NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

PRC-005-2 — Protection System Maintenance

Frequently Asked Questions

Practical Compliance and Implementation (Draft 1)

Protection System Maintenance and Testing
Standard Drafting Team

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to ensure the reliability of the bulk power system

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Introduction

The following is a draft collection of questions and answers that the PSMT SDT believes could be helpful to those implementing NERC Standard PRC-005-2 Protection System Maintenance. As the draft standard proceeds through development, this FAQ document will be revised, including responses to key or frequent comments from the posting process. The FAQ will be organized at a later time during the development of the draft Standard.

This FAQ document will support both the Standard and the associated Technical Reference document.

Executive Summary

- To be added later if needed.

Terms Used in PRC-005-2

Maintenance Correctable Issue — As indicated in footnote 2 of the draft standard, a maintenance correctable issue is a failure of a device to operate within design parameters that can be restored to functional order by calibration, repair or replacement

Segment — As indicated in *PRC-005 Attachment A Criteria for a Performance-Based Protection System Maintenance Program*, a segment is a "A grouping of Protection Systems or component devices of a particular model or type from a single manufacturer, with other common factors such that consistent performance is expected across the entire population of the segment, and shall only be defined for a population of 60 or more individual components."

Component — This equipment is first mentioned in Requirement 1, Part 1.1 of this standard. A component is any individual discrete piece of equipment included in a Protection System, such as a protective relay or current sensing device. Types of components are listed in Table 1 ("Maximum Allowable Testing Intervals and Maintenance Activities for Unmonitored Protection Systems"). For components such as dc circuits, the designation of what constitutes a dc control circuit element is somewhat arbitrary and is very dependent upon how an entity performs and tracks the testing of the dc circuitry. Some entities test their dc circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of "dc control circuit elements." Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

Countable Event — As indicated in footnote 4 of *PRC-005 Attachment A, Criteria for a Performance-based Protection System Maintenance Program*, countable events include any failure of a component requiring repair or replacement, any condition discovered during the verification activities in Table 1a through Table 1c which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. 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.

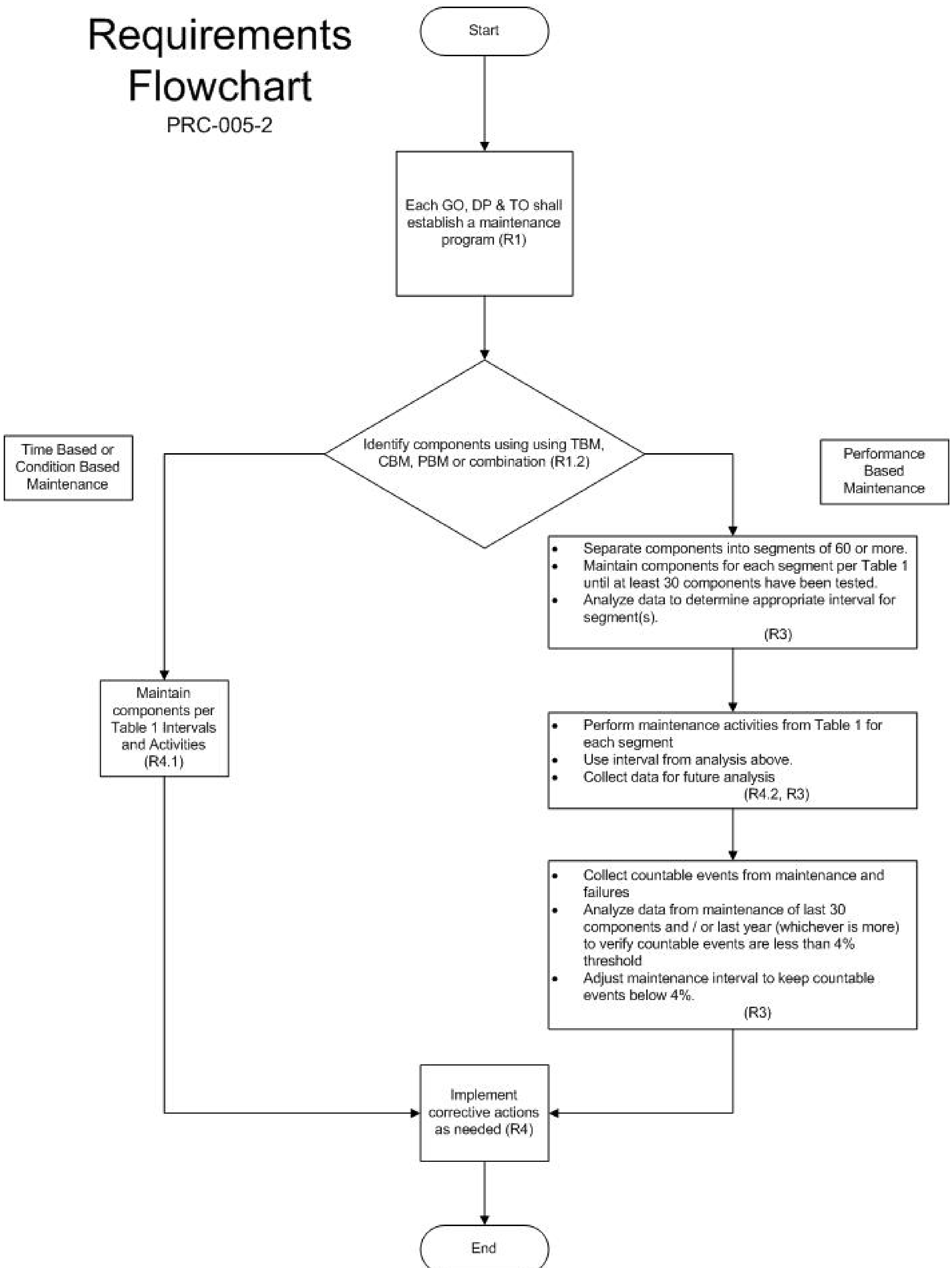
Frequently Asked Questions

General FAQs:

1. **The standard seems very complicated, and is difficult to understand. Can it be simplified?**

   Because the standard is establishing parameters for condition-based Maintenance (R2) and performance-based Maintenance (R3) in addition to simple time-based Maintenance, it does appear to be complicated. At its simplest, an entity needs to follow R1 and R4 and perform ONLY time-based maintenance according to Table 1a, eliminating R2 and R3 from consideration altogether. If an entity then wishes to take advantage of monitoring on its Protection System components, R2 comes into play, along with Tables 1b and 1c. If an entity wishes to use historical performance of its Protection System components to perform performance-based Maintenance, R3 applies.

   Please see the following diagram, which provides a "flow chart" of the standard.


Requirements Flowchart
PRC-005-2
Start
Each GO, DP & TO shall establish a maintenance program (R1)
Identify components using using TBM, CBM, PBM or combination (R1.2)
Time Based or Condition Based Maintenance
Performance Based Maintenance
Separate components into segments of 60 or more.
Maintain components for each segment per Table 1 until at least 30 components have been tested.
Analyze data to determine appropriate interval for segment(s).
(R3)
Maintain components per Table 1 Intervals and Activities (R4.1)
Perform maintenance activities from Table 1 for each segment
Use interval from analysis above.
Collect data for future analysis
(R4.2, R3)
Collect countable events from maintenance and failures
Analyze data from maintenance of last 30 components and / or last year (whichever is more) to verify countable events are less than 4% threshold
Adjust maintenance interval to keep countable events below 4%.
(R3)
Implement corrective actions as needed (R4)
End

Group by Type of Protection System Component:

1. **All**

   A. **Are power circuit reclosers, reclosing relays, closing circuits and auto-restoration schemes covered in this standard?**

   No. As stated in R1, this standard covers protective relays that use measurements of voltage, current and/or phase angle to determine anomalies and to trip a portion of the BES. Reclosers, reclosing relays, closing circuits and auto-restoration schemes are used to cause devices to close as opposed to electrical-measurement relays and their associated circuits that cause circuit interruption from the BES; such closing devices and schemes are more appropriately covered under other NERC Standards. There is one notable exception: if a Special Protection System incorporates automatic closing of breakers, the related closing devices are part of the SPS and must be tested accordingly.

   B. **Why does PRC-005-2 not specifically require maintenance and testing procedures as reflected in the previous standard, PRC-005-1?**

   PRC-005-1 does not require detailed maintenance and testing procedures, but instead requires summaries of such procedures, and is not clear on what is actually required. PRC-005-2 requires a documented Maintenance program, and is focused on establishing Requirements rather than prescribing methodology to meet those Requirements. Between the activities identified in Tables 1a, 1b, and 1c, and the various components of the definition established for a "Protection System Maintenance Program", PRC-005-2 establishes the activities and time-basis for a Protection System Maintenance Program to a level of detail not previously required.

2. **Protective Relays**

   A. **How do I approach testing when I have to upgrade firmware of a microprocessor relay?**

   The component "Upkeep" in the definition of a Protection System Maintenance Program, addresses "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." The Maintenance Activities specified in Table 1a, Table 1b, and Table 1c do not present any requirements related to Upkeep for Protective Relays. However, the entity should assure that the relay continues to function properly after implementation of firmware changes.

   B. **I use my protective relays only as sources of metered quantities and breaker status for SCADA and EMS through a substation distributed RTU or data concentrator to the control center. What are the maintenance requirements for the relays?**

   This standard addresses only devices "that are applied on, or are designed to provide protection for the BES." Protective relays, providing only the functions mentioned in the question, are not included.

   C. **I use my protective relays for fault and disturbance recording, collecting oscillographic records and event records via communications for fault analysis to meet NERC and DME requirements. What are the maintenance requirements for the relays?**

For relays used only as disturbance monitoring equipment, the NERC standard PRC-018-1 R3 & R6 states the maintenance requirements, and is being addressed by a Standards activity that is revising PRC-002-1 and PRC-018-1. For protective relays "that are applied on, or are designed to provide protection for the BES," this standard applies, even if they also perform DME functions.

3. Voltage and Current Sensing Device Inputs to Protective Relays

A. What is meant by "…verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays …" Do we need to perform ratio, polarity and saturation tests every few years?

No. You must prove that the protective relay is receiving the expected values from the voltage and current sensing devices (typically voltage and current transformers). This can be as difficult as is proposed by the question (with additional testing on the cabling and substation wiring to ensure that the values arrive at the relays); or simplicity can be achieved by other verification methods. Some examples follow:

- ◊ Compare the secondary values, at the relay, to a metering circuit, fed by different current transformers, monitoring the same line as the questioned relay circuit.
- ◊ Compare the values, as determined by the questioned relay, to another protective relay monitoring the same line, with currents supplied by different CTs.
- ◊ Query SCADA for the power flows at the far end of the line protected by the questioned relay, compare those SCADA values to the values as determined by the questioned relay.
- ◊ Totalize the Watts and VARs on the bus and compare the totals to the values as seen by the questioned relay.

The point of the verification procedure is to ensure that all of the individual components are functioning properly; and that, an ongoing proactive procedure is in place to re-check the various components of the protective relay measuring systems.

B. The verification of phase current and voltage measurements by comparison to other quantities seems reasonable. How, though, can I verify residual or neutral currents, or 3V0 voltages, by comparison, when my system is closely balanced?

These values will be zero, or very small, for any reasonably balanced system. To verify these values by comparison, you will need to rely on the normal condition that your system is not perfectly balanced, and there will usually be a small zero-sequence current or voltage, and these values can be measured with instruments having a sufficiently low resolution range. A reading of precisely zero will probably suggest that there is an opening (or some other problem) in the measuring circuit. A finite value of a few percent of the phase quantities, however, may suggest that the measuring circuit is indeed performing properly.

These quantities may be also verified by use of oscillographic records for connected microprocessor relays as recorded during system disturbances. Such records may compare to similar values recorded at other locations by other microprocessor relays for the same event, or compared to expected values (from short circuit studies) for known fault locations.

C. Is wiring insulation or hi-pot testing required by this Maintenance Standard?

No, wiring insulation and equipment hi-pot testing are not required by the Maintenance Standard.

4. Protection System Control Circuitry

A. Is it permissible to verify circuit breaker tripping at a different time (and interval) than when we verify the protective relays and the instrument transformers?

Yes, provided the entire Protective System is tested within the individual components' maximum allowable testing intervals.

B. The Protection System Maintenance Standard describes requirements for verifying the tripping of circuit breakers. What is this telling me about maintenance of circuit breakers?

Requirements in PRC-005-2 are intended to verify the integrity of tripping circuits, including the breaker trip coil, as well as the presence of auxiliary supply (usually a dc battery) for energizing the trip coil if a protection function operates. Beyond this, PRC-005-2 sets no requirements for verifying circuit breaker performance, or for maintenance of the circuit breaker.

C. How do I test each dc Control Circuit path, as established for level 2 (partially monitored protection systems) monitoring of a "Protection System Control Circuitry (Trip coils and auxiliary relays)"?

Table 1b specifies that each breaker trip coil, auxiliary relay, and lockout relay must be operated within the specified time period. The required operations may be via targeted maintenance activities, or by documented operation of these devices for other purposes such as fault clearing.

D. What does this standard require for testing an Auxiliary Tripping Relay?

Table 1 requires that the trip test must verify that the auxiliary tripping relay (94) or lockout relay (86) operates electrically and that their trip output(s) perform as expected.

E. What does a functional trip test include?

An operational trip test must be performed on each portion of a trip circuit. Each control circuit path that produces trip signal must be verified; this includes trip coils, auxiliary tripping relays (94), lockout relays (86) and communications-assisted-trip schemes.

A trip test may be an overall test that verifies the operation of the entire trip scheme at once, or it may be several tests of the various portions that make up the entire trip scheme, provided that testing of the various portions of the trip scheme verifies all of the portions, including parallel paths, and overlaps those portions.

A circuit breaker or other interrupting device needs to be trip tested at least once per trip coil. Breaker auxiliary contacts that are essential for the proper operation of the protective relay trip-circuit (or trip-logic) must be verified as providing the correct breaker open/close status information to the Protection System.

Discrete-component auxiliary relays (94) and lock-out relays (86) must be proven by trip test. The trip test must verify that the auxiliary or lock-out relay operates electrically and that the relay's trip output(s) change(s) state. Software latches or control algorithms, including trip logic processing implemented as programming component such as a microprocessor relay that take the place of (conventional) discrete component auxiliary relays or lock-out relays do not have to be routinely trip tested.

Normally-closed auxiliary contacts from other devices (for example, switchyard-voltage-level disconnect switches, interlock switches, or pressure switches) which are in the breaker trip path do not need to be tested.

F. Is a Sudden Pressure Relay an Auxiliary Tripping Relay?

No. IEEE C37.2-2008 assigns the device number 94 to auxiliary tripping relays. Sudden pressure relays are assigned device number 63, and is excluded from the Standard by footnote 1.

G. The standard specifically mentions Auxiliary and Lock-out relays; what is an Auxiliary Tripping Relay?

An auxiliary relay, IEEE Device Number 94, is described in IEEE Standard C37.2-2008 as “A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.”

H. What is a Lock-out Relay?

A lock-out relay, IEEE Device Number 86, is described in IEEE Standard C37.2 as “A device that trips and maintains the associated equipment or devices inoperative until it is reset by an operator, either locally or remotely.”

I. My mechanical device does not operate electrically and does not have calibration settings; what maintenance activities apply?

You must conduct a test(s) to verify the integrity of the trip circuit. This standard does not cover circuit breaker maintenance or transformer maintenance. The standard also does not cover testing of devices such as sudden pressure relays (63), temperature relays (49), and other relays which respond to mechanical parameters rather than electrical parameters.

5. Station dc Supply

A. What constitutes the station dc supply as mentioned in the definition of Protective System?

The station direct current (dc) supply normally consists of two components: the battery charger and the station battery itself. There are also emerging technologies that provide a source of dc supply that does not include either a battery or charger.

Battery Charger — The battery charger is supplied by an available ac source. At a minimum, the battery charger must be sized to charge the battery (after discharge) and supply the constant dc load. In many cases, it may be sized also to provide sufficient dc current to handle the higher energy requirements of tripping breakers and switches when actuated by the protective relays in the Protection System.

Station Battery — Station batteries provide the dc power required for tripping and for supplying normal dc power to the station in the event of loss of the battery charger. There are several technologies of battery that require unique forms of maintenance as established in Table 1.

Emerging Technologies — Station dc supplies are currently being developed that use other energy storage technologies beside the station battery to prevent loss of the station dc supply when ac power is lost. Maintenance of these station dc supplies will require different kinds of tests and inspections. Table 1 presents maintenance activities and maximum allowable testing intervals for these new station dc supply technologies. However, because these technologies are relatively new the maintenance activities for these station dc supplies may change over time.

B. In the Maintenance Activities for station dc supply in Table 1, what do you mean by “continuity”?

Because the Standard pertains to maintenance not only of the station battery, but also the whole station dc supply, continuity checks of the station dc supply are required. “Continuity” as used in Table 1 refers to verifying that there is a continuous current path from the positive terminal of the station battery set to the negative terminal, otherwise there is no way of determining that a station battery is available to supply dc current to the station.

The current path through a station battery from its positive to its negative connection to the dc control circuits is composed of two types of elements. These path elements are the electrochemical path through each of its cells and all of the internal and external metallic connections and terminations of the batteries in the battery set. If there is loss of continuity (an open circuit) in any part of the electrochemical or metallic path the battery set will not be available for service.

C. Why is it necessary to verify the continuity of the dc supply?

In the event of the loss of the ac source or battery charger, the battery must be capable of supplying dc current, both for continuous dc loads and for tripping breakers and switches. Without continuity, the battery cannot perform this function.

If the battery charger is not sized to handle the maximum dc current required to operate the protective systems, it is sized only to handle the constant dc load of the station and the charging current required to bring the battery back to full charge following a discharge. At those stations, the battery charger would not be able to trip breakers and switches if the battery experiences loss of continuity.

At generating stations and large transmission stations where battery chargers are capable of handling the maximum current required by the Protection System, there are still problems that could potentially occur when the continuity through the connected battery is interrupted.

◊ Many battery chargers produce harmonics which can cause failure of dc power supplies in microprocessor based protective relays and other electronic devices connected to station dc supply. In these cases, the substation battery serves as a filter for these harmonics. With the loss of continuity in the battery, the filter provided by the battery is no longer present.

◊ Loss of electrical continuity of the station battery will cause, regardless of the battery charger’s output current capability, a delayed response in full output current from the charger. Almost all chargers have an intentional 1 to 2 second delay to switch from a low substation dc load current to the maximum output of the charger. This delay would cause the opening of circuit breakers to be delayed which could violate system performance standards.

D. How do you verify continuity of the dc supply?

Monitoring of the station dc supply voltage will not indicate that there is a problem with the dc current path through the battery unless the battery charger is taken out of service. At that time a break in the continuity of the station battery current path will be revealed because there will be no voltage on the substation dc circuitry.

Although the Standard prescribes what must be done during the maintenance activity it does not prescribe how the maintenance activity should be accomplished. There are several methods that can be used to verify the electrical continuity of the battery.

- ◊ One method is to measure that there is current flowing through the battery itself by a simple clamp on milliamp-range ammeter. A battery is always either charging or discharging. Even when a battery is charged there is still a measurable float charge current that can be detected to verify that there is continuity in the electrical path through the battery.
- ◊ A simple test for continuity is to remove the battery charger from service and verify that the battery provides voltage and current to the dc system. However, the behavior of the various dc-supplied equipment in the station should be considered before using this approach.
- ◊ Manufacturers of microprocessor based battery chargers have developed methods for their equipment to periodically (or continuously) tested for battery continuity. For example, one manufacturer periodically reduces the float voltage on the battery until current from the battery to the dc load can be measured to confirm continuity.

No matter how the electrical continuity of a battery set is verified it is a necessary maintenance activity that must be performed at the intervals prescribed by Table 1 to insure that the station dc supply will provide the required current to the Protection System at all times.

E. Why is specific gravity testing required?

Specific gravity testing measures the state of the charge for each individual cell, and is performed to determine the condition of the charging system as well as the condition of the individual cell.

Specific gravity measurements can also be used as an indication of loss of continuity over a period of time. Specific gravity measurement is a method of determining the state of charge of a battery. Loss of continuity in the battery circuit will not allow charging current to flow through the battery and the battery cells will eventually self discharge causing the specific gravity to approach the specific gravity value of water which is 1.0.

If the specific gravity measurements taken during an inspection are determined to be low, this indicates that the battery is in a state of discharge. If no recent high discharges of the battery have occurred and the float voltage is normal, then the continuity of the battery circuit can be suspected and other tests such as measuring battery current should be made to determine if the specific gravity readings are an indication of loss of battery continuity.

F. When should I check the station batteries to see if they have sufficient energy to perform as designed?

The answer to this question depends on the type of battery (valve regulated lead-acid, vented lead acid, or nickel-cadmium), the maintenance activity chosen, and the type of time based monitoring level selected.

For example, if you have a Valve Regulated Lead-Acid (VRLA) station battery, and you have chosen to evaluate the measured cell/unit internal ohmic values to the battery cell's baseline, you will have to perform verification at a maximum maintenance interval of no greater than every three months.

If, for a VRLA station battery, you choose to conduct a performance capacity test on the entire station battery as the maintenance activity, then you will have to perform verification at a maximum maintenance interval of no greater than every 3 calendar years.

G. Why in Table 1 are there two Maintenance Activities with different Maximum Maintenance Intervals listed to verify that the station battery can perform as designed?

The two acceptable methods for proving that a station battery can perform as designed are based on two different philosophies. The first activity requires a capacitive discharge test of the entire battery set to prove that degradation of one or several components (cells) in the set has not deteriorated to a point where the total capacity of the battery system falls below its designed rating. The second maintenance activity requires tests and evaluation of the internal ohmic measurements on each of the individual cells/units of the battery set to determine that each component can perform as designed and therefore the entire battery set can be proven to perform as designed.

The maximum maintenance interval for discharge capacity testing is longer than the interval for testing and evaluation of internal ohmic cell measurements. An individual component of a battery set may degrade to an unacceptable level without causing the total battery set to fall below its designed rating under capacity testing. However, since the philosophy behind internal ohmic measurement evaluation is based on the fact that each battery component must be proven to be able to perform as designed, the interval for verification by this maintenance activity must be shorter to catch individual cell/unit degradation.

H. What is the justification for having two different Maintenance Activities listed in Table 1 to verify that the station battery can perform as designed?

IEEE Standards 450, 1188, and 1106 for vented lead-acid, valve-regulated lead-acid (VRLA), and nickel-cadmium batteries, respectively (which together are the most commonly used substation batteries on the BES) go into great detail about capacity testing of the entire battery set to determine that a battery can perform as designed.

The first maintenance activity listed in Table 1 for verifying that a station battery can perform as designed uses maximum maintenance intervals for capacity testing that were designed to align with the IEEE battery standards. This maintenance activity is applicable for vented lead-acid, valve-regulated lead-acid, and nickel-cadmium batteries.

The second maintenance activity listed in Table 1 for verifying that a station battery can perform as designed uses maximum maintenance intervals for evaluating internal ohmic measurements in relation to their baseline measurements that are based on industry experience, EPRI technical reports and application guides, and the IEEE battery standards. By evaluating the internal ohmic measurements for each cell and comparing that measurement to the cell's baseline ohmic measurement (taken at the time of the battery set's acceptance capacity test), low-capacity cells can be identified and eliminated to keep the battery set capable of performing as designed. This maintenance activity is applicable only for vented lead-acid and VRLA batteries.

I. Why in Table 1 of PRC-005-2 is there a maintenance activity to inspect the structural intergrity of the battery rack?

The three IEEE standards (1188, 450, and 1106) for VRLA, vented lead-acid, and nickel-cadmium batteries all recommend that as part of any battery inspection the battery rack should be inspected. The purpose of this inspection is to prove that the battery rack is correctly installed and has no deterioration that could weaken its structural integrity. Because the battery rack is specifically designed for the battery that is mounted on it, weakening of its structural members by rust or corrosion can physically jeopardize the battery.

6. Protection System Communications Equipment

A. What are some examples of mechanisms to check communications equipment functioning?

For Level 1 unmonitored Protection Systems, various types of communications systems will have different facilities for on-site integrity checking to be performed at least every three months during a substation visit. Some examples are:

◊ On-off power-line carrier systems can be checked by performing a manual carrier keying test between the line terminals, or carrier checkback test from one terminal.

◊ Systems which use frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be checked by observing a loss-of-guard indication or alarm. For frequency-shift power line power-line carrier systems, the guard signal level meter can also be checked.

◊ Hard-wired pilot wire line Protection Systems typically have pilot-wire monitoring relays that give an alarm indication for a pilot wire ground or open pilot wire circuit loop.

◊ Digital communications systems have some sort of data reception indicator or data error indicator (based on loss of signal, bit error rate, or frame error checking).

For Level 2 partially monitored Protection Systems, various types of communications systems will have different facilities for monitoring the presence of the communications channel, and activating alarms that can be monitored remotely. Some examples are:

◊ On-off power-line carrier systems can be shown to be operational by automated periodic power-line carrier checkback tests, with remote alarming of failures.

◊ Systems which use a frequency-shift communications with a continuous guard signal (over a telephone circuit, analog microwave system, etc.) can be remotely monitored with a loss-of-guard alarm or low signal level alarm.

◊ Hard-wired pilot wire line Protection Systems can be monitored by remote alarming of pilot-wire monitoring relays.

◊ Digital communications systems can activate remotely monitored alarms for data reception loss or data error indications.

For Level 3 fully monitored Protection Systems, the communications system must monitor all aspects of the performance and quality of the channel that show it meets the design performance criteria, including monitoring of the channel interface to protective relays.

◊ In many communications systems signal quality measurements including signal-to-noise ratio, received signal level, reflected transmitter power or standing wave ratio, propagation delay, and data error rates are compared to alarm limits. These alarms are connected for remote monitoring.

◊ Alarms for inadequate performance are remotely monitored at all times, and the alarm communications system to the remote monitoring site must itself be continuously monitored to assure that the actual alarm status at the communications equipment location is continuously being reflected at the remote monitoring site.

B. What is needed for the 3-month inspection of communication-assisted trip scheme equipment?

The 3-month inspection applies to Level 1 (Unmonitored) equipment. With each site visit, check that the equipment is free from alarms, check any metered signal levels, and that power is still applied.

C. Does a fiber optic I/O scheme used for breaker tripping or control within a station, for example - transmitting a trip signal or control logic between the control house and the breaker control cabinet, constitute a communication system?

This equipment is presently classified as being part of the Protection System Control Circuitry and tested per the portions of Table 1 applicable to Protection System Control Circuitry rather than those portions of the table applicable to communication equipment.

D. In Table 1b, the Maintenance Activities section of the Protective System Communications Equipment and Channels refers to the quality of the channel meeting “performance criteria”. What is meant by performance criteria?

Protection System communications channels must have a means of determining if the channel and communications equipment is operating normally. If the channel is not operating normally an alarm will be indicated. For Level 1 systems this alarm will probably be on the panel. For Level 2 and Level 3 systems, the alarm will be transmitted to a remote location.

Each entity will have established a nominal performance level for each protective system communications channel that is consistent with proper functioning of the Protection System. If that level of nominal performance is not being met, the system will go into alarm. Following are some examples of protective system communications channel performance criteria:

◊ For direct transfer trip using a frequency shift power line carrier channel, a guard level monitor is part of the equipment. A normal receive level is established when the system is calibrated and if the signal level drops below an established level, the system will indicate an alarm.

◊ An on-off blocking signal over power line carrier is used for directional comparison blocking schemes on transmission lines. During a fault, block logic is sent to the remote relays by turning on a local transmitter and sending the signal over the power line to a receiver at the remote end. This signal is normally off so continuous levels cannot be checked. These schemes use checkback testing to determine channel performance. A predetermined signal sequence is sent to the remote end and the remote end decodes this signal and sends a signal sequence back. If the sending end receives the correct information from the remote terminal, the test passes and no alarm is indicated. Full power and reduced power tests are typically run. Power levels for these tests are determined at the time of calibration.

◊ Pilot wire relay systems use a hardwire communications circuit to communicate between the local and remote ends of the protective zone. This circuit is monitored by circulating a dc current between the relay systems. A typical level may be 1 mA. If the level drops below the setting of the alarm monitor, the system will indicate an alarm.

◊ Modern digital relay systems use data communications to transmit relay information to the remote end relays. An example of this is a line current differential scheme commonly used on transmission lines. The protective relays communicate current magnitude and phase information over the communications path to determine if the fault is located in the protective zone. Quantities such as digital packet loss, bit error rate and channel delay are monitored to determine the quality of the channel. These limits are determined and set during relay commissioning. Once set, any channel quality problems that fall outside the set levels will indicate an alarm.

The previous examples show how some protective relay communications channels can be monitored and how the channel performance can be compared to performance criteria established by the entity. This standard does not state what the performance criteria will be - it just requires that the entity establish nominal criteria so protective system channel monitoring can be performed.

7. UVLS and UFLS Relays that Comprise a Protection System Distributed Over the Power System

A. We have an Under Voltage Load Shedding (UVLS) system in place that prevents one of our distribution substations from supplying extremely low voltage in the case of a specific transmission line outage. The transmission line is part of the BES. Does this mean that our UVLS system falls within this standard?

The situation as stated indicates that the tripping action was intended to prevent low distribution voltage for a transmission system that was intact except for the line that was out of service.

This Standard is not applicable to this UVLS.

UVLS installed to prevent system voltage collapse or voltage instability for BES reliability is covered by this standard.

8. SPS or Relay Sensing for Centralized UFLS or UVLS

A. Do I have to perform a full end-to-end test of a Special Protection System?

No. All portions of the SPS need to be maintained, and the portions must overlap, but the overall SPS does not need to have a single end-to-end test.

B. What about SPS interfaces between different entities or owners?

All SPS owners should have maintenance agreements that state which owner will perform specific tasks. SPS segments can be tested individually, but must overlap.

C. What do I have to do if I am using a phasor measurement unit (PMU) as part of a Protection System or Special Protection System?

Any Phasor Measurement Unit (PMU) function whose output is used in a protection system or Special Protection System (as opposed to a monitoring task) must be verified as a component in a Protection System.

D. How do I maintain a Special Protection System or Relay Sensing for Centralized UFLS or UVLS Systems?

Components of the SPS, UFLS, or UVLS should be maintained like similar components used for other Protection System functions.

The output action verification may be breaker tripping, or other control action that must be verified, but may be verified in overlapping segments. A grouped output control action need be verified only once within the specified time interval, but all of the SPS, UFLS, or UVLS components whose operation leads to that control action must each be verified.

Group by Type of BES Facility:

1. All BES Facilities

A. What, exactly, is the BES, or Bulk Electric System?

BES is the abbreviation for Bulk Electric System. BES is a term in the Glossary of Terms Used in Reliability Standards, and is not being modified within this draft Standard.

NERC's approved definition of Bulk Electric System is:

> As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.

Each Regional Entity implements a definition of the Bulk Electric System that is based on this NERC definition, in some cases, supplemented by additional criteria. These regional definitions have been documented and provided to FERC as part of a *June 16, 2007 Informational Filing*.

2. Generation

A. Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, and generator connected station auxiliary transformer to meet the requirements of this Maintenance Standard.

Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay may include but are not necessarily limited to:

- Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
- Loss-of-field relays
- Volts-per-hertz relays
- Negative sequence overcurrent relays
- Over voltage and under voltage protection relays
- Stator-ground relays
- Communications-based protection systems such as transfer-trip systems
- Generator differential relays

- Reverse power relays
- Frequency relays
- Out-of-step relays
- Inadvertent energization protection
- Breaker failure protection

For generator step up or generator connected station auxiliary transformers, operation of any the following associated protective relays frequently would result in a trip of the generating unit and, as such, would be included in the program:

- Transformer differential relays
- Neutral overcurrent relay
- Phase overcurrent relays

A loss of a system connected station auxiliary transformer could result in a loss of the generating plant if the plant was being provided with auxiliary power from that source. Thus, operation of any of the following relays associated with system connected station auxiliary transformers would be included in the program:

- Transformer differential relays
- Neutral overcurrent relay
- Phase overcurrent relays

Relays which trip breakers serving station auxiliary loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program even if the loss of the those loads could result in a trip of the generating unit.

3. Transmission

A. Why is Distribution Provider included within the Applicable Entities and as a responsible entity within several of the requirements? Wouldn't anyone having relevant facilities be a Transmission Owner?

Depending on the station configuration of a particular substation, there may be Protection System equipment installed at a non-transmission voltage level (Distribution Provider equipment) that is wholly or partially installed to protect the BES. PRC-005-2 would apply to this equipment. An example is underfrequency load-shedding, which is frequently applied well down into the distribution system to meet PRC-007-0.

Group by Type of Maintenance Program:

1. All Protection System Maintenance Programs

A. I can't figure out how to demonstrate compliance with the requirements for level 3 (fully monitored) Protection Systems. Why does this Maintenance Standard describe a maintenance program approach I cannot achieve?

Demonstrating compliance with the requirements for level 3 (fully monitored) Protection Systems is likely to be very involved, and may include detailed manufacturer documentation of complete internal monitoring within a device, comprehensive design drawing reviews, and other detailed documentation. This Standard does not presume to specify what documentation must be developed; only that it must be comprehensive.

There may actually be some equipment available that is capable of meeting level-3 monitoring criteria, in which case it may be maintained according to Table 1c. However, even if there is no equipment available today that can meet this level of monitoring, the Standard establishes the necessary requirements for when such equipment becomes available.

By creating a roadmap for development, this provision makes the Standard technology-neutral. The standard drafting team wants to avoid the need to revise the Standard in a few years to accommodate technology advances that are certainly coming to the industry.

B. What forms of evidence are acceptable?

Acceptable forms of evidence, as relevant for the Requirement being documented, include but are not limited to:

- Process documents or plans
- Data (such as relay settings sheets, photos, SCADA, and test records)
- Database screen shots that demonstrate compliance information
- Diagrams, engineering prints, schematics, maintenance and testing records, etc.
- Logs (operator, substation, and other types of log)
- U.S. or Canadian mail, memos, or email proving the required information was exchanged, coordinated, submitted or received
- Database lists

C. If I replace a failed Protection System component with another component, what testing do I need to perform on the new component?

The replacement component must be tested to a degree that assures that it will perform as intended. If it is desired to reset the Table 1 maintenance interval for the replacement component, all relevant Table 1 activities for the component should be performed.

2. Time-Based Protection System Maintenance (TBM) Programs

A. What does this Maintenance Standard say about commissioning?

Commissioning tests are regarded as a construction activity, not a maintenance activity.

B. The established maximum allowable intervals do not align well with the scheduled outages for my power plant. Can I extend the maintenance to the next scheduled outage following the established maximum interval?

No. You must complete your maintenance within the established maximum allowable intervals in order to be compliant. You will need to schedule your maintenance during available outages to complete your maintenance as required, even if it means that you may do protective relay maintenance more frequently than the maximum allowable intervals.

C. If I am unable to complete the maintenance as required due to a major natural disaster (hurricane, earthquake, etc), how will this affect my compliance with this standard.

The NERC Sanction Guidelines provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions.[1]

D. What if my observed testing results show a high incidence of out-of-tolerance relays, or, even worse, I am experiencing numerous relay misoperations due to the relays being out-of-tolerance?

Any entity can choose to test some or all of their Protection System more frequently (or, to express it differently, exceed the minimum requirements of the Standard). Particularly, if you find that the maximum intervals in the Standard do not achieve your expected level of performance, it is understandable that you would maintain the related equipment more frequently.

3. Performance-Based Protection System Maintenance (PBM) Programs

A. I'm a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity?

Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for performance-based maintenance must be met for the overall aggregated program on an ongoing basis.

The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

B. Can an owner go straight to a performance-based maintenance program schedule, if they have previously gathered records?

Yes. An owner can go to a performance-based maintenance program immediately. The owner will need to comply with the requirements of a performance-based maintenance program as listed in the standard. Gaps in the data collected will not be allowed; therefore, if an owner finds that a gap exists such that they can not prove that they have collected the data as required for a performance-based maintenance program then they will need to wait until they can prove compliance.

C. When establishing a perfomance-based maintenance program, can I use test data from the device manufacturer, or industry survey results, as results to help establish a basis for my performance-based intervals?

No. You must use actual in-service test data for the components in the segment.

D. What types of misoperations or events are not considered countable events in the performance-based Protection System Maintenance (PBM) Program?

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1 Sanction Guidelines of the North American Electric Reliability Corporation. Effective January 15, 2008.

Countable events are intended to address conditions that are attributed to hardware failure or calibration failure; that is, conditions that reflect deteriorating performance of the component. These conditions include any condition where the device previously worked properly, then, due to changes within the device, malfunctioned.

Human errors resulting in Protection System Misoperations during system installation or maintenance activities are not considered countable events. Examples of excluded human errors include relay setting errors, design errors, wiring errors, inadvertent tripping of devices during testing or installation, and misapplication of Protection System components. Examples of misapplication of Protection System components include wrong CT or PT tap position, protective relay function misapplication, and components not specified correctly for their installation.

Certain types of Protection System component errors that cause Misoperations are not considered countable events. Examples of excluded component errors include device malfunctions that are correctable by firmware upgrades and design errors that do not impact protection function.

E. What are some examples of methods of correcting segment perfomance for Performance-Based Maintenance?

There are a number of methods that may be useful for correcting segment performance for mal-performing segments in a performance-based maintenance system. Some examples are listed below.

- The maximum allowable interval, as established by the performance-based maintenance system, can be decreased. This may, however, be slow to correct the performance of the segment.
- Identifiable sub-groups of components within the established segment, which have been identified to be the mal-performing portion of the segment, can be broken out as an independent segment for target action. Each resulting segment must satisfy the minimum population requirements for a performance-based maintenance program in order to remain within the program.
- Targeted corrective actions can be taken to correct frequently occurring problems. An example would be replacement of capacitors within electromechanical distance relays if bad capacitors were determined to be the cause of the mal-performance.
- Components within the mal-performing segment can be replaced with other components (electromechanical distance relays with microprocessor relays, for example) to remove the mal-performing segment.

F. If I find (and correct) a maintenance-correctable issue as a result of a misoperation investigation (Re: PRC-004), how does this affect my performance-based maintenance program?

If you perform maintenance on a Protection System component for any reason (including as part of a PRC-004 required misoperation investigation/corrective action), the actions performed count as a maintenance activity, and “reset the clock” on everything you’ve done. In a performance-based maintenance program, you also need to record the maintenance-correctable issue with the relevant component group and use it in the analysis to determine your correct performance-based maintenance interval for that component group.

G. Why are batteries excluded from PBM? What about exclusion of batteries from condition based maintenance?

Batteries are the only element of a Protection System that is a perishable item with a shelf life. As a perishable item batteries require not only a constant float charge to maintain their freshness (charge), but periodic inspection to determine if there are problems associated with their aging process and testing to see if they are maintaining a charge or can still deliver their rated output as required.

Besides being perishable, a second unique feature of a battery that is unlike any other Protection System element is that a battery uses chemicals, metal alloys, plastics, welds, and bonds that must interact with each other to produce the constant dc source required for Protection Systems, undisturbed by ac system disturbances.

No type of battery manufactured today for Protection System application is free from problems that can only be detected over time by inspection and test. These problems can arise from variances in the manufacturing process, chemicals and alloys used in the construction of the individual cells, quality of welds and bonds to connect the components, the plastics used to make batteries and the cell forming process for the individual battery cells.

Other problems that require periodic inspection and testing can result from transportation from the factory to the job site, length of time before a charge is put on the battery, the method of installation, the voltage level and duration of equalize charges, the float voltage level used, and the environment that the battery is installed in.

All of the above mentioned factors and several more not discussed here are beyond the control of the Functional Entities that want to use a Performance-based Protection System Maintenance (PBM) program. These inherent variances in the aging process of a battery cell make establishment of a designated segment based on manufacturer and type of battery impossible.

The whole point of PBM is that if all variables are isolated then common aging and performance criteria would be the same. However, there are too many variables in the electro-chemical process to completely isolate all of the performance-changing criteria.

Similarly Functional Entities that want to establish a condition based maintenance program using Level 3 monitoring of the battery used in a station dc supply can not do so. Inspection of the battery is required on a Maximum Maintenance Interval listed in the tables due to the aging processes of station batteries. However, Level 3 monitoring of a battery can eliminate the requirement for periodic testing and some inspections (see Level 3 Monitoring Attributes for Component of table 1c).

Group by Monitoring Level:

1. **All Monitoring Levels**

   A. Please provide an example of the level 1 monitored (unmonitored) versus other levels of monitoring available?

   A level 1 (Unmonitored) Protection System has no monitoring and alarm circuits on the Protection System components.

   A level 2 (Partially) monitored Protection System or an individual component of a level 2 (Partially) monitored Protection System has monitoring and alarm circuits on the Protection System components. The alarm circuits must alert a 24-hr staffed operations center.

   There can be a combination of monitored and unmonitored Protection Systems within any given substation or plant; there can also be a combination of monitored and unmonitored components within any given Protection System.

Example #1: A combination of level 2 (Partially) monitored and level 1 (unmonitored) components within a given Protection System is:

◊ A microprocessor relay with an internal alarm connected to SCADA to alert 24-hr staffed operations center. (level 2)
◊ Instrumentation transformers, with no monitoring, connected as inputs to that relay. (level 1)
◊ A vented lead-acid battery with low voltage alarm connected to SCADA. (level 2)
◊ A circuit breaker with a trip coil, with no monitor circuit. (level 1)

Given the particular components, conditions, and using the Table 1 ("Maximum Allowable Testing Intervals and Maintenance Activities"), the particular components have maximum test intervals of:

◊ The microprocessor relay is verified every 12 calendar years.
◊ The instrumentation transformers are verified every 12 calendar years.
◊ The battery is verified every 6 calendar years by performing a performance capacity test of the entire battery bank or by evaluating the measured cell/unit internal ohmic values to station battery baseline every 18 months.
◊ The circuit breaker trip circuits and auxiliary relays are tested every 6 calendar years.

Example #2: A combination of level 2 (partially) monitored and level 1 (unmonitored) components within a given Protection System is:

◊ A microprocessor relay with integral alarm that is not connected to SCADA. (level 1)
◊ Instrument transformers, with no monitoring, connected as inputs to that relay. (level 1)
◊ A vented lead-acid battery with low voltage alarm connected to SCADA. (level 2)
◊ A circuit breaker with a trip coil, with no circuits monitored. (level 1)

Given the particular components, conditions, and using the Table 1 ("Maximum Allowable Testing Intervals and Maintenance Activities"), the particular components have maximum test intervals of:

◊ The microprocessor relay is verified every 6 calendar years.
◊ The instrumentation transformers are verified every 12 calendar years.
◊ The battery is verified every 6 calendar years by performing a performance capacity test of the entire battery bank or by evaluating the measured cell/unit internal ohmic values to station battery baseline every 18 months.
◊ The circuit breaker trip circuits and auxiliary relays are tested every 6 calendar years.

Example #3: A combination of level 2 (partially) monitored and level 1 (unmonitored) components within a given Protection System is:

◊ A microprocessor relay with alarm connected to SCADA to alert 24-hr staffed operations center. (level 2)
◊ Instrument transformers, with no monitoring, connected as inputs to that relay (level 1)
◊ Battery without any alarms connected to SCADA (level 1)
◊ Circuit breaker with a trip coil, with no circuits monitored (level 1)

Given the particular components, conditions, and using the Table 1 (“Maximum Allowable Testing Intervals and Maintenance Activities”), the particular components have maximum test intervals of:

◊ The microprocessor relay is verified every 12 calendar years.

◊ The instrument transformers are verified every 12 calendar years.

◊ The battery is verified every 3 months, every 18 months, plus, depending upon the type of battery used it may be verified at other maximum test intervals, as well.

◊ The circuit breaker trip circuits and auxiliary relays are tested every 6 calendar years.

B. What is the intent behind the different levels of monitoring?

The intent behind different levels of monitoring is to allow less frequent manual intervention when more information is known about the condition of Protection System components.

C. Do all monitoring levels apply to all components in a protection system?

No. For some components in a protection system, certain levels of monitoring will not be relevant. See table below:

Monitoring Level Applicability Table

(See related definition and decision tree for various level requirements)

Protection Component	Level 1 (Unmonitored)	Level 2 (Partially Monitored)	Level 3 (Fully Monitored)
Protective relays	Y	Y	Y
Instrument transformer Inputs to Protective Relays	Y	N	Y
Protection System control circuitry (Other than aux-relays & lock-out relays)	Y	Y	Y
Aux-relays & lock-out relays	Y	N	N
DC supply (other than station batteries)	Y	Y	Y
Station batteries	Y	N	N
Protection system communications equipment and channels	Y	Y	Y
UVLS and UFLS relays that comprise a protection scheme distributed over the power system	Y	Y	Y
SPS, including verification of end-to-end performance, or relay sensing for centralized UFLS or UVLS systems	Y	Y	Y

Y = Monitoring Level Applies
N = Monitoring Level Not Applicable

D. When documenting the basis for inclusion of components into the appropriate levels of monitoring as per Requirement R2 of the standard, is it necessary to provide this documentation via a device by device listing of components and the specific monitoring attributes of each device?

No. While maintaining this documentation on the device level would certainly be permissible, it is not necessary. Global statements can be made to document appropriate levels of monitoring for the entire population of a component type or portion thereof.

For example, it would be permissible to document the conclusion that all BES substation dc systems are Level 2 - Partially Monitored by stating the following within the program description:

> "All substation dc systems are considered Level 2 - Partially Monitored and subject to Table 1b requirements as all substation dc systems are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center."

Similarly, it would be acceptable to use a combination of a global statement and a device level list of exclusions. Example:

> "Except as noted below, all substation dc systems are considered Level 2 - Partially Monitored and subject to Table 1b requirements as all substation dc systems are equipped with dc voltage alarms and ground detection alarms that are sent to the manned control center. The dc systems of Substation X, Substation Y, and Substation Z are considered Level 1 - Unmonitored and subject to Table 1a requirements as they are not equipped with ground detection capability."

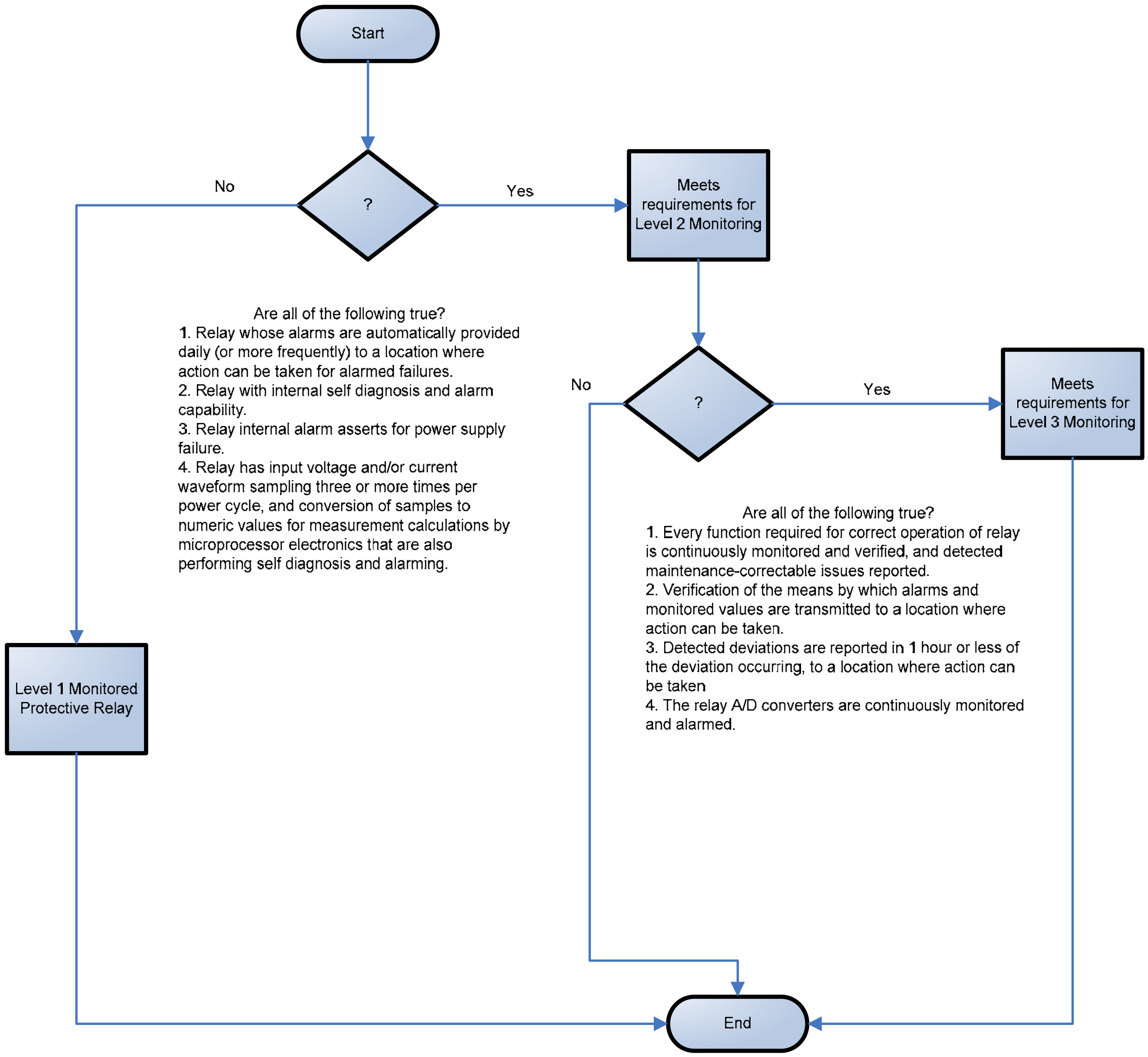
Regardless whether this documentation is provided via a device by device listing of monitoring attributes, by global statements of the monitoring attributes of an entire population of component types, or by some combination of these methods, it should be noted that auditors may request supporting drawings or other documentation necessary to validate the inclusion of the device(s) within the appropriate level of monitoring. This supporting background information need not be maintained within the program document structure but should be retrievable if requested by an auditor.

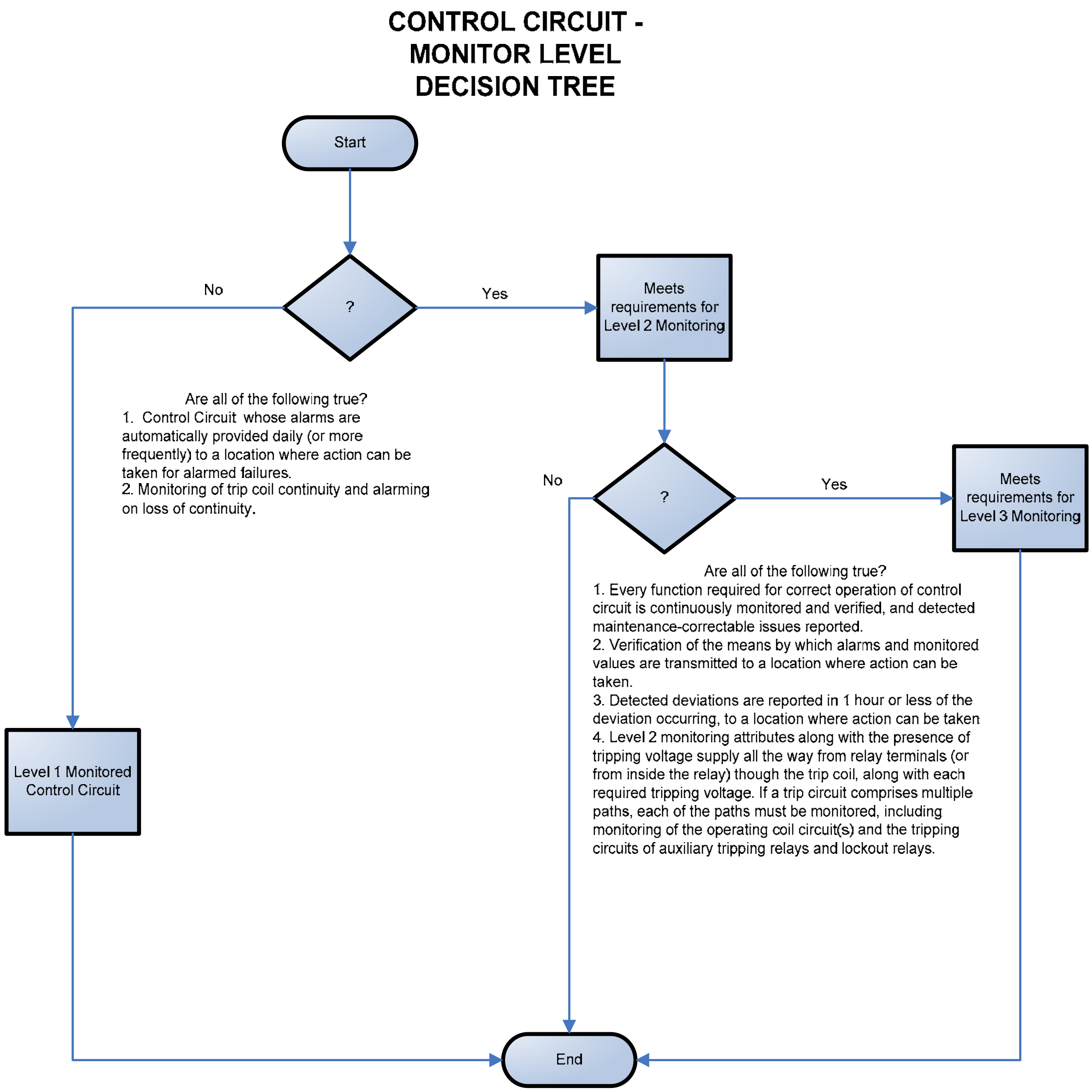
E. How do I know what monitoring level I am under? – Include Decision Trees

Decision Trees are provided below for each of the following categories of equipment to assist in the determination of the level of monitoring.

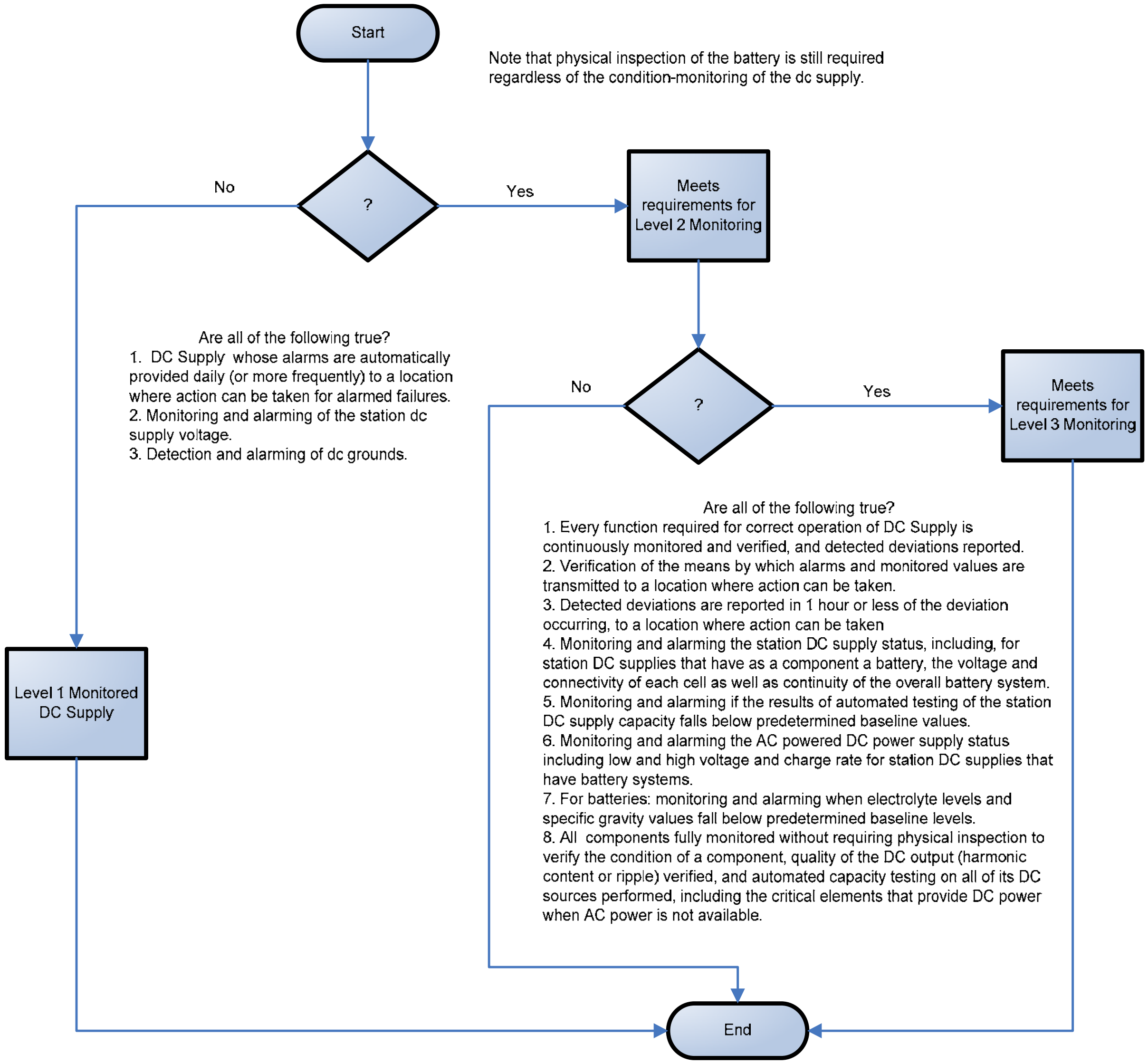
- ◊ Protective Relays
- ◊ Protection System Control Circuitry
- ◊ Station dc Supply
- ◊ Protection System Communications Equipment and Channels

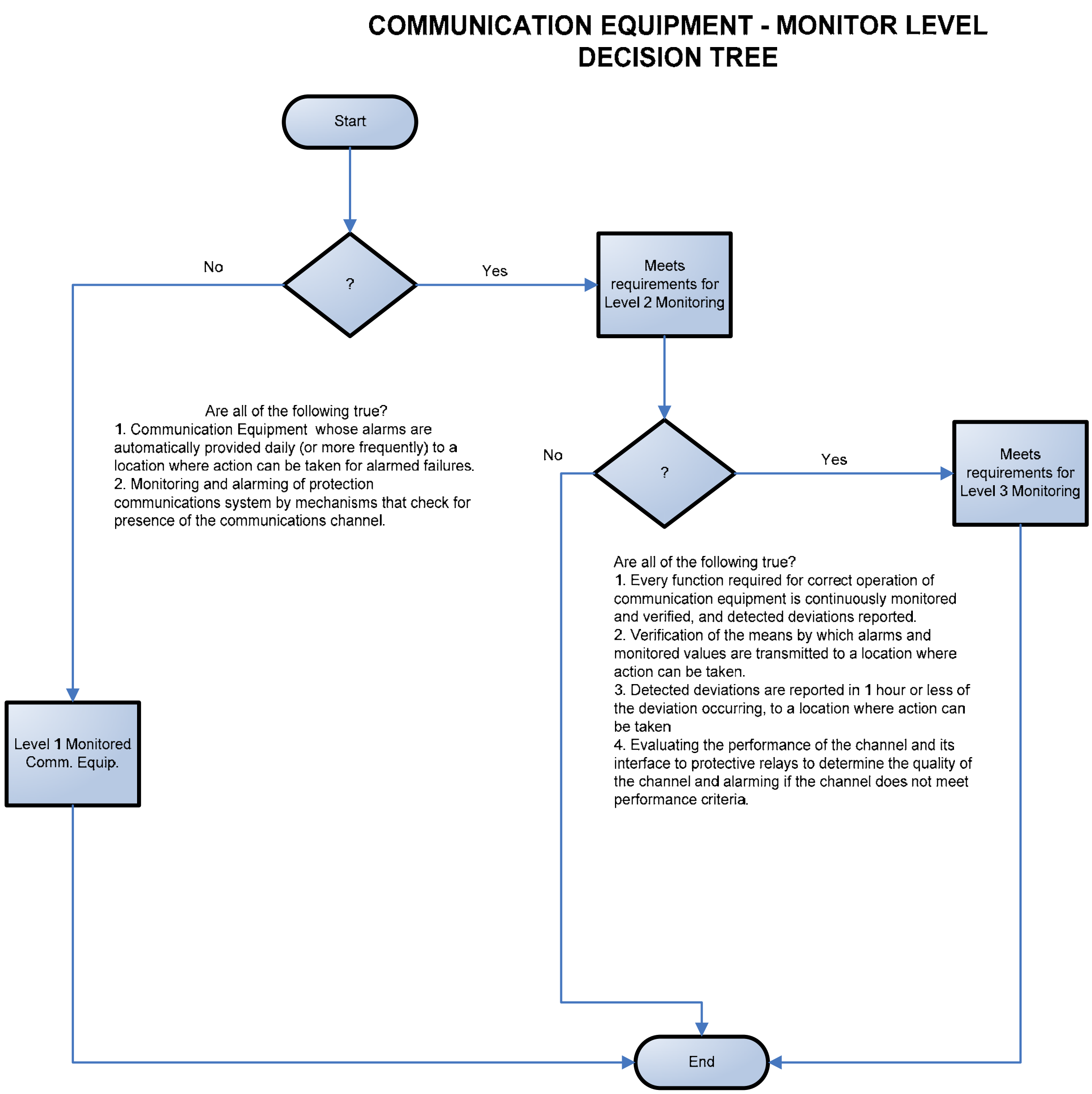
RELAY - MONITOR LEVEL DECISION TREE




CONTROL CIRCUIT -
MONITOR LEVEL
DECISION TREE
Start
?
No
Yes
Meets requirements for Level 2 Monitoring
Are all of the following true?
1. Control Circuit whose alarms are automatically provided daily (or more frequently) to a location where action can be taken for alarmed failures.
2. Monitoring of trip coil continuity and alarming on loss of continuity.
?
No
Yes
Meets requirements for Level 3 Monitoring
Are all of the following true?
1. Every function required for correct operation of control circuit is continuously monitored and verified, and detected maintenance-correctable issues reported.
2. Verification of the means by which alarms and monitored values are transmitted to a location where action can be taken.
3. Detected deviations are reported in 1 hour or less of the deviation occurring, to a location where action can be taken
4. Level 2 monitoring attributes along with the presence of tripping voltage supply all the way from relay terminals (or from inside the relay) though the trip coil, along with each required tripping voltage. If a trip circuit comprises multiple paths, each of the paths must be monitored, including monitoring of the operating coil circuit(s) and the tripping circuits of auxiliary tripping relays and lockout relays.
Level 1 Monitored Control Circuit
End

DC SUPPLY - MONITOR LEVEL DECISION TREE





2. **Level 1 Monitored Protection Systems (Unmonitored Protection Systems)**

   A. **We have an electromechanical (unmonitored) relay that has a trip output to a lockout relay (unmonitored) which trips our transformer off-line by tripping the transformer's high-side and low-side circuit breakers. What testing must be done for this system?**

   This system is made up of components that are level 1 (unmonitored). Assuming a time-based protection system maintenance program schedule, each component must be maintained per Table 1a – Level 1 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities.

3. Level 2 Monitored Protection Systems (Partially Monitored Protection Systems)

A. We have a 30 year old oil circuit breaker with a red indicating lamp on the substation relay panel that is illuminated only if there is continuity through the breaker trip coil. There is no SCADA monitor or relay monitor of this trip coil. The line protection relay package that trips this circuit breaker is a microprocessor relay that has an integral alarm relay that will assert on a number of conditions that includes a loss of power to the relay. This alarm contact connects to our SCADA system and alerts our 24-hour operations center of relay trouble when the alarm contact closes. This microprocessor relay trips the circuit breaker only and does not monitor trip coil continuity or other things such as trip current. Is this an unmonitored or a partially-monitored system? How often must I perform maintenance?

The protective relay is a level 2 (partially) monitored component of your protection system and can be maintained every 12 years or when a maintenance correctable issue arises. Assuming a time-based protection system maintenance program schedule, this component must be maintained per Table 1b – Level 2 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities

The rest of your protection system contains components that are level 1 (unmonitored) and must be maintained within at least the maximum verification intervals of Table 1a.

B. How do I verify the A/D converters of microprocessor-based relays?

There are a variety of ways to do this. Examples include using values gathered via data communications and automatically comparing these values with values from other sources, and using groupings of other measurements (such as vector summation of bus feeder currents) for comparison if calibration requirements assure acceptable measurement of power system input values. Other methods are possible.

C. For a level 2 monitored Protection System (Partially Monitored Protection System) pertaining to Protection System communications equipment and channels, how is the performance criteria involved in the maintenance program?

The entity determines the performance criteria for each installation, depending on the technology implemented. If the communication channel performance of a Protection System varies from the pre-determined performance criteria for that system, these results should be investigated and resolved.

4. Level 3 Monitored Protection Systems (Fully Monitored Protection Systems)

A. Why are there activities defined for a level-3 monitored Protection System? The technology does not seem to exist at this time to implement this monitoring level.

There may actually be some equipment available that is capable of meeting level-3 monitoring criteria, in which case it may be maintained according to Table 1c.

However, even if there is no equipment available today that can meet this level of monitoring, the Standard establishes the necessary requirements for when such equipment becomes available. By creating a roadmap for development, this provision makes the Standard technology-neutral. The standard drafting team wants to avoid the need to revise the Standard in a few years to accommodate technology advances that are certainly coming to the industry.

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