoring technologies in use
- Table 1-5 – Control Circuitry Associated with Protective Functions
- Table 2 – Alarming Paths (unmonitored and monitored)
- Table 3 – Components in Distributed UFLS, UVLS, and SPS schemes (simplified activities for certain components as compared to what Tables 1 require)
- New in PRC-005-3 - Table 4 – Automatic Reclosing Components (only the particular reclosing schemes defined elsewhere in the standard that could incorrectly reclose on very large generation facilities)
- New in PRC-005-X – Table 5 - Maintenance Activities and Intervals for Sudden Pressure Relaying
Commissioning versus maintenance tests

The focus of this testing discussion is maintenance testing, which we now distinguish from commissioning tests. A site acceptance test (SAT) or commissioning test is performed at time of installation. The protection system is subjected to a comprehensive test of every needed function, to show it performs all the functions exactly as required for service. The goal is to uncover any design, setting, or installation errors; or problems of interaction between the installed system and the power apparatus to which it connects. A new recommissioning test may be required after a disruptive repair or modification of an existing installation.

In general, commissioning tests include system tests in which the overall correct operation of the Protection System is demonstrated under a variety of simulated real-world scenarios.

In FERC's July 2013 Notice of Proposed Rulemaking (NOPR) that proposed to make PRC-005-2 mandatory and enforceable, FERC also directed NERC to start looking at new standards for commissioning testing, which has different objectives as we just explained. However, the future standard requirements for commissioning testing will be developed during a long journey on which the industry now finds itself – the subject of future papers. At this time, the NERC System Protection and Control Subcommittee (SPCS) is investigating what might comprise a reasonable and effective commissioning test standard. It will issue a technical report or reference document for use by a future commissioning standard drafting team.

Commissioning test is also a maintenance test

It is important for users to note that the commissioning test is also the first maintenance test for the new installation. The commissioning tests should include all the testing requirements of PRC-005-2 – and they certainly must go a lot further to validate the correct design, installation, and full functioning of the protection system.

The commissioning test date defines the deadlines for all future tests according to the maximum time intervals for each component type in PRC-005-2. Keep the records of the commissioning test as evidence of this first maintenance test – it may be a key component for maintenance testing audits by NERC or its regional reliability organizations (RROs) like WECC.

When the commissioning test plan is developed, the recording of results should be structured to easily demonstrate that all the maintenance testing requirements were met on the date of each component or system commissioning test. This may simplify future audit efforts.

Maintenance testing objectives

In subsequent maintenance tests, equipment in service is periodically tested to verify that it is still functioning as it was when it was commissioned. The goal is to determine that there have been no failures of components, damage to the installation, loss of calibration, or unobserved changes in configuration that could cause the system not to function as it did in the past. There is no objective of proving yet again that the already-commissioned installation was designed, wired, or configured properly, as long as the configuration has not been changed.

For maintenance testing, each component can be tested individually, as long as the boundaries of tests overlap so that no part of the system is left untested (including wiring or signal exchange paths). End-to-end tests are also a fine way to validate the operation of a protection system, as long as the user is aware of exactly which hardware elements (elements that could have failed or drifted since the last test) were or were not tested in such a system test. For example, multiple trip contacts to breakers that were isolated for testing need to be checked individually with their wiring.

The most important observation about the maintenance test is that it does not need to repeat what was shown in laboratory or commissioning tests. The design doesn’t change in service by itself. We are only looking for failures and human-induced unknown changes. What might fail or change depends on the equipment generation – electromechanical relays can exhibit drift or failure of any piece in a large protection system, and there is no way to find this hidden failure but to test the performance of each of those pieces. By contrast, newer microprocessor based products tend to work as designed and set - observably alive, stable, and accurate - until there is a clear failure that is easy to spot.

In many cases we explain below, an invasive test or a microprocessor relay or communications device by a human technician is neither required nor a good idea. Condition monitoring of microprocessor relays can alarm for most of the same problems the maintenance test would find, and the new NERC standard tells users how to avoid unneeded testing with proper use of condition monitoring features in these relays – the
condition based maintenance (CBM) program we discuss below. In CBM, we generalize the idea of a maintenance test to that of maintenance verification – knowing by any means that there are no failures or problems that a maintenance test was aimed at finding.

Validating settings

In maintenance tests, it is not necessary to reverify the performance of a part that doesn’t change or fail on its own. For example, the Zone 2 phase distance relay on an electromechanical panel can fail or drift, and needs periodic testing. However, in a multifunctional microprocessor relay, it is only necessary to determine that the relay is measuring its ac inputs properly, that its internal processing electronics are running, that it is able to close its trip contact, and that it is still set for Zone 2 reach (and the rest of its multiple zones and functions are set) as intended and validated in the commissioning test.

The settings of a microprocessor relay can be validated by comparing them with a reference setting file, as opposed to testing each zone or function. There is no further benefit in testing all the distance zone boundary points with a relay test set to make sure they are all where they should be. They will be in the intended places - they can’t move around in this type of relay if the setting file has been validated. On the other hand, if the relay was not applied correctly or settings were incorrectly calculated at the outset, and the problem eluded the commissioning test, no amount of extra maintenance testing will show the problem – the problem needs to be fixed in the application and setting calculation process.

It is worth noting here that some application settings, like zone reaches or overcurrent thresholds, may be updated after a periodic coordination study, perhaps performed using wide area fault simulation and coordination study software. It is valid to update these settings in a monitored microprocessor relay without retesting, if the utility has a rigid file or configuration management system that can always provide the assured valid settings for each relay. This version control or configuration management can eliminate a lot of testing of changes, although some utilities still prefer to take each relay out of service and test the changed settings.

Maintenance testing program choices – TBM, CBM, and PBM

Relationship of Maintenance Types

TBM is the overarching maintenance process of which CBM and PBM are subsets.

In a TBM program for protection systems, the maintenance time intervals and activities are fixed, and are set by experience and/or by regulatory specifications like NERC PRC-005-2 maintenance tables.

Fig. 1 Relationship of time based maintenance types
CBM is a form of TBM in which automatic maintenance checks are embedded in the on-line operation of the monitored equipment, with time intervals that typically range from milliseconds to hours rather than months or years.

PBM is another form of TBM in which the time intervals are adjusted based on good or bad failure experiences in TBM testing. However, as we explain later, the experience must still be processed into a (longer) TBM interval with a basis calculated from a data mining process. Maintenance activities still tend to be fixed as in TBM, but with greatly extended time intervals for reliable component types.

TBM, PBM, and CBM may be combined for individual components, or within a complete protection system, to achieve the best overall result.

Figure 1 illustrates the relationship among various types of maintenance practices. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- **Region 1**: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.

- **Region 2**: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.

- **Region 3**: Optimal TBM intervals based on regions 1 and 2.

**Time Based Maintenance (TBM)**

Testing on a periodic time schedule, as the industry has done since its inception with electromechanical and analog solid state relays, is described today as Time Based Maintenance (TBM). Prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior user or industry experience, or from manufacturers’ recommendations. The PRC-005-2 tables defining intervals and activities were listed in a section just above. The protection asset owner can test more often, and generally will create a maintenance program with time intervals considerably less than the maximum allowed intervals in the standard to accommodate practical scheduling of work, maintenance emergencies, or personnel errors without slipping into non-compliance findings and audit fines. For example, an electromechanical or analog solid state distance relay must be tested within six calendar years. A relay tested any time in 2010 must thus be tested by the end 2016 at the latest to be in compliance. The owner may schedule the next maintenance session for 2015, five years after the 2010 test, to stay well within the limit and to have margin for personnel, work rescheduling, or storm induced delays.

**Documentation**

Requirement 1 of PRC-005-2 calls for the asset owner to document all the implementation specifics of the chosen protection system maintenance program (PSMP) that complies with PRC-005-2. They must also document all of the actual maintenance activities in accordance with that PSMP – down to specifics of every test of every relay, each time it is tested. Auditors will review the PSMP for compliance with the Standard, and will study maintenance records to find specific evidence that the PSMP is being carried out. The standard of performance is 100% - failing to perform properly documented tests in accordance with the PSMP and within the PSMP scheduled time limits, for even a single relay, is a failure of compliance that auditors may cite and fine.

**Event based maintenance (EBM)**

EBM is not a testing choice in itself. However, a TBM program can include review of records of protection system response to faults and power system events near a particular protective relaying terminal – oscillograms and sequence-of-event records, evaluated along with the protection design drawings. These operational records may help with TBM by proving that some portion of the protection system has operated correctly since the last time-based maintenance test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those specific components. This has been described as event based maintenance (EBM).

EBM may be difficult to apply broadly because of the human effort required to parse the operating records for evidence, combined with analysis and written documentation of exactly what was and was not validated by
natural fault and system events. For example, a routine lightning-induced Zone 1 fault may pick up Zone 2 and Zone 3 relays in a DFR record, but their calibration within required limits is not verified. If the Zone 1 or pilot primary relay works as it should and neither Zone 2 nor Zone 3 gets to trip, then the backup tripping capability is not validated. The Zone 1 relay tripping is validated, but its calibration is not validated either.

Notwithstanding these limitations, most users evaluate all BES relay operations looking for misoperations that must be reported to regional organizations anyway, and may be able to check off certain components whose operation and/or calibration were proven.

While EBM cannot replace the other choices, EBM event analysis has a strong ability to reveal hidden in-service problems that no maintenance test would find – such as engineering application errors or relay firmware bugs from the vendor. [6] is a comprehensive reference on analysis of protection system event data, and benefits of investing effort in this analysis.

**Condition Based Maintenance (CBM)**

CBM is a maintenance program based on equipment whose integrity and performance can be observed while the equipment is in service – relays or components that are actually monitoring or testing themselves as they perform their protection jobs. Continuously or frequently reported results from non-disruptive self monitoring of components demonstrate that the equipment is operational - we are achieving maintenance verification that is as good as or better than that of human TBM testing. The self-monitoring components of the protection system do not need to be manually tested – we leave them alone until the monitoring reports a failure. It is also possible for a self-monitoring component like a microprocessor relay to monitor other protection system components connected to it – notably instrument transformer signals, trip circuit continuity, and end-to-end functioning or performance of a communications channel between relays.

Whatever is verified by CBM does not require manual TBM testing, but taking advantage of this requires precise technical focus on exactly what parts are included in the self diagnostics. Most of the internal components of a modern microprocessor relay are monitored. Self-monitoring capabilities may include the ac signal inputs, analog measuring circuits, processors and memory, trip circuit monitoring, and protection or data communications signals. For failure of those parts, a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips.

**Monitored components versus components requiring test**

In general, self monitoring can be instituted for parts of a relay that have some continuous, repetitive loop or heartbeat process in normal operation whose disruption can be detected and reported. Most of the protection-critical elements inside a microprocessor relay meet this criterion, and their failures will be alarmed. Quiescent, unchanging circuits can’t monitor their ability to operate; the same is true for any mechanical device, such as an output relay with contacts.

Accordingly, a few internal circuits such as trip output relay driver transistors and output tripping relay coils and contacts are not equipped with self-monitoring capability, and they must be periodically tested. Contact inputs that remain in the same state most of the time are similarly not subject to monitoring. These circuits and devices must be periodically tested. The method of TBM testing may be local or remote operation, or through observing correct performance of the component during a system event via EBM.

NERC PRC-005-2 effectively eliminates maintenance testing for any component or part of a component whose failures are monitored and alarmed.

**Extending maintenance intervals and reducing work steps with monitoring**

Even without thorough analysis of the internal design, PRC-005-2 extends the six-year maximum testing interval that applies electromechanical (EM) or analog solid state (SS) relays to 12 years for any full microprocessor relay (defined in the standard as one that samples its incoming current and voltage signals and mathematically processes the resulting digital numeric values). The microprocessor relay self-monitoring alarm output must be monitored for failure response by maintenance personnel. Even at 12 years, the maintenance tests are simpler than those for EM or SS relays, mostly validating ac and status inputs, trip and control outputs, and checking to be sure the settings are as intended (by comparing the in-service setting file to a reference setting file; actual field testing of settings is not required).

If the alarms are conveyed by mechanical contacts, the alarming contacts and resulting maintenance notification must be validated every 12 years. However, Table 3 of PRC-005-2 shows that if the alarming path itself is continuously monitored, no testing of the alarming ability is needed either. For example, a relay whose microprocessor communicates via DNP3 or IEC 61850 heartbeat messaging to a substation host processor, which in turn communicates by DNP3 heartbeat with the control center computer, can alarm
system operators or maintenance personnel. The alarm messaging function has a constant communications message heartbeat process so that failure of the alarming path always produces its own alarm or notification to the operators. This alarming path needs no time-based maintenance testing.

Tables 1-1 through 1-3 of PRC-005-2 show how we can approach a maintenance free design if we incorporate the following design features that are widely available today:

- Monitored microprocessor relay – virtually all internal electronics of a modern relay needed for protection are self-monitoring and produce alarming messages (or complete loss of operational messaging heartbeat) for any failure.
- Validation of ac input calibration by automated comparison with other relays or independent measurements. This checks not only the relay calibration, but that of the instrument transformers, and the integrity of their connections to the relays.
- Trip circuit continuity/energization monitoring (TCM function in relay).
- Alarming for any change of settings, so technicians can validate that the change was intentional and that the revised settings are as intended.
- Performance monitoring of the communications channel for the pilot line protection scheme.

With this design, the only testing ever required is for the relay’s ability to close its trip contacts, and to sense any binary inputs needed for correct protection operation (like 52a breaker status contact input in certain pilot protection schemes). These two testing details can be carried out from the control center by tripping through the relay and observing the breaker state change; it can be performed by an operator at the substation (as opposed to a relay technician with test equipment and a scheduled outage); or it can be gathered from operating records. This is very close to complete freedom from maintenance, until there is an actual failure needing repair or replacement.

With dual trip coil breakers, each trip coil must be validated independently. One design strategy is to use both coils for protection, but to use one for operator tripping from the control center, and the other for operator tripping in the substation. Then the control center and on-site operator trips taken together validate both trip coils. This is only required every six years; most utilities perform breaker maintenance more often than that and thus have plenty of opportunities to deal with trip output and trip coil tests.

**Reliability enhancement with CBM**

The protection reliability enhancement with CBM is a benefit just as important as the reduction in maintenance work. CBM verification comprises non-disruptive, repeated functional checks that are embedded in the normal operating cycles of monitored devices like microprocessor relays, or communications systems with heartbeat messaging whose degradation or disappearance can trigger an immediate failure alarm.

The internal checking intervals can be minutes, seconds, or even milliseconds within or around Protection System components as they continue to perform their protection job. Human testing every few years cannot provide this instant identification of a problem. A manually tested component may fail shortly after it was tested, leaving a hidden problem that is discovered when it causes a misoperation before the next scheduled test. CBM exposes the failure right away. Therefore, CBM can greatly enhance overall reliability of a monitored protection system.

**CBM program documentation**

Documentation is different for CBM than for TBM. The owner must compile a PSMP document for CBM that shows what parts of the protection system are monitored, versus those that are TBM tested, with some justification from manufacturers’ literature. Relay or communications equipment vendor instructions can support the self-monitoring justification for internal electronics, while inputs and outputs must be tested. Ac voltage and current inputs can be monitored by an automated, continuous comparison of microprocessor relay metered values with readings of redundant relays or with EMS values, all during normal service. As long as an excessive comparison error will always produce an alarm, ac input calibration need not be tested. Note that the alarm doesn’t have to point to whether it was the relay or its reference comparison source that failed – the actual troubleshooting diagnosis can be left for the technician who carries out the repair. It is sufficient to show that any functional problem that impacts protection will produce an alarm and will trigger technician troubleshooting.

If the relay alarms for a change of settings, and a maintenance person checks for validity of that settings change, then no other periodic settings tests or confirmation are needed either.

There is extra work to create this CBM program documentation. Therefore, CBM design is easiest to document when the asset owner has developed a standard protection and control design that is deployed in
most BES stations – it is more work if every station is different and requires its own CBM-based PSMP document.

When CBM is used, the owner realizes huge benefits. Most of the expensive TBM field maintenance testing work is avoided. The massive task of keeping records of every single maintenance test is also mostly eliminated. As explained above, CBM can also improve protection reliability.

For a more positive auditing experience, it is helpful to keep a log of monitoring failure alarms, and remedial actions taken in response. This demonstrates effective CBM management to auditors.

**Performance Based Maintenance (PBM)**

PBM is a maintenance program whose time intervals are established based on analysis of historical results of TBM failure rates on a statistically significant population of similar protection system components. This approach is also sometimes called reliability-centered maintenance or RCM. If a particular category of components has shown very low failure rate in TBM testing records, the maintenance interval is extended as much as possible while keeping an acceptably low failure rate.

Even after documented low failure rate experience has been used to justify extended time intervals, some infrequent TBM must be carried out to justify continued use of extended intervals, and to discover any increase in population failure rates requiring a change back to a more frequent testing program. More frequently, such an adverse trend in test results points to remediation of a specific failure problem across the particular population of devices.

NERC PRC-005-2 has a specific PBM program option documented in Attachment A of the standard. We describe this in more detail in the next section. With this PBM process, highly reliable electromechanical or other relay types with low failure rate findings can have their maintenance intervals extended to as much as 20 years. Examples are EM time overcurrent relays, most lockout relays, and high impedance bus differential relays that rarely fail or lose acceptable calibration. These example relay types have maximum TBM intervals of 6 years in Table 1 of PRC-005-2. PBM can be applied to any protection system component that has good reliability experience as documented in TBM records – even to microprocessor relays.

**Specifics of PBM programs**

PBM is the undiscovered territory of opportunity for reduction of maintenance effort, so we focus special attention on it in this paper. Since it is applied to reliable component types that rarely fail, it can actually enhance reliability by reducing maintenance induced errors (such as failure to restore all test switch positions, disruption of wiring, or damage to internal components by improper mechanical or electrical test procedures).

**Process overview**

The NERC PRC-005-2 Attachment A process describes a structured method of developing and managing a PBM maintenance program. The fundamental process steps are listed here. With each step, we include an example to clarify the process for the reader.

1. Identify and document the specific population groups or segments of protection system components that your experience shows to be reliable and needing less testing. The group or segment comprises devices of a particular design from a single manufacturer. There need to be at least 60 similar devices in each documented population group. Similar devices from different manufacturers must be classified in separate segments.
   a. *Example* – Create a population group or segment with an asset list of 600 single-phase high impedance bus differential relays from one manufacturer for which we have maintenance data and have observed very low failure rates.

2. Perform TBM on each of these groups according to PRC-005-2 tables to get hard failure rate data. Users who kept good databases of maintenance test results from the past can use that data to begin PBM right away.
   a. *Example* – For the segment of high impedance relays, we already have data showing that with a maintenance interval of 6 years (about 100 relays tested per year), we find only one failed relay every other year on the average (failure rate of 1% of tested relays in a year
when one relay is found to have failed or been out of acceptable calibration; 0.5% on the average).  

3. Use the test results to determine the maintenance interval, longer than the standard TBM table interval, for which the failure rate findings are expected to come in below an acceptance threshold of 4% per year for NERC compliance. While 4% is specified as the limit in Attachment A, this paper suggests that a failure rate of 2% per year or less is a more practical threshold for a hassle-free PBM experience. There are plenty of reliable devices with test failure rates of under 2% per year.

   a. *Example* – For our high impedance relay segment, we observe that with our average failure rate of 0.5%, we could in theory increase our test interval by a factor of 4, to 24 years and still stay under a finding of 2% found failed per year, which is well under the 4% NERC limit. Extension of the test intervals is not causing the relays to fail more – the failure finding rate is expected to go up because we are leaving relays for a much longer time between tests.

4. Use the interval determined in (3.) to establish a practical testing time interval for the subject component population. Test with more or less uniform distribution of testing event counts from year to year, testing at least 5% of the population group each year to catch adverse trends.

   a. *Example* – For the segment of high impedance relays, we implement a test interval of 20 years by testing 5% of the segment or 30 relays each year. Even though the low failure rate we saw in the past would seem to support an even longer interval of 24 years, we are required to test enough relays each year to observe an increase in failures to an aging or wear-out problem. A different utility might have an established 5-year cycle for substation visits, and might choose to test the subject relays on every third visit (every 15 years) to be sure of staying in compliance with the 20-year interval.

5. Review the maintenance results every year, *documenting the analysis of the numbers* and showing that the failure rate finding is below the annual threshold.

   a. *Example* – Our PBM Management Team conducts a documented meeting each year, in accordance with what our PSMP says we do. In the majority of years, we learn that none of the 30 tested high impedance relays in this group had a problem. About every third year on the average, we learn that one relay had failed – the failure rate for that year is 3.3% of units tested. This is within the NERC 4% limit, but we can also observe for our own action planning that our average failure rate is a little more than 1%, well under the limit.

6. If the failure rate rises above the threshold, implement a monitoring and mitigation program so that the annual failure percentage will drop back below the 4% threshold within 3 years.

   a. *Example* – If we were to find two failures after testing 30 devices in one year, we would exceed 4% in that year. If the two failures seem unrelated, we can note this fact and wait for the next year, as we have 3 years to show a rate back under 4%. If we found two similar failures, we would then watch closely for causes of subsequent failures, and decide on mitigation or a repair program if some age-related problem may be affecting the entire segment.

Our example high impedance relays are generally reliable and stable over many decades of service. If we had chosen for our example a group of analog solid state relays, we might find similar reliable behavior for perhaps 20 years. It could happen that, after this time, capacitors in the power supply deteriorate and begin to fail at too high a rate to allow continued PBM with long intervals. In this case, the owner must either fix the problem by replacing the capacitors and showing that the failure rate has returned to a low value within 3 years; or must move the segment back to 6-year TBM. If the problem is very serious, these particular relays may need even more frequent testing than NERC PRC-005-2 requires, avoiding the risk of misoperations that could cause a blackout. Perhaps it is time to replace this group of relays.

**Component population segments**

The population group of similar devices is called a *Segment* in the NERC Standard. A Segment is a group of “Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.”

The segment normally includes similar devices (same product model) from a single vendor. Examples could be Electroswitch® type LOR® lockout relays, GE® type HEA® lockout relays in a separate segment, and
GE® type PVD® high impedance bus differential relays in yet another segment. Each of the components in a segment should have similar service conditions – for example if a component is of a type that may be impacted by a dirty power plant environment, the population in power plants should be placed in a segment that is separate from those in cleaner transmission and distribution substations.

The author believes that it is plausible to group microprocessor relays of different specific models from a single manufacturer in one segment if the internal electronic platform is demonstrably the same platform shared among the grouped models. However, we have not yet accumulated compliance audit results that would validate this belief. Manufacturers need to supply documentation regarding products that share a common platform such that the reliability experience is expected to be about the same.

**Segments via assembled multiuser database**

60 or more components are required in a segment to yield a statistically valid assessment of failure rate. Thus, at least 3 components are tested each year to meet the 5% per year minimum testing requirement. The standard specifically allows multiple owners of smaller populations to bring their segments together in a joint PBM program and management process, as long as the device types and service conditions are consistent among the collaborating owners. For example, generating plant owners each of whom only own a small count of lockout switches could form a PBM PSMP consortium in which they aggregate the maintenance programs and data for their populations, to reach a jointly-managed PBM PSMP for more than 60 devices owned by the consortium.

The author believes that, as PBM is understood and valued as a PSMP choice, the industry will develop the means of gathering, normalizing, and assembling data from populations of like devices across the industry. These centrally managed populations will then provide evidence of failure rates for use by all the participants in the database process in their PBM based PSMPs.

**Failure events that count for PBM**

Adverse maintenance findings (performance deficiencies or hard failures) that count as failures in the official PBM segment performance assessment process are called *Countable Events*. A Countable Event is defined as “a failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in [NERC PRC-005-2 maintenance tables] which require corrective action, or a Misoperation attributed to hardware failure or calibration failure.”

Conversely, the definition explains what problems should *not* be counted against the population statistics - “Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.”

Failures that are not countable events will not draw attention or action during the PBM PSMP annual performance review for a segment. Nonetheless, it is important to act on the causes of uncounted failure events to avoid misoperations that will appear after a system event to have been predictable and avoidable. For example, if maintenance work shows a high rate of setting value errors, the owner should look at finding and fixing problems in the settings management and application process, as well as checking the whole population for application of correct settings. If application errors are common, an organizational peer review process for application and settings development may be lacking.

**Reliable field assessment of countable versus non-countable events**

One of the key implementation challenges in PBM is to set up maintenance activity databases so that *technicians can distinguish between counted and uncounted maintenance fixes, and put the distinction into the database*. Clearly, part of this challenge is to teach those technicians how to tell the difference. As a general rule, a problem that was not there at the time of the last test and emerged on its own since that test is countable. If the problem was there all along, perhaps hidden, and didn’t result from an actual hardware deterioration or failure, it is generally not countable.

One strategy under development is to offer the technician a specific list of choices to describe exactly what was the nature of the adverse maintenance finding. The list is cast in terms of what the technician saw (e.g. device out of acceptable calibration range) rather than using any NERC PBM language. The database, rather than the technician, then automatically assigns the problem to the countable or non-countable tally.

**Failure rates**
NERC PRC-005-2 requires that 4% or less of the tested devices in a segment show countable event failures in a review year. This number was chosen to allow application of PBM to small populations of 60 devices, for which a lower allowed failure rate would end the PBM program even if one device in the segment suffers a random failure.

The author has found that many utilities are interested in implementing PBM, but a few are just beginning work on collecting the justification data. In time, there will be a stronger base of experience to justify a specific threshold.

Meanwhile, [7] is a reference showing experience suggesting that a threshold of 4% is easily achievable for a reliable subset of relays, while known less reliable products like EM distance relays are not amenable to PBM – some will show calibration problems every time they are tested. For the reliable products, a lower threshold might be used for sensitive tracking of performance.

**Proposed practical failure rate targets**

In practical programs, a 4% failure rate is judged by the author to be a rather high value. Reliable devices should do much better. Many reliable device types in widespread use have failure rates under 1% per year even for 6, 8, or 10 year maintenance intervals.

If a user attempts to apply PBM to a segment that is barely better than 4%, there is a high risk that failure problems will arise, making the management program unstable and complex to run. Constantly-changing maintenance intervals will be challenging for field maintenance organizations.

To understand this problem, see the PBM implementation examples in the NERC PRC-005-2 Technical Reference and FAQ guidance document [2], in Section 9.2, beginning on Page 40. The chosen example components have a significant failure rate, not suitable for a 20 year interval, and requiring changes of interval in the 6 to 8 year range as the failure rate drifts above and below 4%. While the most challenging mathematical calculations are clearly demonstrated in these examples, the reader is left with the impression that PBM is way too challenging for practical use.

The author proposes to completely avoid this problem by starting with *segments whose failure rates are below 1% in an existing 6-year program*, or less than 2% in existing programs having longer time intervals. If the failure rate is well below 1% for testing after 6 years, it is permissible to go straight to a 5% per year (20 year) testing regimen, and there is still some reliability margin for performance deterioration without having to reduce the maintenance interval again.

One attractive specific use for PBM is to extend the 6-year TBM interval for lockout switches to 12 years, to align the testing work for the lockout switch with the 12-year test cycle for the rest of the control circuitry. The author has seen evidence that most lockout switch types do in fact have low failure rates in testing that would justify this extension; utilities would experience stress-free and stable PBM management processes as they find failure rates far below 4% per year for the one-twelfth of the population of lockout switches tested.

**Conclusion - role of technicians and test sets in CBM and PBM**

A reader might conclude here that the author foresees a decline in the amount of testing work to be performed as new testing methods are absorbed, so that there will be fewer jobs for maintenance technicians and less need for relay test sets. Actually, the author expects the opposite – the workload will remain high and the need for new equipment will remain strong.

TBM as performed in past decades is supported in the new NERC maintenance standard, and many or most utilities will carry on for years as they begin a process of adapting to new methods and opportunities described above.

**Asset sustainment and replacement challenges**

Meanwhile, the newest microprocessor-based Protection System relays and components that are most amenable to CBM are experiencing dramatic reductions in service life – they are built of programmable electronic components whose technology is advancing so rapidly that a vendor can supply a platform for only a few years. Vendors only assure a 15 year service life, and even that assurance includes a warning that the vendor may have to substitute a newer product of similar form and function within that interval. A rather different paper co-authored by the present author [8] explores the asset management challenges of mixed fleets of old and new relays, and highlights the asset sustainment problems when EM fleets are replaced with new systems having a shorter service life. In short, the rate of replacement must be higher in the future than most users are carrying out today. The paper [8] advocates new protection system panel and building design approaches to help with the sustainable asset replacement programs.
**Need for technician focus**

In accordance with this situation – the author has found in surveys that major utilities' protection asset replacement programs are often *handicapped more by the lack of technicians for commissioning new equipment* than by capital budgets! The needed technicians are too busy testing old relays as required by NERC reliability standards. On top of this, many experienced technicians are retiring or will retire in the next few years. Utilities which have not yet engaged in vigorous relay replacement programs yet will need to do so in coming years, and will then experience these same problems.

This makes a strong case for using CBM and PBM to free technicians for protection system asset renewal work that will continue forever into the future. Strong employment opportunities and technically interesting work will remain. The fact that CBM and PBM can improve protection reliability is a huge additional benefit of making the change.

**New testing equipment**

While CBM seems to reduce the need for test sets, in fact they are still required for troubleshooting – the microprocessor based systems with CBM will fail, alarm, and need attention. Similarly, test systems are needed for commissioning the new protection systems that will be replaced more often than in the past, as explained above. There may be an increase rather than a decrease in demand. On top of this, new test sets must handle more complex testing requirements, especially for new designs based on Ethernet networking and/or on IEC 61850 communications that replaces much of the conventional wiring. Sophisticated, easy to use test sets are needed to analyze network traffic and show correct performance of functions that once operated over masses of dedicated wires.

It should be apparent that, on top of test equipment, maintenance organizations will need new database systems and tools to manage any of these maintenance programs. The test equipment, databases, and users must interoperate and collaborate to achieve a compliant and efficient maintenance program based on TBM, CBM, or PBM.

**References**


About the Author

Eric A. Udren has a 45 year distinguished career in design and application of protective relaying, utility substation control, and communications systems. He works with major utilities to develop new substation protection, control, and communications designs. Eric is IEEE Life Fellow, Chair of the Relaying Communications Subcommittee of the IEEE Power System Relaying Committee. He is US Technical Advisor for IEC relay standards; and is member of the IEC TC 57 WG 10 that develops IEC 61850. Eric serves on the NERC System Protection and Control Subcommittee (SPCS), and the NERC Protection System Maintenance Standard Drafting Team developing NERC Standard PRC-005-2 and -3. He has written and presented over 100 technical papers and book chapters and has 6 patents. He currently serves as Executive Advisor with Quanta Technology, LLC of Raleigh, NC with his office in Pittsburgh, PA. Eric can be reached at eudren@quanta-technology.com or at +1 (412) 596-6959.