NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

PRC-005-2 Protection — System Maintenance Supplementary Reference (Draft 1)

Protection System Maintenance and Testing Standard Drafting Team

to ensure the reliability of the bulk power system

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Table of Contents

1. Introduction and Summary 3
2. Need for Verifying Protection System Performance 3
2.1 Existing NERC Standards for Protection System Maintenance and Testing 3
2.2 Proposed Modification to NERC Glossary Definition 4
2.3 Applicability of New Protection System Maintenance Standards 4
2.4 Applicable Relays 4
3. Relay Product Generations 4
4. Definitions 5
5. Time Based Maintenance (TBM) Programs 5
Maintenance Practices 6
5.1 Extending Time-Based Maintenance 7
6. Condition Based Maintenance (CBM) Programs 8
7. Time Based versus Condition Based Maintenance 8
8. Maximum Allowable Verification Intervals 9
Maintenance Tests 9
8.1 Table of Maximum Allowable Verification Intervals 9
Level 1 Monitoring (Unmonitored) Table 1a 10
Level 2 Monitoring (Partially Monitored) Table 1b 10
Level 3 Monitoring (Fully Monitored) Table 1c 11
8.2 Retention of Records 12
8.3 Basis for Table 1 Intervals 12
8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays 13
9. Performance-Based Maintenance Process 14
9.1 Minimum Sample Size 15
10. Overlapping the Verification of Sections of the Protection System 17
11. Monitoring by Analysis of Fault Records 18
12. Importance of Relay Settings in Maintenance Programs 18
13. Self-Monitoring Capabilities and Limitations 19
14. Notification of Protection System Failures 20
15. Maintenance Activities 20
15.1 Protective Relays 20
15.2 Voltage & Current Sensing Devices 20
15.3 DC Control Circuitry 21
15.4 Batteries and DC Supplies 21
15.5 Tele-protection equipment 22
16. References 24
Figures 25
Figure 1: Typical Transmission System 25
Figure 2: Typical Generation System 26
Figure 3: Requirements Flowchart 28
Appendix A 28
PRC-005-2 Protection Systems Maintenance & Testing Standard Drafting Team 32

This supplementary reference to PRC-005-2 borrows heavily from the technical reference by the System Protection and Control Task Force (SPCTF) Protection System Maintenance Technical Reference paper approved by the Planning Committee in September 2007). Additionally the Protection System Maintenance and Testing Standard Drafting Team (PSMT SDT) for PRC-005-2 (Project 2007-17) utilized data available from IEEE, EPRI and maintenance programs from various generation and transmission utilities across the NERC boundaries.

1. Introduction and Summary

NERC currently has four reliability standards that are mandatory and enforceable in the United States and address various aspects of maintenance and testing of protection and control systems. These standards are:

PRC-005-1 — *Transmission and Generation Protection System Maintenance and Testing*

PRC-008-0 — *Underfrequency Load Shedding Equipment Maintenance Programs*

PRC-011-0 — *UVLS System Maintenance and Testing*

PRC-017-0 — *Special Protection System Maintenance and Testing*

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a fault or other power system problem requires that they operate to protect power system elements, or even the entire Bulk Electric System (BES). Lacking faults or system problems, the protection systems may not operate for extended periods. A misoperation - a false operation of a protection system or a failure of the protection system to operate, as designed, when needed - can result in equipment damage, personnel hazards, and wide area disturbances or unnecessary customer outages. A maintenance or testing program is used to determine the performance and availability of protection systems.

Typically, utilities have tested protection systems at fixed time intervals, unless they had some incidental evidence that a particular protection system was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring relays, and correctness of settings. Typically, a protection system must be visited at its installation site and removed from service for this testing.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical BES protection functions, NERC standards have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

Purpose: To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

PRC-005 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms Used in Reliability Standards indicates what must be included as a minimum.

Definition of *Protection System* (excerpted from the NERC Standards Glossary of Terms):

Protective relays, associated communication systems, voltage and current sensing devices, station batteries and dc control circuitry.

Applicability: Owners of generation, transmission, and transmission Protection Systems.

Requirements: The owner shall have a documented maintenance program with test intervals. The owner must keep records showing that the maintenance was performed at the specified intervals.

2.2 Proposed Modification to NERC Glossary Definition

The Protection Systems Maintenance and Testing Standard Drafting Team (PSM SDT), proposes changes to the NERC glossary definition of *Protection Systems* as follows:

Protection System (modification) - Protective relays, associated communication systems necessary for correct operation of protective devices, voltage and current sensing devices inputs to protective relays, station DC supply, and DC control circuitry from the station DC supply through the trip coil(s) of the circuit breakers or other interrupting devices.

2.3 Applicability of New Protection System Maintenance Standards

The BES purpose is to transfer bulk power. The applicability language has been changed from the original PRC-005:
"*...affecting the reliability of the Bulk Electric System (BES)…*"

To the present language:
"*… and that are applied on, or are designed to provide protection for the BES."*

The drafting team intends that this Standard will not apply to "merely possible" parallel paths, (sub-transmission and distribution circuits), but rather the standard applies to any Protection System that is designed to detect a fault on the BES and take action in response to that fault. The Standard Drafting Team does not feel that Protection Systems designed to protect distribution substation equipment are included in the scope of this standard; however, this will be impacted by the Regional definitions of the BES.

2.4 Applicable Relays

The NERC Glossary definition has a Protection System including relays, dc supply, current and voltage sensing devices, dc control circuitry and associated communications circuits. The relays to which this standard applies are those relays that that use measurements of voltage, current, frequency and/or phase angle and provide a trip output to trip coils, dc control circuitry or associated communications equipment. This definition extends to IEEE device # 86 (lockout relay) and IEEE device # 94 (tripping or trip-free relay) as these devices are tripping relays that respond to the trip signal of the protective relay that processed the signals from the current and voltage sensing devices.

Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included.

3. Relay Product Generations

The likelihood of failure and the ability to observe the operational state of a critical protection system, both depends on the technological generation of the relays as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices such as primary measuring relays, monitoring devices, control systems, and telecommunications equipment.

Modern microprocessor based relays have six significant traits that impact a maintenance strategy:

- Self monitoring capability - the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs such as trip coil continuity. Most relay users are aware that these relays have self monitoring, but are not focusing on exactly what internal functions are actually being monitored. As explained further below, every element critical to the protection system must be monitored, or else verified periodically.
- Ability to capture fault records showing how the protection system responded to a fault in its zone of protection, or to a nearby fault for which it is required not to operate.
- Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-fault times. The relays can compute values such as MW and MVAR line flows that are sometimes used for operational purposes such as SCADA.
- Data communications via ports that provide remote access to all of the results of protection system monitoring, recording, and measurement.
- Ability to trip or close circuit breakers and switches through the protection system outputs, on command from remote data communications messages or from relay front panel button requests.
- Construction from electronic components some of which have shorter technical life or service life than electromechanical components of prior protection system generations.

4. Definitions

Protection System Maintenance Program (PSMP) – An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program can include:

- **Verification** — A means of determining that the component is functioning correctly.
- **Monitoring** — Observation of the routine in-service operation of the component.
- **Testing** — Application of signals to a component to observe functional performance or output behavior, or to diagnose problems.
- **Physical Inspection** — To detect visible signs of component failure, reduced performance and degradation.
- **Calibration** — Adjustment of the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
- **Upkeep** — Routine activities necessary to assure that the component remains in good working order and implementation of any manufacturer's hardware and software service advisories which are relevant to the application of the device.
- **Restoration** — The actions to restore proper operation of malfunctioning components.

5. Time Based Maintenance (TBM) Programs

Time based maintenance is the process in which protection systems are maintained or verified according to a time schedule. The scheduled program often calls for technicians to travel to the physical site and perform a functional test on protection system components. However, some components of a TBM program may be conducted from a remote location - for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire protection system tripping chain is able to operate the breaker.

Maintenance Practices

Maintenance and testing programs often incorporate the following types of maintenance practices:

- TBM — time based maintenance — externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed, and may range in number of months or in years.

  TBM can include review of recent power system events near the particular terminal. Operating records may prove that some portion of the protection system has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock is reset for those components.

- PBM — performance based maintenance — maintenance intervals are established based on analytical or historical results of TBM failure rates on a statistically significant population of similar components. Some level of TBM is generally followed. Statistical analyses accompanied by adjustments to maintenance intervals are used to justify continued use of PBM-developed extended intervals when test failures or in-service failures occur infrequently.

- CBM — condition based maintenance — continuously or frequently reported results from non-disruptive self monitoring of components demonstrate operational status as those components remain in service. 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 as part of the self diagnostics.

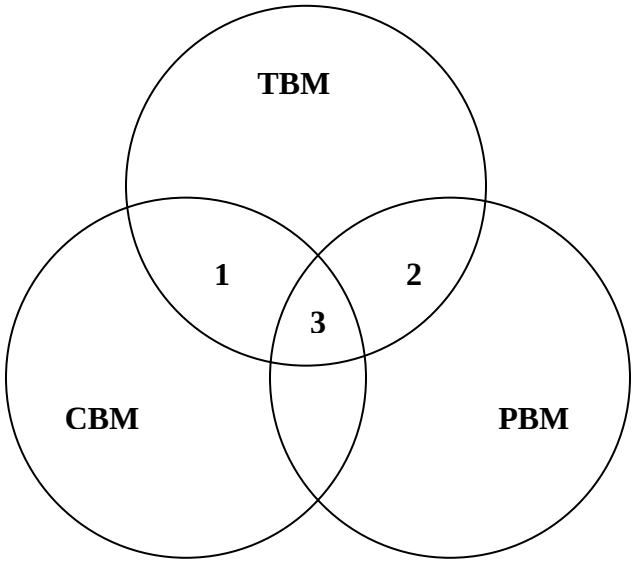
  Microprocessor based protective relays that perform continuous self-monitoring verify correct operation of most components within the device. Self-monitoring capabilities may include the ac signal inputs, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals. For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. When internal components, such as critical output relay contacts, are not equipped with self-monitoring, they can be manually tested. The method of testing may be local or remote, or through inherent performance of the scheme during a system event.

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours or even milliseconds between non-disruptive self monitoring checks within or around components as they remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. The following diagram illustrates the relationship between various types of maintenance practices described in this section. 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.



Relationship of time based maintenance types

5.1 Extending Time-Based Maintenance

All maintenance is fundamentally time-based. Default time-based intervals are commonly established to assure proper functioning of each component of the protection system, when data on the reliability of the components is not available other than observations from time-based maintenance. The following factors may influence the established default intervals:

- If continuous indication of the functional condition of a component is available (from relay self monitoring, for example), the intervals may be extended or manual testing may be eliminated. This is referred to as condition-based maintenance or CBM. CBM is valid only for precisely the components subject to monitoring. In the case of microprocessor-based relays, self-monitoring may not include automated diagnostics of every component within a microprocessor.
- Previous maintenance history for a group of components of a common type may indicate that the maintenance intervals can be extended while still achieving the desired level of performance. This is referred to as performance-based maintenance or PBM. It is also sometimes also referred to as reliability-centered maintenance or RCM, but PBM is used in this document.
- Observed proper operation of a component may be regarded as a maintenance verification of the respective component or element in a microprocessor-based device. For such an observation, the maintenance interval may be reset only to the degree that can be verified by data available on the operation. For example, the trip of an electromechanical relay for a fault verifies the trip contact and trip path, but only through the relays in series that actually operated; one operation of this relay cannot prove correct calibration.

Excessive maintenance can actually decrease the reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical overcurrent relays, test currents have been known to destroy convolution springs.

In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures.

6. Condition Based Maintenance (CBM) Programs

Condition based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor protection system elements. These relays and IEDs generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two basic types:

> Information can come from background self-monitoring processes, programmed by the manufacturer, or by the user in relay logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
>
> Information can come from event logs, captured files, and/or oscillograph records for faults and disturbances, metered values, and binary input status reports. Some of these are available on the relay front panel display, but may be available via data communications ports. Large files of fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the protection system.

Using these two types of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

> Non-invasive Maintenance: The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.
>
> Virtually Continuous Monitoring: CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some relays will show health problems by incorrect relaying before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval.

7. Time Based versus Condition Based Maintenance

Time based and condition based maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time based and condition based maintenance.* The standard requirements introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1 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. Accordingly, this Supplementary Reference Paper refers to the specific maximum allowable intervals in PRC-005-2. The defined time limits allow for longer time intervals if the maintained device is monitored.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the protection system owner knows about it, for the monitored segments of the protection system. In some cases, the verification is practically continuous - the time interval between verifications is minutes or seconds. Thus, technically sound, condition-based verification (as specified in the header and the "Monitoring Attributes" column of Tables 1a, 1b and 1c of PRC-005-2), meets the verification requirements of the FERC order even more effectively than the strictly time-based tests of the same system elements as contained in Table 1a.

The result is that:

This NERC standards permits utilities to use a technically sound approach and to take advantage of remote monitoring, data analysis, and control capabilities of modern protection systems to reduce the need for periodic site visits and invasive testing of components by on-site technicians. This periodic testing must be conducted within maximum time intervals specified in Tables 1a, 1b and 1c of PRC-005-2.

8. Maximum Allowable Verification Intervals

The Table of Maintenance Activities and Maximum Interval requirements shows how CBM with newer relay types can reduce the need for many of the tests and site visits that older protection systems require. As explained below, there are some sections of the protection system that monitoring or data analysis may not verify. Verifying these sections of the Protection Systems requires some persistent TBM activity in the maintenance program. However, some of this TBM can be carried out remotely - for example, exercising a circuit breaker through the relay tripping circuits using the relay remote control capabilities via data communications, if there has been no fault or routine operation to demonstrate performance of relay tripping circuits.

Maintenance Tests

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a period of time of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total protection system functions from measurement of power system values, to properly identifying fault characteristics, to the operation of the interrupting devices.

8.1 Table of Maximum Allowable Verification Intervals

Table 1, in the standard, specifies maximum allowable verification intervals for various generations of protection systems and categories of equipment that comprise protection systems. The right column indicates verification or testing activities required for each category.

The types of components are illustrated in Figures 1 and 2 at the end of this paper. Figure 1 shows an example of telecommunications-assisted line protection system comprising substation equipment at each terminal and a telecommunications channel for relaying between the two substations. Figure 2 shows a typical Generation station layout. The various subsystems of a Protection System that need to be verified are shown. UFLS, UVLS, and SPS are additional categories of Table 1 that are not illustrated in these Figures.

While it is easy to associate protective relays to the three levels of monitoring, it is also true that most of the components that can make up a Protection System can also have technological advancements that place them into higher levels of monitoring.

To use the Maintenance Activities and Intervals Tables (Tables 1a, 1b and 1c collectively *Tables*) from PRC-005-2:

- First check the table header description to verify that your equipment meets the monitoring requirements. If your equipment does not meet the monitoring requirements of Table 1c then check Table 1b. If your equipment does not meet the requirements of Table 1b then use Table 1a.
- If you find a piece of equipment that meets the monitoring requirements of Table 1b or 1c then you can take advantage of the extended time intervals allowed by Table 1b and 1c. Your maintenance plan must document that this category of equipment can be maintained by the requirements of Table 1b or 1c because it has the necessary attributes required within that Table.
- Once you determine which table applies to your equipment's monitoring requirements then check the Maintenance Activity that is required for that particular category of equipment. This Maintenance Activity is the minimum maintenance activity that must be documented.
- After the maintenance activity is known, check the Maximum Maintenance Interval; this time is the maximum time allowed between hands-on maintenance activity cycles of this category of your equipment.
- Any given set of Protection System equipment can be maintained with any combination of Tables 1a, 1b and 1c. An entity does not have to stick to Table 1a just because some of its equipment is un-monitored.
- An entity does not have to utilize the extended time intervals in Tables 1b or 1c. An easy choice to make is to simply utilize Table 1a. While the maintenance activities resulting from choosing to use only Table 1a would require more maintenance man-hours, the maintenance requirements may be simpler to document and the resulting maintenance plans may be easier to create.

For each Protection System component, Table 1 shows maximum allowable testing intervals for unmonitored, partially monitored and fully monitored protection systems:

Table 1 Maintenance Activities and Maximum Intervals

Level 1 Monitoring (Unmonitored) Table 1a

This table applies to electromechanical, analog solid state and other un-monitored Protection Systems components. This table represents the starting point for all required maintenance activities. The object of this group of requirements is to have specific activities accomplished at maximum set time intervals. From this group of activities it follows that CBM or PBM can increase the time intervals between the hands-on maintenance actions.

Level 2 Monitoring (Partially Monitored) Table 1b

This table applies to microprocessor relays and other associated Protection System components whose self-monitoring alarms are transmitted to a location where action can be taken for alarmed failures. The attributes of the monitoring system must meet the requirements specified in the header of the Table 1b. Given these advanced monitoring capabilities, it is known that there are specific and routine testing functions occurring within the device. Because of this ongoing monitoring hands-on action is required less often because routine testing is automated. However, there is now an additional task that must be accomplished during the hands-on process – the monitoring and alarming functions must be shown to work.

Level 3 Monitoring (Fully Monitored) Table 1c

This table applies to microprocessor relays and other associated Protection System components in which every element or function required for correct operation of the Protection System component is monitored continuously and verified, including verification of the means by which failure alarms or indicators are transmitted to a central location for immediate action. This is the highest level of monitoring and if it is available then this gives an entity the ability to have continuous testing of their (Level 3 Monitored) Protection System Component and thus does not have to manually intervene to accomplish routine testing chores. Level 3 Fully Monitored yields continuous monitoring advantages but has substantial technical hurdles that must be overcome; namely that monitoring also verifies the failure of the monitoring and alarming equipment. Without this important ingredient a device that is thought to be continuously monitored could be in an alarm state without the central location being made aware.

Additional Notes for Table 1a, Table 1b, and Table 1c

1. For electro-mechanical relays, adjustment is required to bring measurement accuracy within the tolerance needed by the asset owner. Microprocessor-relays with no remote monitoring of alarm contacts, etc, are un-monitored relays and need to be verified within the Table interval as other un-monitored relays but may be verified as functional by means other than testing by simulated inputs.
2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified (verification of the Analog to Digital [A/D] converters) within the Table intervals. The integrity of the digital inputs and outputs must be verified within the Table intervals.
3. Any Phasor Measurement Unit (PMU) function whose output is used in a protection system or SPS (as opposed to a monitoring task) must be verified as a component in a protection system.
4. In addition to verifying the circuitry that supplies dc to the protection system, the owner must maintain the station dc supply. The most widespread station dc supply is the station battery and charger. Unlike most Protection System elements physical inspection of station batteries for signs of component failure, reduced performance, and degradation are required to ensure that the station battery is reliable enough to deliver dc power when required. IEEE Standards 450, 1188, and 1106 for Vented Lead-Acid, Valve-Regulated Lead-Acid, and Nickel-Cadmium batteries, respectively (which are the most commonly used substation batteries on the NERC BES) have been developed as an important reference source of maintenance recommendations. The Protection System owner should attempt to use the applicable IEEE recommended practice which contains information and recommendations concerning the maintenance, testing and replacement of its substation battery. However, the methods prescribed in these IEEE recommendations cannot be specifically required because they do not apply to all battery applications.
5. Aggregated small entities will naturally distribute the testing of the population of UFLS/UVLS systems, and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program.
6. Voltage & Current Sensing Device circuit input connections to the protection system relays can be verified by comparison of known values of other sources on live circuits or by using test currents and voltages on equipment out of service for maintenance. The verification process can be automated or manual. The values should be verified to be as expected, (phase value and phase relationships are both equally important to prove).

7. Verify the protection system tripping function by performing an operational trip test on all components contained in the trip circuit. This includes circuit breaker or circuit switcher trip coils, auxiliary tripping relays (94), lock-out relays (86), and communications-assisted trip scheme elements. Each control circuit path that carries trip signal must be verified, although each path must be checked only once. A maintenance program may include performing an overall test for the entire system at one time, or several split system tests with overlapping trip verification. Trip coil continuity and aux-contact verification may be accomplished by inspection for the proper control panel light indication. Remote alarm monitoring of the trip coil and aux-contact continuity eliminates the need for tri-monthly inspections of trip coil indications. A documented real-time trip of any given trip path is acceptable in lieu of a functional trip test.
8. "End-to-end test" as used in this supplementary reference is any testing procedure that creates a remote input to the local communications-assisted trip scheme. While this can be interpreted as a GPS-type functional test it is not limited to testing via GPS. Any remote scheme manipulation that can cause action at the local trip path can be used to functionally-test the dc Control Circuitry. A documented real-time trip of any given trip path is acceptable in lieu of a functional trip test. It is possible, with sufficient monitoring, to be able to prove each and every parallel trip path that participated in any given dc Control Circuit trip. Or, another possible solution is that a single trip path from a single monitored relay can be proven to be the trip path that successfully tripped during a real-time operation. The variations are only limited by the degree of engineering and monitoring that an entity desires to pursue.
9. A/D verification may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements assure acceptable measurement of power system input values.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three year retention cycle, the records of verification for a protection system will typically be discarded before the next verification, leaving no record of what was done if a misoperation or failure is to be analyzed.

PRC-005-2 corrects this by requiring that the documentation be retained for two maintenance intervals. Additionally, this requirement assures that the interval between maintenance cycles correctly meets the maintenance interval limits.

8.3 Basis for Table 1 Intervals

SPCTF authors collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak load, or 64% of the NERC peak load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of protection systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of 5 years for electromechanical or solid state relays, and 7 years for un-monitored microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond 7 years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1] as summarized in Section 8.4. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1 only when such relays are monitored as specified in the header of Table 1b. Monitoring is capable of reporting protection system health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, protection system availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve protection system availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades protection system availability.

8.4 Basis for Extended Maintenance Intervals for Microprocessor Relays

Table 1 allows maximum verification intervals that are extended based on monitoring level. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for partial monitoring as explained in Section 8.3. To develop a basis for the maximum interval for monitored relays in their *Protection System Maintenance — A Technical Reference*, the SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability — the probability that the relay is out of service due to failure or maintenance activity while the power system element to be protected is in service.
- Abnormal Unavailability — the probability that the relay is out of service due to failure or maintenance activity when a fault occurs, leading to failure to operate for the fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical STvalues are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

Sn, Normal tripping operations per hour = 21600 (reciprocal of normal fault clearing time of 10 cycles)

Sb, Backup tripping operations per hour = 4320 (reciprocal of backup fault clearing time of 50 cycles)

Rc, Protected component repairs per hour = 0.125 (8 hours to restore the power system)

Rt, Relay routine tests per hour = 0.125 (8 hours to test a protection system)

Rr, Relay repairs per hour = 0.08333 (12 hours to complete a protection system repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for Relay Unavailability and Abnormal Unavailability versus maintenance interval

showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay Mean Time between Failures (MTBF) of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

PSMT SDT further notes that the SPCTF also allowed 25% extensions to the "maximum time intervals". With a 5 year time interval established between manual maintenance activities and a 25% time extension then this equates to a 6.25 year maximum time interval. It is the belief of the PSMT SDT that the SPCTF understood that 6.25 years was thereby an adequate maximum time interval between manual maintenance activities. The PSMT SDT has followed the FERC directive for a *maximum* time interval and has determined that no extensions will be allowed. Six years has been set for the maximum time interval between manual maintenance activities. This maximum time interval also works well for maintenance cycles that have been in use in generator plants for decades.

For monitored relays, the PSMT SDT notes that the SPCTF called for 10 years as the interval between maintenance activities. A 10 year interval with a 25% allowed extension equates to a maximum allowed interval of 12.5 years between manual maintenance activities. The Standard does not allow extensions on any component of the protection system; thus the maximum allowed interval for these devices has been set to12 years. Twelve years also fits well into the traditional maintenance cycles of both substations and generator plants.

Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval". The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. An electro-mechanical protective relay that is maintained in year #1 need not be revisited until 6 years later (year #7). For example: a relay was maintained December 15, 2008; it would be due for maintenance again no later than December 31, 2014.

Section 9 describes a performance-based maintenance process which can be used to justify maintenance intervals other than those described in Table 1.

Section 10 describes sections of the protection system, and overlapping considerations for full verification of the protection system by segments. Segments refer to pieces of the protection system, which can range from a single device to a panel to an entire substation.

Section 11 describes how relay operating records can serve as a basis for verification, reducing the frequency of manual testing.

Section 13 describes how a cooperative effort of relay manufacturers and protection system users can improve the coverage of self-monitoring functions, leading to full monitoring of the bulk of the protection system, and eventual elimination of manual verification or testing.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a performance-based maintenance process may be used to establish maintenance intervals. A performance-based maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a performance-based maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered protection systems in order to provide historical justification for intervals other

than those established in Table 1. Furthermore, the asset owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Utilities with performance-based maintenance track performance of protection systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a performance-based maintenance program would serve the utility well in explaining to regulators and the public a misoperation leading to a major system outage event.

A performance-based maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality management systems — Requirements;*** or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

In order to opt into a Performance Based Maintenance (PBM) program the asset owner must first sort the various Protection System components into population segments. Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM but does not own 60 units to comprise a population then that asset owner may combine data from other asset owners until the needed 60 units is aggregated. Each population segment must be composed of like devices from the same manufacturer and subjected to similar environmental factors. For example: One segment cannot be comprised of both GE & Westinghouse electro-mechanical lock-out relays; likewise, one segment cannot be comprised of 60 GE lock-out relays, 30 of which are in a dirty environment and the remaining 30 from a clean environment.

9.1 Minimum Sample Size

Large Sample Size

An assumption that needs to be made when choosing a sample size is "the sampling distribution of the sample mean can be approximated by a normal probability distribution." The Central Limit Theorem states: "In selecting simple random samples of size *n* from a population, the sampling distribution of the sample mean *x* can be approximated by a normal probability distribution as the sample size becomes large." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003)

To use the Central Limit Theorem in statistics, the population size should be large. The references below are supplied to help define what is large.

> "… whenever we are using a large simple random sample (rule of thumb: n>=30), the central limit theorem enables us to conclude that the sampling distribution of the sample mean can be approximated by a normal distribution." (Essentials of Statistics for Business and Economics, Anderson, Sweeney, Williams, 2003)
>
> "If samples of size n, when n>=30, are drawn from any population with a mean *u* and a standard deviation σ, the sampling distribution of sample means approximates a normal distribution. The greater the sample size, the better the approximation." (Elementary Statistics - Picturing the World, Larson, Farber, 2003)
>
> "The sample size is large (generally n>=30)… (Introduction to Statistics and Data Analysis - Second Edition, Peck, Olson, Devore, 2005)

> "… the normal is often used as an approximation to the *t* distribution in a test of a null hypothesis about the mean of a normally distributed population when the population variance is estimated from a relatively large sample. A sample size exceeding 30 is often given as a minimal size in this connection." (Statistical Analysis for Business Decisions, Peters, Summers, 1968)

Error of Distribution Formula

Beyond the large sample size discussion above, a sample size requirement can be estimated using the bound on the Error of Distribution Formula when the expected result is of a "Pass/Fail" format and will be between 0 and 1.0.

The Error of Distribution Formula is:

$$B = z\sqrt{\frac{\pi(1-\pi)}{n}}$$

Where:

B = bound on the error of distribution (allowable error)

z = standard error

π = expected failure rate

n = sample size required

Solving for n provides:

$$n = \pi(1-\pi)\left(\frac{z}{B}\right)^2$$

Minimum Population Size to use Performance Based Program

One entity's population of components should be large enough to represent a sizeable sample of a vendor's overall population of manufactured devices. For this reason the following assumptions are made:

B = 5%

z = 1.96 (This equates to a 95% confidence level)

π = 4%

Using the equation above, n=59.0.

Minimum Sample Size to evaluate Performance Based Program

The number of components that should be included in a sample size for evaluation of the appropriate testing interval can be smaller because a lower confidence level is acceptable since the sample testing is repeated or updated annually. For this reason, the following assumptions are made:

B = 5%

z = 1.44 (85% confidence level)

π = 4%

Using the equation above, n=31.8.

Recommendation
Based on the above discussion, a sample size should be at least 30 to allow use of the equation mentioned. Using this and the results of the equation, the following numbers are recommended:

Minimum Population Size to use Performance Based Maintenance Program = 60

Minimum Sample Size to evaluate Performance Based Program = 30.

Once the population segment is defined then maintenance must begin within the intervals as outlined for Level 1 monitoring, (Table 1a). Time intervals can be lengthened provided the last year's worth of devices tested (or 30 units, whichever is more) had fewer than 4% countable events. It is notable that 4% is specifically chosen because an entity with a small population (60 units) would have to adjust its time intervals between maintenance if more than 1 countable event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a mis-operation.

The minimum number of units that can be tested in any given year is 5% of the population. Note that this 5% threshold sets a practical limitation on total length of time between intervals at 20 years.

If at any time the number of countable events equals or exceeds 4% of the last year's tested-devices (or 30 units whichever is more) then the time period between manual maintenance activities must be decreased. There is a time limit on reaching the decreased time at which the countable events is less than 4%; this must be attained within three years.

This additional time period of three years to restore segment performance to <4% countable events is mandated to keep entities from "gaming the PBM system". It is believed that this requirement provides the economic disincentives to discourage asset owners from arbitrarily pushing the PBM time intervals out to 20 years as subsequent analysis might show that an excessive number of countable events could then require that the entire population segment be re-tested and re-evaluated within 3 years.

10. Overlapping the Verification of Sections of the Protection System

Table 1 requires that every protection system element be periodically verified. One approach is to test the entire protection scheme as a unit, from voltage and current sources to breaker tripping. For practical ongoing verification, sections of the protection system may be tested or monitored individually. The boundaries of the verified sections must overlap to ensure that there are no gaps in the verification.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a protection system may be divided into multiple overlapping sections with a different maintenance methodology for each section:

- Time based maintenance with appropriate maximum verification intervals for categories of equipment as given in the Unmonitored, Partially Monitored, or Fully Monitored Tables;
- Full monitoring as described in header of Table 1c;
- A performance-based maintenance program as described in Section 9;
- Opportunistic verification using analysis of fault records as described in Section 11

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve fault event records and oscillographic records by data communications after a fault. They analyze the data closely if there has been an apparent misoperation, as NERC standards require. Some advanced users have commissioned automatic fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured digital fault recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on protection systems whose operations are analyzed. Even electromechanical protection systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of faults in the vicinity of the relay that produce relay response records, and the specific data captured.

A typical fault record will verify particular parts of certain protection systems in the vicinity of the fault. For a given protection system installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external fault records that completely verify the protection system.

For example, fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby protection systems may verify that they restrain from tripping for a fault just outside their respective zones of protection. The ensemble of internal fault and nearby external fault event data can verify major portions of the protection system, and reset the time clock for the Table 1 testing intervals for the verified components only.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity in the record and the associated wiring paths are verified. Be careful about using fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple faults close to either side of a setting boundary, setting or calibration could still be incorrect.

If fault record data is used to show that portions or all of a protection system have been verified to meet Table 1 requirements, the owner must retain the fault records used, and the maintenance related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These 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. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to protection system performance.

Monitoring does not check measuring element settings. Analysis of fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them. For background and guidance, see [5].

Table 1 requires that settings must be verified to be as specified. The reason for this requirement is simple. With legacy relays (non-microprocessor protective relays) it is necessary to know the value of the intended setting in order to test, adjust and calibrate the relay. Proving that the relay works per specified setting was the de facto procedure. However, with the advanced microprocessor relays it is possible to change relay settings for the purpose of verifying specific functions and then neglect to return the settings to the specified values. While there is no specific requirement to maintain a settings management process there remains a need to verify that the settings left in the relay are the intended, specified settings. This need may manifest itself after any of the following:

- One or more settings are changed for any reason.
- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored or partially monitored intervals established in Table 1.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals.

To enable the use of full monitoring, the manufacturers of the microprocessor-based self-monitoring components in the protection system should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact protection system performance.
- Which connected circuits are monitored by checks implemented within the product; how to connect and set the product to assure monitoring of these connected circuits; and what circuits or potential problems are not monitored.

With this information in hand, the user can document full monitoring for some or all sections by:

- Presenting or referencing the product manufacturer’s documents.
- Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
- Extending the monitoring to include the alarm transmission facilities through which failures are reported to remote centers for immediate action, so that failures of monitoring or alarming systems also lead to alarms and action.
- Documenting the plans for verification of any unmonitored elements according to the requirements of Table 1.

14. Notification of Protection System Failures

When a failure occurs in a protection system, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable loading conditions.

This formal reporting of the failure and repair status to the system operator by the protection system owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early-generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. Maintenance Activities

Some specific maintenance activities are a requirement to ensure reliability. An example would be that a BES entity could be prudent in its protective relay maintenance but if its battery maintenance program is lacking then reliability could still suffer. The NERC glossary outlines a Protection System as containing specific components. PRC-005-02 requires specific maintenance activities be accomplished within a specific time interval. As noted previously, higher technology equipment can contain integral monitoring capability that actually performs maintenance verification activities routinely and often; therefore *manual intervention* to perform certain activities on these type devices may not be needed.

15.1 Protective Relays

These relays are defined as the devices that receive the input signal from the current and voltage sensing devices and are used to isolate a faulted portion of the BES. Devices that sense thermal, vibration, seismic, pressure, gas or any other non-electrical input are excluded.

Non-microprocessor based equipment is treated differently than microprocessor based equipment in the following ways, but the relays must meet the calibration requirements of the asset owner.

- Non-microprocessor devices must be tested with voltage and/or current applied to the device.
- Microprocessor devices may be tested through the integral testing of the device.
    - There is no specific protective relay commissioning test or relay routine test mandated.
    - There is no specific documentation mandated.

15.2 Voltage & Current Sensing Devices

These are the current and voltage sensing devices, usually known as instrument transformers. There is presently a technology available (fiber-optic Hall-effect) that does not utilize conventional transformer technology; these devices and other technologies that produce quantities that represent the primary values of voltage and current are included in this standard.

The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.

There is no specific test mandated for these devices. The important thing about these signals is to know that the expected output from these devices actually reaches the protective relay. Therefore, the proof of the proper operation of these devices also demonstrates the integrity of the wiring (or other medium used to convey the signal) from the current and voltage sensing device all the way to the protective relay. The following observations apply.

- There is no specific ratio test, routine test or commissioning test mandated.
- There is no specific documentation mandated.

- It is required that the signal be present at the relay.
- This expectation can be arrived at from any of a number of means; by calculation, by comparison to other circuits, by commissioning tests, by thorough inspection, or by any means needed to prove the circuit to the satisfaction of the asset owner.
- An example of testing might be a saturation test of a CT with the test values applied at the relay panel; this therefore tests the CT as well as the wiring from the relay all the back to the CT.
- Another possible test is to measure the signal from the voltage and/or current sensing devices, during load conditions, at the input to the relay.
- Another example of testing the various voltage and/or current sensing devices is to query the microprocessor relay for the real-time loading; this can then be compared to other devices to verify the quantities applied to this relay. Since the input devices have supplied the proper values to the protective relay then the verification activity has been satisfied. Thus event reports (and oscillographs) can be used to prove that the voltage and current sensing devices are performing satisfactorily.
- Still another method is to measure total watts and vars around the entire bus; this should add up to zero watts and zero vars thus proving the voltage and/or current sensing devices system throughout the bus.
- Another method for proving the voltage and/or current sensing devices is to complete commissioning tests on all of the transformers, cabling, fuses and wiring.
- Other methods that provide documentation that the expected transformer values are applied to the inputs to the protective relays are acceptable.

15.3 DC Control Circuitry

This component of Protection Systems includes the trip coil(s) of the circuit breaker, circuit switcher or any other interrupting device. It includes the wiring from the batteries to the relays. It includes the wiring from every trip output to every trip coil. In short, every trip path must be verified; the method of verification is optional to the asset owner. Each trip coil must be tested to trip the circuit breaker (or other interrupting device) at least once.

The dc control circuitry also includes each auxiliary tripping relay (94) and each lock-out relay (86) in any given trip scheme. These electro-mechanical devices must be trip tested. The PSMT SDT considers these devices to share some similarities in failure modes as electro-mechanical protective relays; as such there is a six year maximum interval between mandated maintenance tasks.

When verifying the operation of the 94 and 86 relays each normally-open contact that closes to pass a trip signal must be verified as operating correctly. Normally-open contacts that are not used to pass a trip signal and normally-closed contacts do not have to be verified. Verification of the tripping paths is the requirement.

New technology is also accommodated here; there are some tripping systems that have replaced the traditional hard-wired trip circuitry with other methods of trip-signal conveyance such as fiber-optics. It is the intent of the PSMT SDT to include this, and any other, technology that is used to convey a trip signal from a protective relay to a circuit breaker (or other interrupting device) within this category of equipment.

15.4 Batteries and DC Supplies

IEEE guidelines were used to mandate maintenance activities for batteries. The following guidelines were used: IEEE 450 (for Vented Lead-Acid batteries), IEEE 1188 (for Valve-Regulated Lead-Acid batteries) and IEEE 1106 (for Nickel-Cadmium batteries).

The present NERC definition of a Protection System is “protective relays, associated communication systems, voltage and current sensing devices, station batteries and dc control circuitry.” The station battery is not the only component that provides dc power to a Protection System. In the new definition for Protection System “station batteries” are replaced with “station dc supply” to make the battery charger and dc producing stored energy devices (that are not a battery) part of the Protection System that must be maintained.

To insure that there are no open circuits in a lead acid battery string, IEEE 450-2002 recommends that during the monthly inspection “battery float charging current or pilot cell specific gravity” should be measured and recorded. Similarly IEEE 1188-2005 states that during the monthly general inspection, the “dc float current (per string)” should be checked and recorded “using equipment that is accurate at low (typically less than 1 A) currents.” These tests are recommended by the IEEE standards for lead acid batteries to detect an open circuit in a battery set that will make a battery unable to deliver dc power.

The PSMT SDT recognizes that there are several technological advances in equipment and testing procedures that allow the owner to choose how to verify that a battery string is free of open circuits. The term “continuity” was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to the two methods recommended in the IEEE standards. Continuity as used in Table 1 of the standard refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal. Without verifying continuity of a station battery, there is no way to determine that the station battery is available to supply dc power to the station.

Batteries cannot be a unique population segment of a Performance Based Maintenance Program (PBM) because there are too many variables in the electro-chemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery systems.

15.5 Tele-protection equipment

This is also known as associated telecommunications equipment. The equipment used for tripping in a communications assisted trip scheme is a vital piece of the trip circuit. Remote action causing a local trip can be thought of as another parallel trip path to the trip coil that must be tested.

Besides the trip output and wiring to the trip coil(s) there is also a communications medium that must be maintained.
Newer technologies now exist that achieve communications-assisted tripping without the conventional wiring practices of older technology.

For example: older technologies may have included *Frequency Shift Key* methods. This technology requires that guard and trip levels be maintained.

The actual tripping path(s) to the trip coil(s) may be tested as a parallel trip path within the dc control circuitry tests.

Emerging technologies transfer digital information over a variety of carrier mediums that are then interpreted locally as trip signals.

The requirements apply to the communicated signal needed for the proper operation of the protective relay trip logic or scheme. Therefore this standard is applied to equipment used to convey both trip signals and block signals.

It was the intent of this standard to require that a test be made of any communications-assisted trip scheme regardless of the vintage of the technology. The essential element is that the tripping occurs locally when the remote action has been asserted.

Evidence of operational test or documentation of measurement of signal level, reflected power or data-error rates is needed.

Some newer installations utilize digital signals over fiber-optics from the protective relays in the control house to the circuit interrupting device in the yard. This method of tripping the circuit breaker, even though it might be considered communications, must be maintained per the dc control circuitry maintenance requirements.

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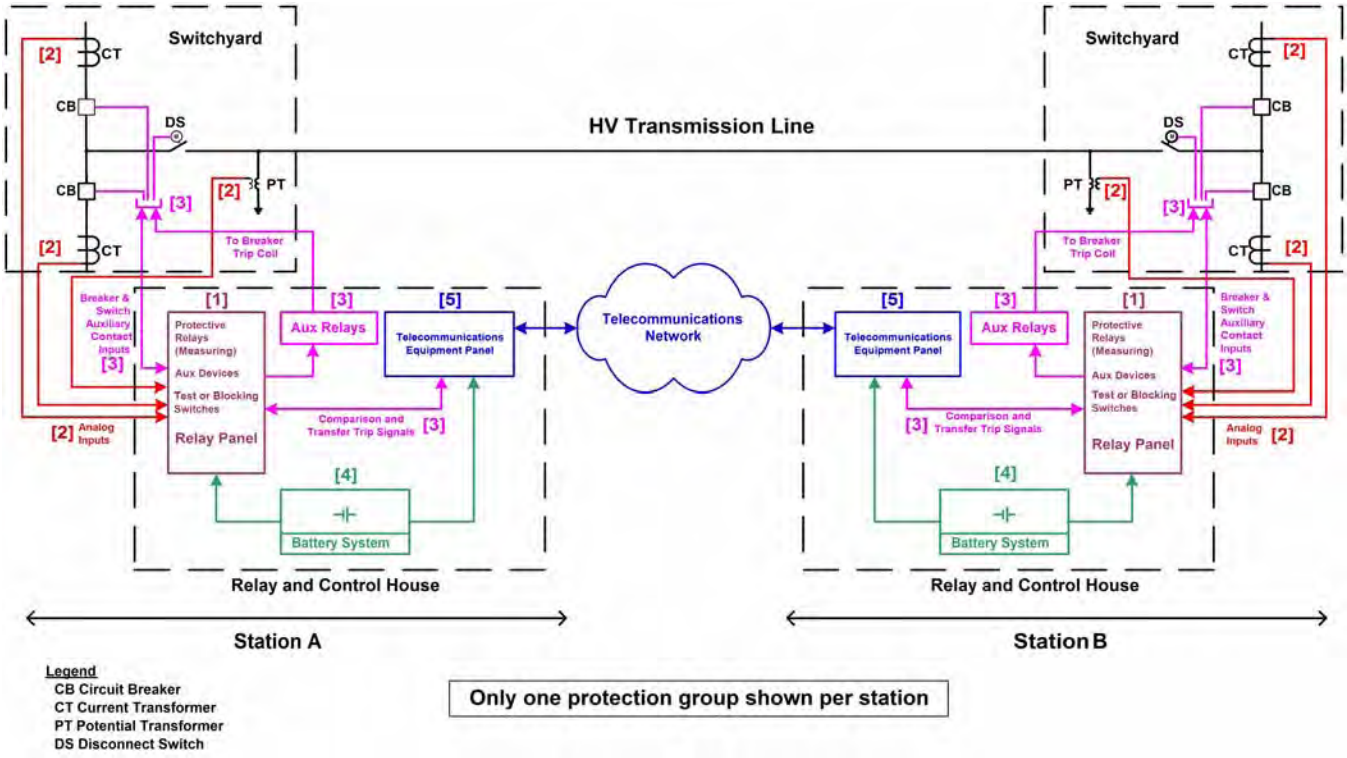
10. "Introduction to Statistics and Data Analysis" - Second Edition, Peck, Olson, Devore, 2005
11. "Statistical Analysis for Business Decisions" Peters, Summers, 1968

Figures

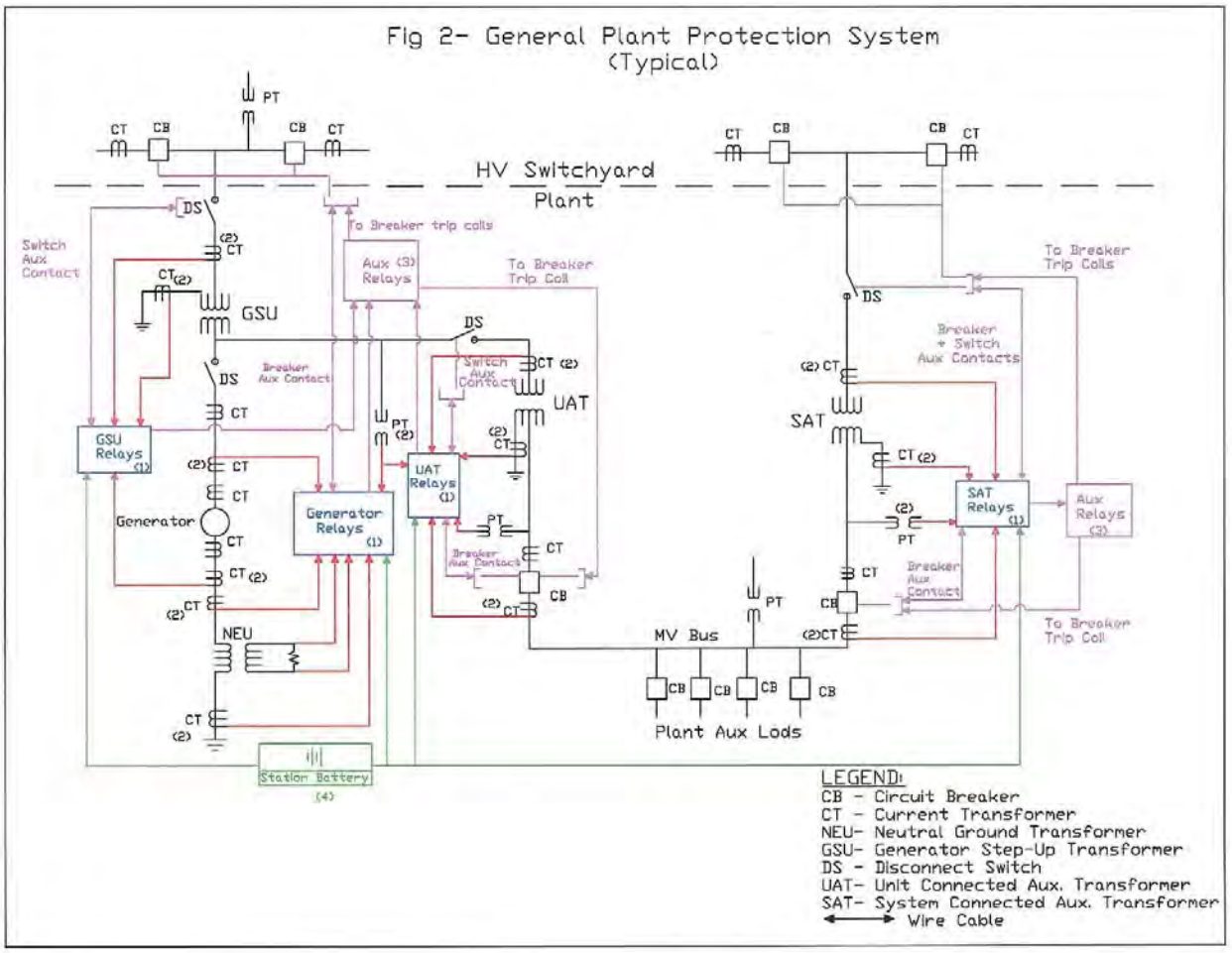
Figure 1: Typical Transmission System



For information on numbered components, see ***Figure 1 & 2 Legend – Components of Protection Systems***

(Return)

Figure 2: Typical Generation System



For information on numbered components, see ***Figure 1 & 2 Legend – Components of Protection Systems***

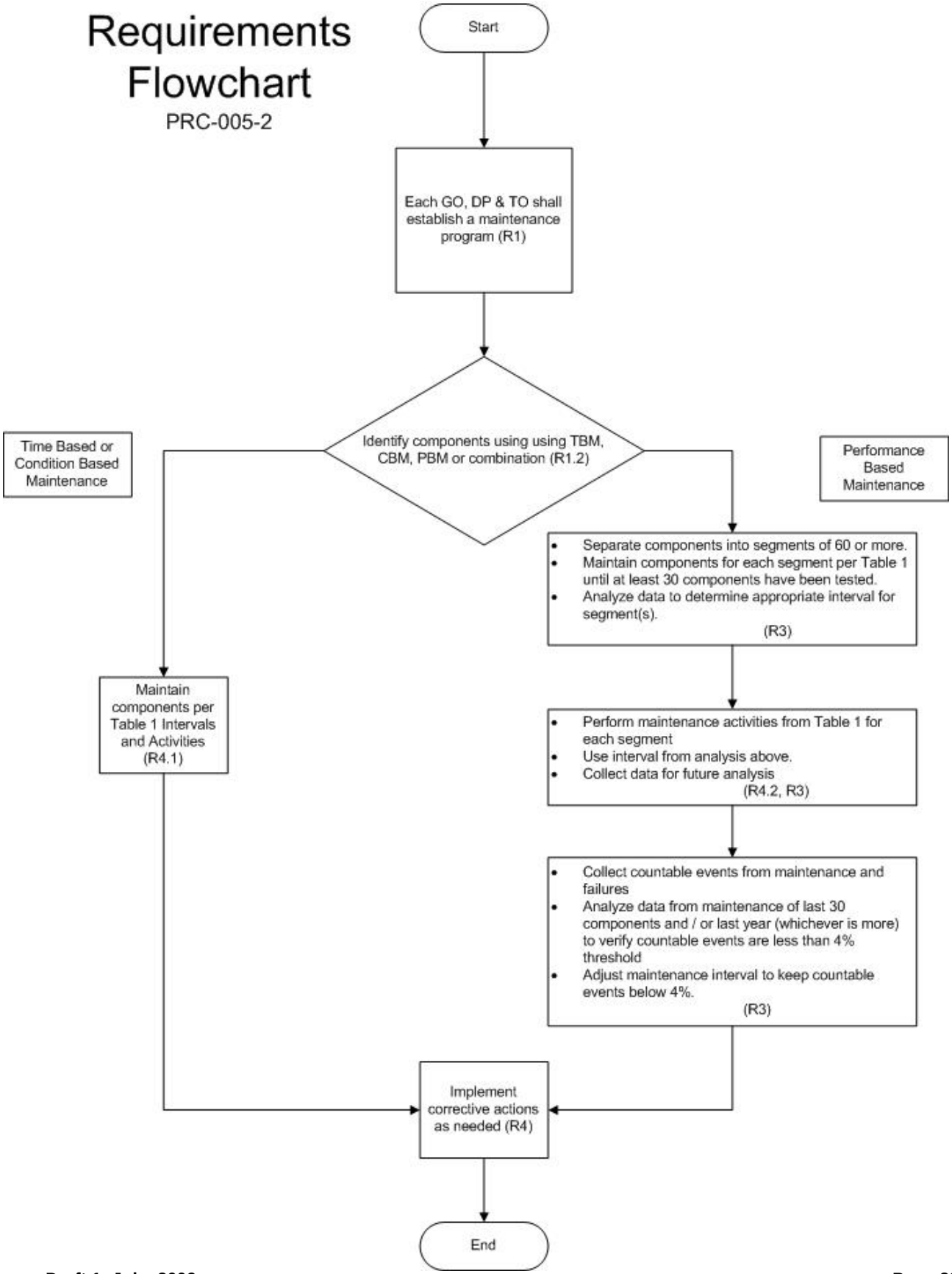
(Return)

Figure 1 and 2 Legend — Components of Protection Systems

Number In Figure	Component of Protection System	Includes	Excludes
1	Protective relays	All protective relays that use current and/or voltage inputs from current & voltage sensors and that trip the 86, 94 or trip coil.	Devices that use non-electrical methods of operation including thermal, pressure, gas accumulation, and vibration. Any ancillary equipment not specified in the definition of Protection systems. Control and/or monitoring equipment that is not a part of the automatic tripping action of the Protection System
2	Current & voltage sensors	Transformers or other current & voltage sensing devices that produce signals for protective relays as well as the wiring (or other medium) used to convey signal output from the sensor to the protective relay input.	Voltage & current sensing devices that are not a part of the Protection System, including sync-check systems, metering systems and data acquisition systems.
3	DC Circuitry	All control wiring (or other medium for conveying trip signals) associated with the tripping action of 86 devices, 94 devices or trip coils (from all parallel trip paths). This would include fiber-optic systems that carry a trip signal as well as hard-wired systems that carry trip current. Also, it includes auxiliary contacts providing breaker position data that is necessary for the proper operation of the Protection System.	Closing circuits, SCADA circuits
4	DC Supply	Batteries and battery chargers and any control power system which has the function of supplying power to the protective relays, associated trip circuits and trip coils.	Any power supplies that are not used to power protective relays or their associated trip circuits and trip coils.
5	Associated communications equipment	Tele-protection equipment used to convey remote tripping action to a local trip coil or blocking signal to the trip logic (if applicable)	Any communications equipment that is not used for remote tripping action to a local trip coil or blocking signal to the trip logic (if applicable)

(Return)

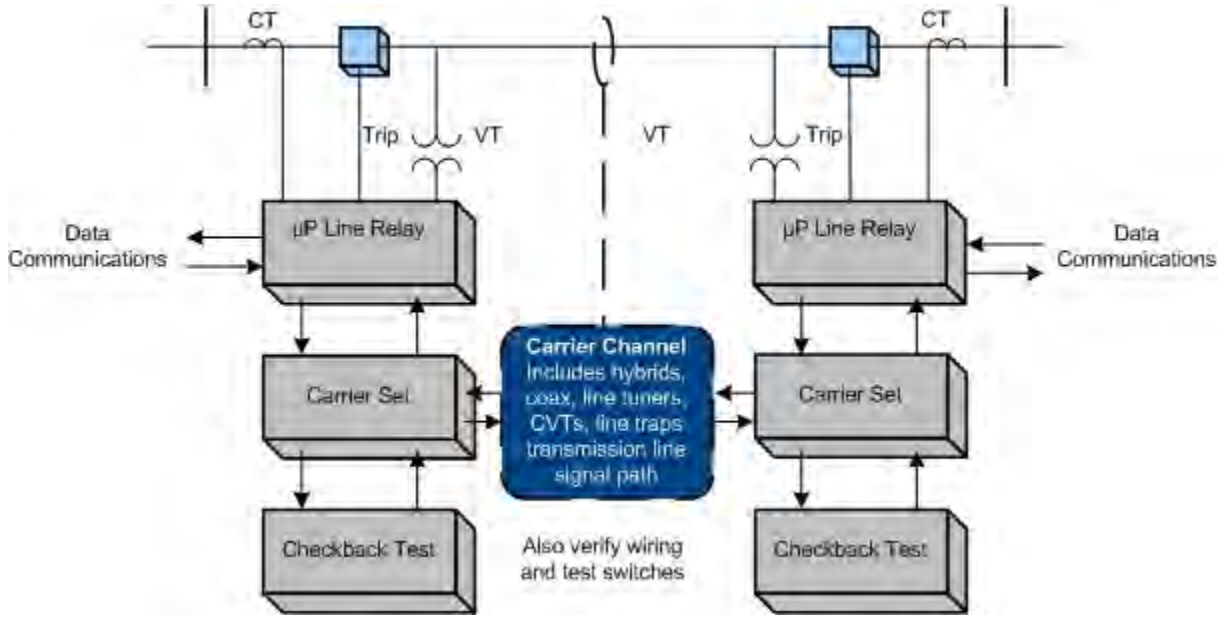
Figure 3: Requirements Flowchart



Appendix A

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure A-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line faults, and to avoid over-tripping for faults external to the transmission line zone of protection bounded by the current transformer locations.

Figure A-1



In this example (Figure A1), verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

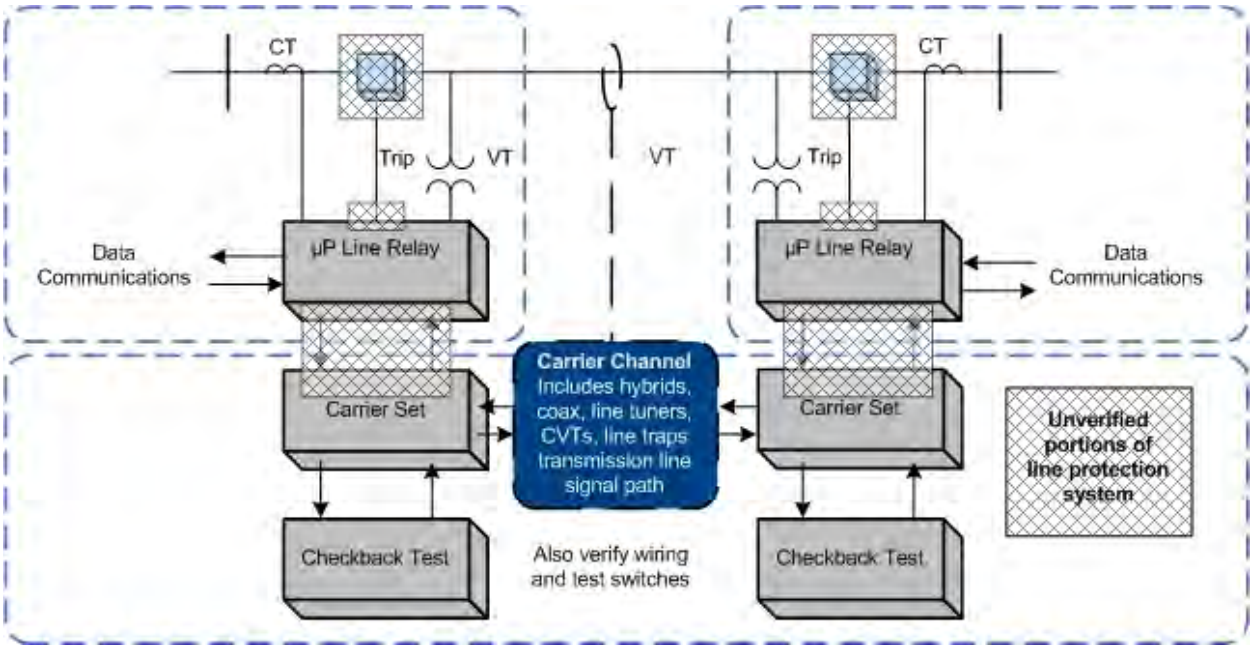
1. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state of the dc battery supply.
4. The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. Comparison with other such readings to within required relaying accuracy verifies Voltage & Current Sensing Devices, wiring, and analog signal input processing of the relays. One effective way to do

this is to utilize the relay metered values directly in SCADA, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). Status indications must be consistent with the flow or absence of current.
6. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay and reported via communications.
7. Correct operation of the on-off carrier channel is also critical to security of the protection system, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

These monitoring activities plus the check-back test comprise automatic verification of all the protection system elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

Figure A-2



The dotted boxes of Figure A-2 show the sections of verification defined by the monitoring and verification practices just listed. These sections are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to trip if the trip coil should be energized.

2. Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the contacts of a small telephone-type "ice cube" relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a fault.
3. The check-back test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.
4. The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005 does not address breaker maintenance, and its protection system test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated fault with a relay test set. However, utilities have found that breakers often show problems during protection system tests. It is recommended that protection system verification include periodic testing of the actual tripping of connected circuit breakers.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring faults, or by a manual test. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

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