Protection System Maintenance
and the New NERC Standard PRC-005-2

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On the way out…NERC PRC-005-1

Old "Fill in the blank" standard

- In 2007, FERC declared it enforceable with potential fines.
- No specific maintenance requirements (FERC wanted this fixed).
- You must have a *documented* maintenance *program*.
- You must have a *factual basis* for time intervals (tough!)
- You must have *concrete* evidence that you are doing *everything* in your program – 100 % execution.
  - *Weak evidence = you're not doing it.*
- Audits yield high noncompliance compared to other NERC standards, and *companies have been fined*.

NERC PRC-005-1 requirements

- R1 Have a Protection System maintenance and testing program for Protection Systems that shall include:
  - R1.1 Maintenance & **testing intervals & their basis**
  - R1.2 Summary of maintenance & testing **procedures**.
- R2 Provide documentation of Protection System maintenance and testing program and its implementation to RRO on request. Documentation shall include:
  - R2.1 **Evidence** Protection System devices were maintained & tested within defined intervals.
  - R2.1 **Date each Protection System device was last tested/maintained**.
- Data Retention - Shall retain evidence of implementation of Protection System maintenance and testing program for **three years.**

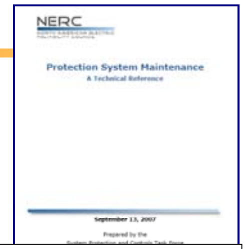
What's happening to protection system maintenance?

- FERC Order 693 (3/2007) mandates new NERC Protection System Maintenance standard.

> Docket No. RM06-16-000 - 386 -
>
> 1473. FirstEnergy and ISO-NE suggest that PRC-005-1, PRC-008-0, PRC-011-0 and PRC-017-0 should be combined into a single Reliability Standard relating to the maintenance of protection and control equipment.
>
> ii. Commission Determination
>
> 1474. For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC-005-1 as mandatory and enforceable.
>
> 1475. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop a modification to PRC-005-1 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System. We further direct the ERO to consider FirstEnergy's and ISO-NE's suggestion to combine PRC-005-1, PRC-008-0, PRC-011-0 and PRC-017-0 into a single Reliability Standard through the Reliability Standards development process.

- FERC demanded **standard maximum time intervals & minimum activities for maintenance**.

PRC-005-2 development process



- NERC SPCTF (now SPCS) creates 2007 Technical Reference for PSM.
  - Includes TBM, **CBM, PBM – *escape hatches* from FERC demands.**
- NERC Project 2007-17 - Protection System Maintenance & Testing Standards Drafting Team (PSMT SDT).
- PRC-005-2 approved by industry and by NERC, November 2012.
- Awaiting FERC approval.
- Meanwhile, **FERC Order 758**, Feb. 2012, kicks off work on **PRC-005-3**!

Combine four related standards

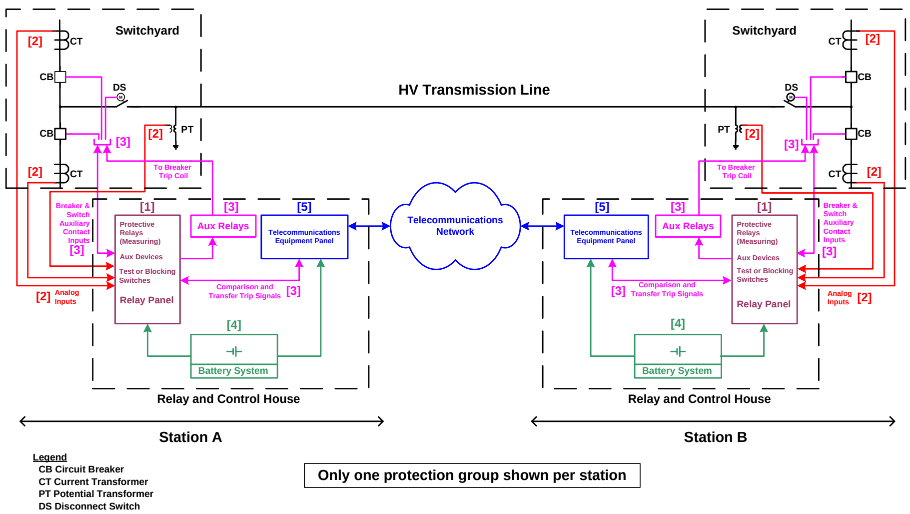
Old standards -

- PRC-005-1 – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-1 – Underfrequency Load Shedding Equipment Maintenance
- PRC-011-1 – Undervoltage Load Shedding Equipment Maintenance and Testing
- PRC-017-1 – Special Protection System Maintenance and Testing

All being combined into -

- PRC-005-2 – Protection System Maintenance
- **Systems built from the same types of equipment, same issues.**

NERC Protection System example (line protection)



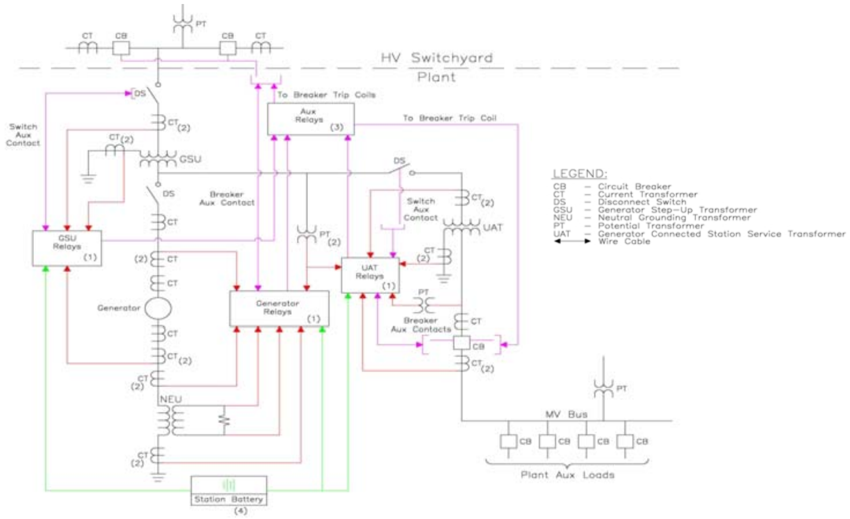
NERC Protection System *definition (new in 2010)*

- Protective relays [1] which respond to *electrical* quantities*,
- Communications systems [5] necessary for correct operation of *protective functions*,
- Voltage and current sensing devices [2] *providing inputs to protective relays*,
- Station dc supply [4] associated with protective functions (including station batteries, *battery chargers*, and non-battery-based dc supply), and
- Control circuitry [3] associated with protective functions *through the trip coil(s) of the circuit breakers* or other interrupting devices.

FERC Order 758 and PRC-005-3 will add **mechanical sensing devices that trip (e.g. SPR/FPR, vibration)** and **certain reclosing relays** that could impact reliability by misoperating.

Example (generating plant protection)

Generally, any **electrical** *protection that trips the lockout switch. (Stay tuned for FERC changes). Auxiliary systems mostly excluded.*



Which protection systems must comply?

NERC reliability standards apply to the Bulk Electric System (BES) – presently defined by regions; NERC creating standard definition now – Project 2010-17.

- Transmission, generation, some distribution owners.
- Generally, 100 kV and above.
- Protection systems for critical generating plant equipment.
- UFLS, UVLS schemes & SPSs that protect the BES, even for equipment applied at distribution.
  - Easier tests for distribution components

What is maintenance *testing or verification?*

Assumption:

- The system was *already commissioned*, so we don't have to retest correct wiring, configuration, functioning.

We want to know…

- Has *any element of hardware* needed for fault protection failed or drifted?
- Are the *settings as intended*?

Approaches:

- We can test in sections, or end-to-end.
- We have a tight *settings management process* - we know what settings *should* be – are settings as officially signed off?

Electromechanical relays

We don't know if they are working unless we test them.

- They can drift, change characteristics, or fail.
- Check settings = apply V & I.
- Check voltage and current *inputs* (CT, VT) with instruments.
- Test trip circuits.
- *Track repair & calibration history* - manage fleet or unit problems over time.

Same for analog solid state relays.

It's not a microprocessor relay unless it meets definitions of PRC-005-2 tables. Not good enough just to have a microprocessor in it.

Microprocessor relays

µP relays have no calibration adjustment or drift.

- *Definition* - µP relay samples V & I waveforms for measurement calculations in µP system.
- *Behavior* - It protects correctly, or it *blocks* and reports its problems.

Maintenance verification and testing:

- Verify the V & I metered value accuracy.
- Check protection binary I/O
- Check self-monitoring alarms.
- No testing needed *for monitored parts*.
- **Be aware of what is not monitored and needed for protection** – e.g. trip output

Self-monitoring of µP relay systems

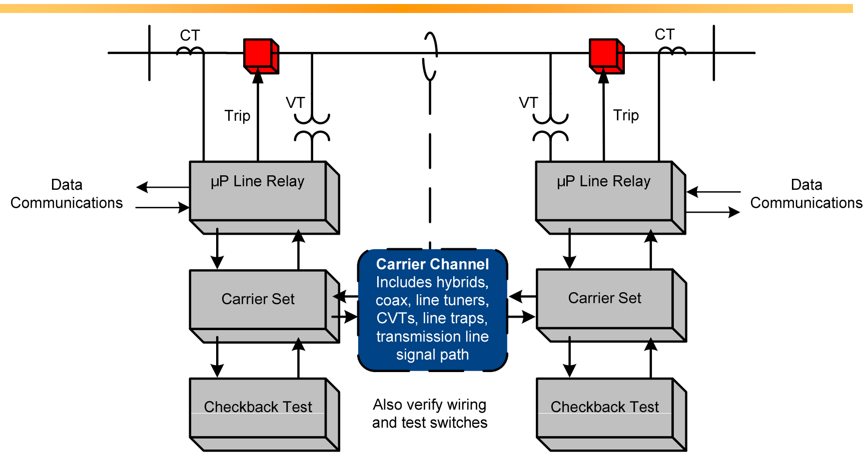
- Multiple processors, data buses, peripheral parts communicate constantly & check for failures.
- A/D converters check calibration.
- Relay logic checks consistency of measurements.
- Power supply or catastrophic failure – dead man alarm.
- Checks dc supply voltages.
- Data comms failure – streaming traffic stops.
- SCADA compares metered values from 2 relays to verify A/D conv., CTs and VTs, ac input wiring.
- Monitor *continuity* of trip circuit (TCM).
  - We still don't know if trip output works.
  - We still don't know if breaker will actually trip.

Verifying the complete protection system

Every part of the system that is required for correct protection performance must either be:

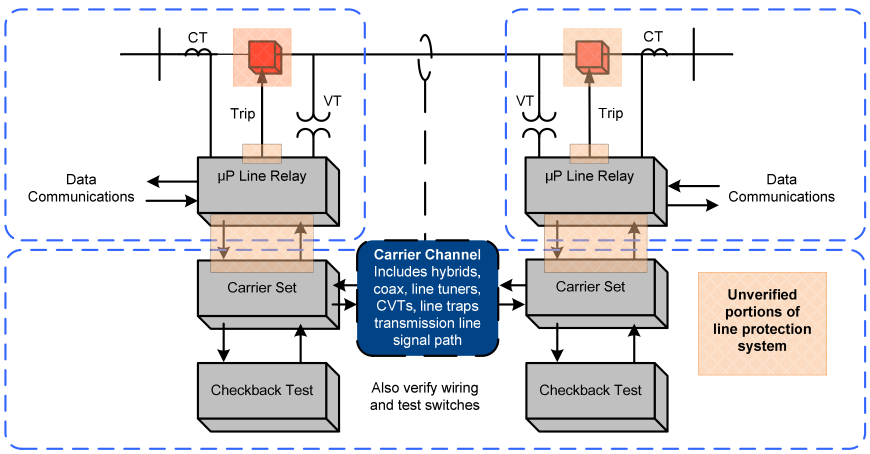
- Verified by monitoring and alarming, or
- Tested periodically.
- No gaps – overlapping checks.
- Monitor the alarming paths, or test those periodically.
- In general – E/M relays, mechanisms, contacts – <u>anything that moves</u> - cannot be fully monitored and must be tested periodically.
- Natural operations can be valid tests that reset the clock for a periodic test (*event-based maintenance, EBM*).
  - Be careful – <u>exactly</u> what did you observe in a routine operation?

Completeness of monitoring



- Assume we have two redundant systems like this reporting analog metered values.
- What can we know from monitoring?

Gaps in monitoring require periodic tests



Monitoring benefits

Monitoring advantages over human testing:

- Continuous verification – we know it's working – or we fix it as soon as it fails. **Protection reliability improvement.**
- Non-invasive - **no risk of damage or human error trips**.
- No risk of leaving equipment in a non-operating state.
- Frees human resources for asset replacement & fixing problems.

Be aware of what is not monitored

- Talk to vendor – focus only on what is needed for relaying.
- PRC-005-2 will give manufacturers and users reasons to invent monitoring improvements.

Maintenance program concepts in PRC-005-2

- **Time based maintenance (TBM)** – test at specified intervals (what FERC 693 ordered).
- **Condition based maintenance (CBM)** – **extend** TBM test intervals and/or **eliminate** testing steps by taking advantage of **monitoring**.
- **Performance based maintenance (PBM)** – a.k.a. RCM - **extend** TBM test time intervals by analyzing **records showing low failure rates of particular equipment families** receiving TBM - demonstrated reliability.

Mix and match within a protection system – get the optimum program.

- **Event-based maintenance (EBM) –** use natural operations as TBM tests to check off selected items.

PRC-005-2 maintenance tables

- Basic TBM, CBM time extensions, CBM activity reductions.
- PBM is separate in Appendix A.

PRC-005-2 maintenance tables

Tables 1-X exclude distribution UFLS, UVLS, SPS parts – see Tables 1-4(e) & 3

- Table 1-1 - Protective Relays
- Table 1-2 - Communications Systems
- Table 1-3 - Voltage and Current Sensing Devices Providing Inputs to Protective Relays
- Table 1-4(a) - Protection System Station dc Supply…
  - (a) Using Vented Lead-Acid (VLA) Batteries
  - (b) Using Valve-Regulated Lead-Acid (VRLA) Batteries
  - (c) Using Nickel-Cadmium (NiCad) Batteries
  - (d) Using Non Battery Based Energy Storage
  - (e) For non-BES Interrupting Device - SPS & non-distributed UVLS & UFLS
  - (f) Exclusions due to Station dc Supply Monitoring Devices and Systems
- Table 1-5 - Control Circuitry Associated With Protective Functions
- Table 2 - Alarming Paths and Monitoring
- Table 3 - Maintenance Activities/Intervals - distributed UFLS & UVLS Systems

Table 1-1 – Protective Relays

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2).	12 calendar years	Verify: • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.
Monitored microprocessor protective relay with preceding row attributes and the following: • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2).	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 – Communications Systems

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 calendar months	Verify that the communications system is functional.
	12 calendar years	Verify that the channel meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 calendar years	Verify that the channel meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with: • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 -V & I Sensing Devices

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 calendar years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value as measured by the microprocessor relay to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4 (a) – Vented lead acid battery system

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • continuity • terminal connection resistance • intercell or unit-to-unit connection resistance Inspect: • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. -or- Verify that the station battery can perform as designed by conducting a performance, service, or modified performance capacity test of the entire battery bank.

Table 1-4 (e) - Non-BES *UFLS/UVLS & SPS dc supply*

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System dc supply for tripping only non-BES interrupting devices as part of a SPS or non-distributed UVLS and UFLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage

Table 1-4 (f) - Dc supply monitoring

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure. (See Table 2)	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2)		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2)		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2)		No periodic verification of float voltage of battery charger is required
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2)		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2)		No periodic verification of the intercell and terminal connection resistance is required.
Any lead acid battery based station dc supply with internal ohmic value monitoring, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2)		.No periodic measurement and evaluation relative to baseline of battery cell/unit internal ohmic values is required to verify the station battery can perform as designed .
Any Valve Regulated Lead-Acid (VRLA) station battery with monitoring and alarming of each cell/unit internal Ohmic value. (See Table 2)		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA battery is required.

Table 1-5 - Control Circuitry

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 calendar years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 calendar years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 calendar years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 - Alarming & monitoring

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any alarm path through which alarms in Tables 1-1 through 1-5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below. Alarms are reported within 24 hours of DETECTION to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	No periodic maintenance specified.

Table 3 - Distributed UFLS and UVLS (extracted key info)

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Relays – unmonitored or monitored	6 or 12 calendar years	Similar to Table 1(a).
Voltage and/or current sensing devices	12 calendar years	Verify V&I to relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	**12 calendar years**	**Verify Protection System dc supply voltage.**
Control circuitry up to lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	**12 calendar years**	**Verify the path from the relay to the lockout and/or tripping auxiliary relay**
EM aux devices	12 calendar years	Verify operation
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting device.	**No periodic maintenance specified**	**None.**
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	**No periodic maintenance specified**	**None.**

Standard requirements paraphrased

- R1 – Owner/Provider shall establish a Protection System Maintenance Program (PSMP).
  - R1.1 – Identify components using of TBM and PBM (Attachment A – coming up) programs.
  - R1.2 – Identify monitoring attributes of component types with CBM time extensions.
- R2 – If running a PBM program, follow Attachment A for managing performance and time intervals.
- R3 – If running a TBM program, follow the maximum times and minimum activities of the tables.
- R4 – Use the PSMP for PBM program.

(continued)

Standard requirements paraphrased

- R5 - Demonstrate [*document*] efforts to correct identified Unresolved Maintenance Issues.

Unresolved Maintenance Issue –

A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

- **Relay out of service?** Don't forget to coordinate and notify operators and others affected as required in other NERC standards!

PBM – Attachment A of PRC-005-2

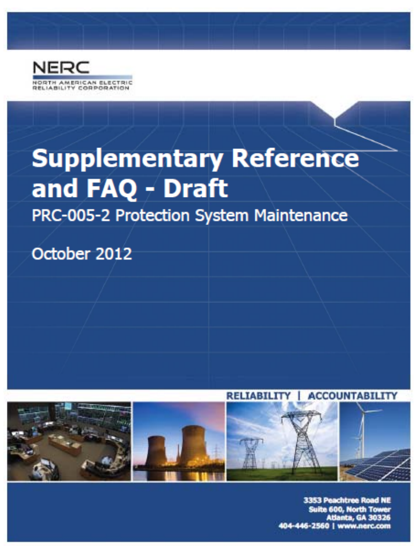
- Start with a population of 60 or more like devices of a reliable type.
  - Keep above 30 w/ attrition.
  - Users can aggregate populations.
- Perform PSMP TBM and *document* failure rate under 4%.
- Extend maintenance intervals while staying under 4%.
- Must test at least 5% of population per year with PSMP.
- Review results every year.
- Maintenance time interval could reach <u>20 years</u>!

Use the Supplementary Reference and FAQ!

105 pages of solid, useful help:

- FAQ answers
- Technical explanations of requirements
- Interpretations
- Tips and tricks
- Tutorial information on Protection System components
- Record keeping advice
- Audit handling advice

Your industry colleagues working to help you succeed!



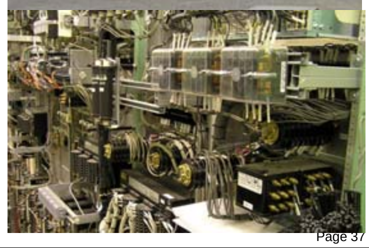
Implementation plan

- Develop PSMP within 12 months of FERC approval – R2, R2, R5.
  - Non-FERC locations – 24 months from November 2012 (assumes 12 months for FERC to approve).
- Compliance of components rolls out gradually over the interval for the populations of components with that interval (R3 & R4).
- Example – 6 year interval (unmonitored relays):
  - 30% compliant by 3 years after FERC approves.
  - 60% compliant by 5 years after FERC approves.
  - 100% compliant by 7 years after FERC approves.
- See implementation plan on NERC web with standard.

Table observations

- Time limits are **<u>firm</u>** – plan shorter times to comply when:
  - Field crews get busy.
  - Experts retire.
  - Outages are blocked by Operations.
  - Disasters distract focus.
- Your program can do more than NERC requires.
  - Visual inspections.
  - Focus on known problems – risky if you don't.
  - Consider uniform program - even at lower voltages.
    - For *maintenance efficiency* – but **keep separate non-BES program and implementation documentation out of audit!**

Table observations



- Batteries require lots of physical attention and testing – unpredictable electrochemical system.
- Dual trip coils – make sure you can trip through each coil *by itself*.
- E/M aux & lockout relays
  - Must test things that move.
  - Today, we can design these out of schemes.
- Can't validate CT signal during maintenance outage? Check secondary excitation curve against baseline.

Table observations

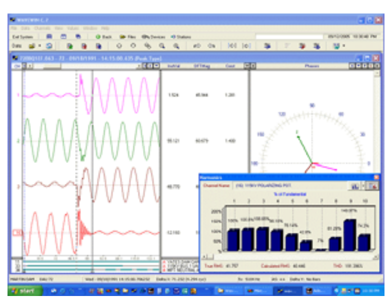
- Data communications among relays (µP to µP) with a heartbeat - fully monitored paths that never need testing.
  - IEC 61850 GOOSE messaging on Ethernet replaces wiring.
  - Serial data streams with monitoring & continuous traffic heartbeat – µP current differential relays, serial I/O port control protocols.
  - Use performance monitoring feature with alarm – e.g. error count or lost packet rate.

Table observations

- For complete monitoring, the *alarm path itself must also be monitored* – this is easy to do with integrated relays.
- Include test switches between trip circuit merge points and the breaker trip coil:
  - Trip the breaker once as you test the first path.
  - Open test switch and test the other trip paths by connecting an auxiliary test relay.
- Trip test and battery maintenance activities are relaxed for distribution UFLS and UVLS relays.
  - Distributed BES protection scheme.
  - Don't interrupt customers by testing breaker.
  - BES is protected if *most* of the relays trip.

Take advantage of in-service operations

- A natural operation can reset maintenance time clocks.
- *EBM - Exactly* what was observed?
  - E/M relay trip circuit proven, but calibration is not proven.
  - Dual trip coils – do we know *each* can trip the breaker?
- Operational integration of µP relays reduces testing.
  - Remotely trip breaker.
  - SCADA data concentrator compares V&I readings of redundant relays/CTs/VTs.
  - SCADA monitors alarming path.



- Analyze and keep records to prove compliance.
- But…does the database support this?

Documentation is key for compliance audit

- Document the program (PSMP) with intervals and activities – what have you chosen to do?
- Perform every required activity, on every component, within the chosen schedule.
- Keep records of dates & results for every component.
- For CBM - document *Protection System* monitoring features.
  - Standardize designs, or this is difficult.
- For PBM – conduct annual review for each population segment, document results per Attachment A, and keep records.

Conclusions

- NERC PRC-005-2 will become mandatory & enforceable.
- Audits & fines for noncompliance.
- TBM (industry's habit today) will always be acceptable if intervals & activities comply with standard tables.
- Create systems for documenting all field TBM activity.
- Design CBM to extend intervals and eliminate most human testing, while improving reliability.
- Create design documentation and a settings management process to support CBM.
- Use PBM - extend intervals of reliable device types.
- Find all documents for Project 2007-17 on NERC web site: http://www.nerc.com/filez/standards/Protection System Maintenance Project 2007-17.html

(All apparent spaces in URL have underscores, obscured above)

Acknowledgement

NERC Protection System Maintenance and Test Standard Drafting Team (Jan. 2012)

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Questions?

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