Kentucky Power Company
KPSC Case No. 2019-00154
Attorney General’s Second Set of Data Requests
Order Dated October 14, 2019

DATA REQUEST

AG 2-1 Refer to Kentucky Power’s response to Staff DR 1-5 (a). Explain in detail the system conditions or causes of the electrical discharges of high energy, thermal faults, stray gassing and overheating that have led to the need for Transformer #1 and #2 to be replaced earlier than their projected life expectancy.

RESPONSE

These events can be caused by multiple drivers such as tree or other vegetation contact with the conductors, high winds blowing the conductors together, failures of line and station equipment, heavy ice and snow loading, animals, vandalism, forest fires, vehicle accidents, and lightning strikes.

Given the current arrangement of equipment at the Hazard Substation, the 138/69kV Transformers #1 & #2 are exposed to through faults for any forced operation of the Beaver Creek-Hazard 138kV line, 69kV Bus No. 1, 138kV Bus No. 1, 69kV Bus No. 2, or the 161/138kV Transformer #3. There have been 36 such events in the last ten years. Also see the Company's response to KPSC 2-9.

Witness: Michael G. Lasslo

Kentucky Power Company
KPSC Case No. 2019-00154
Attorney General’s Second Set of Data Requests
Order Dated October 14, 2019

DATA REQUEST

AG 2-2 Refer to Kentucky Power’s response to Staff DR 1-5 (b). Fully explain the primary causes of the circuit breaker faults discussed.

RESPONSE

Please refer to the Company's response to AG 2-1. The current arrangement of the Hazard station leads to more element trips than will occur with the new configuration. Over the last ten years, there have been 146 forced outages that have directly impacted the circuit breakers included in the application. Each forced outage that directly impacts the circuit breakers, calls for that specific circuit breaker to operate.

161kV Circuit Breaker M is exposed to faults for any forced operation of the Hazard-Wooton 161kV line, 138kV Bus No. 2 or 161/138kV Transformer #3. There have been 9 such events in the last 10 years.

69kV Circuit Breaker E is exposed to faults for any forced operation of the Hazard-Leslie 69kV line, 69kV Bus No.1 and 138/69kV Transformer #1. There have been 43 such events in the last 10 years.

69kV Circuit Breaker S is exposed to faults for any forced operation of the Hazard-Daisy 69kV line, 69kV Bus No. 2 or 138/69kV Transformer #2. There have been 45 such events in the last 10 years.

69kV Circuit Breaker F is exposed to faults for any forced operation of the Bonnyman-Hazard No. 2 69kV line, Capacitor Bank/Switcher AA, 69kV Bus No. 1, or 138/69kV Transformer #1. There have been 49 such events in the last 10 years.

System conditions that can contribute to the events include tree or other vegetation contact with the conductors, high winds blowing the conductors together, failures of line and station equipment, heavy ice and snow loading, animals, vandalism, forest fires, vehicle accidents and lightning strikes.

Witness: Michael G. Lasslo

DATA REQUEST

AG 2-3 Refer to the two requests above. Explain in detail how Kentucky Power will address the underlying causes or system conditions that have led to the premature retirement of certain equipment following the completion of the proposed projects.

RESPONSE

The premise of the data request, that the Company is prematurely retiring certain equipment, is erroneous. Currently, the substation does not have adequate protection to isolate faults that occur in one part of the substation or on one section of line. Therefore, faults currently affect multiple pieces of equipment, ultimately leading to further deterioration. The upgrades proposed for the Hazard Station will protect the equipment by isolating faults so only a limited section of the substation is affected, and will decrease customer exposure to outages. The type of equipment that aids in the protection, and ultimately the prolonged life of the equipment, is highlighted in Exhibit 2 to the Company's application. These include, but are not limited to, installing new circuit breakers on the 138kV line towards Beckham, on the high side and low side of 138/69kV Transformers #1, #2, and #3, along with upgrading the protection devices with modern and standard relays.

Witness: Michael G. Lasslo

DATA REQUEST

AG 2-4 Refer to Attachment 1 to Kentucky Power's response to Staff DR 1-8. For each "Work Description" item that is only "Needed to comply with existing PJM and Kentucky Power design standards," provide and fully explain the design standards requiring compliance.

RESPONSE

For work at the Hazard Substation needed to comply with PJM design standards, please refer to the Company's response to KPSC 2-3, KPCO_R_KPSC_2_3_Attachment1. Similarly, for work at the Wooton Substation needed to comply with PJM design standards, please refer to the Company's response to KPSC 2-3, KPCO_R_KPSC_2_3_Attachment2.
Standards documents referenced in the above attachments are included as the following attachments:

- PJM Manual 07 - KPCO_R_AG_2_4_Attachment1
- PJM Relay Subcommittee Protective Relaying Philosophy and Design Guidelines - KPCO_R_AG_2_4_Attachment2
- PJM Designated Entity Design Standards Task Force Minimum Required Standards - KPCO_R_AG_2_4_Attachment3
- IEEE PSRC I22 Report - KPCO_R_AG_2_4_Attachment4

Witness: Kamran Ali

PJM Manual 07:

PJM Protection Standards

Revision: 4

Effective Date: May 30, 2019

Prepared by
System Planning Division Transmission Planning Department

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Table of Contents

Approval

Approval Date: 05/30/2019 Effective Date: 05/30/2019

Aaron Berner, Manager

Transmission Planning

Current Revision

Administrative Change (07/24/2019):

- Clarifying that Revision 04 was Periodic Review. Details of changes were included in Revision 04.

Revision 04 (05/30/2019):

- Revised language in Section 1 reflecting the applicable effective date of Manual revisions
- Revised reference in Appendix D to M-14G Attachment C and D, which were previously incorporated in M-14A
- Added technical reference in Appendix D reflecting industry standard updates, including IEEE 1547-2018

Introduction

Welcome to the ***PJM Manual for Protection Standards of PJM***. In this Introduction, you will find the following information:

- What you can expect from the PJM Manuals in general (see “About PJM Manuals”).
- What you can expect from this PJM Manual (see “About This Manual”).
- How to use this manual (see “Using This Manual”).

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of PJM and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and Transmission interconnection
- Reserve
- Accounting and Billing
- PJM Administrative Services

For a complete list of all PJM manuals, go to the Library section on PJM.com.

About This Manual

The ***PJM Manual for Protection Standards*** is the first PJM manual to deal with Protection Systems. This Manual is intended to provide design specification for new protection system installations. This manual can be used as evidence for compliance with NERC Standards:

- PRC-001 - System Protection Coordination
- FAC-001 - Facility Connection Requirements

Intended Audience

The intended audiences for the PJM Manual 07: PJM Protection Standards are:

- PJM Transmission Owners
- PJM Generator Owners
- PJM Interconnection Customers
- PJM Staff

References

The references to other PJM documents that provide background or additional detail directly related to the PJM Manual for PJM Protection Standards are the following:

- PJM Relay Subcommittee Protective Relaying Philosophy and Design Guidelines (http://www.pjm.com/committees-and-groups/subcommittees/rs.aspx)

This manual does not supersede the formal requirements of any of the referenced documents.

Using This Manual

Each section of this manual begins with an overview and the philosophy is reflected in the way material is organized. The following bullet points provide an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents
- An approval page that lists the required approvals and the revision history
- A section on protection philosophy
- New generator protection requirements
- New unit power, unit auxiliary and start-up station service transformer and lead protection requirements
- New line protection requirements
- New substation transformer protection requirements
- New bus protection requirements
- New capacitor and reactor protection requirements
- New breaker failure protection requirements
- New phase angle regulator protection requirements
- New transmission line reclosing requirements
- Information on design of supervision and alarming of relaying and control circuits
- New underfrequency load shedding requirements
- New special protection system requirements
- Information on the use of dual trip coils, direct transfer trip, dual pilot channels and three-terminal line applications

Section 1: Applicability

This document establishes the minimum design standards and requirements for the protection systems associated with the bulk power facilities within PJM. The facilities to which these design standards apply are generally comprised of the following:

- all 100 MVA and above generators connected to the BES facilities,
- all 200 kV and above transmission facilities
- all transmission facilities 100 kV to 200 kV critical to the reliability of the BES as defined by PRC-023 and determined by PJM System Planning
  - o PJM System Planning will also investigate the criticality of equipment (generators, buses, breakers, transformers, capacitors and shunt reactors) associated with the PRC-023 determined lines

General principles of applicability include:

A. Compliance with NERC Transmission Planning Standards, TPL-001 and the associated Table 1, as may be amended from time to time, is mandatory.

B. Where a protection system does not presently meet the requirements of NERC Transmission Planning Standards, TPL-001 and the associated Table 1, action shall be taken by the facility owner to bring the protection system(s) into compliance.

C. Adherence to applicable NERC and Regional reliability standards is mandatory; however, the PJM requirements set forth in this document are in some cases more restrictive than the applicable NERC or Regional reliability standards.

A protection system is defined as those components used collectively to detect defective power system elements or conditions of an abnormal or dangerous nature, to initiate the appropriate control circuit action, and to isolate the appropriate system components. All new projects shall conform to the revision of Manual 07 in effect at the date of approval of the project. It is recognized that some facilities existing prior to the adoption of these requirements do not conform. It is the responsibility of the facility owners to consider retrofitting those facilities to bring them into compliance as changes or modifications are made to those facilities.

Section 2: Protection Philosophy and Reliability

For the background and basis of the philosophy behind the requirements set forth in this document, please refer to the PJM Relay Subcommittee Protective Relaying Philosophy and Design Guidelines document. http://www.pjm.com/~/media/committees-groups/subcommittees/rs/postings/protective-relaying-philosphy-and-design-guidelines.ashx

2.1 Reliability

This section outlines the requirements and recommendations to assure reliability of Protection Systems. These criteria shall apply to all new Bulk Electric System (BES) facilities.

2.1.1 Test Switches

Protective relay schemes shall be designed such that test switches are installed to enable isolation of AC and DC connections to both protective and auxiliary relays. The installation of test switches minimizes primary element (e.g., line, transformer, bus, capacitor bank, shunt reactor) outage requirements for protection system maintenance.

2.1.2 Instrument Transformers

For any zone of protection, independent instrument transformers are required for primary and backup relaying. For a zone of protection which utilizes current sources, independent current transformers are required for the primary and backup protection schemes. For a zone of protection which utilizes voltage sources, independent voltage sources are required for the primary and backup protection schemes. Voltage sources may be provided either from independent voltage transformers or from independent secondary windings of the same voltage transformer.

2.1.3 Communication Channels

Dual pilot communication channels must be utilized if dual pilot is required for stability and/or relay coordination for BES circuits. Dual pilot channels are defined as two separate, independent communications channels which are applied to provide high speed clearing for transmission line faults via both the primary and backup relay schemes (see Appendix C: Dual Pilot Channels for Protective Relaying).

As noted in Section 15.2, all relay communication channels must be monitored to detect any channel problems and initiate an alarm. Channels that cannot be monitored due to the use of a normally off state must be tested automatically at least once a day, preferably at both reduced and full power levels.

The pilot communication for the primary and backup systems shall be designed to minimize the risk of both systems being disabled simultaneously by a single event or condition. For all requirements and recommendations see Appendix C.

2.1.4 Station Batteries

Primary and Backup protection schemes must employ independently protected DC control circuits. Each station battery is required to have its own charger. Physical separation shall be maintained between the two station batteries, if utilized.

For BES substations above 300 kV, dual station batteries are preferred; however, if a single battery is utilized, dual battery chargers are required.

The battery charger(s) and DC control circuits shall be protected against short circuits. The protective devices utilized shall be designed to minimize the number of control circuits interrupted.

DC control systems shall be continuously monitored and alarmed to detect abnormal voltage levels. At a minimum, a low battery voltage condition shall be reported remotely, as per Section 15.1. In addition, it is recommended that high battery voltage and DC ground conditions be also reported remotely.

Battery chargers are recommended to be continuously monitored and alarmed. If a single battery with a single charger is utilized, charger failure and loss of AC source shall be reported remotely.

2.1.5 Station Service (AC Supply)

At BES facilities, there shall be two sources of station service AC supply each capable of carrying all the critical loads associated with protection systems.

Section 3: Generator Protection

This section outlines the requirements for interconnecting unit-connected[1] generators as defined in this manual Section 1 - Applicability. In addition, the requirements specified in this section are applicable to generators interconnecting to utility transmission systems within PJM with output ratings greater than or equal to 100 MVA.

It is emphasized that the requirements specified in this section must not be construed as an all-inclusive list of requirements for the protection of the generator owner's apparatus.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- ANSI/IEEE C37.101 Guide for Generator Ground Protection
- ANSI/IEEE C37.102 Guide for AC Generator Protection
- ANSI/IEEE C37.106 Guide for Abnormal Frequency Protection for Generating Plants

3.1 Generator Stator Fault Protection

The following sections outline the requirements for phase and ground fault protection for the generator stator winding. As outlined in the requirements listed below, phase and ground protection for 100% of the stator winding is required.

3.1.1 Phase Fault Protection

Two independent current differential schemes are required for phase fault protection. The schemes must each employ individual current sources and independently protected DC control circuits. The backup scheme may, for example, consist of an overall generator and unit transformer differential. Both schemes must function to issue a simultaneous trip of the generator breaker(s), excitation system, and turbine valves.

3.1.2 Ground Fault Protection

Two independent schemes are required for ground fault protection with independent current or voltage sources and independently protected DC control circuits. At least one of the schemes is required to be designed to provide protection for 100% of the stator winding. The relays must be properly coordinated with other protective devices and the generator voltage transformer fuses. Both schemes must function to issue a simultaneous trip of the generator breaker(s), excitation system, and turbine valves.

Units with output ratings under 500 MVA are exempt from the redundancy requirement. Generators grounded through an impedance which is low enough to allow for detection of all ground faults by the differential relays do not require dedicated ground fault protection.

3.2 Generator Rotor Field Protection

Field ground fault protection must be provided to detect ground faults in the generator field winding. Upon detection of a ground fault, tripping of the generator is acceptable, but not

[1] Unit with a dedicated generator step-up transformer ("GSU"). Cross-compound units are considered unit-connected.

required. At a minimum, the protection scheme must initiate an alarm and upon activation of the alarm, the generator should be shut down as quickly as possible.

3.3 Generator Abnormal Operating Conditions

The requirements specified in this section are to provide protection for the generator and interconnected transmission system for abnormal operating (non-fault) conditions that the generator may be exposed to. The reader is referred to the documents cited in the beginning of this section for additional protection schemes that they may choose to include in the generator protection scheme design.

3.3.1 Loss of Excitation (Field)

Independent primary and backup relay schemes are required to detect loss of excitation (or severely reduced excitation) conditions. The schemes must employ independent current and voltage sources and independently protected DC control circuits and must function to trip the generator output breaker(s). The loss of excitation protection must be set to coordinate with (operate prior to encroachment upon) the generator’s steady-state stability limit (SSSL).

A simultaneous trip of the excitation system and turbine valves is recommended but, not required.

Units with output ratings under 500 MVA are exempt from the redundancy requirement for this protection scheme.

3.3.2 Unbalanced Current Protection

A negative-sequence overcurrent relay is required for protection from the effects of sustained unbalanced phase currents. An alarm shall be generated if the generator’s continuous negative-sequence current (I_2)capability is exceeded. For sustained unbalanced currents, the relay must coordinate with the I_2^2 t damage curves as normally supplied by the generator manufacturer and must trip the generator breaker(s). A simultaneous trip of the excitation system and turbine valves is recommended but not required.

3.3.3 Loss of Synchronism

Detailed stability studies are required to be performed by PJM to determine if an out-of-step protection scheme is required for the generator installation. If the results of the study indicate that the apparent impedance locus during an unstable swing is expected to pass through the generator step-up transformer (GSU) or generator impedance, an out-of-step protection scheme is required. This scheme must function to trip the generator breaker(s) within the first slip cycle. A simultaneous trip of the excitation system and turbine valves is recommended but not required.

3.3.4 Overexcitation

Two independent protection schemes are required for protection against the effects of sustained overexcitation. Both schemes shall respond to generator terminal volts/Hz and must be in service whenever field is applied. The schemes must employ independent voltage sources and independently protected DC control circuits. Relays either with inverse-time characteristics or with stepped-time characteristics configured to simulate an inverse-time characteristic are required. An alarm shall be generated if the generator continuous volts/Hz rating is exceeded. For sustained overexcitation the relays must coordinate with volts/Hz damage curves as normally supplied by the generator manufacturer and must trip the generator breaker(s) and the excitation. A simultaneous trip of the turbine valves is recommended but not required.

Note:
It is typical to protect both the generator and the GSU with the same volts/Hz protection schemes. In this case, the protection must coordinate with the volts/Hz damage curves for the more restrictive of the two.

Units with output ratings under 500 MVA are exempt from the redundancy requirement for this protection scheme.

3.3.5 Reverse Power (Anti-Motoring)

Anti-motoring protection which initiates an alarm followed by a simultaneous trip of the generator breaker(s), excitation system, and turbine valves is required.

Standard industry practice is to use the reverse power relay as the means for opening the generator breaker(s) following a routine manual or automatic trip of the turbine valves. Typical steam turbine anti-motoring protection consists of a reverse power relay set with a short time delay and supervised by closed turbine valve contacts to initiate a trip. Due to inherent reliability problems with valve position switches, this scheme must be backed up by a reverse power relay (may be the same relay) acting independently of the turbine valve position switches to initiate a trip. The latter scheme must incorporate a time delay as needed to provide security against tripping during transient power swings.

3.3.6 Abnormal Frequencies

Abnormal frequency protection (where applied) must be set to allow generators to remain in operation in accordance with PJM and Regional generator off-frequency operation requirements.

3.3.7 Generator Breaker Failure Protection

Breaker failure protection shall be provided for all relay-initiated generator trips with the exception of anti-motoring. It should be noted that some generator abnormalities that require the generator to be tripped will not result in an overcurrent condition and therefore may not operate current-actuated fault detectors incorporated in the breaker failure scheme. In these cases the current actuated fault detectors must be supplemented with breaker auxiliary switches using “OR” logic.

3.3.8 Excitation System Tripping

Redundant methods for removal of field current (where available) shall be utilized for all protective relay trips. Available methods include the tripping of two field breakers (i.e., main field breaker and the exciter field breaker) or the tripping of a single field breaker with simultaneous activation of the static de-excitation circuit.

Units with output ratings under 500 MVA are exempt from the redundancy requirement.

3.3.9 Generator Open Breaker Flashover Protection

Open breaker flashover protection is required for all gas and/or air circuit breakers used for generator synchronizing.

3.3.10 Protection During Start-up or Shut-down

The generator must be adequately protected if field is applied at less than rated speed during generator start-up or shut-down.

3.3.11 Inadvertent Energization Protection

Protection schemes designed specifically to detect the inadvertent energization of a generator while on turning gear is required for all generator installations. This scheme must function to trip the generator breaker(s).

3.3.12 Synchronizing Equipment

A synchronism checking relay is required to supervise all manual and automatic synchronizing of the generator. If the generator is required for system restoration, the synchronism checking scheme shall be designed to permit a close of the generator breaker into a de-energized grid.

3.3.13 Generator Lead Protection

The generator leads, which consist of the phase conductors from the generator terminals to the unit power transformer and the unit auxiliary transformer, shall be protected by a primary current differential relay scheme. A redundant current differential relay scheme is required if either (1) the generator leads are not installed in bus duct segregated by phase or (2) the generator is not grounded through a high impedance to limit ground faults to levels undetectable by current differential relays. Where redundant schemes are required, independent current sources and independently protected DC control circuits are required. The scheme(s) must function to simultaneously trip the generator breaker(s), excitation system, and turbine valves.

Section 4: Unit Power Transformer and Lead Protection

This section outlines the requirements for the protection of unit power transformers and associated high-side leads where the transformers are (1) rated greater than or equal to 100 MVA, or (2) are connected to utility systems at transmission system voltages above 200 kV, or (3) are connected to facilities as defined in this manual Section 1 - Applicability.

The following standards and publications were used as a reference for developing the requirements specified in this section.

ANSI/IEEE C37.91 Guide for Protective Relay Applications to Power Transformers

4.1 Transformer Fault Protection

Two independent schemes providing high-speed protection for 100% of the transformer winding are required. Acceptable combinations of protective relay schemes to satisfy this requirement are the following:

- Two independent current differential schemes.
- One current differential scheme and one sudden pressure relay scheme.

The zone of protection for one of the current differential schemes may also include other equipment such as the transformer leads, the generator, and the unit auxiliary transformer and its leads. The schemes must employ independent current sources (where applicable) and independently protected DC control circuits.

4.2 Transformer High-Side Lead Protection

The transformer high-side leads are required to be protected by two independent current differential schemes or equivalent high-speed schemes. The schemes must utilize independent current sources and independently protected DC control circuits.

4.3 Overexcitation Protection

Overexcitation protection for the unit power transformer is required. Generally, this protection is provided by the generator overexcitation protection. Refer to Section 3 for the requirements for this protection.

Section 5: Unit Auxiliary Transformer and Lead Protection

This section outlines the requirements for the protection of unit-connected auxiliary power transformers and associated high and low-side leads where the associated generating units are (1) rated greater than or equal to 100 MVA, or (2) are connected to transmission systems at transmission system voltages above 200 kV, or (3) as defined in this manual Section 1 - Applicability.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- ANSI/IEEE C37.91 Guide for Protective Relay Applications to Power Transformers

5.1 Transformer and Low-Side Lead Protection

Two independent protection schemes are required for protection of the transformer and low-side leads. At least one of the schemes must provide high-speed protection for the entire protection zone. Acceptable combinations of schemes for satisfying the redundancy requirement are the following:

- Two current differential schemes
- One current differential scheme and one high-side overcurrent scheme
- One current differential scheme, one sudden pressure relay scheme, and one low-side overcurrent scheme

If the transformer low-side neutral is grounded through an impedance which limits ground fault currents to levels not detectable by current differential relays, then the above must be supplemented with a neutral overcurrent scheme. Backup protection for the neutral overcurrent scheme is not required. Independent current sources and independently protected DC control circuits are required for the schemes listed above.

5.2 Transformer High-Side Lead Protection

The transformer high-side leads must be included in a current differential scheme (i.e., the unit differential scheme). A redundant current differential scheme is required if either (1) the high-side leads are not installed in bus duct segregated by phase or (2) ground faults are not limited to levels undetectable by current differential relays. Where redundant schemes are required, independent current sources and independently protected DC control circuits are required for each of the schemes.

Section 6: Start-up Station Service Transformer and Lead Protection

This section outlines the requirements for the protection of start-up station service transformers and associated high and low-side leads connected to transmission systems at system voltages above 200 kV or as defined in this manual Section 1 - Applicability.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- ANSI/IEEE C37.91 Guide for Protective Relay Applications to Power Transformers

6.1 Transformer and Low-Side Lead Protection

Two independent protection schemes are required for protecting the transformer and low-side leads. At least one of the schemes must provide high-speed protection for the entire protection zone. Acceptable combinations of schemes for satisfying this redundancy requirement are the following:

- Two current differential schemes
- One current differential scheme and one high-side overcurrent scheme
- One current differential scheme, one sudden pressure relay scheme, and one low-side overcurrent scheme

If the transformer low-side neutral is grounded through an impedance which limits ground fault currents to levels not detectable by current differential relays, then the above must be supplemented with a neutral overcurrent scheme. Backup protection for the neutral overcurrent scheme is not required.

Independent current sources and independently protected DC control circuits are required for each of the schemes listed above.

6.2 Transformer High-Side Lead Protection

Two independent current differential or other high-speed relaying schemes are required to protect the transformer high-side leads. Independent current (and voltage, where applicable) sources and independently protected DC control circuits are required for each of the schemes.

Section 7: Line Protection

This section outlines the requirements for the protection of lines at system voltages above 200 kV and for Critical BES lines built after January 1, 2012 in this manual Section 1 - Applicability.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- ANSI/IEEE C37.113 Guide for Protective Relay Applications to Transmission Lines

7.1 General Requirements

Two independent protection schemes are required for all lines covered by these requirements. For the purposes of this document, these schemes will be referred to as primary and backup. Both schemes must be capable of detecting all types of faults including maximum expected arc resistance that may occur at any location on the protected line.

Both primary and backup protection schemes must employ independent current and voltage sources and independently protected DC control circuits. Details on the requirements for the current and voltage sources are provided below.

7.1.1 Current Sources

Independent current transformers (CTs) are required for the primary and backup line protection schemes. For dead tank breakers, both primary and backup relays shall be connected such that breaker faults will be detected by the primary and backup relays of both protection zones adjacent to the breaker. Overlapping zones of protection are required in all cases.

7.1.2 Voltage Sources

Independent voltage sources are required for the primary and backup line protection schemes unless one of the schemes operates based on current only such as a current differential scheme. The following design options are acceptable:

- Independent voltage transformers (VTs)
- Independent secondary windings of the same VT

7.2 Primary Protection

The primary line protection scheme must provide high-speed simultaneous tripping of all line terminals. The scheme must have sufficient speed so that it will provide the required fault clearing times for system stability as defined in the NERC TPL-001 Transmission Planning Standard. To meet the speed and coverage requirements as defined above, a high speed communication channel is required for this scheme.

7.3 Back-up Protection

The back-up line protection scheme shall be independent of the primary line protection scheme and must utilize independent current and voltage sources and independently protected DC control circuits. The following requirements apply for the back-up protection:

- Relays from the same manufacturer are acceptable for both the primary and back-up systems. The use of different models is recommended but not required.

- Back-up protection must have sufficient speed to provide the clearing times necessary to maintain system stability as defined in the NERC TPL Transmission Planning Standards.
- The back-up protection may require the inclusion of a communications-assisted tripping system in order to meet clearing time requirements. In such cases, the communication path must be independent of the communication path for the primary relays. Refer to Appendix C for further details on requirements for the communications channels. When redundant communications-assisted protection is required, alarms must be provided sufficient to detect a failure which disables both primary and back-up communications-assisted tripping.
- One protection scheme must always include a non-communications-assisted tripping scheme for phase and ground faults, regardless of whether a backup communications-assisted tripping system is employed.
    - Non-communications-assisted instantaneous impedance based protection (traditionally referred to as Zone 1) or instantaneous directional overcurrent protection is required for all line terminals unless the line impedance is insufficient for both reliable and secure operation. This protection scheme shall be set to operate without additional time delay (other than as required to override transient overreach behavior) and to be insensitive to faults external to the protected line.
    - Non-communications-assisted time delayed impedance based protection (traditionally referred to as Zone 2) or time delayed directional overcurrent protection is required for all line terminals. This protection scheme shall be set with sufficient time delay to coordinate with adjacent circuit protection including breaker failure protection. For two-terminal-line applications, sufficient sensitivity is required to provide complete line coverage of the protected line. For three-terminal-line applications, see Appendix E

7.4 Restricted Ground Fault Protection

A scheme must be provided to detect ground faults with high fault resistance. The relay(s) selected for this application must be set at 600 primary amperes or less, provided that this setting is greater than the maximum line zero-sequence load unbalance. These relays may serve as the overreaching non-communications-assisted ground tripping function.

7.5 Close-in Multi-Phase Fault Protection (Switch-Onto-Fault Protection)

Protection must be provided to clear zero-voltage faults present when a line is energized with the relay potential source provided by line-side voltage transformers. A scheme designed to specifically provide this protection must be provided if this protection is not inherently provided by the primary and/or back-up line protection schemes. Scheme redundancy is not required.

7.6 Out-of-Step Protection

Out-of-step protection is typically not utilized within the PJM system. The application of out-of-step relays in any transmission application must be reviewed and approved by the PJM Planning Department, with input from the PJM Relay Subcommittee as necessary.

7.7 Single-Phase Tripping

Single-phase tripping is typically not utilized within the PJM system. The application of single-phase tripping must be reviewed and approved by the PJM Planning Department, with input from the PJM Relay Subcommittee as necessary.

Section 8: Substation Transformer Protection

This section outlines the requirements for the protection of substation transformers with high-side voltages of 200kV and above or as defined in this manual Section 1 - Applicability.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- ANSI/IEEE C37.91 Guide for Protective Relay Applications to Power Transformers
- ANSI/IEEE C37.110 Guide for the Application of Current Transformers Used for Protective Relaying Purposes

8.1 Transformer Protection

8.1.1 Bulk Power Transformers

Bulk Power Transformers are transformers with low-side voltages greater than or equal to 100 kV and networked on the low side

Two independent high-speed protection schemes are required. Acceptable combinations of schemes for satisfying the redundancy requirement are the following:

- Two independent current differential schemes
- One current differential scheme and one sudden pressure relay scheme

Independently protected DC control circuits are required.

8.1.2 All other substation transformers

Two independent protection schemes, at least one of which must be high-speed, are required. Acceptable combinations of schemes for satisfying the redundancy requirement are the following:

- Two independent current-based schemes, one of which must be differential
- One current-based scheme and one sudden pressure relay scheme

Independently protected DC control circuits are required.

8.1.3 Sudden Pressure Relay Applications

When a sudden pressure relay scheme is used as one of the two independent protection schemes and the transformer has a tap changer in a compartment separate from the main tank, the sudden pressure relay scheme must use sudden pressure relays in both the main tank and the tap changer compartment.

8.1.4 Current Differential Zone Considerations

If the transformer current differential zone is extended to include the bus between breakers on the high or low sides of the transformer, the current circuit from each breaker must be connected to separate restraint windings in the differential relay, with the following exception. Two or more current circuits may be paralleled into one restraint winding only if current can flow in no more than one of the paralleled circuits for all faults external to the differential protective zone (i.e., radial feeder breakers with no source of fault current).

8.2 Isolation of a Faulted Transformer Tapped to a Line

This section addresses the requirements for isolating a fault on a transformer tapped on a line. Bulk power lines operated at greater than 300 kV shall not be tapped. Lines operated at less than 300 kV lines may be tapped with the concurrence of the transmission line owner(s).

8.2.1 Transformer HV Isolation Device Requirements

This section is concerned with the isolation of power transformers tapped a line.

All transformers tagged to a line require a device (e.g. circuit breaker, circuit switcher, disconnect switch, etc.) which will automatically isolate the transformer from the line following transformer fault clearing.

Transformers with low-side voltage ratings less than 60 kV are at increased risk of having animal contacts. Therefore, a fault interrupting device capable of interrupting low-side faults is required for transformers with low-side voltage ratings less than 60 kV in order to prevent tripping the tapped line.

Since Bulk Power Transformers have low-side voltage ratings above 100 kV, they are considered less prone to animal contact and therefore are not required to have fault interrupting devices.

Fault interrupting devices do not have to be rated to interrupt all faults within the transformer zone of protection (i.e. circuit switchers may not be capable of interrupting source side faults). An alternate means of tripping for faults exceeding the capability of the device will be required. Protection and coordination requirements for transformer primary faults shall be determined by, or in discussions with the transmission line owner(s). Examples of alternate means of tripping for primary transformer faults are direct transfer trip or remote line relay operation.

When a fault interrupting device is not required and is not installed, a motor operated disconnect switch will be required on the tapped line side of the transformer. The switch will isolate the transformer after the fault has been cleared to allow line restoration. The switch will be opened by the transformer protection schemes in coordination with the clearing of the tapped line.

In cases where an increased exposure to line tripping is a reliability concern, the use of a high side-interrupting device will be required.

8.2.2 Protection Scheme Requirements

A fault interrupting device requires a device failure scheme when the transformer associated with the failed device serves anything other than a radial distribution load or independent from it. The requirement to install a disconnect switch and any requirements for the operation of the switch shall be determined by, or in discussions with the when the transmission line owner(s) requires it.

- When a device failure scheme is required for a fault interrupting device that is fully rated for all faults on the transformer, the following are acceptable schemes for isolating the faulted transformer for the contingency of a stuck interrupting device:
    - Direct transfer trip scheme
    - Second interrupting device
    - Ground switch and motor operated disconnect switch combination.

- When the interrupting device is not fully rated to interrupt all faults in the transformer zone of protection, such as a disconnect switch or a circuit switcher that is not rated to interrupt high side faults on the transformer, the following are acceptable schemes for providing primary and backup fault clearing of the transformer:
    - Two independent direct transfer trip schemes - Once the remote line terminals have opened, the faulted transformer shall be automatically isolated from the line and automatic reclosing of the line shall be permitted.
    - Combination of a direct transfer trip scheme and a ground switch - Where carrier direct transfer trip is used, the ground switch and direct transfer trip shall not be connected to the same phase. Once the remote line terminals have opened, the faulted transformer shall be automatically isolated from the line and automatic reclosing of the line shall be permitted.
    - Remote primary and backup line relays capable of tripping for all faults not cleared by the transformer protection schemes - Once the remote line terminals have opened, the faulted transformer shall be automatically isolated from the line and automatic reclosing of the line shall be permitted.

8.2.3 Protection Scheme Recommendations

Certain situations may require the transformer protection to initiate tripping of the transmission line terminals. For line restoration or other purposes, the tripping logic frequently utilizes auxiliary switch contacts of the primary disconnect switch. The following application recommendations apply. (Elevation of the recommendations to requirements shall be determined by, or in discussions with the transmission line owner(s).

- Auxiliary contacts associated with the disconnect switch operating mechanism (e.g., a motor-operator) should not be used if the mechanism can be de-coupled from the switch. Otherwise, the switch may indicate open when it is in fact closed, likely defeating desired protection functions. A separate auxiliary switch assembly attached to the operating shaft of the switch itself should be used.
- Due to dependability concerns with auxiliary switches, it is recommended that the transformer primary disconnect switch auxiliary contacts not be used in such a manner that if the auxiliary switch (i.e., 89a) contact were to falsely indicate that the disconnect switch is open, the required tripping of local breakers or the direct transfer tripping of remote breakers would be defeated. The use of auxiliary switches in the protection scheme should be limited to local trip seal-in, direct transfer trip termination, etc. For example, assume that a fault occurs within the transformer with a magnitude which exceeds the capability of the interrupter, but cannot easily be detected by the line relays at the terminals. Trip (local and/or remote) logic of the form T = 94+T*89a is permissible. Trip logic of the form T = 94*89a is not recommended. Alternatively, trip logic of the form T = 94*(89a + 50) may be acceptable, where “50” is a current detector set as low as practical and connected to monitor current through the switch.
- Using the above example, if the transformer is connected in such a manner that it can be switched between two bulk-power lines, there may be no alternative than to use auxiliary switch contacts to determine which line to trip. In this case, any redundancy requirements will extend to the auxiliary switches, which should be electrically and mechanically independent.

8.3 Transformer Leads Protection

The transformer high and low side leads must be protected by two independent schemes, both of which must be high-speed unless the leads are included in a line protection zone. The schemes must utilize independent current and/or voltage sources and independently protected DC control circuits. Where the voltage rating of the low-side leads is less than 100 kV, redundancy in the low side lead protection is not required.

Blind spots in a lead protection scheme can result during an operating condition, such as an open disconnect switch, where a portion of the transformer leads may be unprotected. If a blind spot in the lead protection can result from any operating condition, independent protection systems for the blind spot must be provided for the Bulk Power Transformers.

Section 9: Bus Protection

This section outlines the requirements for the protection of substation buses rated 200 kV and above or as defined in this manual Section 1 - Applicability.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- ANSI/IEEE C37.234 Guide for Protective Relay Applications to Power System Buses
- ANSI/IEEE C37.110 Guide for the Application of Current Transformers Used for Protective Relaying Purposes

Two independent high-speed protection schemes are required for protecting the bus. They must utilize independent current and/or voltage sources and independently protected DC control circuits.

Section 10: Shunt Reactor Protection

This section outlines the minimum requirements for the protection of shunt reactors rated 200 kV and above or as defined in this manual Section 1 - Applicability.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- ANSI/IEEE C37.109 Guide for the Protection of Shunt Reactors
- ANSI/IEEE C37.110 Guide for the Application of Current Transformers Used for Protective Relaying Purposes

In general, the requirements for the protection of shunt reactors are functionally equivalent to the requirements for the protection of substation transformers. Some requirements do not apply to reactors, for example those relating to multiple windings.

The specific hardware used for reactor protection will generally be different from that used for transformer protection; however, as noted above, the functional requirements are equivalent and are summarized as follows:

- The reactor must be protected by two independent high-speed schemes. The two schemes must utilize independently protected DC control circuits.
- The reactor leads must be protected by two independent schemes, both of which must be high-speed unless the leads are included in a line protection zone. The two schemes must utilize independent current and/or potential sources and independently protected DC control circuits.
- For additional detail and for other requirements (e.g., the use of auxiliary contacts in the protection scheme), see Section 8 on Substation Transformer Protection.

Section 11: Shunt Capacitor Protection

This section outlines the minimum requirements for the protection of shunt capacitors rated 200 kV and above or as defined in this manual Section 1 - Applicability.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- ANSI/IEEE C37.99 Guide for the Protection of Shunt Capacitor Banks
- ANSI/IEEE C37.110 Guide for the Application of Current Transformers Used for Protective Relaying Purposes
- IEEE 1036-Guide for Application of Shunt Power Capacitors

The following schemes must be provided to protect each capacitor bank:

11.1 Primary Leads Protection

The capacitor bank leads must be protected by two independent schemes, both of which must be high-speed unless the leads are included in a line protection zone. The two schemes must utilize independent current and/or potential sources and independently protected DC control circuits.

11.2 Unbalance Detection Scheme

Primary and back-up capacitor bank unbalance detection schemes must be installed. These schemes should be set to trip the capacitor bank for unbalances resulting in greater than 110% of rated voltage across the individual capacitor cans. For externally-fused capacitor banks, the bank must be designed such that a single can failure does not result in greater than 110% of rated voltage across the remaining cans. Independently protected DC control schemes must be used for each of the schemes. Where potential sensing is used in both the primary and back-up schemes, independent voltage sources are required, with the exception of voltage differential schemes which will result in a trip of the capacitor bank upon the loss of the voltage source to the scheme.

11.3 Capacitor Bank Fusing

For externally fused capacitor banks, the fuse size should be chosen to protect the capacitor can from catastrophic can rupture in the event of an internal can fault. In the case of fuseless banks, the protection scheme operating characteristics and bank design must be selected to protect against catastrophic can ruptures.

Section 12: Breaker Failure Protection

This section outlines the minimum requirements for breaker failure protection for fault interrupting devices (including circuit switchers, where applicable) at system voltages above 200 kV or as defined in this manual Section 1 - Applicability.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- ANSI/IEEE Std C37.119 - IEEE Guide for Breaker Failure Protection of Power Circuit Breakers

12.1 Local breaker failure protection requirements

A dedicated[2] breaker failure scheme shall be used for each fault-interrupting device and shall initiate tripping of all local sources of fault current.

The breaker failure output tripping relay shall block both manual and automatic closing of all local breakers required to trip until the failed breaker has been electrically isolated.

12.2 Direct transfer trip requirements (See also Appendix B)

Local breaker failure protection shall initiate direct transfer tripping of associated remote terminals if any of the following conditions exist.

- Speed is required to assure system stability.
- Remote back-up protection is unacceptable because of the number of circuits and area affected.
- The sensitivity of remote relay schemes is inadequate due to connected transformers, connected generators, line-end fault levels, or due to strong infeed from parallel sources.

Tripping shall be maintained at the remote terminal until the failed breaker has been electrically isolated.

Automatic reclosing shall be prevented at the remote terminal until the failed breaker has been electrically isolated.

12.3 Breaker failure scheme design requirements

Failure of a single component shall not disable both the tripping of the breaker and the breaker failure scheme.

For security against possible false breaker failure scheme operation, the minimum acceptable margin between normal fault clearing and a breaker failure trip decision is 24 msec.

[2] A “dedicated” scheme is defined for purposes of this document as one which utilizes a separate breaker failure timer (or timers) for each breaker as opposed to a scheme which utilizes a breaker failure timer common to all breakers supplied by a bus. A dedicated scheme may utilize elements common to other breakers such as an auxiliary tripping relay which trips all breakers on the affected bus.

Current actuated fault detectors are always required. However, when the primary and backup relays detect conditions for which the current actuated fault detectors lack the required sensitivity, breaker auxiliary switches shall also be used.

Breaker failure scheme designs generally include an optional “re-trip” feature whose purpose is to prevent unnecessary breaker failure operations which could occur for various reasons[3]. The re-trip feature must be implemented unless it has been established that fault-detector settings, scheme logic, or other considerations negate the advantages of the re-trip feature. The re-trip feature must function to re-trip the protected interrupting device upon initiation of the breaker failure scheme.

12.4 Pole Disagreement Tripping

Pole Disagreement Tripping must be installed on all fault interrupting devices capable of individual pole operation. The pole disagreement scheme must incorporate the following features:

- All poles of the device must be opened if the position of one pole fails to agree with the position of either of the other two.
- An alarm specifically for “pole disagreement” must be initiated by the above scheme.
- The disagreement scheme is to trip only the affected device.

12.5 Live tank circuit breakers

Live tank circuit breakers must be provided with high speed flashover protection to detect and isolate a phase-to-ground flashover of the circuit breaker column if the column would be in a blind spot from local protection schemes for such a flashover.

12.6 Current transformer support columns

Current transformer support columns must be provided with high speed flashover protection to detect and isolate a phase-to-ground flashover of the current transformer support column if the current transformers would be in a blind spot from local protection schemes for such a flashover.

[3] Applications of the re-trip feature include (1) activation of a second trip coil in recognition of the possibility that the first trip coil may be defective; (2) the attempt to trip the breaker prior to the expiration of breaker failure timing in the event that breaker failure has been initiated without trip having been initiated. Events of the latter type have occurred due to improper test procedures and due to certain relay failure modes.

Section 13: Phase Angle Regulator Protection

This section outlines the minimum requirements for the protection of phase angle regulating transformers connected at system voltages above 200 kV or as defined in this manual Section 1 - Applicability. The protection of phase angle regulating transformers is a highly specialized subject and the design of the protection scheme should take into consideration such factors as application requirements, transformer manufacturer input, design of surrounding system protection systems, and clearing time requirements

The following standards and publications were used as a reference for developing the requirements specified in this section.

- Protection of Phase Angle Regulating Transformers, an IEEE Power System Relaying Committee Report, October 1999
- IEEE Guide for the Application, Specification, and Testing of Phase-Shifting Transformers, IEEE Standard C57.135

13.1 Detailed Protection Requirements

The detailed protection requirements (especially in regard to the differential protection) are highly specific to the transformer winding connections, for which there are different designs in use. The protection scheme is generally developed through discussions with the transformer manufacturer, protection equipment manufacturers, applicable industry guides and technical papers, and through consultations with the interconnecting utility.

The following requirements pertain to the protection of phase angle regulating transformers of all types:

- Individual pressure actuated devices which operate for a change in gas or oil pressure must be provided for each individual winding and Load Tap Changer (LTC) compartment. The operation of these protective devices must be wired to trip the unit.
- A protection scheme to detect an out-of-step tap changer position.
- Independent current sources and independently protected DC control circuits

The following are the minimum requirements specific to the current-derived protection of the most common type of phase angle regulating transformer[4] in use within PJM

- A primary current differential scheme which includes the primary series winding and the primary excitation (shunt) winding.
- A secondary current differential scheme which includes the secondary series winding and the secondary excitation (LTC) winding.
- An overcurrent scheme for the neutral connection of the primary excitation (shunt) winding.
- An overcurrent scheme for the neutral connection of the secondary excitation (LTC) winding.

[4] Wye-grounded exciting winding, delta-connected secondary series winding.

Some Phase Angle Regulators are equipped with an “Advance-Retard Switch” (ARS) that reconfigures the series transformer delta winding to control the direction of power flow. The secondary differential scheme must be designed to allow for a full transition from the Advance state to the Retard state and vice-versa. During the transition, the CT delta connection or the CT compensation settings in the secondary differential relay must be modified accordingly without causing the unit to trip. A microprocessor relay capable of multiple setting groups is strongly suggested for the secondary differential protection.

Section 14: Transmission Line Reclosing

This section outlines the requirements for applying automatic reclosing schemes for fault interrupting devices at system voltages above 200 kV or as defined in this manual Section 1 - Applicability.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- ANSI/IEEE Std C37.104 Guide for Automatic Reclosing of Line Circuit Breakers for AC Transmission and Distribution Lines

14.1 Reclosing Requirements

The following requirements must be met when applying automatic reclosing on transmission lines:

- The impact on generator shaft torque of system connected generators due to line reclosing must be considered. An appropriate time delay must be used to maintain the generator shaft torque within acceptable values.
- Reclosing times and sequences must take into account the capability of the fault interrupting device.
- Reclosing for line faults shall not be used on transmission lines consisting entirely of cable. Where combinations of open wire and cable are used, an evaluation should be made to determine if reclosing should be used for faults in the aerial portion of the circuit and blocked for cable faults.
- Automatic reclosing shall be configured to prevent reclosing on a failed transformer or reactor, or on a failed breaker. For such conditions, see the appropriate section for further discussion.
- Automatic reclosing shall not be used where transient voltage analysis studies indicate that reclosing may produce switching surges exceeding equipment design levels.
- Automatic reclosing following out-of-step conditions must be reviewed and approved by PJM Planning Department, with input from the PJM Relay Subcommittee as necessary.

14.2 High-Speed Reclosing Requirements

For purposes of this document, the following statements in ANSI/IEEE Std C37.104 apply:

> *High-speed autoreclosing: Refers to the autoreclosing of a circuit breaker after a necessary time delay to permit fault arc deionization with due regard to coordination with all relay protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.*

The following requirements must be met when applying high-speed automatic reclosing (HSR) on transmission lines:

- The reclose interval must be selected to allow for proper de-ionization of the fault arc. Based on voltage level, the minimum dead time required to de-ionize the fault can be determined from the following equation:

  T=10.5 + (kV/34.5) cycles

  where kV is the rated line-line voltage.

Note:
The equation above is valid for voltages as high as 230 kV but may be overly-conservative at higher voltages. For example, industry experience indicates that 30 cycle dead time is adequate at 765 kV.

- Most applications of HSR do not require study for stability, unless the HSR is on a line electrically close to a line originating at a generating station. If the results from such stability studies indicate that reclosing following a specific type of fault or system condition would result in an unacceptable situation, adaptive reclosing as defined in IEEE Standard C37.104 may be used.
- High-speed reclosing must only be initiated by a communications assisted relaying scheme.

Section 15: Supervision and Alarming of Relaying and Control Circuits

This section outlines the requirements for supervision and alarming of relaying and control circuits applied to protect equipment at system voltages above 200 kV or as defined in this manual Section 1 - Applicability.

15.1 Design Standards

The following conditions shall be reported remotely from unattended stations. Some functions can be grouped together when reporting the alarm condition to the remote site based on common operator response and the availability of alarm points. Facilities shall be provided to indicate the specific trouble at the local site.

- Battery low voltage condition
- Blown fuse on protective relaying DC control circuit
- Loss of AC relaying potential
- Alarm condition of protective relay pilot channels as described in Section 15.2
- Relay trouble alarms where internal alarm features are provided

15.2 Relaying Communication Channel Monitoring and Testing

All relay communication channels must be monitored to detect any channel problems and initiate an alarm. Channels that cannot be monitored due to the use of a normally off state must be tested automatically at least once a day, preferably at both reduced and full power levels.

Section 16: Underfrequency Load Shedding

This section outlines the requirements for under-frequency load shedding within PJM.

- Under-frequency load-shedding (UFLS) schemes shall be designed and implemented in accordance with PJM requirements as outlined in PRC-006, PJM Manual 13 and PJM Manual 36.
- The specific design of an UFLS scheme is left to the UFLS Owner, but the following general comments apply:
    - The load-shedding scheme shall be distributed in application as opposed to a centralized design.
    - Loads tripped by the load-shedding scheme shall require manual restoration (local or remote) unless otherwise authorized by PJM.

Section 17: Special Protection Schemes/Remedial Action Schemes

This section outlines the requirements for Special Protection Schemes (SPSs) and Remedial Action Scheme (RAS) which are occasionally employed in response to an abnormal condition or configuration of the electric system.

17.1 Introduction

A Special Protection System (SPS) or Remedial Action Scheme (RAS) is designed to detect abnormal system conditions (e.g., abnormal system configuration) and to automatically take appropriate corrective action to maintain system stability, acceptable system voltages, and acceptable facility loading.

Whereas “normal” protective relaying systems are typically designed to isolate faulted elements, SPS/RAS’s may take seemingly unrelated actions such as the tripping of local or remote system elements (including generators), generator runback, and load shedding.

Transmission line out-of-step tripping, trip blocking, and reclose blocking are not considered to be SPS/RAS’s, nor are standard generator protection functions such as loss-of-field protection, over-excitation protection, and out-of-step protection.

17.2 Installation Requirements

SPS/RAS’s should not be installed as a substitute for good system design or operating practices. Their implementation is generally limited to temporary conditions involving the outage of critical equipment.

The decision to employ an SPS/RAS should take into account the complexity of the scheme and the consequences of misoperation as well as its benefits. The use of an SPS/RAS, like any protection scheme, entails the risk that it will misoperate. However, the consequences of an SPS/RAS misoperation are often more severe than those of fault protection schemes.

When conditions are such that an SPS/RAS is no longer required, the SPS/RAS shall be retired.

For SPS/RAS’s which are needed only under certain conditions, procedures shall be established to ensure that these schemes are disabled when the conditions requiring their use no longer exist.

For SPS/RAS’s which are not normally armed, there may be two levels of action. The first stage is designed to recognize a predetermined condition (often system configuration) and “arm” a second stage. The second stage takes concrete action (e.g., tripping of system elements) if certain subsequent events occur. When the SPS/RAS is armed, there shall be indication of that fact in a manned facility.

Refer to Regional Reliability Organization documentation for additional regional requirements.

Appendix A: Use of Dual Trip Coils

This section outlines the requirements for the use of dual trip coils in circuit breakers.

Dual trip coils must be applied to meet the dependability requirements mandated by this document to assure that a failed trip coil does not result in the failure of a breaker to operate.

If the design of the operating mechanism is such that the simultaneous energization of both trip coils with voltages of opposite polarity results in a failure of the mechanism to operate, testing shall be performed to verify proper polarity of the trip coil circuits.

Undesirable breaker failure operations are possible if the primary trip path is open and tripping is initiated through slower-operating backup relays. Where this is the case, one of the following measures must be taken:

- Energize both sets of trip coils with both the primary and backup relays or at least with the relaying system which is known to be faster. In such designs, care must be taken to maintain independence of the primary and backup control circuitry.
- Use high-speed relays to cover the entire zone of protection for both the primary and backup protection.
- Apply the breaker failure retrip logic to energize the trip coil associated with the slower relays prior to expiration of the breaker failure timer. If identification of the slower relays is difficult, then the retrip logic shall energize both trip coils.
- Apply “cross-trip” auxiliary relays in the breaker tripping control scheme.

Appendix B: Direct Transfer Trip Requirements

This section outlines the requirements for Direct Transfer Trip (DTT) schemes.

Audio tone transceivers operating over analog multiplexed systems - the design of the equipment and/or the scheme must be immune from the effects of frequency translation (or "drift") in the carrier. This requires the transmission of two tones, one configured to shift up in frequency and the other to shift down in frequency.

Audio tone transceivers operating over digital multiplexed systems – the design of certain older audio tone receivers make them subject to generating false trip outputs in the presence of the type of noise characteristic of digital systems. The audio tone equipment manufacturer should be consulted in regard to the application of the tone equipment in any environment which may include digital transmission for any portion of the communications path.

Digital transceivers – it is required that the overall DTT scheme include addressing capability between transmitters and receivers connected through a multiplexing system or through direct fiber where a fiber patch panel is employed.

Power Line Carrier- When using Frequency Shift Keying (FSK) over power line carrier, the channel integrity is monitored continuously by the presence of a guard signal. An alarm for loss of guard signal shall be sent to the control center. Fault detecting relays will key the frequency shift from guard to trip.

Appendix C: Dual Pilot Channels for Protective Relaying

This section outlines the requirements for the application of dual pilot channels when required by the standards presented in this document. Dual pilot channels are defined as two separate, independent communications channels which are applied to provide high speed clearing for transmission line faults via both the primary and backup relay schemes. Each scheme must have sufficient speed to provide the clearing times necessary to maintain system stability as defined in the NERC Transmission Planning Standards, TPL-001 and the associated Table 1.

The following standards and publications were used as a reference for developing the requirements specified in this section.

- IEEE 643 – IEEE Guide for Power Line Carrier Applications
- ANSI/IEEE C37.93 – IEEE Guide for Power System Protective Relay Applications of Audio Tones over Voice Grade Channels
- ANSI/IEEE C37.113 – Guide for Protective Relay Applications to Transmission Lines

1. Channel Independence

Communications channels utilized for the dual pilot relaying systems must be designed with the same level of independence as the primary and backup protection and control systems.

The following factors are used to determine the level of independence of communications channels used for dual pilot relaying systems:

- Physical relationship between the communication facilities and paths used for both channels
- Physical relationship between the channel path(s) and related power system facilities
- Probability of a simultaneous failure due to physical proximity
- Performance of the relay system in the event of a path failure
- Time required to repair a failed path
- Capability to repair or maintain one pilot channel while keeping the remaining channel fully functional

Steady-state loss of both channels

- Upon loss of both pilot channels, the associated transmission line must be taken out of service, or if possible, tripping delay time reduced to a level at which stability requirements are met and relay coordination is maintained for normal clearing of faults.

2. Applications

The following sections provide the specific requirements for the different types of communications channels.

2.1 Power Line Carrier

Dual independent paths can be achieved by using two separate carrier systems, connected to separate phases. Each carrier system will consist of a transmitter and receiver, hybrids, coax cable, line tuner, Capacitive-Coupled Voltage Transformer (CCVT) and wave trap for each coupled phase. Signal attenuation must be reviewed and other system arrangements must be used if signal attenuation will be above acceptable levels.

Directional Comparison Blocking (DCB)

- Phase to Ground Coupling – Single Phase: Unacceptable for a dual pilot protection scheme as defined in the beginning of this appendix, but its benefits merits its mention.
- Phase to Ground Coupling – Two Phases: Acceptable but not recommended
- Phase to Phase Coupling – Outer Phase to Outer Phase: Acceptable
- Phase to Phase Coupling – Center Phase to Outer Phase: Recommended

Directional Comparison Unblocking (DCUB)

- Phase to Ground Coupling – Single Phase: Unacceptable for a dual pilot protection scheme.
- Phase to Ground Coupling – Two Phases: Acceptable but not recommended
- Phase to Phase Coupling – Outer Phase to Outer Phase: Acceptable
- Phase to Phase Coupling – Center Phase to Outer Phase: Recommended

2.2 Microwave Radio Channels

Two completely independent microwave systems can rarely be justified from an economic standpoint. However, modern systems are often configured with a high degree of redundancy. To the extent that susceptibility to a common-mode failure is limited to passive equipment generally considered to have an extremely low probability of failure (e.g., a single communications battery or common microwave tower), a single microwave system is acceptable. No single-contingency failure of an active component shall compromise both pilot schemes.

Complete redundancy in the radio frequency path (i.e., two antennas) and in the electronic RF multiplexing equipment is required. No single path failure is permitted to result in the unavailability of both pilot protection schemes for longer than the switching time from normal to alternate facilities which is normally of the order of milliseconds.

2.3 Leased Telephone Circuits

If dual pilot channels are required, they may not both utilize leased telephone circuits.

2.4 Fiber Optic Systems

Dual pilot protection systems utilizing fiber optic communications channels must be designed to maintain high speed coverage for the transmission line in the event of a single contingency. In evaluating the level of redundancy, both the fiber path routing and protection scheme types must be considered. The following protection fiber optic path examples are presented as with protection scheme scenarios of the analysis which must be performed to determine adequate redundancy:

One fiber optic shield wire:

- Two permissive tripping schemes: Unacceptable for dual pilot protection
- A break in the shield wire would disable both protection systems and could create a fault on the protected line.

- In addition, using two fibers in the shield wire may result in the loss of both channels if the shield is damaged and maintenance outages may be difficult to obtain to repair the fibers in a timely manner.
- Two unblocking schemes: Unacceptable for dual pilot protection
- In the case of a broken shield wire, both channels would be disabled if the fault takes longer than 300 msec to develop.
- In addition using two fibers in the shield wire may result in the loss of both channels when the shield is damaged with uncertain repair time.

Two independent fiber optic shield wires:

- Two permissive tripping schemes: Acceptable for dual pilot protection, but not recommended.
- Although this scheme offers some improvement over one fiber optic shield wire utilization, outside interference such as an aircraft could cause the loss of both shield wires during a fault.
- Two unblocking schemes: Acceptable for dual pilot protection, but not recommended.
- This arrangement is similar to the Two permissive tripping schemes, but with the repair problem of one fiber optic shield wire utilization alleviated.

Underbuilt fiber optic cable:

- Use of an underbuilt fiber optic cable in conjunction with an overhead fiber optic cable, or use of two underbuilt fiber optic cables, is acceptable for dual pilot protection. However, as in Two permissive tripping schemes with Two Independent fiber optic shield wires, outside interference such as an aircraft could cause the loss of both fiber paths during a fault.

Independent fiber paths are not required for the following:

- If at least one of the pilot schemes is a blocking scheme
- Loss of the channel will not disable the high speed tripping of the blocking scheme. However, system security implications with the application of a blocking scheme must be considered.
- <u>If at least one of the pilot schemes is a current differential scheme</u>, which reverts to a sensitive overcurrent element or otherwise provides for high speed tripping for the entire line on loss of channel.

Fiber Optic Multiplexed Communications

- If the fiber optic channel utilizes multiplexing equipment, the failure of this equipment must be considered when evaluating susceptibility to a single mode failure. A single mode failure must not result in the unavailability of both pilot protection systems for longer than the switching time from normal to alternate facilities which normally occur within milliseconds of a channel failure.

Fiber Optic Self-healing Ring Topology

- Fiber optic systems utilizing a self-healing ring topology can be utilized to provide path redundancy. However, the failure of the multiplexing/switching equipment must not result in the unavailability of both pilot protection systems

Note:
In a DCUB (Directional Comparison Unblocking) scheme, tripping is typically permitted for 100-300 msec following the loss of the received signal.

Appendix D: Small Generator Protection Requirements

For generating units less than 100 MVA and connected below 200 kV and not previously addressed in this document, generation developers are referred to the following sources of requirements depending on generator size.

- Generators < 20 MVA: Refer to PJM Manual 14G, Attachments C and D
- Generators ≥ 20 MVA and <100 MVA: Refer to requirements of the applicable transmission owner.

The following standards and publications can also be used as a reference for developing the requirements for applicable small generator protections:

- IEEE 1547-2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

Appendix E: Acceptable Three Terminal Line Applications

This appendix outlines the categories of three terminal line applications and associated protection requirements which have been deemed acceptable for use within PJM. Three terminal line applications are only permitted at voltages less than 300 kV when the requirements listed below are met. No three terminal line applications are permitted on systems at 300 kV and above.

1.0 Category I – Temporary Installation

This category applies when an acceptable long-term reinforcement was already identified but cannot be installed in time and consequently the reliability of the transmission system may be compromised. Examples include construction delays, unusual combinations of system demand and long term transmission equipment forced outages. The three terminal line configurations must be removed when the planned permanent reinforcement is in place.

The following requirements apply to Category I installations.

1.1 Protection Requirements

A detailed relay coordination review must be performed which establishes that the planned addition will result in no compromises to coordination. The review shall include consideration of apparent impedances at each terminal, weak sources, fault current nulls or outflows.

The protection scheme(s) must be designed to provide high-speed (pilot) clearing of faults at all locations on the three terminal line. Designing for sequential clearing of faults is not acceptable.

Backup protection must be provided and applied such that for faults anywhere on the circuit, each terminal shall be able to detect the fault and initiate tripping without regard to whether the other terminals have opened or are still closed.

The backup line protection may be pilot (high-speed, communications dependent) or non-pilot (stepped-distance, ground time overcurrent) depending on the specific circumstances and results of fault and stability studies, etc. Each affected Transmission Owner will evaluate the proposed installations on a case-by-case basis. If a backup high-speed pilot scheme is required, the requirements for dual pilot channels outlined in Appendix C of this document must be met.

2.0 Category II – Permanent Installation

2.1 Protection Requirements

A detailed relay coordination review must be performed which establishes that the planned addition will result in no compromises to coordination. The review shall include consideration of apparent impedances at each terminal, weak sources, fault current nulls or outflows.

The protection scheme(s) must be designed to provide high-speed (pilot) clearing of faults at all locations on the three terminal line. Designing for sequential clearing of faults is not acceptable.

Backup relays must be provided and applied such that for faults anywhere on the circuit, each terminal shall be able to detect the fault and initiate tripping without regard to whether the other terminals have opened or are still closed.

The backup line protection may be pilot (high-speed, communications dependent) or non-pilot (stepped-distance, ground time overcurrent) depending on the specific circumstances and results of fault and stability studies, etc. Each affected Transmission Owner will evaluate the proposed installations on a case-by-case basis. If a backup high-speed pilot scheme is required, the requirements for dual pilot channels outlined in Appendix C of this document must be met.

For reliability reasons, extending an existing two-terminal directional comparison blocking or unblocking scheme operating over power line carrier to a third terminal is not acceptable for primary or backup line protection.

In all cases where a pilot scheme is required, digital communications channels between the three terminals must be used. No portions of these channels may be metallic (i.e. telephone cable, coaxial cable, etc.) other than between relays and multiplex equipment (where used) within the control house. External audio-tone interfaces are not acceptable. Where multiplexing schemes are use, they must be evaluated with respect to the characteristics of the proposed protection (i.e. susceptibility to mal-operation due to variances in path delay) on a case-by-case basis.

Revision History

Revision 03 (05/24/2018):

- Revised Manual Owner from Mark Sims to Aaron Berner
- Added new section on Reliability related requirements. It details new consensus requirements on Test Switches, Instrument Transformers, Communication Channels, Station Batteries and Station Service (AC).
- Updated references to current versions of NERC Standards
- Added the new NERC name for Special Protection Schemes (SPS) which is Remedial Action Schemes (RAS)

Revision 02 (07/01/2016):

- Manual Ownership changed from Paul McGlynn to Mark Sims
- Section 7: Line Protection reworded to clarify the terms “Primary” and “Backup” and specified PJM Planning Department to review and approve out-of-step relay and single-phase tripping applications.
- Section 8: Substation Transformer Protection revised to better account for practices of all member TOs.
- Power Line Carrier requirements added to Appendix B: Direct Transfer Trip.
- Power Line Carrier added and Fiber Optic Systems rearranged in Appendix C: Dual Pilot Channels.
- Removed Appendix F: Triggered Current Limiters.
- Cover to Cover Periodic Review

Revision 01 (02/27/2014):

- Revised Sections 7-Line Protection and 8-Substation Transformer Protection to align better with the PJM Relay Subcommittee Protective Relaying Philosophy and Design Guidelines.

Revision 00 (11/16/2011):

- This is a new manual. This manual establishes the minimum design standards and requirements for the protection systems associated with the bulk power facilities within PJM.

Protective Relaying Philosophy and Design Guidelines

PJM Relay Subcommittee

July 12, 2018

Contents

SECTION 1: Introduction

Introduction

This document supplements PJM Manual 07 which contains the minimum design standards and requirements for the protection systems associated with the bulk power facilities within PJM. This document provides recommendations, background and philosophy on relay protection that is not available in M07. The facilities to which this Document applies are generally comprised of the following:

- all 100 MVA and above generators connected to the BES facilities,
- all 200 kV and above transmission facilities
- all transmission facilities 100 kV to 200 kV critical to the reliability of the BES as defined by PRC-023 and determined by PJM System Planning

- PJM System Planning will also investigate the criticality of equipment (generators, buses, breakers, transformers, capacitors and shunt reactors) associated with the PRC-023 determined lines

In analyzing the relaying practices to meet the broad objectives set forth, consideration must be given to the type of equipment to be protected, e.g., generator, line, transformer, bus, etc., as well as the importance of the particular equipment to the integrity of the PJM Interconnection. Thus, practices may vary for different equipment. While it is recognized that the probability of failure should not negate the single contingency principle, the practices adopted may vary based on judgment and experience as to the probability in order to adopt a workable and practical set of guidelines. Special local conditions or considerations may necessitate the use of more stringent design criteria and practices.

Protection systems are only one of several factors governing power system performance under specified operating and fault conditions. Accordingly, the design of such protection systems must be clearly coordinated with the system design and operation.

Advances in technology, such as the microprocessor and fiber optics, will continue to produce relays, systems, and schemes with more capabilities than existing equipment. Application of these new devices may produce system protection with more security and dependability. Although the application may appear to be in conflict with the wording of the document, it may still fulfill the intent. As these new devices become available and are applied, the PJM Relay Subcommittee will incorporate them initially into these philosophy and design guidelines as an interpretation of a specific section and finally upon revision of the document.

SECTION 2: Protective Relaying Philosophy

2.1 Objectives

The basic design objectives of any protective scheme are to:

- Maintain dynamic stability.
- Prevent or minimize equipment damage.
- Minimize the equipment outage time.
- Minimize the system outage area.
- Minimize system voltage disturbances.
- Allow the continuous flow of power within the emergency ratings of equipment on the system.

2.2 Design Criteria

To accomplish the design objectives, four criteria for protection should be considered: fault clearing time; selectivity; sensitivity and reliability (dependability and security).

2.2.1 Fault clearing time is defined as the time required to interrupt all sources supplying a faulted piece of equipment. In order to minimize the effect on customers and maintain system stability, fault clearing time should be kept to a minimum. This normally requires the application of a pilot relay scheme on transmission lines and high speed differential relaying on generators, buses and transformers.

2.2.2 Selectivity is the ability of the protective relaying to trip the minimum circuits or equipment to isolate the fault. Coordination is required with the adjacent protection schemes including breaker failure, generator potential transformer fuses and station auxiliary protection.

2.2.3 Sensitivity demands that the relays be capable of sensing minimum fault conditions without imposing limitations on circuit or equipment capabilities. The settings must be investigated to determine that they will perform correctly during transient power swings from which the system can recover.

2.2.4 Reliability is a measure of the protective relaying system's certainty to trip when required (dependability) and not to trip falsely (security).

2.2.4.1 Dependability should be based on a single contingency, such that the failure of any one component of equipment, e.g., relay, current transformer, breaker, communication channel, etc., will not result in failure to isolate the fault. Protection in depth (i.e., primary and back-up schemes) necessary to accomplish this must be designed so as not to compromise the security of the system.

The following should be considered when designing protective schemes:

- Additional dependability can be gained through physical separation of the primary and back-up schemes.
- The use of different types of relays for primary and backup schemes will enhance dependability.

2.2.4.2 Security will be enhanced by limiting the complexity of the primary and back-up relay protection schemes to avoid undue exposure to component failure and personnel errors.

These schemes should be insensitive to:

- Peak circuit emergency ratings to assure the transfer of power within PJM considering the impact of a recoverable system transient swing.

- System faults outside the protective zones of the relays for a single contingency primary equipment outage (line, transformer, etc.) or a single contingency failure of another relay scheme.

2.3 Equipment Considerations

In comparing protection design to the objectives and criteria set forth, consideration must be given to the type of equipment to be protected as well as the importance of this equipment to the system. While protection should not be defeated by the failure of a single component, several considerations should be weighed when judging the sophistication of the protection design:

- Type of equipment to be protected (e.g., bus, transformer, generator, lines, etc.).
- Importance of the equipment to the system (e.g., impact on transfer capability, generation, etc.).
- Replacement cost (and replacement time) of the protected equipment.
- Probability of a specific fault occurring.
- Protection design in a particular system may vary based upon judgment and experience.

SECTION 3: Generator Protection

Generator protection requirements vary with the size of the unit. For units 500 MVA and above, the requirements identified in this section apply in full. The requirements are generally less strict for units below 500 MVA. The document will identify the differences in the requirements.

For units below 100 MVA and not connected at 200 kV or above, see Appendix H of this document.

3.1 Generator Stator Fault Protection

3.1.1 General Consideration

Generator stator faults can be very serious and cause costly damage. Therefore, the fault must be detected and cleared in the least amount of time possible. Because of the generator field decay time, damage may occur after all the required breakers have been tripped.

3.1.2 Ground Fault Protection

Grounding the generator through a high impedance is the most common industry practice for large generators. This is done to limit the magnitude of ground fault current, and with proper selection of components, reduces the risk of transient over-voltages during ground faults.

3.2 Generator Rotor Field Protection

The generator rotor field winding is normally ungrounded. The presence of one ground, therefore, will not affect the generator's operation. The presence of the first ground, however, greatly increases the probability that a second ground will occur, causing imbalances, and overheating.

3.3 Generator Abnormal Operating Conditions

3.3.1 Loss of Field

Loss of field (excitation) will cause the generator to lose synchronism, subject the generator to thermal damage, and may impose an intolerable VAR load on the power system. Detection of the loss of field condition is usually done with impedance relays.

3.3.2 Unbalanced Currents

Unbalanced currents are a result of unbalanced loading (e.g., one phase open) or uncleared unbalanced system faults. These unbalanced currents produce negative sequence current (I_2) in the generator rotor causing overheating.

3.3.3 Loss of Synchronism

Loss of synchronism, out-of-step operation, and pole slipping are synonymous and can result from transients, dynamic instability, or loss of excitation. This condition may be both damaging to the unit and highly disruptive to the power system.

3.3.4 Overexcitation

Overexcitation is excessive flux in the generator core. This condition can cause rapid overheating, even to the point of core failure. Volts/Hertz is a measure of an overexcitation condition.

It should be recognized that the most severe overexcitation events are the result of inadvertent application of excessive field current prior to generator synchronizing. It is strongly recommended that with the generator off-line, the protection be armed to trip the excitation system with minimum time delay for excitation levels above the setpoint of the lowest tripping element.

3.3.5 Reverse Power (Anti-Motoring)

Generator motoring is caused by the lack of energy supplied to the prime mover resulting in the electrical system driving the machine as a motor. Sustained synchronous motoring will not damage the generator, but may damage the prime mover.

3.3.6 Abnormal Frequencies

The generator can withstand off-frequency operation for long periods of time provided the load and voltage are reduced a sufficient amount. The turbine, however, is usually limited in its capability due to possible mechanical resonance caused by off-frequency operation under load. Automatic system-wide load shedding is the primary protection against abnormal frequency operation. However, for protection of the turbine, underfrequency relays are generally required unless the turbine manufacturer states that this protection is unnecessary. (The turbine manufacturer should be consulted for comprehensive requirements.)

When underfrequency protection is employed, two underfrequency relays connected with “AND” tripping logic and connected to separate voltage sources are recommended to enhance scheme security. A sequential trip of the turbine valves, excitation system, and generator breakers is recommended.

Units with output ratings under 500 MVA would be exempt from the two-relay security recommendation.

3.4 Generator Breaker Failure Protection

Refer to M07. No supplementary information available

3.5 Excitation System Tripping

Refer to M07. No supplementary information available.

3.6 Generator Open Breaker Flashover Protection

Open breaker flashover is more likely on generator breakers since 2.0 per-unit voltage will appear across the open contacts prior to synchronizing.

3.7 Protection during Start-Up or Shut-Down

Since some relays are frequency-sensitive, each of the relay's operating characteristics vs. frequencies should be checked to ensure proper operation at frequencies below 60 Hz.

3.8 Protection for Accidentally Energizing a Generator on Turning Gear

The accidental energizing of a generator from the high voltage system has become an increasing concern in recent years. Severe damage to the generator can result in a very short time for this condition.

Consideration should also be given to potential damage from accidental energizing from the low-voltage side of the unit auxiliary station service transformer.

SECTION 4: Unit Power Transformer and Lead Protection

Refer to M07. No supplementary information available

SECTION 5: Unit Auxiliary Transformer and Lead Protection

Refer to M07. No supplementary information available

SECTION 6: Start-up Station Service Transformer and Lead Protection

Refer to M07. No supplementary information available

SECTION 7: Line Protection

7.1 General Requirements

Fault incidents on transmission lines are high due to their relatively long lengths and exposure to the elements. Highly reliable transmission line protective systems are critical to system reliability. M07 states that the systems applied must be capable of detecting all types of faults, including maximum expected arc resistance that may occur at any location on the protected line. This includes:

- Three phase faults
- Phase-to-phase faults
- Phase-to-phase-to-ground faults
- Phase-to-ground faults

A single protection system is considered adequate for detecting faults with low probability or system impact:

- Restricted phase-to-ground faults
- Zero-voltage faults

The design and settings of the transmission line protection systems must should be secure during faults external to the line or under non-fault conditions.

See Appendix G, 'Voltage Transformers' for a description of acceptable VT arrangements.

7.2 Primary Protection

Refer to M07. No supplementary information available

7.3 Back-up Protection

- Back-up protection should have sufficient speed to provide the clearing times necessary to maintain system stability as defined in the NERC TPL Transmission Planning Standards
    - Non-pilot Zone 1 should be set to operate without any intentional time delay and to be insensitive to faults external to the protected line.
    - Non-pilot Zone 2 should be set with sufficient time delay to coordinate with adjacent circuit protection including breaker failure protection and with sufficient sensitivity to provide complete line coverage.

See Appendix E guidelines on the use of dual pilot channels

7.4 Restricted Ground Fault Protection

Refer to M07. No supplementary information available

7.5 Close-in Multi-Phase Fault Protection (Switch onto Fault Protection)

Refer to M07. No supplementary information available

7.6 Out-of-Step Protection – Transmission Line Applications

Out-of-step relays are sometimes used in the following applications associated with transmission line protection:

- Block Automatic Reclosing – The use of out-of-step relays to block automatic reclosing in the event tripping is caused by instability.
- Block Tripping – the use of out-of-step relays to block tripping of phase distance relays during power swings.
- Preselected Permissive Tripping – The use of out-of-step relays to block tripping at selected locations and permit tripping at others during unstable conditions so that load and generation in each of the separated systems will be in balance.

These applications require system studies and usually go beyond the scope of protective relaying.

7.7 Single-Phase Tripping

Single-phase tripping of transmission lines may be applied as a means to enhance transient stability. In such schemes, only the faulted phase of the transmission line is opened for a phase-to-ground fault. Power can therefore still be transferred across the line after it trips over the two phases that remain in service. A number of details need to be considered when applying single-phase tripping schemes compared to three phase tripping schemes. These issues include: faulted phase selection, arc deionization, automatic reclosing considerations, pole disagreement, and the effects of unbalanced currents. Such schemes have not been typically applied on the PJM system.

SECTION 8: Substation Transformer Protection

8.1 Transformer Protection

Substation transformers tapped to lines should have provisions to automatically isolate a faulted transformer and permit automatic restoration of the line. If the transformer is connected to a bus, the decision about whether or not to automatically isolate the transformer and restore the bus should consider the bus configuration and the importance of the interrupted transmission paths.

8.2 Isolation of a Faulted Transformer Tapped to a Line

8.2.1 Transformer HV Isolation Device Requirements

Refer to M07. No supplementary information available

8.2.2 Protection Scheme Requirements

When a fault interrupting device is used on the tapped side of the transformer that is fully rated for all faults on the transformer, the use of a motor-operated disconnect switch beyond the ground switch for stuck breaker protection allows the line to be restored after motor-operated disconnect switch opens to isolate the high-side interrupting device.

False operation of ground switches can present unnecessary risks to nearby equipment due to fault current stresses, increase the potential for adjacent line over-trips, and decrease customer service quality due to voltage sags. As such, schemes employing direct transfer trip equipment are preferred over ground switches.

8.2.3 Protection Scheme Recommendations

If transformer rate-of-rise of pressure relays are connected to trip, and if protection redundancy requirements are fully satisfied by other means (e.g. two independent differential relays), then the use of transformer primary isolation switch auxiliary contacts for trip supervision of the rate-of-rise of pressure relay(s) is acceptable This is in recognition of the relative insecurity of rate-of-rise of pressure relays during transformer maintenance.

8.3 Transformer Leads

Refer to M07. No supplementary information available

8.4 Overexcitation

Overexcitation protection should be considered on transformers connected to 500 kV and higher systems. While Overexcitation protection is usually only a concern for generator step-up transformers, it can occasionally be a problem for transformers remote from generation stations during periods of light load or system restoration conditions. In Appendix D of the EHV Engineering Committee report entitled " Conemaugh Project - Relay Protection for 500 kV Transmission System, January 1971" discusses the development of PJM autotransformer overvoltage protection guidelines.

It is recommended that the relay be connected to the secondary side of the transformer.

SECTION 9: Bus Protection

Refer to M07. The only supplementary information is that two examples of high-speed protection schemes are current differential or high impedance differential.

SECTION 10: Shunt Reactor Protection

Shunt reactors are used to provide inductive reactance to compensate for the effects of high charging current of long open-wire transmission lines and pipe-type cables. At transmission voltages, only oil-immersed reactors are used which are generally wye-connected and solidly grounded. Reactors are built as either three-phase or single-phase units.
It should be recognized that details associated with effective application of protective relays and other devices for the protection of shunt reactors is a subject too broad to be covered in detail in this document.

10.1 Reactor Protection

Shunt reactors tapped to lines should have provisions to automatically isolate a faulted shunt reactor and permit automatic restoration of the line. If the shunt reactor is connected to a bus, the need to both automatically isolate the reactor and restore the bus will depend on the bus configuration and the importance of the interrupted transmission paths.

It is recommended that an over-temperature tripping device be provided if single phasing, which results in considerable heating, is possible.

10.2 Isolation of a Faulted Shunt Reactor Tapped to a Line

For protection requirements, follow the requirements/recommendations in PJM Manual 07 set forth in Section 8.2 for a Substation Transformer tapped to a line.

In cases where the increased exposure of line tripping is a reliability concern, the use of a high side-interrupting device is recommended

SECTION 11: Shunt Capacitor Protection

Refer to M07. No supplementary information available.

SECTION 12: Breaker Failure Protection

12.1 Local breaker failure protection requirements

Refer to M07. No supplementary information available

12.2 Direct transfer trip requirements (See also Appendix C)

Refer to M07. No supplementary information available

12.3 Breaker failure scheme design requirements

A direct transfer trip signal initiated by a remote stuck breaker scheme should not operate a hand-reset lockout relay at the receiving terminal.

Consideration of pickup and dropout times of auxiliary devices used in a scheme should ensure adequate coordination margins.

When protected apparatus (transformer, reactor, breaker) is capable of being isolated with a switch (especially a motor-operated switch), auxiliary contacts of that switch are sometimes used in the associated breaker failure schemes. This can result in degradation to the dependability of the breaker failure protection. Recommendations regarding the use of auxiliary switches follow. Note that the recommendations represent "good engineering practice" and are not specifically mandated.

(1) Other than as noted below, apparatus isolation switch auxiliary contacts should preferably not be used in the apparatus protection scheme in such a manner that if the auxiliary switch (e.g.., 89a/b) contact falsely indicates that the isolation switch is open, breaker failure initiation would be defeated or the breaker failure scheme otherwise compromised. Breaker failure initiation logic of the form <u>BFI = 94+ BFI * 89a</u> is permissible. Breaker failure initiation logic of the form <u>BFI = 94 * 89a</u> is not recommended.

The same principle applies for the breaker failure outputs, e.g., the tripping of local breakers and the sending of transfer trip for the tripping of remote breakers. In the specific case of transfer trip an auxiliary switch contact should preferably not be used such that its failure would prevent the initial sending of transfer trip. The auxiliary switch may be used to terminate sending of transfer trip once the transfer trip input is removed.

(2) If the protected apparatus is tapped in such a manner that it is switchable between two sources, there may be no alternative other than to use auxiliary switch contacts to determine which breakers to initiate breaker failure on, which breakers to

trip with the breaker failure output, etc. Auxiliary switch redundancy is not specifically required provided that breaker tripping and breaker failure initiation and outputs are not supervised by the same auxiliary switch or auxiliary switch assembly. Redundancy in breaker failure initiation will be achieved automatically if breaker failure is initiated by a contact from the same auxiliary relay that initiates tripping of the breaker, and that relay is connected in a manner which satisfies auxiliary switch redundancy requirements. (See the sections of this document on isolation of faulted transformers and reactors.)

SECTION 13: Phase Angle Regulator Protection

Refer to M07. No supplementary information available.

SECTION 14: Transmission Line Reclosing

Transmission Line Reclosing

14.1 Philosophy

Experience indicates that the majority of overhead line faults are transient and can be cleared by momentarily de-energizing the line. It is therefore feasible to improve service continuity and stability of power systems by automatically reclosing those breakers required to restore the line after a relay operation. Also, reclosing can restore the line quickly in case of a relay misoperation.

Section 14 provides information on reclosing of transmission line on the PJM system. For greater detail on reclosing, refer to the latest version of the ANSI/IEEE Std. C37.104

14.2 Definitions

- Reclosing

  Automatic closing of a circuit breaker by a relay system without operator initiation Note: For the purpose of this document, all reference to "reclosing" will be considered as "automatic reclosing."

  Reclosing should always be effected using a single or multiple shot reclosing device. The use of the reclosing function in a microprocessor relay is an acceptable substitute for a discrete reclosing relay.

- High-Speed Autoreclosing

  Refers to the autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit fault arc deionization with due regard to coordination with all relay protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

- High-Speed Line Reclosing

  The practice of using high-speed autoreclosing on both terminals of a line to allow the fastest restoration of the transmission path

- Delayed Reclosing

  Reclosing after a time delay of more than 60 cycles

- Reclosing Through Synchronism Check

  A reclosing operation supervised by a synchronism check relay which permits reclosing only when it has determined that proper voltages exist on both sides of the open breaker and the phase angle between them is within a specified limit for a specified time.

- Single-Shot Reclosing

  A reclose sequence consisting of only one reclose operation. If the reclose is unsuccessful, no further attempts to reclose can be made until a successful manual closure has been completed.

- Multiple-Shot Reclosing

  A reclose sequence consisting of two or more reclose operations initiated at preset time intervals. If unsuccessful on the last operation, no further attempts to reclose can be made until a successful manual closure has been completed.

- Dead Time

  The period of time the line is de-energized between the opening of the breaker(s) by the protective relays and the reclose attempt.

- Initiating terminal

  The first terminal closed into the de-energized line; also, referred to as the leader.

- Following terminal

  The terminal which recloses following the successful reclosure of the initiating terminal; also, referred to as the follower. The following terminal is supervised by voltage and/or synchronism check functions.

14.3 Prevailing Practices

The following information on prevailing practices is provided for reference. Each application must be reviewed to determine the most appropriate reclosing scheme.

- General

  Normally, one reclosure is used for 500 kV lines and one or more reclosures for 230 kV lines. High-speed reclosing of both ends of a transmission line is generally not used at 230kV and above.

- Lines Electrically Remote from Generating Stations

  The initiating terminal will reclose on live bus-dead line in approximately one second and the following terminals will reclose through synchrocheck approximately one second later. The synchrocheck relay setting is generally 60 degrees. Longer reclosing times and smaller angle settings of the synchrocheck relays are applied under certain conditions.

- Lines Electrically Close to Generating Stations

  Turbine generator shaft damage could occur due to oscillations created by reclosing operations on nearby transmission lines. If the initiating terminal is electrically close to a generating station, reclosing is delayed a minimum of 10 seconds. The synchrocheck relay setting should be determined with regard to shaft torque considerations.

- Multiple Breaker Line Termination

  For reclosing at a terminal with more than one breaker per line, it is recommended to reclose with a pre-selected breaker. After a successful autoreclose operation, the other breaker(s) associated with the line at that terminal may be reclosed.

- Preventing reclosing on a failed transformer or reactor, or failed breaker
  - Automatic reclosing of transmission line circuit breakers should be blocked while a direct transfer trip (DTT) signal is being received.
  - The operation of the breaker failure relay scheme on a breaker should block reclosing on adjacent breakers. If the failed breaker can be automatically isolated, the reclose function may be restored to the adjacent breakers.
  - The operation of a transformer or bus protective relay scheme may also be a reason for blocking reclosing.

- Adaptive Reclosing

  Most adaptive reclosing autoreclosing schemes or selective reclosing schemes use the operation of specific relays or relay elements to initiate the scheme. Some schemes only permit reclosing for pilot relay operations, while others permit reclosing for all instantaneous relay operations. Others only block (or fail to initiate) reclosing for conditions such as multi-phase faults where system stability is of concern or where sensitive or critical loads may be affected.

SECTION 15: Supervision and Alarming of Relaying and Associated Control Circuits

In order to assure the reliability of protective relaying to the greatest practical extent, it is essential that adequate supervision of associated AC and DC control circuits be provided. Supervisory lamps or other devices may adequately supervise most of a given circuit. It is very difficult to supervise some parts, such as open relay contacts and AC current circuits. Back-up protection will provide reasonable assurance against a failure to trip which may originate in a portion of a circuit that is difficult to supervise.

SECTION 16: Underfrequency Load Shedding

Refer to M07. The only supplementary information is that the underfrequency detection scheme should be secure for a failure of a potential supply.

Note: Time delays incorporated into the scheme are subjected to Regional Reliability requirements

SECTION 17: Special Protection Schemes

Refer to M07. No supplementary information available

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APPENDIX A - Use of Dual Trip Coils

Refer to M07. The only supplementary information is that "Cross-trip" auxiliary relays in the breaker tripping control scheme are sometimes provided as a standard by the breaker manufacturer. While this solution covers an open trip coil, it does not cover an open circuit on the source side of both the trip coil and the cross-trip auxiliary.

APPENDIX B - Disturbance Monitoring Equipment

Disturbance Monitoring Equipment (DME) should be installed at locations on the entity's Bulk Electric System (BES) as per applicable NERC PRC standards to facilitate analyses of events.

The Disturbance Monitoring Equipment includes Sequence of Events (SOE) recording, fault recording, most commonly termed Digital Fault Recording (DFR), and Dynamic Disturbance Recording (DDR)

APPENDIX C - Direct Transfer Trip Application

Background

Until the mid-to-late 1980's, only two types of direct transfer trip (DTT) transceivers were available: (1) power-line carrier units operating at high frequency; (2) audio-tone units operating into commercial or privately-owned voice-channels. In either case dual frequency-shift transmitter-receiver pairs are used in conjunction with appropriate logic. The requirement for a valid trip involves the shift from "guard" to "trip" for each of the two channels—the intent being to provide security against the possibility of a noise burst appearing as a valid trip condition to a single channel. The logic imposes the further requirement that the above-described shift occurs nearly simultaneously on both channels. Loss of the guard signal on either channel without a shift to trip is interpreted as a potential channel problem—tripping through the DTT system is automatically blocked until proper guard signaling is reestablished. For the permanent loss of one channel, the DTT system may be manually switched to allow single-channel operation using the remaining channel while repairs are undertaken.

In the case of audio-tone units, it has been typical to shift the frequency "up" on one channel and "down" on the other to guard against the effects of possible frequency-translation in the associated multiplex equipment.

An additional benefit of the dual-channel approach is the relative ease of channel testing. Facilities are typically provided for keying the channels one-at-a-time, either manually or using a semiautomatic check-back technique.

Modern Trends in Transfer Trip Equipment

The advent of digital communications has stimulated the development of digital transfer trip equipment. Rather than transmitting an analog signal, digital equipment generates a sequential, binary code which may be transmitted directly over a dedicated fiber or multiplexed with other services in a pulse-code-modulation (PCM) format. Given the nature of digital transmission, these systems are considered, and have proven to be, more secure, more dependable, and faster than conventional analog systems.

DTT Systems

- Carrier/Audio Tone systems – Dual-channel systems is a common practice. In For dual-channel systems, single-channel operation has been allowed only for testing or while repairs are underway subsequent to a channel failure.

Audio tone transceivers operating over digital multiplexed systems False trips have been experienced in conjunction with the momentary loss and subsequent reestablishment of the digital system.

- Digital systems – The use of dual channels is not a requirement with this type of equipment. Retention of dual-channel configuration is allowed, however, if preferred by the user for standardization of end-to-end procedures or other reasons.

APPENDIX D - Tapping of Bulk Power Transmission Circuits for Distribution Loads

For economic reasons, it has become increasingly popular to tap existing bulk power transmission circuits as a convenient supply for distribution type loads. The following discussion is presented in recognition of the need to protect the integrity of the bulk transmission system.

It should be pointed out that the tapping of transmission lines for distribution load increases the likelihood of interruptions (natural or by human error) to the bulk power path. Per M07 Section 8.2, bulk power lines operated at greater than 300 kV shall not be tapped. Lines operated at less than 300 kV lines may be tapped with the concurrence of the transmission line owner(s).

Distribution station transformer low voltage leads and bus work is more susceptible to faults than higher voltage equipment. The bulk power path should be protected from interruption due to any such faults by the use of local fault-interrupting devices applied on the transformer high side. (The source terminal relays should not initiate the interruption of the bulk power path for low side faults.)

The local interrupting device may be either a breaker or a circuit switcher. In either case, provisions must be made for a failure of the device to clear a fault. These provisions are enumerated in the PJM Manual 07: PJM Protection Standards, Section 8.2.

If the device selected is a circuit breaker (presumably fully rated for interruption of both high and low voltage faults), there are several ways in which it can be applied as part of the overall line protection scheme. Two are listed and discussed below.

1. Selective clearing for all faults beyond the breaker.

2. Clearing of all faults, but on a selective basis for low voltage faults only.

With respect to item (1) above, while it might seem questionable to install a breaker and then not require selective clearing for all faults downstream of same, there may be situations where this is preferred, based on the following considerations:

   a. The amount of exposure beyond the breaker and the impact of a momentary outage to the bulk power path.

   b. The availability of economic and reliable telecommunication channels between the breaker and the source terminals.

   c. The probable increase in the complexity of the pilot relaying scheme.

   d. The probable necessity of "pulling back" the Zone 1 settings of the source terminals, and therefore degrading the non-pilot protection of the circuit.

In recognition of these considerations, it may be preferable to tolerate a momentary outage on the bulk power circuit for faults beyond the breaker but within the high voltage system. The relaying would be designed to trip the breaker instantaneously for such faults, allowing the source terminals to reclose automatically as they would for a line fault. As implied in item (2) above, complete selectivity is required for low voltage faults, which are both more prevalent and easier to immunize the source terminals against.

When deciding which of the various possible schemes to utilize, take the above considerations into account and make the evaluation on a case by case basis.

APPENDIX E - Dual Pilot Channels for Protective Relaying

Pilot Relaying

Pilot relaying provides a means for clearing faults at all locations on a transmission line by action of high speed relaying. Such schemes require the use of a communication system to provide a means for each terminal of the protected line to recognize the status of related relaying at all associated remote terminals. Media commonly used to provide communications for pilot relaying systems include power line carrier, microwave, leased telephone lines, and fiber optics.

Requirements for Dual Pilot Relaying

In some instances, high speed clearing of all faults on a transmission line is required due to system stability or protection coordination constraints. In such cases, a pilot relaying scheme is applied on both the primary and backup relaying systems. Such application is referred to as dual pilot relaying.

Channel Independence Considerations

Communication facilities for pilot relaying are an integral part of the pilot protection system.
An extremely low probability must exist that a single failure involving the communications system could prevent tripping through both pilot systems for a fault on the protected line. During repair or maintenance of either the primary or backup communication channel, one pilot protection scheme should remain functional.

Per NERC Transmission Planning Standards, transmission protection systems should provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements as outlined in Table I of each standard. Dual pilot relaying is required if delayed clearing results in miscoordination allowing the potential for overtripping an additional transmission path. In pilot relaying, the communication channel and associated equipment are considered part of the protective system. As such, if dual pilot channels are required to meet the above performance criteria, then the communication channel and associated equipment for the primary and backup relaying must be held to this same standard.

Applications

A. Power Line Carrier

Power line carrier communication systems utilize the conductors of the transmission line to carry the communication signals. Pilot systems utilizing power line carrier for communications typically use ‘blocking’ logic since a fault on the line may disrupt the signal.

It should be noted that pilot systems that use blocking logic are inherently insecure since a failure to receive the blocking signal will result in an overtrip. Utilizing two such systems on a line results in an even more degradation in security. For this reason, use of ‘unblocking’ logic for one of the pilot systems should be given consideration.

In some cases, the extended high speed clearing coverage provided by the dual pilot systems to meet stability constraints is only required for multi-phase faults. In such cases, with power line carrier applications, security can be enhanced by enabling one of the pilot systems only for multi-phase faults.

General Recommendations for Power Line Carrier

- Directional Comparison Blocking (DCB)

  - Phase to Ground Coupling - Single Phase: Unacceptable for a dual pilot protection scheme as defined in the beginning of this appendix, but its benefits merit its mention.

    Advantages
    - Provides dependable high speed clearing for internal faults, even with the loss of the channel, for both the primary and backup protection schemes.
    - A checkback test every 24 hours will provide sufficient information to prove the integrity of the carrier system.
    - Requires one set of primary equipment (line tuner, CCVT, wave trap, and coaxial cable).
    - Modern relays use logic to ride through carrier holes.

    Disadvantages
    - A protection overtrip can occur for an external fault if a carrier hole occurs
    - The loss of the channel would not allow the a blocking signal to be transmitted, exposing the protection on the channel to over tripping for external faults on the system.

  - Phase to Ground Coupling – Two Phases: Acceptable but not recommended

    Advantages
    - Two totally separate channels connected to two phases.
    - Loss of any channel would not prevent high speed tripping for internal faults for both primary and backup protection.
    - A checkback test every 24 hours will provide sufficient information to prove the integrity of the carrier system.
    - Modern relays use logic to ride through carrier holes.

    Disadvantages
    - The loss of one channel would not allow the a blocking signal to be transmitted, exposing the protection on that channel to over tripping for external faults on the system
    - One channel would be couple to the outer phase which has very poor coupling efficiency
    - There is minimal isolation between transmitters which can cause intermodulation distortion

        - A protection over trip can occur for an external fault if a carrier hole occurs
        - Requires two sets of primary equipment (line tuner, CCVT, wave trap, and coaxial cable)

    - Phase to Phase Coupling – Outer Phase to Outer Phase: Acceptable

    - Phase to Phase Coupling – Center Phase to Outer Phase: Recommended

- Directional Comparison Unblocking (DCUB)

    - Phase to Ground Coupling – Single Phase: Unacceptable for a dual pilot protection scheme.

    - Phase to Ground Coupling – Two Phases: Acceptable but not recommended
        - The two totally separate channels connected to two phases.
        - The block signal (guard) is continuously monitored and, if lost, should alarm after a short time delay pickup.

    - Phase to Phase Coupling – Outer Phase to Outer Phase: Acceptable

    - Phase to Phase Coupling – Center Phase to Outer Phase: Recommended

        <u>Advantages</u>

        - Loss of any channel would not prevent high speed tripping for internal faults for both primary and backup protection
        - Cross channel coupling to allow both systems to transmit a block signal with the loss of primary equipment on one channel
        - Better coupling efficiency than single phase to center coupling and phase to phase outer to outer coupling
        - Modern relays use logic to ride through carrier holes
        - Center phase less likely to experience a phase to ground fault
        - Better isolation with the additional hybrids
        - All hybrids should be located in control house and two coaxial cable runs to the yard to strengthen redundancy
        - A checkback test every 24 hours will provide sufficient information to prove the integrity of the carrier system

        <u>Disadvantages</u>

        - Higher losses with the additional hybrids
        - The loss of one channel would not allow the a blocking signal to be transmitted, and may expose the protection on that channel to over tripping for external faults on the system
        - A protection over trip can occur for an external fault if a carrier hole occurs
        - Requires two sets of primary equipment (line tuner, CCVT, wave trap, and coaxial cable)

Another disadvantage of power line carrier is that repair or maintenance on associated wave traps requires that the related transmission line be taken out of service.

For additional application details on utilizing power line carrier in protective systems see IEEE 643—IEEE Guide for Power Line Carrier Applications.

B. Microwave Radio Channels

Modern digital communications may utilize microwave radio and optical fiber either alone or in combination. In either case, transmission is independent of the power system and is therefore frequently applied in pilot protection schemes using 'permissive' logic rather than 'blocking' logic.

C. Leased Telephone Circuits

If dual pilot channels are required, they may not both utilize leased telephone circuits.
Historically, problems have been experienced with the performance of leased telephone circuits utilized in protection applications due to the receivers being incapable of discriminating between valid signals and spurious signals which may be introduced into the voice grade audio channels particularly during power system disturbances. Also, control of the phone circuits themselves may be an issue in such applications since ownership of the channels exists within an entity separate from the transmission owner. Care should be taken to deal with these issues when applying telephone circuits in pilot protection systems.

For additional application details on utilizing audio tone signals in protective systems see ANSI/IEEE C37.93—IEEE Guide for Power System Protective Relay Applications of Audio Tones over Voice Grade Channels.

A. Fiber Optics

1. Fiber Routing
   Applications of fiber optic systems for communications in pilot relaying systems can be categorized based on the physical location of the routing of the fibers:

   a) Routing in close physical proximity to that of the associated protected transmission line. (Fiber may be integral to the shield wire, suspended from the towers themselves, or buried in the right of way.)

   b) Routing on a path that is completely independent of that of the associated protected transmission line.

   c) Routing as in (a) above but with a backup system that is automatically utilized and routed independently of the protected transmission line. (Self-healing ring topology.)

For routings as in (b) and (c) above, there exists a low probability for a failure on the protected line to disrupt the channels in a manner that would prevent tripping through both systems utilized for a dual pilot relaying system.

Fibers that are above ground and routed as in (a) have a chance of being physically involved in a fault on the protected line. For instance, the shield wire may contact the phase wire resulting in a fault. For such cases, the conditions that relate to the specific application must be evaluated to determine if an adequate level of redundancy is being provided.

Dual pilot protection systems utilizing fiber optic communications channels must be designed to maintain high speed coverage for the transmission line in the event of a single contingency. In evaluating the level of redundancy, both the fiber path routing and protection scheme types must be considered. The following protection fiber optic path examples are presented as with protection scheme scenarios of the analysis which must be performed to determine adequate redundancy:

Underbuilt optical fiber cable

It is possible, although unlikely, that an underbuilt fiber cable will break and cause a fault on the protected circuit.

Conditions to consider when applying dual pilot fiber optic communication channels with common failure mode:

a) Cause of fiber failure can result in a simultaneous line fault:

pilot systems that use blocking logic are inherently insecure since a failure to receive the blocking signal will result in an overtrip. Utilizing two such systems on a line results in even more degradation in security. However, blocking schemes using dedicated fiber offer a tremendous improvement in security over those using power line carrier.)

Note: In regard to the above-mentioned compromise in security, the use of blocking schemes may be particularly unwise if, for example, four parallel transmission lines were protected identically with pilot communications in a common shield wire. Three lines would be subject to an overtrip for a broken fiber-optic shield wire which involves only one of the lines.

b) Steady-state loss of both fiber channels

For the loss of both fibers channels for required dual pilot protection systems, the associated transmission line is requested to be taken out of service or, if possible, tripping delay time immediately reduced to a level at which stability requirements are met and relay coordination is maintained for normal clearing of faults. Allowing for potential overtrips is not acceptable unless specifically approved by the system operator.

2. Fiber Optic Multiplexed Communications

   The use of dedicated fibers for relaying is preferable, but not always practical. The prevailing trend is to combine teleprotection with other services on the same fiber using a DS1 (digital channel bank with 24 separate DS0 channels) operating either directly into a fiber, or, in many cases, into a higher-order multiplexer connected to a fiber.

   Blocking schemes are not recommended over multiplexed channels.

3. Fiber Optic Self-Healing Ring Topology

   Ring topologies can be utilized for purposes of path redundancy such that when a break in a fiber occurs, the affected traffic is quickly re-routed along an alternate path. While this is a very useful feature, especially for non-protection-related services such as voice, SCADA, telemetry, etc which are not themselves redundant, it may not of itself eliminate all failure modes common to the teleprotection channels. For example, it would be unacceptable to utilize a common DS1 multiplexer for both teleprotection channels even when the multiplexer is connected to a switched system.

B. Communication Channel Speed

Speed of a protective relay communication channel is a measure of the time it takes to assert an element in the receiving relay after a logic status change is initiated in the transmitting relay. Channel time includes time delays associated with operation of input/output devices, communications equipment, and channel propagation.

Channel speed may impact the overall operating time of a pilot relay scheme and, as such, needs to be considered in the application analysis. Also, variations in channel speed may cause operating problems in some schemes. Pilot schemes that use blocking or differential type logic are particularly sensitive to variations in channel time. When operating channel speed and consistent channel time is critical to a pilot application, use of communication facilities that operates into a higher order switched network, in which an array of alternate paths may be arbitrarily switched into use for the channel routing, is not recommended. In applications with a fixed number of known alternate paths, channel time for all paths should be considered in evaluating the pilot scheme application.

APPENDIX F - Calculation of Relay Transient Loading Limits

The loadability of bulk power transmission lines is not usually limited by the settings of the relays protecting the line. However, under certain emergency loading situations, there is a possibility that a relay setting could be exceeded, resulting in unexpected tripping. Relay settings are chosen to adequately protect the system from electrical faults and other disturbances, which would affect the safe and reliable operation of the power system. Sometimes this results in relay settings which could restrict line loading. When necessary, techniques such as load encroachment logic and blinders can be used to increase the relay loading limit. The system planner must incorporate relay limitations into equipment loadability limits. The system operator must abide by those equipment loadability limits, so as not to allow loading of sufficient magnitude as to invite relay tripping.

Transient swings precipitated by sudden large load changes, faults, or switching procedures can cause the load characteristic to travel within the operating characteristic of the relay for a period of time, even though under normal steady state conditions it might be well outside the characteristic. To account for this transient condition a safety margin is applied to the calculation based on the operating speed of the relay. Additional safety factors are used to account for CT and PT errors, drift in relay calibration, and for Mho distance elements – deviation from a perfect circle on the R-X diagram. The load limits are calculated and reported based on nominal PJM system voltages (500, 230, 138, 115, and 69 kV). However, it must be kept in mind that the load limit expressed in MVA will decrease with lower than nominal system voltages. In the case of distance relays, since the load limit varies with the square of the voltage, the load limit at 95% system voltage will be $(0.95)^2$ or 90% of the calculated nominal MVA load limit.

OVERCURRENT RELAYS

Overcurrent Relay Transient Load Limit (MVA) = Ke x Kt x (Relay pick-up in MVA)

Where, Ke = 0.92 to account for errors in relay setting, calibration, and CT performance
Kt = 0.90 for inverse time overcurrent relays,
0.53 for instantaneous overcurrent relays,
See Figure F-4 for definite time overcurrent relays

Overcurrent Relay Example: Consider an inverse time phase overcurrent relay applied to a terminal of a 138 kV transmission line. The relay is set on an 8.0 ampere tap with a 1200/5 A CT ratio. The overcurrent relay transient load limit would be calculated as follows:

Overcurrent Relay Transient Load Limit (MVA) = Ke x Kt x (Relay pick-up in MVA)
= 0.92 x 0.90 x (8 x 1200/5 x 138/1000 x $\sqrt{3}$)
= 380 MVA

DISTANCE RELAYS

Distance relay transient load limits are determined based on the characteristics of the relay when plotted on an R-X diagram. For Mho relays, or lens characteristics, the loading limit is referenced to a maximum "bulge point" or maximum projection along the R axis (See Figures F-1 & F-2). For relays with straight line or blinder characteristics, a slightly different procedure is required. In those instances the bulge point is determined by drawing a line perpendicular to the transmission line impedance and which passes through the midpoint of the transmission line impedance. Where this line intersects the relay operating characteristic is defined as the maximum bulge point (See Figure F-3). In all subsequent examples the relay load limit is calculated assuming that load flow is out of the bus and into the line. In that case, all analyses will be performed on relay characteristics, which fall in the first quadrant. To determine load limitations for load flow out of the line and into the bus, similar analyses would have to be performed using the relay characteristics that fall in the second quadrant.

The Distance Relay Transient Load Limit (DRTLL) should be calculated as follows:

Distance Relay Transient Load Limit (MVA) = Ke x Kt x $(kV)^2$ / Zr

Where, Ke = 0.93 to account for errors in relay setting, calibration, and CT and PT performance
Kt = See Figure F-4 for definite time delay relays
Zr = Impedance (in ohms primary) from the origin to the max. bulge point
kV = Nominal voltage in kV at which relay is applied

Figure F-1 Mho Relay Characteristic showing Maximum Bulge Point

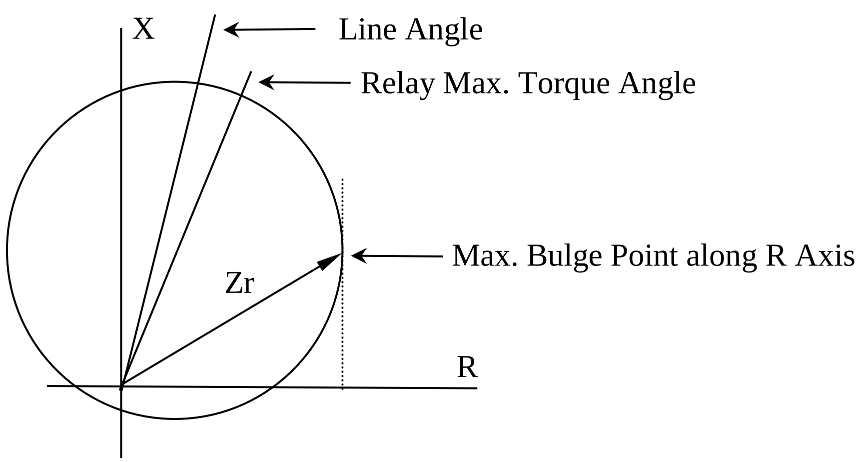


Figure F-2 Lens Relay Characteristic showing Maximum Bulge Point

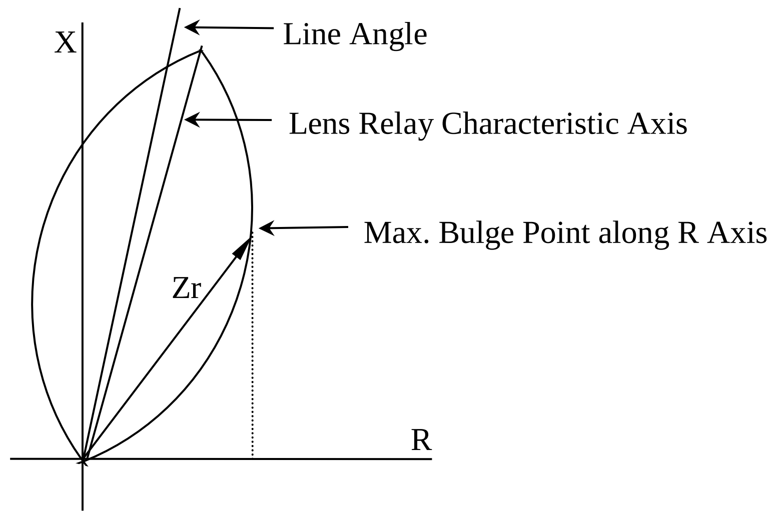
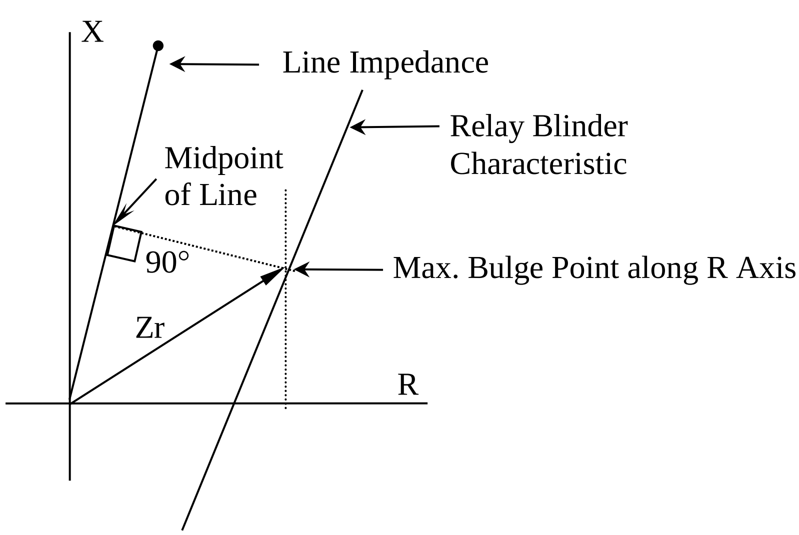


Figure F-3 Straight Line / Blinder Relay Characteristic showing Maximum Bulge Point

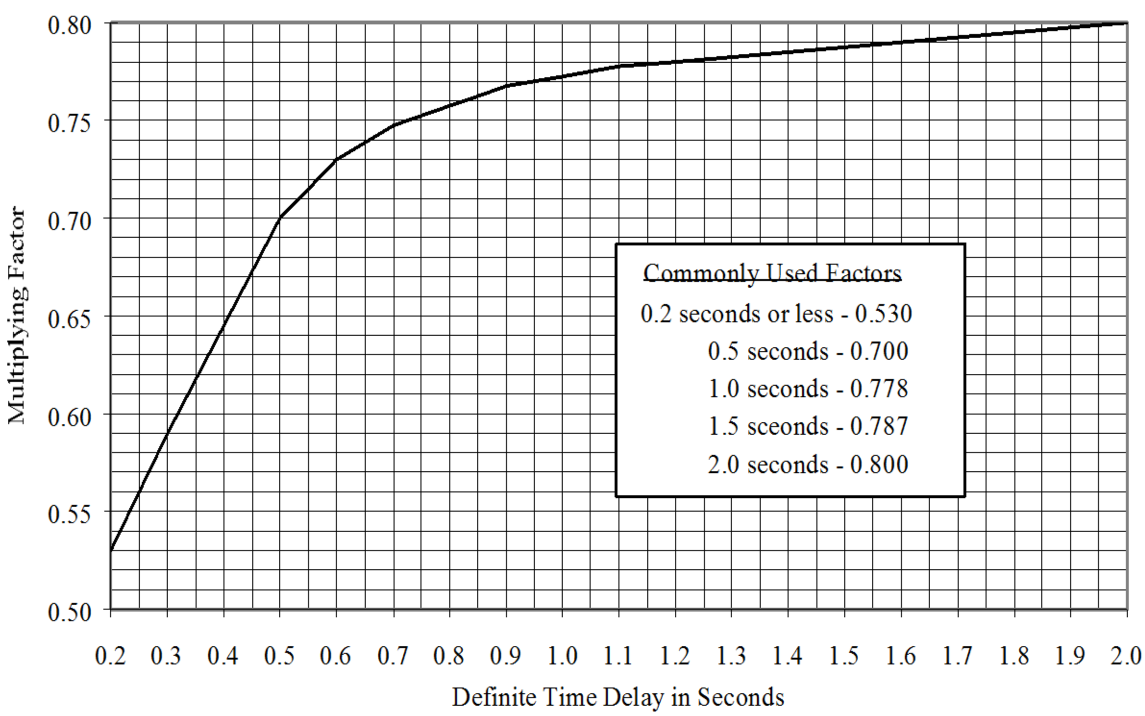


Mho Distance Relay Example: Consider a Mho distance relay applied in a Zone 2 application on a 230 kV transmission line terminal. The relay is set with a 15.0 ohms primary reach and a maximum torque angle of 75 degrees. A 0.5 second time delay is used. Assuming no offset (i.e. circular characteristic passes through the origin) it can be shown that the maximum bulge point occurs at a location where the angle that Zr makes with the +R axis is equal to ½ the relay maximum torque angle. As such, Zr = 15.0 Cos (75/2) = 11.9 ohms primary. From Figure F-4 the Kt adjustment factor for a 0.5 second time delay is 0.70. The distance relay transient load limit would be calculated as follows:

Distance Relay Transient Load Limit (MVA) = Ke x Kt x $(kV)^2$ / Zr

= 0.93 x 0.70 x $(230)^2$ / 11.9
= 2894 MVA

Figure F-4 Definite Time Relay Transient Load Limit Adjustment Factor



REACTANCE RELAYS

Relay transient load limits for reactance relays are also determined based on the characteristics of the relay when plotted on an R-X diagram. Similar to Mho relays the loading limit is referenced to a maximum "bulge point" or maximum projection along the R axis (See Figures F-5A, F-5B & F-5C). For relays with multiple reactance zones, the distance relay transient load limit (DRTLL) should be computed for all zones up to and including the zone where the maximum bulge point is located. In all subsequent examples the relay load limit is calculated assuming that load flow is out of the bus and into the line. In that case, all analyses will be performed on relay characteristics that fall in the first quadrant. To determine load limitations for load flow out of the line and into the bus, similar analyses would have to be performed using the relay characteristics that fall in the second quadrant.

The distance relay transient load limit should be calculated as follows:

Distance Relay Transient Load Limit (MVA) = Ke x Kt x $(kV)^2$ / Zr

Where, Ke = 0.93 to account for errors in relay setting, calibration, and CT and PT performance
Kt = See Figure F-4 for definite time delay relays
Zr = Impedance (in ohms primary) from the origin to the max. zone reach or bulge point projection along the R axis
kV = Nominal voltage in kV at which relay is applied

Figure F-5A Reactance Relay Characteristics with Maximum Bulge Point in Zone 3 Area

DRTLL should be computed for All Three Zones
Using Zr = Zr_1, Zr_2, & Zr_m with corresponding Kt time delay factors for each Zone

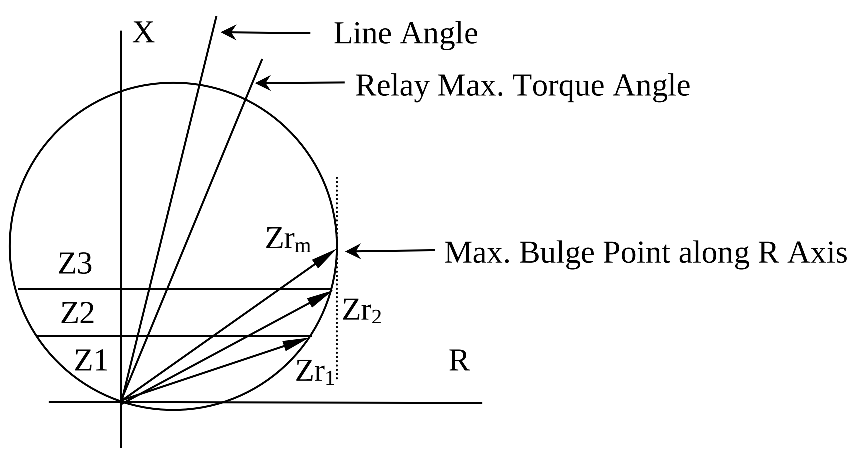
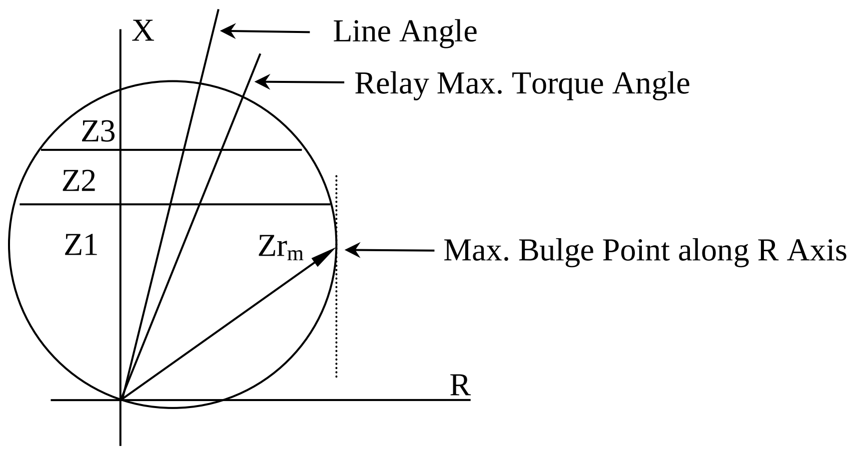


Figure F-5C Reactance Relay Characteristics with Maximum Bulge Point in Zone 1 Area

DRTLL ~~must~~ should be computed for Zone 1 only

Using $Zr = Zr_m$ with corresponding Kt time delay factor for Zone 1



Reactance Relay Example: Consider a three zone Mho supervised reactance relay applied in a back up application on a 230 kV transmission line terminal. The Mho relay is set with a 15.0 ohms primary reach and a maximum torque angle of 75 degrees. The Zone 1 element is set for 3.0 ohms primary reactance with no intentional time delay. The Zone 2 element is set for 5.0 ohms primary reactance with a 0.5 second time delay. The Zone 3 element uses a 1.5 second time delay. Using Figure F-5A as an example, the following impedance can be calculated: Zr_1= 8.66 ohms, Zr_2 = 10.38 ohms, and Zr_m= 11.9 ohms primary. From Figure F-4 the Kt adjustment factors for Zones 1, 2, and 3 will be 0.53, 0.70, and 0.787 respectively. The distance relay transient load limits would be calculated as follows:

Distance Relay Transient Load Limit (MVA) = Ke x Kt x $(kV)^2$ / Zr

Zone 1 = 0.93 x 0.530 x $(230)^2$ / 6.88 = 3011 MVA

Zone 2 = 0.93 x 0.700 x $(230)^2$ / 10.38 = 3,318 MVA

Zone 3 = 0.93 x 0.787 x $(230)^2$ / 11.90 = 3,254 MVA

In this case, Zone 1 will be the most restrictive setting from a DRTLL standpoint, followed by Zone 3 and then Zone 2.

COMMUNICATION ASSISTED / PILOT RELAY SCHEMES

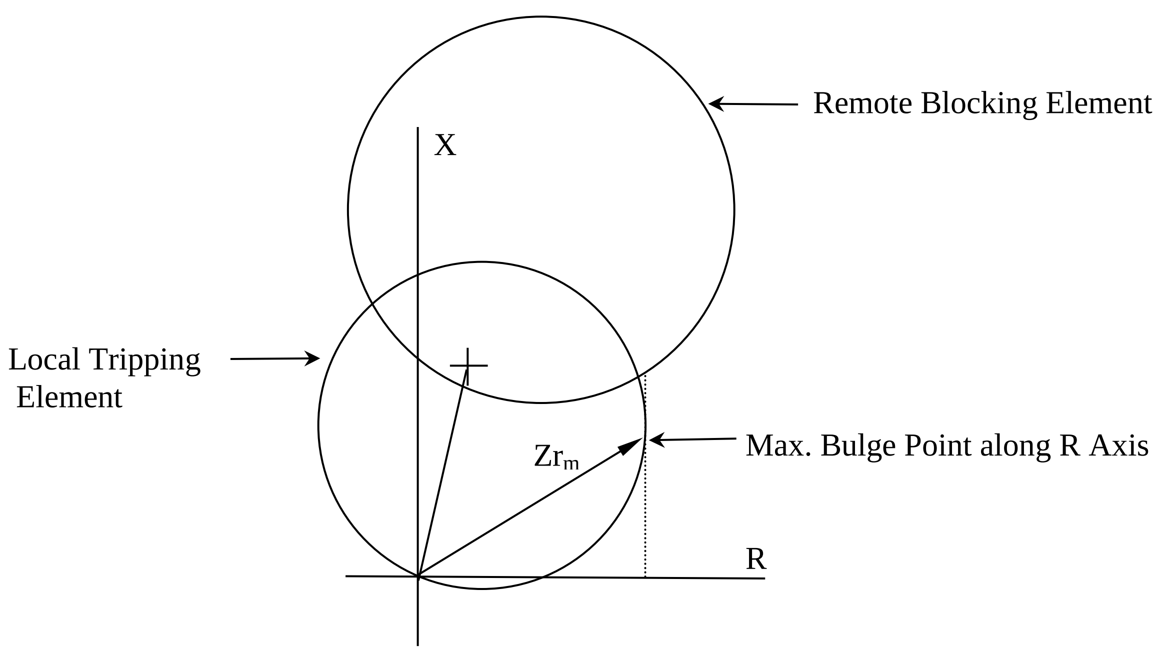
Relay schemes employing some form of line current differential protection technique (pilot wire, phase comparison, charge comparison, etc.) are not load limiting and, as such, no transient load limits are calculated. However, distance relays used in communication assisted / pilot schemes can have loading limitations that need to be calculated. This section addresses DRTLL of distance relays used in pilot schemes. If the same relays are also used to provide non-communication assisted zone backup protection, then additional DRTLL calculations, as discussed previously, also apply. In all subsequent examples the relay load limit is calculated assuming that load flow is out of the bus and into the line. In that case, all analyses will be performed on relay characteristics that fall in the first quadrant. To determine load limitations for load flow out of the line and into the bus, similar analyses would have to be performed using the relay characteristics that fall in the second quadrant.

Blocking Schemes

For blocking type schemes, any line loading which would result in operation of the tripping element at one end of a line, which would not simultaneously cause the blocking element to operate at the remote end of the line, needs to be calculated. In most cases, the maximum bulge point of the local tripping characteristic will not also fall within the blocking characteristic at the remote end of the line (See Figure F-6A). In these cases, the maximum bulge point of the phase tripping element should be used to calculate the DRTLL using the identical procedure discussed previously for distance relays. However, since the blocking scheme is a high speed-tripping scheme, a Kt corresponding to 0.53 should be used.

Figure F-6A Blocking Scheme where the Tripping Element Maximum Bulge Point Falls Outside the Remote Relay Blocking Characteristic

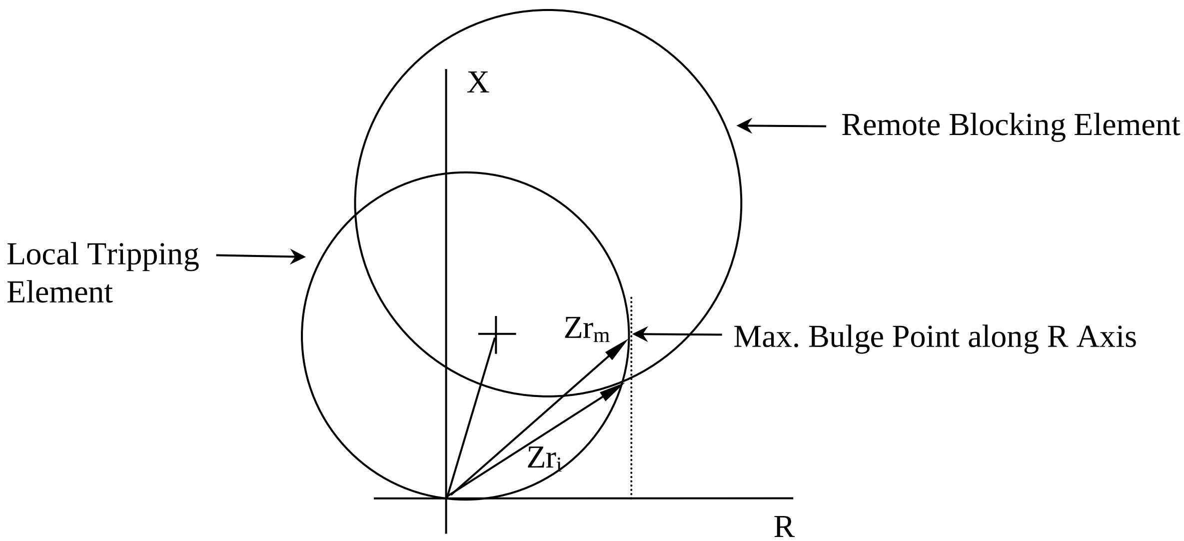
Use Zr_m to calculate DRTLL with Kt = 0.53



In rare cases, the maximum bulge point of the local tripping characteristic will fall within the blocking characteristic at the remote end of the line (See Figure F-6B). In these cases, a slightly higher loading limit can be realized by using the intersection of the tripping and blocking characteristic Zr_i to calculate the DRTLL. Again, since the blocking scheme is a high speed-tripping scheme, a Kt corresponding to 0.53 should be used.

Figure F-6B Blocking Scheme where the Tripping Element Maximum Bulge Point Falls Inside the Remote Relay Blocking Characteristic.

Use Zr_i to calculate DRTLL with Kt = 0.53

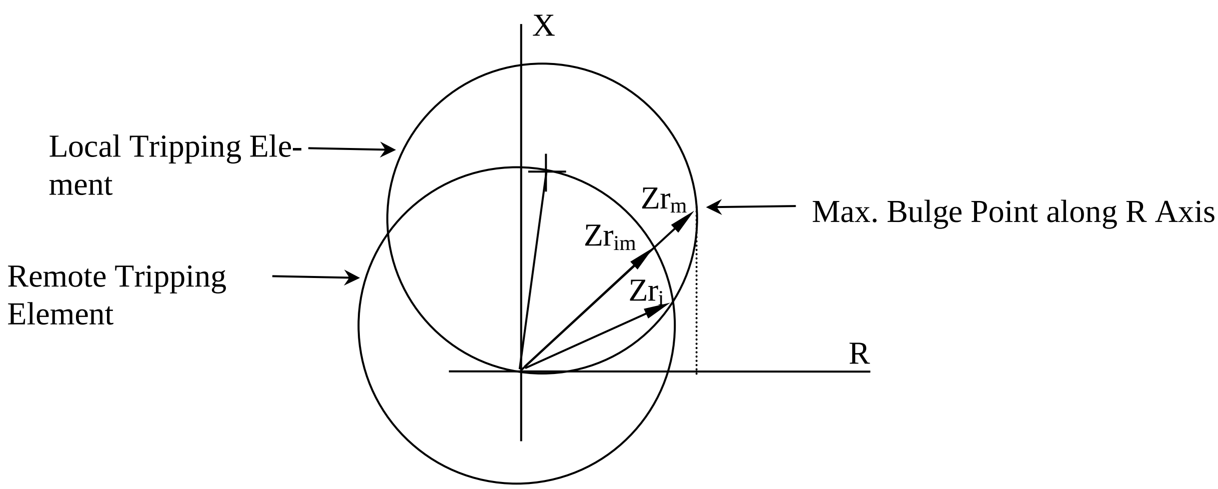


Permissive Schemes

For permissive type schemes, any line loading which would result in simultaneous operation of the tripping elements at both ends of a line needs to be calculated. Similar to blocking schemes, the maximum bulge point of the local tripping characteristic will usually fall outside the relay characteristic at the remote end of the line (See Figure F-7A). However, unlike blocking schemes, the local relay terminal will not trip unless the load is also within the remote tripping characteristic. Therefore, the impedance used to calculate the DRTLL must lie somewhere on the boundary of the overlapping characteristic formed from the two tripping elements. In these cases, two load points must be considered. One point, Zr_i, represents the intersection of the two tripping characteristics in the first quadrant. The second point, Zr_{im} represents the intersection of the overlapping tripping characteristic and a straight line drawn from the origin to the maximum bulge point of the local end tripping characteristic. In most cases, Zr_{im} will be larger than Zr_i , but not always. The larger of Zr_i or Zr_{im} should be used to calculate the DRTLL using the identical procedure discussed previously for distance relays. In no case should a value greater than Zr_m be used in the calculation. To simplify the analysis, many companies will simply use the maximum bulge point of the local tripping characteristic Zr_m in the calculation. In any event, since the permissive scheme is a high speed-tripping scheme, a Kt corresponding to 0.53 should be used.

Figure F-7A Permissive Scheme where the Tripping Element Maximum Bulge Point Falls Outside the Remote Relay Tripping Characteristic

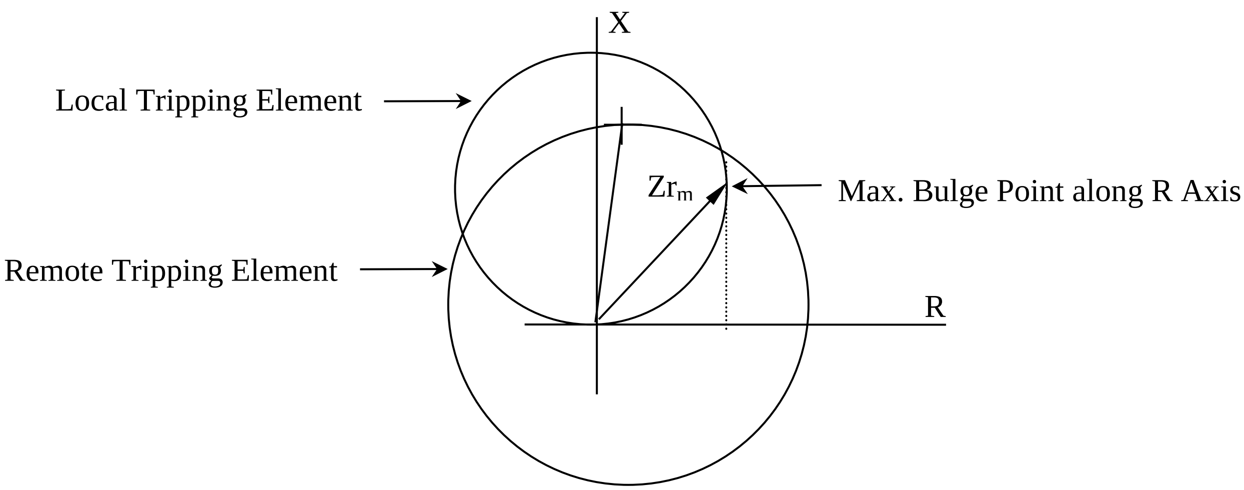
Use larger of Zr_{im} or Zr_i to calculate DRTLL with Kt = 0.53



In rare cases, the maximum bulge point of the local tripping characteristic will fall within the tripping characteristic at the remote end of the line (See Figure F-7B). In these cases, the maximum bulge point of the phase tripping element should be used to calculate the DRTLL. Again, since the pilot scheme is a high speed-tripping scheme, a Kt corresponding to 0.53 should be used.

Figure F-7B Permissive Scheme where the Tripping Element Maximum Bulge Point Falls Inside the Remote Relay Tripping Characteristic

Use Zr_m to calculate DRTLL with Kt = 0.53



Permissive Overreaching Transfer Trip (POTT) Pilot Scheme Example: Consider a 230 kV transmission line with positive sequence impedance of 10.0 $\angle 80°$ ohms primary. Both ends of the line use Mho type phase distance relays with a setting of 15.0 ohms primary and a maximum torque angle of 75 degrees. The relays are connected in a high-speed permissive overreaching transfer trip pilot scheme. The tripping elements are also connected to a discrete 0.5 second timer, so as to function as a traditional back-up Zone 2 function. Using Figure F-7A as an example, the following impedances can be calculated: Zr_i = 7.53 $\angle 15.1°$ ohms, Zr_{im} = 8.6 $\angle 37.5°$ ohms, and Zr_m= 11.9 $\angle 37.5°$ ohms primary. For the POTT case, since Zr_{im} is larger than Zr_1, 8.6 ohms is used in the calculation. From Figure F-4 the Kt adjustment factor for a high speed pilot scheme would be 0.53. When considering the back-up Zone 2 function, the Zr_m impedance is used with a Kt factor of 0.70 corresponding to a 0.5 second time delay. The distance relay transient load limit would be calculated as follows:

Distance Relay Transient Load Limit (MVA) = Ke x Kt x $(kV)^2$ / Zr

POTT = 0.93 x 0.530 x $(230)^2$ / 8.60 = 3032 MVA
Zone 2 = 0.93 x 0.700 x $(230)^2$ / 11.90 = 2894 MVA

In this case, the Zone 2 function has a lower DRTLL than the POTT.

APPENDIX G - Voltage Transformers

Voltage Transformers

For new line protection scheme designs:

1. Independent AC voltage sources are required for primary and back-up protection schemes if both schemes require ac potential for normal operation. Independent Voltage Transformers (VTs) are preferred. Separate control cables for the secondary leads are recommended. A single set of VTs with electrically-independent secondary windings is acceptable, however it should be recognized that a VT primary failure may not only result in a fault, but will likely compromise both protection schemes. If a single set of VTs is used, it is recommended that upon detection of a loss-of-potential condition, the affected protection scheme(s) be automatically re-configured to protect the line using non-directional phase and ground overcurrent elements with suitable time delays. At a minimum, a ground overcurrent element should be enabled. This is considered adequate since the primary failure of a single VT necessarily involves ground.
2. In station configurations where a line can be supplied from multiple sources, VTs should be applied such that the line relays have the appropriate potential when the line is energized regardless of which source is supplying the line. For example, in a breaker-and-a-half arrangement, the VTs used for line protection should be connected to the line position rather than to a bus.

APPENDIX H - Generator Protection for Units Less Than 100 MVA and Connected Below 230 kV

GENERAL

The protection outlined in sections 3, 4, 5 and 6 of the PJM Manual 07: PJM Protection Standards is generally applicable to all synchronous generators and their connection to the utility system. However, below 100 MVA the variety of generation technologies and the diverse nature of their high voltage connections to the utility system make it difficult to outline a single guideline for protection. This class of generator includes both synchronous and induction machines, inverter systems, and hybrids. These installations may exist solely to export power or they may be integrated into a plant to serve local load, operating in parallel with the utility for reliability. Detailing the specific protection requirements for all of these possible combinations is beyond the scope of this appendix.

The purpose of this appendix is to provide an overview of the protection philosophy and point out some pitfalls encountered in the interconnection of smaller generating plants to the utility system. Protection of the generators themselves should be designed in accordance with the generator manufacturer specifications, applicable national standards, and the interconnected utility's requirements.

STANDARDS

Applicable standards include, but are not limited to:

ANSI/IEEE C37.101 Guide for Generator Ground Protection
ANSI/IEEE C37.102 Guide for AC Generator Protection
ANSI/IEEE C37.106 Guide for Abnormal Frequency Protection for Power Generating Plants
ANSI/IEEE C37.95 Guide for Protective Relaying of Utility-Consumer Interconnections
ANSI/IEEE C37.91 Guide for Protective Relay Applications to Power Transformers
IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

ZONES OF PROTECTION

The protection zones of interest here can be loosely grouped into three overlapping areas: the generator, the step-up transformer and interconnection breaker, and the incoming distribution or transmission line. Protection must be provided to isolate the generator for faults in each zone.

REDUNDANCY

The protective system should be designed with sufficient redundancy to operate correctly for the single contingency failure of any protective relaying component. Protection provided specifically to isolate faults on the utility system, or to protect the utility from faults in the generator facility, must be fully redundant. In other words, it is required that two independent devices be able to detect and operate to clear any single contingency fault. Redundancy for generator protection, where the failure of that protection does not impact the utility, is only recommended.

SIGNAL DEPENDENT GENERATORS

In general, induction generators and inverter systems are signal dependent. That is they require a connection to the utility to provide excitation, or commutation, in order to generate power or to sustain fault current.

When the utility opens its breaker to interrupt a fault, the connection to the generator is removed and it can no longer sustain current flow. In this manner it is self-protecting and requires very little extra protection. If the system conditions could be such that the machine can become self-excited, or if the commutation circuit design will allow the inverter to sustain fault current, then the generator must be treated as if it is a synchronous generator and a full complement of protection is required.

GENERATOR ISOLATION DEVICE

All generators require a visible means of isolating the generator from the utility system. System conditions may dictate the use a three phase interrupting device to isolate the generator. Synchronous generators require a breaker for synchronizing to the utility system. The location of the generator breaker is a function of the plant design and operation.

STEP-UP TRANSFORMERS

Most generators will be connected to the utility system through a power transformer. The step-up transformer reduces harmonics, lowers fault currents, and decreases the likelihood of self-excitation for induction generators. While most transformer winding configurations can be used, there are protection issues that must be addressed with each different connection.

WYE (grounded) -WYE (grounded) CONNECTION

Protection is straight forward, but since the wye-wye connection does not provide zero sequence isolation particular care must be taken to coordinate the utility system ground relays with the generator/interconnection ground protection. In certain cases the sensitivity of the utility system ground relaying may be significantly reduced.

WYE (grounded) -DELTA CONNECTION

The delta connection on the generator side provides zero sequence isolation between the high and low sides of the transformer. This transformer can be a significant source of ground current to faults on the utility system. Depending on the system configuration, the sensitivity of the utility system ground relays may be reduced to the point where the protection is compromised. For these cases it may be advisable to ground the step up transformer neutral through a resistor. Note that the transformer has to have the proper insulation and terminating facilities to make this connection.

For ground faults on the delta side of the transformer, the generator protection should operate to isolate the unit from the fault. Depending on the configuration of the plant bus the fault may remain energized from the high side. This will increase the phase to ground voltage by as much as 173%. It is common practice, and highly recommended that the phase to ground insulation of the bus and equipment connected to the delta side of the transformer be rated for full phase-to-phase voltage. If this is not the case, high-speed phase or 3Vo overvoltage protection should be applied that will clear the fault by opening a high side interrupting device.

DELTA-WYE CONNECTION

The delta connection on the high side provides zero sequence isolation from the generator to ground faults on the utility system. After the utility source opens to clear the fault from the utility end, the fault may remain energized from the generator with no ground current flow. This may increase the phase to ground voltage on the unfaulted phases by as much as 173%. Unless the phase-to-ground insulation level of the highside bus and connected equipment is rated for full phase-to-phase voltage, high-speed phase or 3Vo overvoltage protection connected on the utility side is recommended to be applied to isolate the generator from the faulted system. Direct transfer trip and/or sensitive directional power relays may also be used to augment this voltage protection.

FERRORESONANCE

Any delta or ungrounded wye transformer connection may be subject to ferroresonance under open phase conditions. If the system configuration is such that an open phase can create a series resonant path between the transformer windings and the phase to ground capacitance then ferroresonance is possible. For this reason ungrounded wye and delta transformers should use a three phase interrupting device on the high side. Additional relaying may be required to detect and clear the resonant condition.

UNDERFREQUENCY

The PJM specified underfrequency set point on generators is dependent upon the PJM control zone (PJM Mid-Atlantic, PJM West, PJM ComEd or PJM South); see PJM Manual 36, 2.3.1 Generator Frequency Trip Settings for the specific setpoints. These setpoints are designed to provide coordination with the utility system underfrequency load shedding scheme (UFLS). The UFLS scheme is designed to shed blocks of load in order to arrest a system frequency decline caused by a mismatch between generation and load. The specified underfrequency setpoint is usually adequate to provide satisfactory turbine protection. Some units and other generating technologies may have different underfrequency limitations for which the setpoint may not suffice. If generators apply underfrequency protection that is more sensitive than the UFLS scheme, those units will trip offline at precisely the time they are needed to bolster the utility system generating capacity.

Where it is possible, all generators should follow the PJM requirement for tripping. Where a generator (20 MW or greater) requires an underfrequency setting that does not coordinate with the system UFLS scheme, or a more sensitive underfrequency setting is required to detect an islanded condition, PJM should be notified.

UTILITY-GENERATOR INTERCONNECTION PROTECTION

Interconnection protection is applied to protect the utility system to which the generator connects from harm caused by the generating facility. These facilities will typically consist of protection to prevent island operation with part of the utility system, to assure that voltage and frequency are within acceptable limits, to assure the generator trips for faults on the intertie line, and to assure that faults within the generating facility are isolated by the intertie breaker rather than by other interrupting devices located on the utility system. The interconnection protection may be located at a dedicated location at the point of intertie or within the generator facility. In either case, however, the associated design and setpoints for these facilities require the approval of the involved intertie utility. Test documentation is also required to assure these facilities are properly set and maintained.

ISLANDING

In general, relaying must be installed to prevent a generator from operating inadvertently as an island. If the tie between the utility and a generator is opened there is no means of keeping the generator in synch with the utility. Depending on the system configuration, the point of separation between the two systems may not have provisions for re-synchronizing the generator prior to reestablishing the tie. Connecting the generator to the utility when it is out of synchronism may have catastrophic consequences for the generator and may impact the system power quality for other utility customers. Traditionally, under/over frequency and under/over voltage protection has been applied to detect islands. Where these devices are not sufficient to detect all the load/generation conditions for possible islands, supplemental anti-islanding protection (e.g. a rapid change in power factor or transfer trip from the utility supply should be applied).

Direct transfer trip (DTT) requirements may vary depending on the nature of the system of the intertie utility, specific design parameters of the generating station, and the ratio of minimum load connected to the intertie line to the total generation on the line. In general, the need for DTT facilities must be determined on specifics of an individual installation. Typically, larger units (5 MW and above) are probable candidates for the need for DTT. Automatic reclosing on the intertie line may need to be delayed, or supervised by voltage sensing relays, in order to ensure that the generator is disconnected before auto-reclosing takes place.

INTERTIE LINE FAULT PROTECTION

Protection must be provided to rapidly isolate the generator from the utility system for all types of faults, anywhere on the intertie line. Protection settings must take into account the effects of infeed from other generators that may be connected to the line.

Protection for multi-phase faults is generally provided by voltage controlled time overcurrent, or impedance relaying with an appropriate coordination timer. Three single-phase undervoltage relays may be used if adequate sensitivity can be maintained for line faults without sacrificing coordination for faults on other feeders supplied from the same bus. Open phase protection utilizing a negative sequence time overcurrent, or transformer neutral time overcurrent relay should be applied if loading is such that an unbalance can overload the utility transformer.

Protection for ground faults on the intertie line varies depending on the generator step-up transformer connection. Wye (grounded) –wye (grounded) connected transformers provide no isolation for zero sequence current between the generator and the utility. Protection can be provided by a neutral time overcurrent relay on either the generator or the transformer. Three single phase undervoltage relays may also be used if adequate sensitivity and coordination can be achieved.

For wye (grounded) -delta connected transformers (delta on the generator side), the transformer is a source of zero sequence current for ground faults on the utility system. Protection for ground faults is generally provided by a ground time overcurrent relay on the transformer neutral.

For transformer connections with an ungrounded winding on the utility system side, such as delta-wye and delta-delta connected transformers, the generator is isolated from the utility for ground faults on the intertie line. The transformer is not a source of ground current for this fault. Unless detected, a ground fault will remain energized from the generator. Voltage on the faulted phase will be reduced, but voltage on the unfaulted phases may increase to 173% of nominal. This extreme overvoltage, can cause catastrophic failure of surge arresters and lead to other equipment insulation failures. This condition must be detected and removed rapidly (usually within 0.16 seconds based on typical arrester transient overvoltage (TOV) ratings). Protection for this condition is required (Fig 7A PJM Manual 14A) and may consist of three single phase overvoltage relays, or a 3Vo overvoltage relay, connected to phase-to-ground voltage transformers on the utility side of the transformer. As an alternative, a combination of a high-speed overvoltage and an undervoltage relay connected to a single phase may be used. However, because of the high speed with which this scheme must operate, the undervoltage relay may be prone to nuisance tripping.

If the phase-to-ground insulation of the faulted system is rated for full phase-to-phase voltage, a high speed scheme is not required. For this case, time delayed protection, such as directional power relays, may also be used. In addition to the protection listed above, the protection applied for anti-islanding, time delayed phase over/under voltage relays and sensitive definite time over and under frequency relays, provide a useful form of back-up intertie line fault protection.

SYSTEM PROTECTION FOR GENERATOR FACILITY FAULTS

The generator facility encompasses all of the equipment from the utility intertie line connection point to the generator. Protection should be applied to detect and clear any fault within the generator facility. These devices must be set to coordinate with the utility protection to assure isolation of only the faulted zone. Specific requirements depend on the electrical arrangement of the plant, but can generally be grouped into three areas: the primary bus; the step up transformer; and the low side bus.

Protection of the primary bus, that is the zone encompassing the utility interconnection device through the step-up transformer bushings, may be via bus differential relays, phase and ground time delayed and instantaneous overcurrent relays, or power fuses. If overcurrent relays are used, they may need to be made directional so as to properly coordinate with both up-stream and down-stream devices. Power fuses are not recommended for installations 10 MVA or greater, or where delta or ungrounded wye connected transformers are used due to the potential for overvoltage and ferroresonance problems.

Protection of the step-up transformer may be provided by the primary bus overcurrent devices, if they have sufficient sensitivity. More likely, this protection will be provided by dedicated overcurrent relays installed in the transformer high side bushing current transformers. For transformers 10 MVA and greater, a more sensitive method of detecting internal faults (i.e. transformer differential or sudden pressure relay) is recommended. The most complete protection package would combine a transformer differential with a fault pressure relay to detect low magnitude turn-to-turn faults. On grounded wye transformers, a more sensitive ground overcurrent relay can be installed on the transformer neutral to protect the grounded winding.

Faults on the low side bus must be isolated from both the utility side and the generator side. Protection for this zone is generally provided by phase and ground overcurrent relays. This protection should operate a high side breaker to isolate the fault from the utility. For transformer connections with a delta on the generator side, zero sequence overvoltage protection may be used to detect and trip the high side for ground faults.

GENERATOR PROTECTION

Generator protection is the responsibility of the IPP. Good protection practices for small generating facilities vary considerably with size and type of generation. Protection must be provided to comply with all applicable ANSI/IEEE Standards.

APPENDIX I - Acceptable Three Terminal Line Applications

Refer to M07. No supplementary information available

APPENDIX J - Application of Triggered Fault Current Limiters

This appendix describes the concerns and lists the recommendations for the application of triggered fault current limiters (FCL's) when proposed for the mitigation of increased fault current availability at a utility distribution bus resulting from the installation of new equipment or rearrangement of existing equipment at a non-utility station. Note: in the context of this document, "utility" means the delivery, or "wires" company whose equipment is being affected by the addition of the new equipment or rearrangement of existing equipment. Please note there are no formal PJM requirements for Triggered Fault Current Limiters.

General

The installation of new equipment or rearrangement of existing equipment at a non-utility station can result in an increase in fault current at the utility bus to a point beyond the momentary current withstand capability or the interrupting capability (or both) of one or more circuit breakers or other equipment connected to the utility bus. Possible solutions to this problem include the replacement of the underrated equipment, the installation of reactors, splitting buses that were formerly "solid", etc.

Recently a technique has been proposed involving the use of FCL's, which can be described as "smart fuses". If properly applied, the device will carry the required load current and yet operate very quickly to interrupt the fault current contribution from the new equipment, thereby limiting the fault current at the station bus to safe levels. The design of the FCL includes sensing and firing logic, a heavy copper bar fitted with explosive charges, and a current-limiting fuse in parallel with the copper bar. When the sensing logic detects a fault above its threshold setting, it fires the explosive charges to cut the copper bar, diverting all current through the fuse, which clears the fault very quickly. Depending on how fast the FCL is able to sense the fault and operate, the instantaneous fault current peak at the utility bus may be no higher than it would have been without the generators having been connected.

There are, however, a number of concerns surrounding the application of FCL's. The remainder of this discussion presents those concerns and lists requirements relating thereto.

Application Concerns and Recommendations

Selectivity

When a fault occurs on utility equipment and this fault causes the current through the FCL to exceed the threshold value, the FCL will be triggered in order to reduce the total fault current. The FCL may also be triggered for faults within the FCL owner's system. Both of these situations will result in the likelihood of "non-selective tripping", meaning that more power system elements were removed from service than would otherwise have been necessary to clear the original fault. To the extent that this lost equipment is important to the system, the system is degraded. The amount of time that the degradation will be in effect is a function of how long it will take the FCL owner to replace the expended parts of the affected FCL's.

Recommendations: All concerned parties must understand the exposure of the FCL to a range of faults on the utility system and to faults within the FCL owner's system which can result in operation of the FCL, and should formally agree that the loss of equipment resulting from the operation of the FCL for those faults is an acceptable consequence.

Proof of Design Adequacy

When a fault occurs on the utility system that, with the added contribution from the new equipment, exceeds the momentary or the interrupting rating of the utility breaker or other equipment, there is a concern that the FCL design and application may not operate sufficiently fast to protect the utility equipment.

Recommendations:

The FCL owner is expected to provide detailed calculations demonstrating that the fault current limiter will achieve its intended purpose of protecting the utility equipment from being subjected to current beyond its capability. The calculations must include the anticipated current-versus time waveforms of the total asymmetrical current flowing through the utility equipment for the maximum fault and minimum fault that will operate the FCL. The maximum current should be the maximum asymmetrical current available based on the calculated X/R ratio, and should include both the contributions from the system as well as the let-through contribution from the FCL. Detailed waveform analysis may become unnecessary if the calculation method used is sufficiently conservative (i.e. the arithmetic addition of the FCL peak let-through current and the system peak asymmetrical current). The calculations will require modeling of the utility system and the FCL owner's system, and should include the transient effects of induction and synchronous motors. Since the FCL will not operate for fault level values below its threshold, the RMS value of the threshold of the FCL should be added to the short circuit current of the breaker for determination of interrupting duty.

The utility should supply the FCL owner with sufficient modeling information of the utility system to allow the FCL owner to make the analysis described in the preceding paragraph.

The FCL owner should provide design information showing that the operation of the FCL will not be compromised under low AC voltage conditions at the FCL owner's facility resulting from any fault on the utility system requiring the FCL to operate.

Changes to the Electrical System

Changes to the FCL owner's electrical system may render the FCL application incapable of performing its originally-intended function.

Recommendations: If changes are made to the FCL owner's electrical system, the FCL owner should re-apply the analysis outlined in the section titled *Proof of Design Adequacy* and associated subsections and provide documentation of this analysis to the utility for review.

Redundancy

If the FCL, for some reason, fails to operate as intended, a fault on the utility may result in a catastrophic failure. It should be emphasized that this concern is not equivalent to concern for a stuck breaker or a failed relay. A failure of the FCL to operate when required is a substation safety hazard, especially in a situation where an operator may unknowingly be closing a breaker into a fault. Further, a catastrophic breaker failure may cause significant collateral damage to other equipment in the utility substation.

Recommendations: The FCL owner should provide design information showing that for the single-contingency failure of the FCL to perform its intended function, the overall intent of protecting the utility equipment from overduty conditions is still met.

FCL Bypass Arrangements

The FCL may undesirably be electrically bypassed by the owner.

Recommendations: The FCL owner should have a written procedure which prohibits bypassing the FCL unless it is demonstrated to the satisfaction of the utility that conditions do not require the potential operation of the FCL.

Maintenance and Testing

If the FCL is not tested and maintained properly, it may not be capable of operation when required.

Recommendations: Routine testing of FCL trigger levels, firing logic, and firing circuitry should be conducted at least every four years. Documentation of this testing should be available upon request by the utility. The utility should be granted physical access to inspect the FCL as deemed necessary by the utility.

Reference: "Limitations of Fault-Current Limiters for Expansion of Electrical Distribution Systems", J. C. Das, IEEE Transactions on Industry Applications, Vol. 33, No. 4, July/August 1997.

Designated Entity Design Standards Task Force

Minimum Required Standards

Developed by the DEDSTF

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Version 2

Table of Contents

1.0) Introduction

These requirements are intended to be the minimum standards to which any entity shall design and build to, when interconnecting to PJM facilities. Transmission Owners ("TO's") traditionally have additional technical interconnection requirements that may be greater than the requirements outlined in this document. This set of minimum design standards was developed by the Designated Entity Design Standards Task Force to assure a minimum level of robustness is provided such that the new competitively-solicited facilities would not introduce a weak point in the system in terms of performance. The task force consists of PJM Transmission Owners, PJM Transmission Developers and other PJM Stakeholders.

2.0) Applicability

The minimum design standards included in this document are required for all competitively solicited projects which are required to sign the Designated Entity Agreement. Adherence to these minimum design standards will be a consideration in the RTEP Proposal Window selection process.

In addition to the requirements included in this document, designated entities must act in accordance with all PJM and industry requirements as described in Section 4.0 of the Designated Entity Agreement. While this document describes details, criteria and philosophy, it is also understood that all other applicable requirements of other standards shall be followed at a minimum, including, but not limited to IEEE, FERC, NERC, NESC, NFPA, IBC, etc.

Transmission Lines Minimum Required Standards

3.0) Transmission Lines Minimum Required Standards - Overhead Lines

The design of all transmission lines shall meet or exceed the requirements of this document, the National Electrical Safety Code (ANSI/IEEE C-2) [NESC] in effect at the time of the project design, and all additional legislated requirements as adopted by the governmental authority having jurisdiction, including but not limited to environmental and FAA regulations. It shall be the responsibility of the Designated Entity to identify all additional legislated requirements. In the event of conflicts between documents, the most stringent requirement shall apply.

3.1 CONDUCTOR

The Designated Entity shall determine normal and emergency ratings for both summer and winter seasons using an appropriate facility rating methodology.

The loss of strength of the conductor shall be limited to 10% of its initial rated breaking strength for an assumed 40 year life. Conductor connectors and accessories shall have mechanical strength and thermal capabilities compatible with the conductor.

The damaging effects of Aeolian vibration shall be appropriately mitigated. Mitigation measures may include lower design tensions, mechanical vibration dampers, and spacer dampers for bundled conductor.

3.2 LOADING AND STRENGTH REQUIREMENTS

Transmission Line Facilities shall have sufficient strength to resist the individual and cumulative effects of all load cases defined in Section 3.2.1, including all subsections. The applied loads shall be adjusted by the Load Factors defined in the subsections of Section 3.2.1, and the material strengths shall be adjusted by the material strength reduction factors specified by the applicable governing industry publications referenced in Section 3.2.2.

Transmission Line Facilities include all supporting structures, conductors and other wires, insulators, hardware, and foundations.

3.2.1 Design Load Requirements

All Transmission Line Facilities shall be designed to withstand the independent load cases defined in Sections 3.2.1.1 through 3.2.1.7. The effects of gravity, wind, ice, wire tension, construction, and maintenance loads shall be included as applicable.

3.2.1.1 Legislated Loads

Transmission Line Facilities shall be designed to resist the loading conditions defined in Rules 250B, 250C, and 250D of the NESC. For Rule 250B, the provisions of Grade B construction and the Heavy loading district shall be applied. The load factors shall be in accordance with NESC Rule 253.

- The provision of Rules 250C and 250D permitting the exclusion of structures less than 60 feet in height shall not apply.
- The Designated Entity shall identify and design to all additional legislated requirements as adopted by the governmental authority having jurisdiction.

3.2.1.2 Extreme Wind

Transmission Line Facilities shall be designed to resist the wind loads corresponding to a 100 year return period (RP) as defined in the latest edition of ASCE Manual of Practice (MOP) 74.

Wind pressures shall be calculated in accordance with the procedures of the latest edition of ASCE MOP 74, properly adjusted for structure shape, gust, and height. The Load Factor applied shall be a minimum of 1.0.

Wind loads shall be applied in the direction producing the maximum loading effect.

All wires shall be assumed intact.

3.2.1.3 Ice with Concurrent Wind

Transmission Line Facilities shall be designed to resist the ice loads resulting from freezing rain corresponding to a 100 year return period and the associated concurrent wind loads as defined in the latest edition of ASCE MOP 74.

Wind pressures shall be calculated in accordance with the procedures of the latest edition of the ASCE MOP 74, properly adjusted for structure shape, gust, and height. The Load Factor shall be a minimum of 1.0.

Wind loads shall be applied in the direction producing the maximum loading effect.

The weight of ice shall be considered 57 pounds per cubic foot. The temperature used shall be either the values specified or 32°F. The Load Factor shall be a minimum of 1.0.

All wires shall be assumed intact.

3.2.1.4 Heavy Ice

Transmission Line Facilities shall be designed to resist ice loads resulting from freezing rain, snow, and in-cloud icing as defined in below.

In each case, the weight of ice shall be considered 57 pounds per cubic foot, the temperature 0°F, and the wind speed 0 mph. The Load Factor shall be a minimum of 1.0. All wires shall be assumed intact.

Transmission Line Facilities shall be designed to resist the effects of a minimum of 1.0 inch radial ice resulting from freezing rain applied to all wires. Transmission Line Facilities designed for voltages 230kV and greater shall also meet the requirements defined below.

Transmission Line Facilities designed for voltages 230kV and greater and constructed in the following states/districts or portions thereof shall be designed to resist the effects of a minimum of 1.5 inches radial ice resulting from freezing rain applied to all wires.

- District of Columbia
- New Jersey
- Pennsylvania, within 100 miles of the coast of the Atlantic Ocean
- Delaware, within 75 miles of the coast of the Atlantic Ocean
- Maryland, within 75 miles of the coast of the Atlantic Ocean

Transmission Line Facilities designed for voltages 230kV and greater and constructed in regions with a ground elevation greater than 1500 feet and less than 3000 feet above mean sea level shall be designed to resist the effects of a minimum of 1.25 inch radial ice resulting from freezing rain applied to all wires. Greater values shall be considered in areas known to accumulate larger amounts of ice resulting from freezing rain, or are prone to in-cloud icing or accumulation of snow, and when indicated by historical weather data or site-specific ice studies.

Transmission Line Facilities designed for voltages 230kV and greater and constructed in regions with a ground elevation greater than 3000 feet above mean sea level shall be designed to resist the effects of a minimum of 1.5 inch radial ice resulting from freezing rain applied to all wires. Greater values shall be considered in areas known to accumulate larger amounts of ice resulting from freezing rain, or are prone to in-cloud icing or accumulation of snow, and when indicated by historical weather data or site-specific ice studies.

3.2.1.5 Unbalanced Longitudinal Load Cases

Except as described below, in the Unbalanced Load Cases and Line Cascading Mitigation sections, Transmission Line Facilities designed for voltages 230kV and greater shall be designed to withstand longitudinal loads due to broken wire and differential ice conditions as described below in the Broken Wire Loading and Differential Ice Loading sections.

Except as described below, in the Unbalanced Load Cases and Line Cascading Mitigation sections, Transmission Line Facilities designed for voltages less than 230kV, may be designed to withstand longitudinal loads due to broken wire and differential ice conditions as described below in the Broken Wire Loading and Differential Ice Loading sections.

Unbalanced Load Cases

These unbalanced load cases do not apply to insulators; however, insulators must be designed such that they do not detach from the supporting structure.

Broken Wire Loading

For single conductor phase configurations of both single and multiple circuit structures, only one conductor or one shield wire shall be considered broken in each load case. Each wire shall be broken individually to ensure the maximum loading effect is determined for each component. For the design of suspension structures, the conductor tensions may be reduced by the effects of longitudinal insulator displacement.

For phase configurations with more than one sub-conductor of both single and multiple circuit structures, a minimum of one sub-conductor or one static wire shall be considered broken. Each phase shall be evaluated with one broken sub-conductor to ensure the maximum loading effect is determined for each component. For the design of suspension structures, the conductor tensions may be reduced by the effects of longitudinal insulator displacement.

The minimum environmental load condition shall be 0.5 inch of ice, 40 mph wind, and 32°F. The Load Factor shall be a minimum of 1.0.

Differential Ice Loading

With all wires assumed intact, each conductor and shield wire on one side of the structure shall be loaded with 0.5 inch of radial ice and 40 mph wind at a temperature of 32°F. All conductors and shield wires on the other side of the structure shall be loaded with the specified wind only. The weight of ice shall be considered 57 pounds per cubic foot. The Load Factor shall be a minimum of 1.0.

For the design of suspension structures, the conductor tensions may be reduced by the effects of longitudinal insulator displacement.

3.2.1.6 Construction and Maintenance Loads

Transmission Line Facilities shall be designed to facilitate construction and maintenance activities as defined below.

Bound Stringing Block

Transmission Line Facilities designed for voltages 230kV and greater shall be designed to resist longitudinal loads simulating a bound stringing block.

Transmission Line Facilities designed for voltages less than 230kV may be designed to resist longitudinal loads simulating a bound stringing block.

Climbing and Working Loads

In areas where climbing or work activities are reasonably anticipated, members of structures shall be designed to support a point load of 250 pounds. The Load Factor shall be a minimum of 1.5.

Fall Protection

Transmission Line Facilities shall be designed to facilitate compliance with OSHA requirements related to fall protection.

3.2.1.7. Foundation Loading

Foundation reactions shall be determined from the load cases presented in Section 3.2.1.

3.2.2 Strength Requirements

Transmission Line facilities shall meet the strength requirements specified in Sections 3.2.2.1 through 3.2.2.4.

3.2.2.1 Strength Design Standards & Guides

Structures and foundations shall be designed to the requirements of the applicable industry accepted specifications and guidelines including, but limited to:

- ASCE Standard No. 10, *Design of Latticed Steel Transmission Structures*
- ASCE Standard No. 48, *Design of Steel Transmission Pole Structures*
- ASCE Manual No. 91, Design of Guyed Electrical Transmission Structures
- ASCE Manual No. 74, Guidelines for Electric Transmission Structural Loading
- ASCE Manual No. 104, Recommended Practice for Fiber-Reinforced Polymer Products for Overhead Utility Line Structures
- ASCE Manual No. 123, Prestressed Concrete Transmission Pole Structures
- ANSI 05-1, Specifications and Dimensions for Wood Poles
- IEEE Std. 691, Guide for Transmission Structure Foundation Design and Testing
- National Electric Safety Code C2
- ACI 318 Building Code Requirements for Structural Concrete and Commentary
- Exception: The ultimate compressive concrete strength shall not be less than 3500 pounds/square inch.

3.2.2.2 Line Cascading Mitigation

To avoid cascading failures, structures shall be designed to withstand the unbalanced longitudinal load cases of Section 3.2.1.5, or an anti-cascading structure with full dead end load capability shall be placed every 5 miles.

3.2.2.3 Substation Structure Strength

Where Transmission Line Facilities terminate in substations owned by others, the Designated Entity shall coordinate with these owners to ensure adequate strength is provided for each station line terminal structure.

3.2.2.4 Geotechnical Requirements

A geotechnical investigation shall be the basis of the final foundation design parameters.

3.3 ELECTRICAL DESIGN PARAMETERS

Conductor selection and configuration, including conductor size and the number of sub-conductors, shall consider electrical system performance parameters such as voltage, stability, losses, impedance, corona, electric and magnetic fields, audible noise, and television and radio interference. To correct for voltage imbalance, the phases may be transposed.

The estimated levels of audible noise and EMF values shall not exceed those required by the governmental authority having jurisdiction. These estimated values shall be determined by calculations specific to the proposed transmission facility.

3.4 RIGHT-OF-WAY

Rights of way shall be proportioned so that NESC horizontal clearances to buildings are maintained at the edges. Widths shall be calculated with the wires displaced from rest by a 6 psf wind at 60°F with no ice and at final sag. Deflection of flexible structures and insulator swing shall be considered where appropriate.

Consideration shall be given to acquiring uniform right of way widths.

3.5 INSULATION, LIGHTNING PERFORMANCE, & GROUNDING

Insulation, grounding, and shielding of the transmission system (line and station) shall be coordinated between the Designated Entity and the Transmission Owner(s) to which the project interconnects to promote acceptable facility performance. The resulting design shall approach the targeted lightning performance defined below.

- Voltages 345kV and greater – 1 Outage/100 circuit miles/Year
- 230kV – 2 Outage/100 circuit miles/Year
- 138/115kV – 3 Outage/100 circuit miles/Year
- 69kV – 4 Outage/100 circuit miles/Year

Surge arresters, if installed, shall be applied in a manner that reduces the likelihood that the arrester or any of its associated hardware will interfere with reliable normal operation of the line in the event of surge arrester electrical or mechanical failure.

3.6 CLEARANCES

3.6.1 General

Unless otherwise stated, all clearances shall meet or exceed those defined in the NESC.

Clearances shall be maintained applying the maximum operating voltages defined in PJM Manual 3, “Baseline Voltage Limits”, Exhibit 3, Section 3.3.1. The circuit transient overvoltage (TOV) shall be used when considering the alternate clearances permitted by NESC Rules 232D, 233C3, 234H, 235B3.

When a proposed transmission line crosses over an existing supply or communication line, the position of the lower wire shall be determined by a straight line between attachment points, unless specific sag/tension information for the lower wires are known. When the sag/tension characteristics of the lower wires are known, the requirements of the NESC rules may be applied.

3.6.2 Live Line Maintenance Requirements

Adequate clearances shall be provided when live-line maintenance requirements are proposed by the Designated Entity for a line design for any of the following maintenance activities:

- Climbing inspection
- Hot stick maintenance for the specified line components
- Live line maintenance for the specified line components using specified lift equipment
- Helicopter live line maintenance for the specified line components using the specified helicopter

All live line maintenance clearances shall be determined using the OSHA calculation methods for the specified circuit TOV, breaker design, and maintenance program.

3.6.3 Vertical Clearances

The vertical conductor clearances of Section 23 of the NESC shall be maintained at the NESC stated conditions. All terrain points under the conductors shall be considered to be traversable by vehicles. The buffers defined in Section 3.6.5 shall be applied.

3.6.4 Horizontal Clearances

The horizontal conductor clearances of Section 23 of the NESC shall be maintained at the NESC stated conditions. The buffers defined in Section 3.6.5 shall be applied.

3.6.5 Clearance Buffers

Due to uncertainties and inaccuracies in surveying and installation of foundations, structures and conductors, the calculated position of the conductors shall be increased as specified in Sections 3.6.5.1 and 3.6.5.2 to ensure that NESC requirements are met.

3.6.5.1 Vertical Clearance Buffer

The vertical clearance buffer shall be 3'-0".

3.6.5.2 Horizontal Clearance Buffers

The horizontal clearance buffer shall be 2'-0" to other obstructions. This buffer does not apply to clearances to the supporting structure.

3.6.6 Electrostatic Clearance

The short circuit current discharge requirements of NESC Rule 232D3(c) shall be met.

3.6.7 Clearances over Waters of the United States

Clearances over the waters of the United States shall be the larger of the NESC requirements in Rule 232, or the clearance determined by the Army Corps of Engineers, plus the buffer defined in Section 3.6.5.

3.6.8 Galloping

3.6.8.1 General

Lines shall be designed to limit the likelihood that conductor/shield wire galloping will result in a circuit momentary operation. Galloping shall be addressed by one or a combination of the following methods:

- Providing conductor clearances at the structure which produce the in-span conductor clearances defined in Section 3.6.8.3.
- Install in-span interphase insulators or anti-galloping devices designed to reduce the possibility and/or severity of conductor galloping.
- Install twisted pair conductor.

3.6.8.2 Galloping Ellipse Calculations

Conductor galloping ellipses shall be developed using the A.E. Davison method for single loop galloping and the L.W. Toye method for double loop galloping, or the CIGRE method as described in Bulletin 322.

3.6.8.3 Galloping Clearances

Clearances of the calculated galloping ellipses shall meet the following requirements:

Single Loop Galloping

The position of the calculated galloping ellipses shall overlap no more than 10%.

Double Loop Galloping

The calculated positions of the galloping ellipses shall not overlap.

3.6.9 Avian Considerations

The Designated Entity shall comply with all project-specified requirements established by the governmental authority having jurisdiction. The guidelines of the Avian Power Line Interaction Committee shall be considered in the design of Transmission Line Facilities.

3.7 Underground Lines

3.7.0 GENERAL REQUIREMENTS

3.7.0.1 Underground transmission lines 69 kV and above shall be solid dielectric, self-contained fluid filled, or pipe type cables. Definitions for underground design terminology can be found in the “PJM Underground & Submarine Transmission Cable Rating Methodology Guidelines.

3.7.0.2 The best practices and guidelines, along with applicable latest industry standards and procedures outlined in the EPRI Underground Transmission Systems Reference Book, shall be followed.

3.7.0.3 Shunt reactive compensation shall be considered and provided when system conditions dictate. The need for shunt reactive compensation will depend on the overall cable capacitance and the system source impedance under all cable system operating conditions.

3.7.0.4 Surge arresters shall be considered at all termination locations to protect the underground cable system from transients caused by lightning or switching. However, a switching surge analysis should be performed for cable insulation coordination and protection.

3.7.0.5 Parallel spare conduits and/or spare pipes shall be considered for installations at major crossings including water crossings and for long length inaccessible locations.

3.7.0.6 The cable system shall be designed in accordance with, but not be limited to, the latest edition of the following industry standards, as applicable.

<u>Pipe-Type Cable Systems</u>

- Association of Edison Illuminating Companies AEIC CS2, “Specifications for Impregnated Paper and Laminated Paper Polypropylene Insulated High Pressure Pipe Type Cable” when specifying pipe type cable (includes HPFF and HPGF cable types).

- Association of Edison Illuminating Companies AEIC CS4, “Specifications for Impregnated Paper Insulated Low and Medium Pressure Self Contained Liquid Filled Cable” when specifying SCFF cable. Note that although paper-polypropylene-paper (PPP) insulation can be used on SCFF cables, the AEIC Specification does not include PPP insulation in this specification. This is because pipe type systems make up the majority of transmission applications in the US and SCFF designs using PPP have not been installed to date.

- ASTM A523, “Standard for Plain End Seamless and Electric-Resistance-Welded Steel Pipe for High Pressure Pipe Type Cable Circuits.”

- ASTM A312/A312M, “Standard Specification for Seamless, Welded and Heavily Cold Worked Austenitic Stainless Steel Pipes.”

- AEIC CS31, “Specification for Electrically Insulating Pipe Filling Liquids for High-Pressure Pipe-Type Cable.”

- NACE Standard SP0169, “Control of External Corrosion on Underground or Submerged Metallic Piping Systems.”

<u>Solid Dielectric Cable Systems</u>

- Association of Edison Illuminating Companies AEIC CS9, “Specification for Extruded Insulation Power Cables and their Accessories Rated above 46 kV through 345 kV AC” when specifying solid dielectric cable.

- IEEE 575, “Guide for the Application of Sheath-Bonding Methods for Single-Conductor Cables and the Calculation of Induced Voltages and Currents in the Cable Sheaths.”

- IEC 62067, “Power Cable with Extruded Insulation and Their Accessories for Rated Voltages Above 150 kV up to 500 kV – Test methods and Requirements”

- ANSI/ICEA S-108-720, “Standard for Extruded Insulation Power Cables Rated Above 46 through 345 kV.”

- IEC 60840, “Power Cables with extruded insulation and their accessories for rated voltages above 30 kV (Um = 36 kV) up to 150 kV (Um = 170 kV) –Test methods and requirements.”

- AEIC CG13-11, "Guide for Testing Moisture Impervious Barriers Made of Laminated Foil Bonded to the Jacket of XLPE Transmission Cables."

All Cable Systems

- IEEE Std. 404, "Standard for Extruded & Laminated Dielectric Shielded Cable Joints Rated 2.5 kV – 500 kV when specifying cable systems.

- IEEE Std. 48, "Standard Test Procedures and Requirements for Alternating-Current Cable Terminations 2.5 kV – 765 kV when specifying cable systems.

- IEEE Standard 442, "IEEE Guide for Soil Thermal Resistivity Measurements."

DESIGN PARAMETERS

3.7.1 ROUTING

3.7.1.1 The following shall be considered when determining the optimal line route:

A. Length of route
B. Environmentally sensitive areas
C. Archeological or historical areas
D. Type of existing land use (easements, urban, suburban, rural)
E. Ability to obtain ownership or easement rights
F. Maintenance access
G. Proximity to obstacles (rivers, major highways, railroads)
H. Traffic control
I. Adjacent existing underground utilities
J. Existing above and below ground facilities and their required horizontal and vertical separations
K. Jack & bore or Horizontal Directional Drilling (HDD) options and potential frac-out releases
L. Changes in elevation
M. Sources of thermal energy such as other circuits, steam mains
N. Permitting timelines
O. Soil types
P. Soil thermal resistivity
Q. Pulling calculations and maximum reel lengths
R. Manhole and splice locations
S. Feasibility of construction

3.7.2 Ampacity Overview

3.7.2.1 The Designated Entity shall determine normal and emergency ratings for both summer and winter seasons using an appropriate facility rating methodology.

3.7.2.2 Cable ampacity calculations shall be performed for two conditions, normal (steady-state) and emergency, and shall consider the following factors:

A. Cable Insulation
B. Load factor
C. Conductor size, materials, and construction
D. Dielectric losses
E. Mutual heating effect of other heat sources like existing and future cables, ducts, steam mains, or other underground facilities that have an effect on the rating of the cable
F. Ambient earth temperature
G. Depth of burial
H. Type of surrounding environment (soil, duct bank, concrete, grout) and their thermal characteristics
I. Pipe size or conduit size and spacing

3.7.2.3 A route thermal survey and laboratory testing shall be performed to obtain the native soil thermal resistivity and ambient soil temperatures at expected cable installation depths along the route for use in the rating calculations to select the conductor size.

3.7.2.4. Corrective thermal backfill materials shall be considered for transmission cable systems not placed in a duct bank, or when needed to meet or increase ampacity. These can be compacted engineered graded sand, compacted granular backfill, or a fluidized thermal backfill.

3.7.2.5. A comprehensive review of the cable's installation data must be performed in order to determine its final design rating. Installation factors that affect cable ratings include ambient earth temperature, thermal resistivity of existing and placed backfill, spacing between other sources of heat, burial depth, etc.

Final ampacity calculations shall be performed based on the installed line conditions. The original design parameters used for the cable ampacity calculations shall be validated by field testing and using as-builts of the installation. In-situ soils, placed concrete and engineered backfill shall be tested to determine the as-built thermal resistivities for use in performing the final ampacity calculations.

3.7.2.6 For more information concerning how cable rating calculations are implemented in the operation of transmission lines, see PJM Manual 3: Transmission Operations (Section 2 Thermal Operating Guidelines).

3.7.3 Pipe Type Cable Considerations

3.7.3.1 Pipe Type Cables Systems shall be either High Pressure Fluid Filled (HPFF) or High Pressure Gas Filled (HPGF) systems. Pipe Type Cables Systems shall have all three insulated cable phases installed in a common steel pipe. The cables shall transition to three smaller individual stainless steel pipes to permit termination of the cable. Only one insulated cable is installed in the smaller, stainless steel pipe.

3.7.3.2 Coating systems shall be applied to both the inside and outside of the steel pipes to provide primary protection against corrosion prior to and after installation. Coatings shall be mastic, polyethylene, or fusion bonded epoxy with an epoxy-concrete.

3.7.3.3 The design shall include a cathodic protection system, that when installed with the coating system will protect the integrity of the steel pipes and minimize leaks. The system shall be either 1) a passive system where galvanic anodes are installed along the pipe route (if a holiday occurs in the pipe coating, the anode bags provide the sacrificial ions instead of the pipe), or 2) an impressed current system where an alternating current source powers a rectifier supplying the ions from an array of anode bags usually located at one end of the pipe(s).

3.7.3.4 Pipe type cables shall be insulated with kraft paper or laminated paper polypropylene (LPP) tape. Other tapes shall be used for shielding, segmental insulation, moisture barriers, binder tapes and outer shielding tapes. Two “D” shaped skid wires shall be spiral wrapped around the final insulated cable to reducing pulling friction while protecting the cable insulation during installation. Skid wire material shall be specified due to the different coefficient of friction (COF) value of the material.

3.7.3.5 Insulating fluids shall be added to the pipe after cable installation for HPFF cable systems. Insulation fluids shall meet the requirements of the HPFF circuit, such as fluid circulation and/or forced cooling if additional power transfer is required of the HPFF cable system.
Route elevation, pipe size, cable size, and circuit length shall be taken into consideration for hydraulic calculations in determining the rated fluid pressure on the cable system and pressure settings for the relief valves in the pressurization plant.
The fluid in the HPFF system shall be at rated pressure prior to energizing the cables. A hydraulic soak period shall be implemented to bring or return the HPFF system to rated pressure. The fluid shall be at rated pressure for 24 hours before testing or energizing the cable.

3.7.3.6 Straight, anchor, stop, semi-stop, and trifurcating joints shall be designed to connect the cable sections and provide other features for the cable system as needed. Insulation over the splices must meet the same performance standard as the cable insulation and control the electrical stress of the splice. All three cable phases shall be spliced at the same location. The design shall take into account that the splices are encased in a carbon steel telescoping pipe of multiple sections. Design shall consider that splices be installed in manholes for future access.
All phase cables shall be supported to prevent thermal mechanical bending (TMB.) Specialized anchor and skid joints shall be used for steep inclines and drastic changes in elevation to minimize thermal mechanical movement. Restraint locations and design and placement methodology shall follow good engineering practices.

3.7.3.7 For HPFF and HPGF pipe systems, terminations shall be designed and installed to seal the insulating fluid or insulating gas from the environment.
The design shall ensure that the termination is sized to the cable and meets the operating pressures and rating requirements of the cable system for anticipated conditions. The termination’s insulation creepage distance shall be selected based upon the operating environment. Cable terminations shall be selected based on hydraulic calculations for the operating pressure per IEEE Std. 48 for class 1C terminations.
The termination mounting plate and riser pipes shall be test fit prior to welding. Proper fit is required for final weld of the mounting plate’s tail piece pipe to the riser pipe and ensures the termination will be plumb.

The Designated Entity shall ensure coordination between GIS manufacturer, termination manufacturer, cable installation contractor, and GIS contractor for a successful GIS termination installation.

3.7.3.8 A Pressurization/pumping plant shall be designed to pressurize the dielectric fluid in HPFF cable systems for all loading conditions. The nominal operating pressure shall be 200 PSI. The plant shall be designed and built for the specific circuit parameters such as pipe size, cable size, length of the cable circuits and any circulation requirements. Additional pressurization/pumping plants may be required for long underground cables to meet the reliability requirements of the owner, and if there are multiple hydraulic sections in the cable circuit. Environmental concerns shall be considered in the siting and foundation design for dielectric fluid containment.

Pressurization/pumping plants shall have plant alarms and control systems to ensure pressurization of the cable system. Alarm settings shall be based upon criticality and the response time to the alarm. These alarms shall be designed and utilized to minimize the loss of dielectric fluids. Improper operation and abnormal conditions shall be reported to the system or local control center for immediate corrective action. Leak detection systems may be installed in the pressurization plant for HPFF cable systems if the Designated Entity requires it for environmentally sensitive areas. Leak detection compares the predicted fluid entering a cable system versus actual fluid entering the cable system. This can be alarmed before the leak grows larger.

Pressurization/pumping plants shall operate by a programmable logic controller (PLC) that offer information on the circuit(s) and the various systems inside the pressurization plant. These various systems shall be alarmed. A PLC shall provide remote access to the controls in the pressurization plant for a faster response time to an alarm.

Two independent sources of power to the pressurization are required with an automatic transfer of power to ensure continuous AC feed to the pressurization plant. The second power source can be a backup generator, dedicated off site power line, or an alternate bus source or nitrogen driven pumps.

3.7.3.9 A crossover cabinet shall be installed on the opposite end of the pipe type cable system from the pressurization plant. This cabinet shall house an electric valve that will tie the cable pipes together and open when necessary (usually when low pressure develops on one pipe) to hydraulically normalize the pressure on the pipe experiencing low pressure. This valve should be alarmed notifying the control center it has opened for an abnormal reason.

3.7.3.10 Testing

Testing pipe type transmission cables and accessories is required to qualifying cable and cable components for design, installation verification, qualification/acceptance and operations and maintenance purposes.

Test standards and procedures developed for pipe-type cable by organizations such as the Association of Edison Illuminating Companies (AEIC), the Insulated Conductors Committee (ICC) of the IEEE, the International Electrotechnical Commission (IEC), and the Insulated Cable Engineers Association (ICEA) shall be applied to the pipe cable system.

Note: The EPRI Green Book dedicates an entire chapter to cable testing which describes the principles of cable and accessory testing, summarizes the applicable standards, guides, and procedures that are commonly accepted by the cable industry. It addresses specific test procedures, laboratories, equipment for ac, impulse, dc, thermomechanical tests, and describes diagnostic procedures employed in the laboratory and in the field.

3.7.4 Solid Dielectric Cable Considerations

3.7.4.1 Extruded dielectric cable systems shall be insulated with ethylene-propylene rubber (EPR) for installations with voltages up to and including 138 kV, or with cross-linked polyethylene (XLPE) insulation for installations 69 kV and above.

3.7.4.2 A metallic moisture barrier or sheath, such as a lead sheath, corrugated copper or aluminum sheath, or copper or aluminum foil laminate, is required to prevent moisture from entering the cable.

3.7.4.3 The cable shall have a durable, moisture-resistant thermoplastic compound for use as the jacket to provide mechanical and corrosion protection. The cable shall be designed with an electrically conducting coating on the outside of the jacket that is suitable for jacket integrity tests, and that will be electrically continuous after the cable is installed. This coating shall be a graphite varnish coating or a semi-conducting extruded layer.

3.7.4.4 The metallic shield and sheath shall be bonded to the local ground, using either multipoint bonding, single point bonding or cross bonding.

3.7.4.5 The cable sheath, bonding cables, and ground continuity conductors shall be designed for the expected fault current and clearing time. The cable system shall have grounding link boxes and sheath overvoltage protector link boxes for connecting the cable sheath to the substation ground grid and to facilitate performing jacket integrity tests.

3.7.4.6 The design shall consider the time to repair and return to service for direct burial vs. a conduit system.

3.7.4.7 Link boxes shall be constructed of type 316 stainless steel or other non-corroding metal. Link boxes shall have bolted, removable copper or brass links capable to carry the fault current. The link boxes shall be weather-tight. For manhole installations, the link box shall withstand submerged water depths and harsh manhole enviorments. An IP 68 rating is required.

3.7.4.8 For single point grounded cable systems, a ground continuity conductor shall be provided for the line for proper fault current to flow. The quantity and size of the ground continuity conductors shall be calculated per IEEE 575. For single point grounded cable systems, a link box with a sheath voltage limiter is required to protect the cable jacket from damage during a fault. For single point grounding, the voltage rise at the open end of the shield shall be limited to 150V under normal conditions (both normal and emergency ratings) and not under faulted conditions due to lightning or switching situations.

3.7.4.9 For cross bonded grounding, link boxes shall be installed at the transposition points with sheath voltage limiters to protect the cable jacket from damage during a fault.

3.7.4.10 Sheath voltage limiters shall be adequately sized for nominal and transient voltages that occur during fault conditions.

3.7.4.11 Splices shall be of the same insulation class as specified for the cable. The current ratings of the splices shall be as a minimum the current rating of the cable for which the cable splice is designed. The splice construction shall be water tight

3.7.4.12 Terminations shall be sized and rated for the cable system. The terminations and component parts shall be Class 1 terminations as defined in IEEE Standard 48. The proposed terminations shall be supplied with means to maintain the hermetic sealing of the cable system where the metallic cable sheath is connected to the termination. Standoff insulators capable of withstanding 20 kV dc for one minute shall be supplied with each cable termination.

3.7.4.13 The cable system shall be designed to prevent damage to the cable during installation based on the manufacturer specified sidewall pressure and cable bending radius limits.

3.7.4.14 A manhole racking and clamping system shall be designed to withstand cable forces during normal operations and fault conditions. All racking hardware shall be made with corrosion resistant material to withstand the harsh manhole environment.

3.7.4.15 The cable shall be supported at the termination support structures by clamps and other accessories specifically designed for the cable and its diameter. The cable clamps and bolts shall be designed to not corrode in the specified project environment. For long unsupported vertical inclines, the design shall include a cable support system.

3.7.4.16 A jacket integrity test shall be performed on each section of cable prior to and after installation to ensure that the cable jacket has not been damaged during shipping or after cable pulling. The cable jacket shall withstand a dc voltage of 10 kV for 1 minute.

3.7.4.17 Cable voltage tests shall be performed on the terminated cables after installation. The cables shall pass these tests when conducted in accordance with the latest applicable IEEE, AEIC, IEC and CIGRE specifications and guidelines.

3.7.4.18 An AC soak test at no load and full voltage for a period of 24 hours shall be performed on the installed cable system.

3.7.4.19 A one hour AC voltage withstand test at 1.7 x rated line-to-ground voltage shall be performed per IEC 62067 and IEC 60840 for all cable systems 69 kV and above. Partial discharge detection measurements shall be performed on all accessories continuously during the voltage test.

Substations Minimum Required Standards

4.0) Substations Minimum Required Standards

4.1 GENERAL DESIGN CRITERIA:

These design criteria have been established to assure acceptable reliability of the Bulk transmission system facilities. These set forth the service conditions, and establish insulation levels for lines and substations, and short circuit levels for substation equipment. Specific component requirements are listed in their own sections (in addition to NESC the IEC 61936 provides a solid reference).

Environmental Conditions:

Ambient Temperature	-30(-40)°C to +40°C (-40°C may be required for areas of low temperature weather)
Wind	- ASCE MOP 113 - NESC - ASCE 7
Ice	- ASCE MOP 113 - NESC - ASCE 7
Seismic Load	- ASCE MOP 113 seismic map for site specific requirements, Site Specific Soil Class. - Equipment qualification per IEEE 693
Line Load	- NESC - ASCE MOP 113
Flood Plain	Structure ground line above 100yr flood where possible

765 kV Substations Electrical

Line Terminal and Equipment Continuous Current	3,000A minimum, but designed to application
3 second current (short circuit)	50kA minimum, but designed to application
Nominal/ Max Operating Voltage	765kV / 800kV
Lightning Impulse Withstand Voltage w/o line entrance arresters	Dependent on outcome of insulation coordination study

Lightning Impulse Withstand Voltage with line entrance arresters	2050kV
Switching Impulse withstand level (3σ)	1700kV
Typical Surge Arrester	Size based upon Insulation Coordination
Circuit Breaker line closing switching surge factor	2.2 depending on Switching Surge Studies
System Grounding	Effectively Grounded Neutral (always)

500kV Substations Electrical

Line Terminal and Equipment Continuous Current	3,000A minimum, but designed to application
3 second current (short circuit)	40kA minimum, but designed to application
Nominal/ Max Operating Voltage	500kV / 550kV
Lightning Impulse Withstand Voltage w/o line entrance arresters	1,800 kV 1705 (Chopped Wave)
Lightning Impulse Withstand Voltage with line entrance arresters	1550 kV
Switching Impulse withstand level (2σ)	1050 kV
Typical Surge Arrester	Size based upon Insulation Coordination
Circuit Breaker line closing switching surge factor	2.2 depending on Switching Surge Studies
System Grounding	Effectively Grounded Neutral (always)

345kV Substations Electrical

Line Terminal and Equipment Continuous Current	2,000A minimum, but designed to application
3 second current (short circuit)	40kA minimum, but designed to application
Nominal/ Max Operating Voltage	345kV / 362kV

Lightning Impulse Withstand Voltage w/o line entrance arresters	1300 kV
Lightning Impulse Withstand Voltage With line entrance arresters	1050 kV
Switching Impulse withstand level (2σ)	750kV
Typical Surge Arrester	Size based upon Insulation Coordination
Circuit Breaker line closing switching surge factor	2.2 depending on Switching Surge Studies
System Grounding	Effectively Grounded Neutral (always)

230kV Substation Electrical

Line Terminal & Equipment Continuous Current	2,000A minimum, but designed to application
3 second short circuit current	40kA minimum, but designed to application
Nominal/ Max Operating Voltage	230kV / 242kV
Lightning Impulse Withstand Voltage	900kV BIL
Typical Surge Arrester	Size based upon Insulation Coordination
System Grounding	Effectively Grounded Neutral (always)

138kV Substation Electrical

Line Terminal & Equipment Continuous Current	2,000A minimum, but designed to application
3 second short circuit current	40kA minimum, but designed to application
Nominal/ Max Operating Voltage	138kV / 145kV
Lightning Impulse Withstand Voltage	650 kV BIL
Typical Surge Arrester	Size based upon Insulation Coordination
System Grounding	Effectively Grounded Neutral (always)

115kV Substation Electrical

Line Terminal & Equipment Continuous Current	2,000A minimum, but designed to application
3 second short circuit current	40kA minimum, but designed to application
Operating Voltage (Transformer must accommodate this	115kV / 121kV
Lightning Impulse Withstand Voltage	550 kV BIL
Typical Surge Arrester	Size based upon Insulation Coordination
System Grounding	Effectively Grounded Neutral (always)

69kV Substation Electrical

Line Terminal & Equipment Continuous Current	2,000A minimum, but designed to application
3 second short circuit current	40kA minimum, but designed to application
Operating Voltage (Transformer must accommodate this	69kV / 72.5kV
Lightning Impulse Withstand Voltage	350 kV BIL
Typical Surge Arrester	Size based upon Insulation Coordination
System Grounding	Effectively Grounded Neutral (always)

4.2 FUNCTIONAL CRITERIA:

When evaluating a proposed electrical interconnection the designated entity shall consider physical as well as electrical characteristics. This can be done to a certain degree by evaluating the arrangement using the following criteria:

1. The clearing of failed Transmission Owner facility equipment, shall not adversely affect any other TO’s facilities. This generally means that there could be one or more intertie breakers. While this breaker need not be located at the POI, it should be the first element in the adjacent stations. No load, circuits, transformers, or other elements shall be tapped off the interconnection facility prior to its isolation.

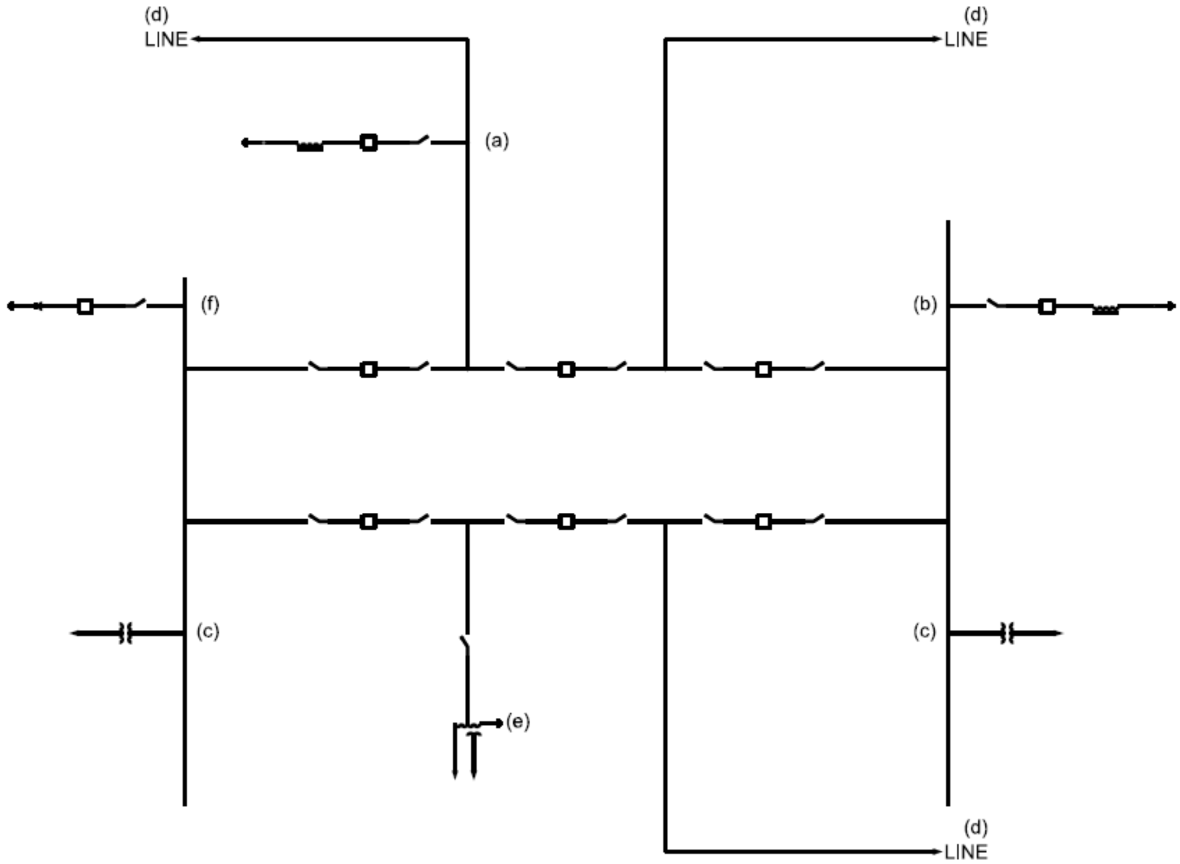
2. The arrangement of circuits and breaker bays shall be considered such that a stuck breaker operation will not trip two circuits on the same double circuit tower line.
3. Multiple ties should be provided between buses for all conditions, including situations where at least one transmission line or station breaker is out of service for maintenance.
4. Every attempt should be made to lay out stations such that a transmission conductor, towers/ poles, or a static wire that drops within the switchyard area should not cause another transmission circuit to trip. This means that line crossings within the switchyard fence should be avoided and there should be adequate spacing between bays to minimize the possibility of a falling wire contacting another line's phase conductor. If this cannot be accomplished the configuration should be evaluated to assure no unacceptable conditions could result from the postulated failure.
5. Electrical equipment within the station must be adequately spaced to:
    - Facilitate equipment replacement
    - Facilitate maintenance activities and associated maintenance equipment
    - Minimize the likelihood that catastrophic failure of a single piece of equipment will adversely impact adjacent equipment.
    - Minimize possibility of total station outage
6. Consideration shall be considered to be given to the distribution of supply and load connection within the station. The connection of circuits and transformers into the station should be arranged to balance flows throughout the station bus. This can be accomplished by alternating the connection of elements anticipated to inject flow with those anticipated to supply load from the station. The objective is to balance flows in the station to reduce bus loading.
7. There will be no customer load served, except for station service, from the transformer's tertiary.
8. In addition to these criteria the following factors must be reviewed and weighed appropriately in performing the assessment of a substation configuration:
    - Operational complexity and flexibility
    - Reliability for the load
    - Reliability for transmission lines and substation equipment
    - Generator interface
    - Line Maintenance
    - NERC, MAAC requirements/criteria
    - Expandability/Adaptability
    - Safety
    - Changes in technology
    - Cost (capital and O&M)
    - Availability of spare equipment
    - CIP / Security

4.3 Bus Configuration

For the bus configuration, an element is classified as a line, or an equipment connection including transformers and devices providing reactive support (capacitor, shunt reactor, SVC, or other FACTS devices), which have a direct connection to the bus. The following equipment are not considered elements:

- Shunt reactor connected to line
- Series reactor
- Series capacitor
- Station service voltage transformer (SSVT)
- Instrument transformer

Every element shall have a form of high side protection device with fault clearing capabilities. The failure or maintenance outage of an element cannot remove another transmission line from service for any time increment. Refer to Figure 1 for a depiction of elements and non-elements on a One-Line diagram.



- *Shunt reactor connected to line (Not an Element)*
- *Note: Required only for particular applications with open end line*
- *Voltage or to control high voltage due to light load conditions.*
- *Shunt reactor connected to bus (Element)*
- *Station service voltage transformer (Not an Element)*
- *Line (Element)*
- *Power Transformer (Element)*
- *Shunt capacitor connected to bus (Element)*

Figure 1 – One-Line diagram showing elements and non-elements

All elements inside the substation must include a fault clearing device to limit the exposure of failures of one element to only the affected element. Isolation or maintenance of an element should not affect the operation of another element. If a capacitor or shunt reactor is to be regularly switched due to system conditions, a switching device is required specific for that element so the ring or breaker-and-a-half configuration is not opened for each switching operation.

Substation busses with voltages less than 200kV must at a minimum meet the criteria outlined above and following the criteria for substations greater than 200kV is recommended, but not required.

Substation busses with voltages greater than 200kV must be designed at a minimum based on the following parameters:

- 3 to 6 elements connected in a normally closed configuration – requires a ring bus connection at a minimum
- 7 or more elements connected in a normally closed configuration – requires a breaker-and-a-half design at a minimum

Stations may have the options for future expansion capabilities for future growth and expansion (e.g., converting ring bus to a breaker-and-a-half as terminals are added). If the solution/design includes future expansion capabilities, the expansion should be outlined for potential evaluation.

Deviations from the above minimum design criteria are acceptable if required to meet all NERC PJM, and Transmission Owner criteria without jeopardizing operating standards and reliability. As all of the above are minimums, each project design can be designed to higher reliability and operating standards based upon the specific project needs.

NOTE: Three terminal lines are not permitted in the PJM footprint at 200kV and above.

4.4 ACCESSABILITY AND LAYOUT:

Adequate space and firm vehicular surface shall be provided on at least one side of each major piece of electrical equipment. Access is required to permit O&M vehicles, including bucket trucks and cranes, to access electrical equipment for any reason without requiring the de-energization of adjacent electrical equipment. The design must also accommodate minimum approach distances (MAD) as part of the layout and arrangement. In a breaker bay this access must be provided the full length of the bay and must not be encumbered by overhead electrical equipment or conductors. Appropriate stone or asphalt roadway shall be provided. For indoor GIS equipment a bridge crane may be used in lieu of roadways as long as this approach provides a feasible means to conduct maintenance including the removal and replacement of all major equipment.

Electrical equipment shall be arranged with adequate clearance for maintenance activities and for associated maintenance equipment, such that only the equipment to be maintained, including its isolating devices, needs to be operated and/or de-energized for the maintenance work to be performed. Depending on the criticality of the facility, each transmission lines and transformer may need to be equipped with a switch to isolate it from the substation such that the station bay or ring bus can be re-energized during maintenance of that transmission lines or transformer.

Electrical equipment shall be arranged with adequate clearances such that a catastrophic failure of equipment associated with one circuit is unlikely to adversely affect equipment associated with another circuit. The layout must accommodate considerations and requirements for fire protection separation distances and fire ratings must be suitable per IEEE 979 at a minimum for fire protection guidance.

A driveway must be provided around the perimeter of the station for vehicle movement. In addition, permanent driveways must be provided to transport all equipment in and out of the station. Each of these driveways must be adequate for the combined weight of the heaviest vehicles/equipment to be accessed. The station must be laid out such that the accessibility of all equipment is maintained in a manner that allows removal and replacement of all equipment throughout the life of the station.

Twenty-four hours, unobstructed access must be provided for the substation. Parking allowance for several vehicles must be provided adjacent to the relay/control house. The entrance gate must be double driveway width with the yard’s safety grounding covering the open gate area.

The station should be suitably graded to facilitate water runoff and to direct spilled dielectric fluid away from other major electrical equipment and toward planned containment.

4.5 EQUIPMENT:

All equipment utilized inside the substation at a minimum shall be specified, designed, built, and tested in accordance with the IEEE and ANSI standards that govern such equipment.

4.6 ABOVE GRADE PHYSICAL:

All design and working clearances shall meet the latest requirements of the NESC, IEEE and OSHA standards. Additional clearance consideration for safety should be considered in areas where foot and vehicular traffic may be. Phase spacing shall not be less than IEEE 1427 and NESC requirements at a minimum.

The physical design must accommodate any through fault condition that may be present. All switching and transient levels must be addressed in the design.

All primary electrical connections utilized in stations 200KV and above must use welded, compression, or swage fittings. Bolted connections must be limited to connections made on equipment itself (bolting of connector to pads), or insulator support fittings. The system shall be designed per the latest IEEE 605 standard. All tubular bus work shall be designed and installed with the appropriate slip, fixed and expansion connections. All Extra High Voltage (EHV) connections 345kV and above must be corona free. Structural steel when used for support of equipment shall be hot dip galvanized.

The physical layout and design must be conducted to ensure proper maintenance and access is accounted for in the design. The design must also allow for sufficient space to maintain OSHA minimum approach requirements, either with or without tools.

4.7 INSULATION COORDINATION AND LIGHTNING PROTECTION:

General Requirements

Insulation coordination is the coordination of electrical insulation levels with overvoltage protection. It includes subjects of shielding from lightning, application of surge arresters, insulator contamination, switching surge mitigation, and temporary overvoltage control. The nominal voltage ratings of the effectively grounded transmission systems are defined as part of this Minimum Basic Insulation Levels (BIL) standard in the General Design Criteria section. All insulation shall be capable of operating at these continuous voltages, and withstanding the transient over voltages allowed by the overvoltage protection. IEEE C62.82.1 “Standard for Insulation Coordination–Definitions, Principles and Rules”, and IEEE 1313.2 “Guide for the Application of Insulation Coordination” should be followed when selecting surge arrester ratings and station and equipment insulation levels.

Shielding from Direct Lightning Strokes

All facilities connected to the PJM system shall be shielded from direct lightning strokes to meet the design criteria in these guides. IEEE Standard 998 “IEEE Guide for Direct Lightning Stroke Shielding of Substations” should be used as guide in designing lightning shielding. Lightning Shielding may be accomplished through, masts, overhead ground wires, or other tall conducting structures. Static wires not connected to or associated with the incoming line terminations should avoid crossing over busses and other circuits.

Arresters shall provide a 20% minimum margin of protection as recommended in the standard IEEE C62.22. This allows for insulation aging and contamination and higher incoming surge magnitudes and faster rise times. It is recommend maintaining 20% margin for breakers, switches and voltage transformers and 50% margin on power transformers.

Arrester shall be applied with adequate pressure relief or fault current withstand rating, and adequate energy capability.

Insulation Coordination Studies

An Insulation Coordination Study must be completed. Detailed studies including lightning traveling wave analysis, switching surge analysis, TOV analysis, Harmonic resonance, etc., may need to be conducted to balance the number and location of surge arresters with proposed insulation levels as required. EMTP and similar tools can be used in these studies.

Power Transformers will require surge arrester protection on all terminals. Additionally, line entrance arresters are required on all lines. Any frequently open position will be a positive reflection point for fast front transients and deserves special attention. Other non-self-restoring devices such as underground cable and accessories and Gas Insulated Switchgear (GIS) shall be protected by a dedicated set of surge arresters.

Specification of Surge Arresters

All surge arresters shall meet or exceed the latest applicable ANSI, IEEE, NEMA, NESC and OSHA Standards.

Surge Arresters shall be designed with adequate electrical and mechanical characteristics for the specific electrical system on which it is installed and for the application for which it is intended. These include but shall not be limited to: Maximum Continuous Operating Voltage (MCOV), Rated duty cycle voltage, energy discharge capability, Temporary Overvoltage capability, and environmental conditions.

Energy discharge capability must be sufficient to survive line or capacitor bank discharge from at least one maximum energy restrike of any switching device in the substation.

Surge arresters shall be designed for an in service operating life, comparable to other electrical apparatus in the system to which it is applied.

Surge arresters, at a minimum, shall be designed to operate at ANSI required ambient of -30_C to +40_C (-22_F to +104_F). All surge arresters shall be designed to operate satisfactorily in the ambient required by their installed location. Some locations in PJM require -40_C capability.

Local environmental conditions should be considered when selecting leakage distances requirements for Surge arresters and other components.

Application and Special Considerations

Surge Arresters generally should be located as close as practical to the equipment they are primarily installed to protect. Both the lead length and the ground return length need to be kept as short and straight as possible.

For example, when possible, surge arresters protecting power transformers should be mounted on the transformer, and the grounded end solidly bonded to the nearest ground that grounds the transformer. Also, incoming transformer lead should be connected to the arrester BEFORE the transformer bushing.

4.8 AC STATION SERVICE:

The following criteria must be met for the AC station service design:

1. There must be two AC sources such that a single contingency cannot de-energize both the primary and back-up station services. An automatic throw-over switch with an auxiliary contact for SCADA alarm is required to provide notification of loss of primary station service.
2. Loads are generally categorized by electrical size in determining the appropriate supply voltage. Typical voltages would be 480Y/277V, 208Y/120V, and 240/120V.
3. Distribution lines shall not be used as a primary source.
4. Station service transformers shall be protected by surge arresters.
5. Emergency generators may be required where black start capability is required.
6. Due to the large distances and auxiliary loads in 765kV and large EHV stations, multiple station service load centers may be required. The relay protective scheme must be selective and remove from service only the faulted station service transformer.
7. All station service transformers shall have high side overcurrent protection (via a fuse or a bus protection scheme if the transformer is tapped to the bus).
8. Transfer switches may be installed internal or external to their associated switchboards, however, if they are located externally, they shall be located adjacent to the switchboard to minimize the exposure of the single set of cables supplying the switchboard. For large electrical loads, such as a power transformer with oil pumps, dedicated transfer switches would be located at the power apparatus with primary and alternate power supplies. Electrical separation is required for this application and physical separation via separate cables at a minimum is required for the supplies routed to the switch.
9. All devices connected to the AC station service system must be capable of operating continuously and properly without malfunction or overheating in the voltage range specified by the designer of the system.
10. AC station service system components must be installed in accordance with manufacturer’s instructions and applicable industry standards.
11. All AC primary and backup station service supplies shall be adequately monitored and alarmed, for all voltage levels and sources, to assure that improper operation and abnormal conditions are reported for immediate corrective action.
12. AC station service systems shall be physically arranged to facilitate safe and effective inspection and maintenance.
13. Critical transmission facilities shall be provided with emergency engine-generator sets sized to carry essential loads considering a reasonable diversity factor, when alternate reliable sources are not available. Essential loads are loads required to maintain normal operation of the station and the loads required to bring a station back online after a period of blackout. If not, facilities shall be available for prompt connection of emergency generation. Remoteness of the location, adversity of weather conditions, refueling cycles, etc. must be considered in determining required fuel capacity.

Requirements for AC Station Service:

1. As a minimum requirement, AC station service systems and equipment shall be designed for the purpose intended and be specified to meet latest requirements of all applicable industry standards, including but not limited to ANSI, IEEE, NEMA, OSHA and NESC.
2. AC station service equipment is available in varying degrees of quality. Equipment installed in a transmission facility shall be designed to operate reliably during the design life of the facility. This requires quality products and specifications that reflect this need.
3. Main distribution panels located on the load side of the fused safety disconnect switch shall have breakers rather than fuses. These breakers shall be designed to coordinate with each other to ensure proper protection.
4. All electrical contact parts and conducting mechanical joints should be properly plated and prepared to insure joints that have low resistance for the equipment's expected life.
5. AC station service cables may be run in the same tray systems as other AC circuits 480 volts and below and with 125vdc control circuits. However, they are not to be commingled with low voltage digital signal circuits and/or analog signal circuits such as data network, Ethernet, etc.
6. AC circuits shall be adequately sized and designed to limit the total voltage drop to no more than 5% continuous and 10% momentary. Greater voltage drops may be acceptable as long as the analysis determines it will not affect the operation or reliability of the equipment.

4.9 STATIONARY BATTERIES AND CHARGERS:

The following criteria must be met for the AC station service design:

1. Requirements for the battery design are to be incorporated on FERC based projects. These requirements are not required in projects required to support local distribution reliability and load as they are not governed by FERC. Stations 300kV and above whose configurations are designed to reinforce the flow of power on the transmission system, must follow the requirements outlined below.
2. Separate batteries for primary and back up protection are required. Each of these batteries must be fed by (1) independently supplied charger (each charger must have its own/ separate AC supply) at a minimum.
3. A single battery for all other requirements is acceptable. In this application, however, the battery must be supplied with two independently supplied chargers (each charger must have its own/separate AC supply) at a minimum.
4. The battery system shall be sized in accordance with the latest version of IEEE 485 Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications or IEEE-1115 Recommended Practice for Sizing Nickel-Cadmium Batteries for Stationary Applications for a minimum duty cycle of no less than 8 hours with the most severe possible multiple breaker operation (usually bus differential operation) at the end of the cycle. It must be taken into consideration when sizing the battery the distance to the site in order to perform an emergency replacement. This distance may require a minimum duty cycle of more than 8 hours.

5. Correction factors shall be included in battery sizing calculations to account for temperature conditions, battery aging and potential load increases.
6. Provisions must be made to facilitate the replacement of a failed charger or battery bank without interruptions to the DC system.
7. The battery charger shall be able to supply the station DC power requirement and at the same time to bring the station battery to “fully charged” condition in less than 24 hours following a prolonged discharge period due to an AC power failure.

Requirements for Battery and Charger

1. As a minimum requirement, battery and charger systems must be designed for the purpose intended and shall be specified to meet the requirements of all latest applicable industry standards, including but not limited to ANSI, IEEE, NEMA, OSHA and NESC.
2. The charger shall be protected by automatic current limiting, and be self-protecting against transients and surge voltages, and be designed to prevent the battery from discharging back into the internal charger load.

Application and Installation for Battery and Charger

1. When multiple battery and charger systems are provided to supply multiple relay systems (referred to as primary and backup or system one and system two), the batteries and chargers, including all associated wiring, are to be kept physically and electrically separated to avoid a problem with one system affecting the other system.
2. Batteries shall be installed in facilities that assure that appropriate ambient temperatures are maintained and that the batteries are not exposed to direct sunlight.
3. Battery systems shall be installed in accordance with manufacturer’s instructions and applicable industry standards, with special attention given to cell handling and cell connections and protection.
4. Before a battery and charger system is placed in service, appropriate acceptance testing shall be conducted and appropriate data, such as cell voltage and specific gravity, shall be recorded for future use.
5. Batteries shall be physically arranged to facilitate safe and effective inspection and maintenance. This requires a 3ft. work area in front of the batteries for replacement and maintenance activities.

DC Station Service

Application and Installation of DC Station Service

1. DC station service system components shall be installed in accordance with manufacturer’s instructions and applicable industry standards.
2. All devices connected to the dc station service system shall be capable of operating continuously and properly without malfunction or overheating in the voltage range specified by the designer of the system.
3. The output cables from the battery to the first breaker or protective device in the main DC panel shall be kept as short as practical; shall be separately routed to reduce the possibility of a short

circuit between the positive and negative cables; shall be installed in conduit for protection; and shall be sized in consideration of the available dc short-circuit current from the battery.

4. DC station service systems must be adequately monitored and alarmed to assure that improper operation and abnormal conditions are reported for immediate corrective action.
5. DC station service systems shall be physically arranged to facilitate safe and effective inspection and maintenance.

Requirements for DC Station Service

1. As a minimum requirement, DC station service systems and equipment shall be designed for the purpose intended and be specified to meet the requirements of all applicable industry standards, including but not limited to ANSI, IEEE and NEMA.
2. The typical nominal rating for this application is 125 VDC.
3. The DC system design must take into consideration the voltage drop between the battery and the load terminals. Under no circumstances should the voltage at each load terminal be less than the manufacturers' specifications. Age, cell failures, and good engineering judgment must also be considered when designing and shall be considered in the initial voltage level of the batteries.
4. The maximum load terminal voltage shall not exceed the product of (the number of cells in battery) times (the maximum defined cell voltage).

4.10 GROUNDING:

The station ground grid shall be designed in accordance with the latest version of IEEE Std. 80, Guide for Safety in AC Substation Grounding. The fault current calculations should include future improvements which would increase the fault current. It is recommended that the ground grid be designed for a fault current growth factor of 20%.

4.11 RACEWAYS:

Design Considerations:

- Design of the raceway and conduit system shall consider the anticipated station build out.
- Troughs shall be routed with sufficient clearance from oil filled equipment to minimize an oil fire in the trough.
- All outdoor raceway components shall be designed for the environment which they are installed in.
- "Primary" and "Backup" systems cannot be in the same cable.
- Long cable runs that parallel to high voltage bus and transmission lines shall be avoided in the design of the trench system.
- All cables rated greater than 1kV shall not be installed in the same trench system as cables less than 1kV.
- All Conduits shall be installed to provide protection from vehicular and environmental conditions.

- Consideration of water flow must be considered when designing the conduit/trench system to ensure excess water flow does not back up in the equipment, cabinets or control house.

Below Grade:

- Typically the outdoor main runs of the raceway/conduit system are surface mounted with its cover sitting flush with finished grade. No direct buried cable shall be permitted.
- Proper drainage shall be included underneath the trench.
- Where vehicles will cross the conduits or trench system, suitable covers and design must be incorporated to protect the cables from the heaviest vehicles and equipment anticipated on crossing the roadway.
- Below grade conduits shall be used to complete the run from the main trench system to the equipment.
- No more than 360 degrees of bends should be installed in a conduit run.
- All metallic conduits shall be bonded directly or indirectly to the ground grid.

Above Grade:

- All cable trays and junction boxes shall be bonded directly or indirectly to the ground grid.
- Fiber shall be routed and protected either in its own separate tray, conduit, or other protective medium such as innerduct.
- All above grade outdoor conduit shall be suitable for the environment in which it is installed in.
- Vertical raceways on control building sidewall should be sized to accommodate the ultimate layout of the substation.

4.12 CONTROL HOUSE OR ENCLOSURE:

General Requirements

The enclosure shall be suitably designed and constructed to contain all substation control and instrument panels, relay panels, metering panels, AC lighting and power panels, Annunciator, DFR, SCADA equipment, DC station batteries, DC Power Panels, fire alarm panel, battery chargers, toilet facilities (when required), office furniture, HVAC equipment, and local required telecommunications. Consideration shall be given to either sizing the enclosure to accommodate the needs of the ultimate station development or to allow for the expansion for such accommodation.

Control Enclosure shall typically not be part of the Substation fence. In the event of a station located inside metropolitan areas and the building does need to be part of the fence, the outside walls shall be designed accordingly.

All materials and equipment used in the control enclosure shall be noncombustible to the greatest extent practical.

Fire detection system must be installed in control enclosures.

Specification

The enclosure shall be designed and constructed in accordance with the latest revisions of all applicable codes including but not limited to:

- ACI – American Concrete Institute
- AISC – American Institute of Steel Construction
- AISI – American Iron and Steel Institute
- ANSI – American National Standards Institute
- ASCE – American Society of Civil Engineers
- ASTM – American Society for Testing and Material
- AWS – American Welding Society
- IBC – International Building Code
    - International Plumbing Code
    - International Energy Code
    - International Mechanical Code
    - International Fire Code
- IEEE – Institute of Electrical and Electronics Engineers
- MBMA – Metal Building Manufacturers Association
- NESC – National Electrical Safety Code (IEEE C2)
- NEC – National Electric Code
- NFPA – National Fire Protection Association
- All applicable state and local building codes and requirements.
- Wind and ice loading criteria as found in the structural section of this document

Structural, Architectural, and Mechanical Requirements

The enclosure shall be as specified below:

1. The enclosure is not intended to be used as a shop.
2. The enclosure is not intended to be used as a storage location for spare parts.
3. The enclosure is not intended to be used for equipment assembly.

Enclosure design loads shall include live, snow, wind, seismic, and dead loads. In addition, enclosure must be designed to carry the auxiliary static loading from interior cable tray systems and air handling ductwork, and additional electrical equipment such as lighting, battery chargers, power panels etc. The floor space supporting the supplied loads need to be braced to handle the weight associated with those loads.

Falling ice: Exterior of control enclosure shall be designed to resist damage by hail and falling ice from adjacent structures or overhangs.

Doors:

1. Typically, two exits with panic bar and door holder mechanism will be required. It is recommended that one exit be a double door and the second exit be a single personnel door. The doors need to be sized and configured to allow delivery of relay panels and other large equipment deliveries. A roll up garage door is acceptable in lieu of double doors.
2. Weather stripping shall be included around all edges.
3. Means for locking and securing all doors shall be included.

Enclosure ceiling, floors and walls shall be insulated. Vapor barriers shall be provided.

Gutters, downspouts, and splash block diffusers shall be considered.

Separate physical cable entrances shall be provided for each AC station service primary and back-up feed. Control cable entrances shall be sealed off to prohibit rodents from entering.

Heating, Cooling, and Ventilation

The enclosure shall be equipped with sufficient heating, cooling, and ventilation equipment to provide acceptable ambient temperatures within the enclosure so as not to impact the operation and life expectancy of the control equipment within.

Automatic temperature control equipment shall be installed. Microprocessor relay and control equipment and the control battery manufacturers should be consulted to establish proper ranges of operation.

Adequate ventilation shall be provided to prevent the accumulation of hydrogen gasses resulting from battery operation. Forced ventilation shall be used when required.

Illumination

See Table 111-1 of the National Electrical Safety Code for minimum illumination levels.

Emergency lighting shall be provided. Automatic initiation may be required. Illumination levels must meet the minimum requirements specified by the National Electrical Safety Code for egress.

Exterior lighting at doorways shall be provided to effect safe access to the enclosure.

Exit signage and emergency lights shall be provided in accordance with local codes.

Grounding

Structural enclosure steel, raceways, relay and control panels, AC and DC distribution panels (not the DC control voltage itself) shall be bonded to the station ground grid in accordance with the NESC.

Each control and relay panel shall be equipped with a ground bus to which instrument transformer secondary circuits or other equipment such as relay case grounds can be grounded.

Cable tray system shall be grounded and adequately bonded without creating a loop for circulating current.

Application and Special Considerations

Raceways

Control cables are to be installed in overhead cable tray raceway, or under the floor if a raised computer floor is used, or in under floor cable troughs. Raceways are to be suspended from enclosure ceiling or walls as required. Cable tray shall be aluminum or galvanized steel construction and be sized adequately for anticipated cable loads. Vertical cable risers shall be provided to physically protect its associated cables (i.e. vertical ladder tray, marshalling cabinets, etc.).

Nonmetallic jacketed cables below 7 feet above the floor level not in ladder tray or otherwise suitably protected shall be enclosed in conduit.

Working Space

A minimum of 3 feet working clearance shall be provided in front of all panels/batteries and 3 feet in back of panels where rear connected equipment access is required. See NESC Rule 125 for additional information.

Safety Equipment

Signage as required by NESC, OSHA, and other applicable organizations shall be provided. Signage is to be in accordance with ANSI Standards Z535.1, Z535.2, Z535.3, Z535.4, and Z535.5, latest revision.

Fire detection and extinguishing equipment shall be installed in accordance with all applicable national and local codes.

Face shields and eyewash stations, if installed, shall meet applicable OSHA requirements.

Provisions for containing acid spillage from the control battery shall be included in design of the facility.

Metering, System Protection, Annunciator, DFR, SCADA, and Telecommunications

The local telecommunications provider shall be consulted for their requirements for space, access, conduit size and routing, working clearances, auxiliary power, grounding, and other aspects of the installation. Isolation equipment may be required to protect telephone equipment from ground potential rise.

Free standing or rack mounted panels are acceptable.

Control panels and equipment shall be arranged in such a manner to allow for safe and reliable operation and maintenance activities of the substation.

4.13 STATION SECURITY:

Substations need to be designed to the requirements of the applicable NESC, IEEE, NERC and CIP publications.

4.14 STRUCTURAL:

Structural Design Loads

Structures, insulators, hardware, bus, and foundations shall be designed to withstand various load conditions based upon the NESC and when required the ASCE-7 code using the weather maps provided in the code. These loads will include various combinations of gravity, wind, ice, conductor tension, construction, maintenance, fault loads, and seismic loads (where applicable).

The magnitude of all weather and seismic related loads, except for NESC or other legislated loads, shall be determined using risk category IV criteria as defined in ASCE- 7 "Minimum Design Loads for Buildings and Other Structures."

Structures and foundations shall be designed to the requirements of the applicable publications:

- ACI 318: Building Code Requirements for Structural Concrete and Commentary
- ACI 336.3R: Report on Design and Construction of Drilled Piers
- TMS 402/602 Building Code Requirements and Specifications for Masonry Structures
- ACI 543R: Guide to Design, Manufacture and Installation of Concrete Piles
- AISC 360: Specification for Structural Steel Buildings
- ASCE/SEI 7: Minimum Design Loads for Buildings and other Structures
- ASCE 10, Design of Latticed Steel Transmission Structures
- ASCE/SEI 48: Design of Steel Transmission Pole Structures
- ASCE 113: Substation Structure Design Guide
- ASCE Manual No. 104, Recommended Practice for Fiber-Reinforced Polymer Products for Overhead Utility Line Structures
- ASCE Manual No. 123, Pre stressed Concrete Transmission Pole Structures
- ANSI 05-1, Specifications and Dimensions for Wood Poles
- IEEE Std. 691, Guide for Transmission Structure Foundation Design and Testing
- IEEE Std. 751, Trial-Use Design Guide for Wood Transmission Structures
- IBC: International Building Code

Dead-End Structures and Shield Wire Poles

Dead-end structures and shield wire poles shall be designed for the wind and conductor loading criteria, load combinations, and deflection criteria described in NESC C2 and ASCE 7. The following load cases shall be completed during the study, NESC Heavy, NESC Unfactored, Heavy Wind, Wind & Ice, Heavy Ice, and Extreme Cold to satisfy the requirements of the above stated standards. The design must be completed to ultimate strength design.

Equipment Structures and Masts

Substation structures shall have sufficient strength to resist all loads as defined in ASCE MOP 113, the NESC, and the load combinations defined below (including proper wind loads and orthogonal directions). The effects of gravity, wind, ice, wire tension, short circuit, seismic, construction & maintenance and operating loads shall be included as applicable.

The following load combinations apply to the substation equipment, equipment supports. The load combinations do not apply to buildings, lightning masts, fire walls, or transmission line dead-end and suspension structures. Structure design shall be ultimate strength using the methodology set forth in the ASCE 113 Guide for Design of Substation Structures (ASCE Guide), in addition to the following load combinations outlined below.

- 1.5 × Dead w/o Ice + 1.6 × Concurrent Wind on iced Structure and Equipment + 1.0 × Short Circuit Load + 1.65 × Conductor Tension
- 1.5 × Dead w/o Ice + 1.6 × Extreme Wind on Bare Structure and Equipment + 1.0 × Short Circuit Load + 1.65 × Conductor Tension
- 1.4 × Dead Load with Heavy Ice

Deflection Calculation

- 1.0 × Dead w/o Ice + 0.8 × Extreme Wind on Bare Structure and Equipment + 1.0 × Conductor Tension
- 1.0 × Dead w/ Ice + 0.8 × 0.75 × Concurrent Wind on Iced Structure and Iced Equipment + 1.0 × Conductor Tension

Earthquake

Per ASCE 113 – Yard/ Structures

Per ASCE 7 – Control Enclosure

- Site specific geotechnical investigation is required to determine site soil classification
- USGS Design Information per the USGS Seismic Design Maps

Rigid bus and bus supports

The following load combinations and load factors shall be used for evaluation of the indicated bus system components. In addition to the combinations shown, load cases shall also include any forces resulting from the thermal expansion of the bus due to current heating effects.

Typically the conditions of maximum icing do not usually occur simultaneously with maximum wind speed conditions. Therefore, two separate wind case loadings shall be considered. The full wind force shall be applied to the bus diameter when no ice is present. The concurrent wind speed shall be used in combination with ice. This reduced wind force is applied to the iced diameter of the bus.

An overload factor of 1.0 is considered sufficient for use with short circuit forces in these load combinations.

Load Combinations for Rigid-Bus Tubing & Equipment Terminal Pads

Per IEEE 605

The elastic limit stress shall be used for strength evaluation of the rigid-bus material when considering loading combinations without short circuit forces. When short circuit forces are included in the loading combination, the yield strength of the material shall be used for strength evaluation. Forces on switch terminal pads shall be limited to one-half the cantilever strength of the switch insulator, using these unfactored load combinations.

- 1.0 (Dead Weight) + 1.0 (Wind on Bare Surfaces) [Note: No ice loads]
- 1.0 (Dead Weight) + 1.0 (*" Radial Ice) + (*Wind on Iced Surfaces)
- 1.0 (Dead Weight) + 1.0 (Wind on Bare Surfaces) + 1.0 (Short Circuit)
- 1.0 (Dead Weight) + 1.0 (*" Radial Ice) + (*Wind on Iced Surfaces) + 1.0 (Short Circuit)

*Actual Ice and Wind load values to be determined based upon ASCE 113.

Load Combinations for Insulators

Insulator loads based on these loading combinations shall be compared with the minimum published cantilever and torsional strength ratings. When applicable, the combined effects of torsion and bending shall be evaluated.

- 1.5 × Dead w/o Ice + 1.6 × Concurrent Wind on iced Structure and Equipment + 1.0 × Short Circuit Load + 1.65 × Conductor Tension
- 1.5 × Dead w/o Ice + 1.6 × Extreme Wind on Bare Structure and Equipment + 1.0 × Short Circuit Load + 1.65 × Conductor Tension
- 1.4 × Dead Load with Heavy Ice

Foundations

Foundation reactions shall be determined from the load cases and load combination defined above. Load Factors shall be a minimum of 1.0. Unfactored loads shall be used for the foundation overturning and soil bearing design. Factored loads shall be used for the design of reinforced concrete per the requirements of ACI.

Deflection of structures shall be limited such that equipment function or operation is not impaired, and that proper clearances are maintained.

A site-specific geotechnical study shall be the basis of the final foundation design parameters.

4.15 CIVIL:

The substation shall be developed in accordance with all the federal, state, and local jurisdiction requirements. These requirements can consist of public safety, zoning, noise levels, poor drainage, wetlands, and aesthetic requirements. Site grading shall be completed to ensure excess runoff is accounted for in the design and ponding does not occur inside the substation. The grading design shall also consider the transition from substation ground pad to the existing grade. Storm water management and erosion control shall be designed with reference to the state and local permitting requirements.

Containment facilities and/ or Spill Prevention Plan may be required for equipment or storage tanks that contain dielectric fluid or fuel.

Roadways shall be designed in accordance with the requirements of the FHWA and AASHTO for large truck and trailer deliveries. Consideration should be given to ease of ingress and egress. Minimum turning radii for equipment shall be considered in the design. Special consideration shall be considered for vehicular access related to transformer hauling equipment, which may include the use of enlarged turning radiuses. Consideration should also be given to access transmission structures located outside the fence within proximity to the substation yard.

System Protection Engineering and Design Minimum Required Standards

5.0) System Protection Engineering and Design Requirements for Facilities that Interconnect to Existing Incumbent Transmission Owners (All Voltage Levels requiring the signing of a DEA)

For transmission circuits and other facilities with protective zones that are shared with existing incumbent Transmission Owners (i.e., facilities that represent ties between existing substations owned by incumbent Transmission Owners and Designated Entity substation facilities, etc.), the parties must coordinate to develop a protection system design that does not degrade the performance or reliability of the system, following the applicable technical requirements and standards of the Transmission Owner that are posted on PJM's website per Manual 14C Section 6.1.3.2., or other mutually agreed to solution for the items listed below. PJM Manual 07 will apply to all aspects of projects subject to the DEDSTF requirements. When interconnecting to multiple Transmission Owners systems, all parties must coordinate to achieve a mutually agreed upon solution.

The following are examples (including but not limited to) of design requirements that must be coordinated between parties.

- Line relay scheme (DCB, POTT, current diff, etc.)
- Line relay types/models
- Line protection communication media (Fiber, Power Line Carrier, etc.)
- Line protection communication scheme requirements – number of channels, channel types (POTT, DCB, DTT, etc.), and channel performance requirements
- Line Relay Setting and Trip Logic Design
  - Design must include sufficient test switches to allow isolation of protection system components and to provide adequate isolation to maintain protection system components and minimize trips caused by testing
- Reclosing method (HBDL, sync check, etc.) and associated timing must be coordinated with the local TO

5.1 System Protection Requirements for Facilities that exist within a developer's station and Do Not Directly Interconnect with Existing Substations Owned by Incumbent Transmission Owners

Facilities with protective zones that are not shared with incumbent Transmission Owners or Generation Owners are not subject to DEA section 4.2 (i.e., facilities entirely within a Designated Entity substation or a facility that interconnects two Designated Entity substation facilities, etc. PJM Manual 07 will apply to the following Designated Entity equipment as minimum design standards for system protection, metering, and control:

- Substation Buses (Manual 07, Section 9)
- Breaker Failure Protection (Manual 07, Section 12)
- Transmission Substation Transformers (Manual 07, Section 8)
- Shunt Reactors and Capacitors (Manual 07, Section 10 and 11)

- Phase Angle Regulating and Voltage Regulating Transformers (Manual 07, Section 13)
- HVDC Transmission Circuits and Converters (No Coverage in Manual 07)

Note 1: Minimum system protection requirements for HVDC Transmission Circuits and associated converter equipment shall be determined on a case-by-case basis and included in the applicable PJM Problem Statement & Requirements Document. At a minimum, completely redundant protection systems will be required for these elements.

Note 2: For phase angle regulators (PAR) at a Designated Entity station that are electrically located at the terminal of a transmission line with a shared protection zone, design and relay setting coordination between the Designated Entity facility and the incumbent Transmission Owner facility is required. The required protection schemes on a PAR are inherently complex, and can adversely affect reliability of the incumbent Transmission Owner system. In these cases, agreement on scope of design and protection philosophy, relay settings and test methods may be required by the incumbent Transmission Owner.

Note 3: Breaker failure design, timing requirements and relay types must be coordinated between the Designated Entity and the Incumbent Transmission Owner prior to the design of the protection system for all breakers in the Designated Entity station. Where generator stability is a concern, the protection requirements must be fully understood by the Designated Entity prior to the selection of relay types and overall design of the breaker failure scheme.

5.2 System Protection Requirements for Facilities below 200kV

For protection systems in the substation subject to a Designated Entity Agreement that do not meet the applicability of PJM Manual 07, Appendix A lists the minimum requirements for those protection systems.

5.3 Appendix A

This appendix outlines the protection requirements for the protection of greenfield project facilities at or above 46kV and below 200kV.

Generator Protection

For generating units less than 100 MVA and connected below 200 kV, see PJM M07 Appendix D

Unit Power Transformer and Lead Protection

PJM Manual 07 Section 4 applies for unit power transformers and associated high-side leads where the transformers are (1) rated less than 100 MVA, or (2) are connected to utility systems at transmission system voltages below 200kV.

Unit Auxiliary Transformer and Lead Protection

PJM Manual 07 Section 4 applies for unit power transformers and associated high-side leads where the transformers are (1) rated less than 100 MVA, or (2) are connected to utility systems at transmission system voltages below 200kV.

Start-up Station Service Transformer and Lead Protection

PJM Manual 07 Section 6 applies for start-up station service transformers and associated high and low-side leads connected to transmission systems at system voltages below 200kV.

Line Protection

PJM Manual 07 Section 7 applies for the protection of lines at system voltages below 200kV except for following requirements:

Primary Protection

- For transmission lines below 200kV, pilot protection may be required to meet coordination requirements of the interconnected Transmission Owner.

Restricted Ground Fault Protection

- For transmission lines <200kV, restricted ground fault protection may be required to meet coordination requirements of the interconnected Transmission Owner.

Substation Transformer Protection

PJM Manual 07 Section 8 applies for the protection of substation transformers with high-side voltages of below 200kV except for following requirements:

Current Differential Zone Considerations

- M07 applies except, separate restraint windings in the differential relays are Not required for substation transformers with high-side voltages below 200kV

Isolation of a Faulted Transformer Tapped to a Line

- PJM Manual 07 Section 8.2 applies since bulk power lines operated below 300 kV may be tapped with the concurrence of the transmission line owner(s).

Protection Scheme Requirements

- A device failure scheme for the fault interrupting device is not required for substation transformers with high-side voltages below 200kV.

Transformer Leads Protection

- High and low side leads of transformers with high-side voltages below 100kV must be protected by two independent schemes, only one of which must be high-speed. If the leads are included in a line protection zone, transformer lead protection is not required.

Bus Protection

For the protection of substation buses at system voltages below 100kV, one high speed protection scheme is required for protecting the bus. Remote or local protection is required as a backup. The schemes must utilize independent current and/or voltage sources and independently protected DC control circuits.

Shunt Reactor Protection

PJM Manual 07 Section 10 applies for the protection of shunt reactors at system voltages below 200kV.

Shunt Capacitor Protection

PJM Manual 07 Section 11 applies for the protection of shunt capacitors at system voltages below 200kV with the following exception:

Unbalance Detection Scheme

- For facilities below 200kV, one capacitor bank unbalance detection scheme must be installed.

Breaker Failure Protection

PJM Manual 07 Section 12 applies for breaker failure protection at system voltages below 200kV with the following exception:

Local breaker failure protection requirements

- For facilities below 100kV, a dedicated breaker failure scheme shall be used for each fault-interrupting device and shall initiate tripping of all local sources of fault current if the remote backup protection is inadequate.

Phase Angle Regulator Protection

PJM Manual 07 Section 13 applies for the protection of phase angle regulating transformers connected at system voltages below 200kV.

Transmission Line Reclosing

PJM Manual 07 Section 14 applies for automatic reclosing schemes for fault interrupting devices at system voltages below 200kV.

Supervision and Alarming of Relaying and Control Circuits

PJM Manual 07 Section 15 applies for supervision and alarming of relaying and control circuits applied to protect equipment at system voltages below 200kV.

Underfrequency Load Shedding

PJM Manual 07 Section 16 applies for underfrequency load shedding schemes at system voltages below 200kV.

Special Protection Schemes or Remedial Action Schemes

PJM Manual 07 Section 17 applies for Special Protection Schemes (SPS) or Remedial Action Schemes (RAS) at system voltages below 200kV.

Use of Dual Trip Coils

The use of dual trip coils in circuit breakers is not required at system voltages below 100kV

Direct Transfer Trip Requirements

The use of dual trip coils in circuit breakers are not required at system voltages below 100kV

Dual Pilot Channels for Protective Relaying

PJM Manual 07 Appendix C applies for facilities below 200kV.

Small Generator Protection Requirements

PJM Appendix D applies for generating units less than 100 MVA and connected below 200kV.

Acceptable Three Terminal Line Applications

PJM Manual 07 Appendix E applies for facilities below 200kV with the following exception:

Protection Requirements

- For facilities below 200kV, directional comparison blocking (DCB) or unblocking scheme (DCUB) operating over power line carrier to a third terminal is acceptable for primary or backup line protection.

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I22: End-Of-Useful Life Assessment of P&C Devices

Report to Main Committee

Final Report – May 2015

Chair: Bob Beresh

Vice Chair: Bruce Mackie

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Assignment

Prepare a PSRC report on the criteria for determining the end-of-useful-life for protection, control, and monitoring devices including electromechanical, solid-state and microprocessor-based devices.

Introduction

The end-of-useful life[1] of a device used for protection, control and metering can be defined as a time during the lifecycle of the device when any of the following situations is reached:

1. The device is no longer able to perform as per its design specification when first installed and it is not possible to repair it.
2. The device is no longer under warranty and the cost of repair outweighs the benefits of a newer device.
3. The device is no longer useful and no longer meets present functional requirements.

The expected useful life of a device from the time of its installation date may vary based on the following factors:

1. The device technology (electromechanical, solid state or microprocessor-based).
2. The designed life of the device as defined by the manufacturer.
3. The availability of parts/components/boards for repair and cost of repair in comparison with the benefits offered by newer devices and the mean-time-to-replace.
4. When the device was actually installed, *not* necessarily when the device was purchased or designed/manufactured.
5. There is a significant excursion of operating parameters by the device from set or designed parameters.
6. The environment in which the device is placed has changed (temperature/humidity/EMC/etc.)
7. Regulatory or other requirements have changed the functional requirements.

There are two terms used throughout this document: “end-of-life” and “end-of-useful-life”. End-of-life is what is expected when the device is installed. A device (relay, for example) is purchased and installed and expected to last for 20 or 25 years (for example). This “end-of-life” is the anticipated and planned in-service life of the device. The second term is that which is discussed at length within this document and refers to when the device actually (in real life, not planned originally at design or procurement time) is done/finished serving its purpose *before* the expected end-of-life, that is, it has come to its end-of-*useful*-life. Instead of lasting 20 or 25 years (for example) the device is replaced earlier for some reason that was not initially anticipated. It is the intent of this document to help asset managers, planners, designers and field staff to understand and anticipate the possibility for the early retirement of protection and control devices in order to better prepare for their replacement or perhaps extend their actual useful life.

This document does not address the benefits of upgrading a device but examines:

- The reasons why a device may no longer be useful.
- Possible ways to determine useful life of a device.
- Why knowing the useful life of a device is important.

[1] “Practical life” may also be used as a similar term to “useful life”.

- How to extend the useful life of a device.

Since P&C equipment life, and specifically, useful-life is the focus of this report, it is important to define what is considered the life of a device. There may be many interpretations of this from the age of the device starting from date of manufacture (date code); or the date it was purchased and received by the company (purchase date/shipped date/received date); or the date at which the device was placed in service (in-service date). To further complicate the definition of device life is the fact that the age of a device is not limited to calendar-based longevity but age may be related to the number of operations it has performed (contacts are rated for a finite number of operations, for example) or the number of heat/cold cycles it endures, or the age may be related to how long the device has been sitting un-energized (as with electrolytic capacitors – a major concern in the nuclear industry). Similarly, the age of a device may be related to the life (age) of the most critical or vulnerable component within the device (battery, crystal, capacitor, MOV, etc.).

For the purpose of this document the life, or age, of a device will be considered the length of time from the date the device was placed in-service (in-service date) to the date the device needs to be replaced.

Knowledge of the useful-life of a device will provide valuable input to a number of operational issues for the end user. These will include:

- Staffing needs regarding maintenance and commissioning: Having a better understanding of the end-of-useful life of a device will enable planners and management to better forecast staffing levels, training and resources required to maintain (or replace) their fleet of protection and control equipment.

- Replacement model: With a better understanding of when a device (speaking categorically) will reach its end-of-useful life, financial requirements can be planned and justification made for increases in budget levels. This will help to avoid last minute, un-planned-for responses that can typically occur when a device reaches its end of useful life when it was expected to last for a much longer period of time.

- Spare equipment. A better understanding of the life of device will also assist in providing valuable input to a spares stocking model for devices. A device expected to last for 20 years will have different spare requirements than one that is expected to last for 12.

- Utility experience and information on end-of-useful life shared with the community would enable better decision making to enhance the reliability of the system as well as reduce operating costs in general.

Once end-of-useful life data has been determined this can be used as input to various planning activities as mentioned above, which will ultimately result in the replacement of the device at the predetermined time.

In some cases the end-of-useful life of a device may actually be after the expected or planned end-of-life, such as is the case with many electromechanical relays still in service today.

1) Indicators of End-Of-Useful Life

Technology used in the protection and control industry has changed from electromechanical to solid state to microprocessor-based platforms. This change in technology has also increased the use and sophistication of various communication protocols and media. The need for more device functionality has accelerated because of the following factors:

- More demanding regulatory requirements
- Advances in technology
- Demand for operational data
- Demand for increased performance and reliability

This has resulted in a faster turnover of technology to meet the increasing needs.

As a result, equipment no longer reaches end-of-life simply based on component failure, wear out (age), and lack of spares. End-of-life is increasingly dependent upon the termination of the device's *useful* life – when it can no longer perform as required.

Consider, as an analogy, the many reasons for changing one's car or TV before it fails irreparably. A car may need replacing due to increasing failures, performance issues, functionality, or simply due to aesthetics. A perfectly good television set may need replacing due to government regulation changing analogue broadcast signals to digital. The automobile and the television, in our example, have reached the end of their *useful* life – not their mechanical, electrical, planned, or expected life. Another example is cell phones, which are being upgraded on a routine basis with newer features though the old phones work fine.

The following section enumerates various drivers that can be used as harbingers for determining the end of the useful life of a device.

1.1) Mergers and Acquisitions

In the event that a utility merges with another utility, it may be necessary to upgrade certain devices prior to their end-of-life due to business or technology-related issues. The new entity may require a common platform of devices for purchasing, maintenance, training, and spares. The new entity may be in a position to better leverage lower costs from a new supplier or one partner in the new entity may have had a poor experience with a particular supplier and subsequently chooses to standardize on an alternative platform. A newly formed entity may want a common platform for line protections at each end of the line. There may be many reasons why an amalgamated utility may want to replace devices before their expected end-of-life.

Mergers and acquisitions are not uncommon, especially considering the purchasing of small local municipal (MUNI's) or regional utilities by larger state/provincial entities. It is clear that some conformity to one way or another of doing things will occur and that technology is one area assailable to change.

1.2) Government Funding

Government funding may impact the end-of-life of a device insofar as a having to buy local or indigenous products to receive funding or tax credits or subsidies. For example, government funding may be available for smart grid or synchrophasor initiatives and this might require upgrading existing facilities. Existing, operable devices are replaced with newer devices manufactured within the jurisdiction of the governing body to help stimulate employment. Government funding is typically limited to within a certain time period and usually comes with various conditions associated with it (buy from local state, buy American, buy from job creating companies, buy from approved suppliers, buy from non-restricted countries, buy from green companies, etc.). Utilities may want to take advantage of these initiatives and upgrade their equipment accordingly to enhance performance before devices actually reach their expected/planned end-of–life.

1.3) Technology Trends

Technology related changes will impact existing devices as newer features and greater performance becomes attractive, and even necessary, for the operation of the power system.

End-of-life prior to device failure could be due to a number of technical factors:

1. The existing reporting capabilities of the device are inadequate (sequence of event recording, oscillography, size of memory available for number of records required, etc.).

2. There are missing features which are highly desirable or required:
   a) Logic functionality may be missing, inadequate, or limited in terms of complexity.
   b) Protection function requirements (or setting ranges) may expand beyond current device capabilities due to DG, smart grid, or other requirements.
   c) Multiple settings groups may be required for increased operational flexibility or system performance
   d) Communications functionality may be inadequate, or limited (the device has a serial port but a high speed Ethernet port is required; device has a proprietary/obsolete communications protocol that is not compatible with other devices; etc.)
3. It may be practical to upgrade a device in order to extend the life of other devices (extend life of primary equipment). For example, replacing a transformer relay with one having monitoring capabilities could help extend the life a transformer by providing better diagnostics.
4. Devices cannot be integrated into a complete substation automation solution.
5. Configuration software can no longer operate on newer computers, or older computers used to run old software are broken down and not available. (Will a software interface program used for configuration of a device today run on a Windows computer 15 or 20 years from now – if Windows computers exist as they do now? Will a laptop running XP with settings software today still be working 20 years from now?).
6. In addition to item 5 above, other trends in computing technology such as obsolescence of the CD ROM and the migration towards cloud computing, will have an impact on the end-of-useful life of devices. (Some new computers do not have CD ROMS and the hard drive is being shrunk in size to accommodate cloud computing and solid-state drives.).

1.4) Expediency

A relay may be replaced due to expediency - it just makes sense to do so (even though the device is working satisfactorily). An example would be to replace a breaker controller relay or breaker failure relay during a breaker replacement program.

Many utilities are now installing pre-fabricated protection and control buildings thereby performing wholesale replacement of existing control/relay rooms. Obviously any device in the old facility would be removed (end-of-useful life) and then replaced by newer technology in the pre-fabricated building. Figure 1 is a photograph of a "drop-in" replacement for an existing relay and control room.

Figure 1 - Drop-In Relay/Control Room

1.5) Station-Centric Asset Management

Some utilities are now adopting a station-centric approach to asset management whereby assets (protection and control devices included) are replaced, not across the fleet as they age, but replaced wholesale - one station at a time. This means that existing devices (old and new) are updated on a station-by-station approach. This obviously means that some devices that are fully functional and in good working order, which have not come to their end-of-life, will be replaced (end-of-useful life) during a station-centric upgrade process. The motivation behind the station-centric approach is to optimize staff deployment; minimize outages and outage scheduling; minimize/simplify work program; and minimize travel (reduce road related hazards) [1]. This does, however, imply that devices will be replaced prior to their expected end-of-life, at least for the initial station upgrade process.

1.6) System Reliability

System reliability is an important factor to consider in the early retirement of an existing device. If system performance can be improved by means of a superior product, then it might be prudent to replace the device before its end-of-life. Outage and blackouts also fall into this category of reliability. If the number of outages on a circuit or customer load can be reduced by improving the performance of the protection with a newer or different device then this would certainly be a driver in upgrading/replacing the device prior to its end of life.

For a sample listing of lawsuits against utilities resulting from blackouts, refer to “Liability of Electric Utility in the USA for Outage or Blackout” [2].

System reliability can be improved by various means including: faster protection operating times; by the use of special protection schemes; through the use of redundancy; by means of improved protection schemes; etc. Replacing an existing device for the purpose of improving reliability is a certainly one reason for replacing a device prior to its end of life. The end of its useful-life has arrived due to the benefits that can be achieved by replacing it.

1.7) Product Reliability and Quality

As consumer product lifecycles seem to dwindle in the light of a disposable attitude within the economy, the effects spill over to the industrial sector where product lifecycles have also become shorter requiring earlier replacement of devices. More features, or newer models, or better performance, or higher profits constantly drive sales and marketing to push innovation, change and new product releases. Also the drive for higher profits can increase pressure to save money on manufacturing and material (components) costs.

This pressure can impact quality and therefore end-of-life. Proper manufacturing must enlist the use of quality controls as well as high quality materials to ensure maximal life of a product. Unfortunately, even if a maximal product life is the goal of the manufacturer, component quality is not always easy to monitor and ensure. There is now a problem of used and/or counterfeit components being passed off as new and therefore impacting device performance and life [3]. Certainly, equipment end-of-life would be impacted if it were ascertained that the quality of the components was not as expected either due to inferior components or inferior manufacturing [4],[5].

1.8) Failure Rates, Performance, Change in Failure Rates (Statistical Data)

The IEC describes useful life as “the time interval beginning at a given moment in time, and ending when the failure intensity becomes unacceptable or when the item is considered to be unrepairable as a result of a fault (IEV 191-19-06) [1].” Therefore, according to this definition the end-of-life is when the failure intensity becomes unacceptable or when the [recovery/repair] time is considered to be unacceptable as a result of a fault. Some examples for end of life include the loss of life of capacitors (loss of capacitance because of electrolyte drying and leakage), and loss of semiconductors (mainly ICs) that degrade because of thermal, vibration and humidity. The ability to determine the end-of-life will better prepare the utility for a successful asset management strategy as well as bolstering their rate case application.

One familiar estimate for predicting end-of-life uses the “bathtub curve” which shows the large infant mortality of brand-new relays, the useful life of in-service relays, and finally, the end-of-life obsolescence period where relay failures accumulate rapidly. The key is to predict the length of useful life. The lognormal probability distribution, r(t), indicates that once the relay has one failure, subsequent failures will occur with lesser and lesser time intervals.

Infant Mortality – Consider the left side of the curve of Figure 2. Because of the high initial failure rate it is advantageous for the manufacturer to both minimize that rate and catch those failures before they can leave the factory. These early failures can be caused by component or manufacturing defects. Dielectric tests described in IEEE Std C37.90™-2005 may catch some manufacturing defects (those that would cause an insulation failure)[2]. The most common method of detecting defective components is to perform a high temperature operation of the relay for 24 to 72 hours. This is not required by standards but does perform the function of pushing a component that might be prone to early life failure into a failure condition that is then detected prior to shipment.

In practice, the number of failures during the “useful life” period will not be zero, but will be some small, finite number compared with the failure’s during the period of infant mortality and wear-out.

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[2] IEEE Std C37.90.1™-2005 states that “Dielectric tests, in accordance with this standard, may be performed once by the user on new relays to determine whether specifications are fulfilled …Additional dielectric tests may be made using 75% of the test voltage determined in accordance with….” See IEEE Std C37.90.1™-2005 for further details.

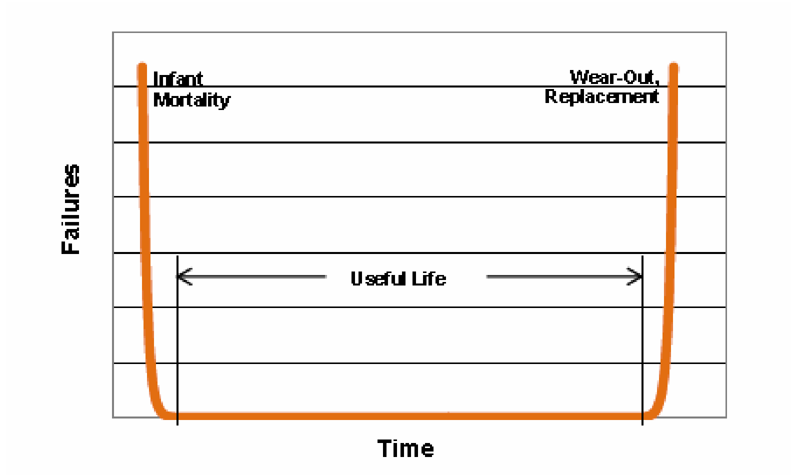

Figure 2 - Relay Failures Over Time

Mean time between failures (MTBF) is another useful parameter that can be calculated for each relay type by evaluating relay failure data in conjunction with the relay asset information for the number of relays installed. This can be broken down by relay class to evaluate relay class performance, or by manufacturer and model to evaluate performance of specific relay types. MTBF is normally calculated for in-service relay failure trends. MTBF can be monitored over time, such as quarterly, to determine positive or negative failure trends.

MTBF = (Total Operating Time) / (Number of Failures) (years)

Relay failures identified during commissioning can be trended to identify quality of relays received out of the box. This may identify manufacturer defects or quality assurance issues. If a negative trend is identified for a particular relay manufacturer or model, then additional relay failure details can be trended to drill down further, such as trending by component failure type or by firmware version or hardware vintage or manufacture date. Always consider whether some system design feature or installation or test procedure is damaging products that seemed to be defective out of the box.

Relay failures can be analyzed based on the age of the relays when a failure occurs. This can be useful to determine at what age relay failures begin to increase significantly and therefore to determine an appropriate and practical relay life. The utility can use this practical life of a relay to be proactive and replace relays prior to end of life failure and avoid possible unplanned outages, loss of customers or damaged equipment. Reliability modeling allows the utility to examine trends occurring in the operation of existing devices [6].

Examining end-of-life based on performance requires diligent recording and analysis of in-service data, failure data, and repair data.

1.9) Incompatibilities/non-interoperability with other Technologies

As new technologies evolve and older technologies become obsolete, it will not only become harder to replace existing devices but also harder to integrate new devices with the old. Newer technologies heavily depend upon communication interfaces using fiber optic cables, for instance.

Even in the modern generation of digital protective devices (numerical, solid state, and microprocessor relays), communication protocol standards for interfacing with the relay have evolved. For example, some devices may only have serial port interfaces while others have options such as USB and Ethernet. However, serial ports are rarely available on laptop computers used to connect to a relay, so consideration must be made as to what interfacing is desired and will survive for the life of the device.

Similarly, digital relays over the past generation have had increased options for input and output interfaces. Early digital relays had discrete set of inputs and outputs, rated at similar speeds and with similar operating values (L/R, ac/dc breaking currents, etc.). Modern relays typically have fully configurable input and output cards, including: options on the number of input and outputs, high speed electronic and standard mechanical outputs, contact Form (A, B, C, etc.), and various current and voltage ratings. Design teams should take into account what inputs and outputs are desired to prevent the need for adding additional devices (such as auxiliary relays) taking up rack space.

Additionally, microprocessor-based relays require software to run on a computer for making logic and setting changes. At some point in a protective device’s life, that software will be made obsolete by the manufacturer due to new product lines being introduced, or by operating system software moving to a different generation without backwards compatibility (such as 16-bit to 64-bit). As the cost of maintaining the software to program a relay increases, the cost of maintaining the relay itself increases.

Another issue is connecting electromechanical relays with a limited number of contacts to external devices, such as digital fault recorders and power quality monitoring equipment. As higher visibility and data requirements become a greater priority, the end-of-useful life of these devices becomes more apparent. The cost of retrofitting transducers and auxiliary relays to these devices could outweigh the cost of replacing the device with a modern equivalent.

1.10) Self-monitoring Capability

Self-monitoring is now a key requirement for extending maintenance intervals. The use of self-monitoring, or self-diagnostic capabilities, can significantly extend the maintenance interval requirements for a device as specified in NERC Standard PRC-005-2. This has advantages in reducing labor costs as well as reducing the possibility of misoperations/false trips due to human error.

Self-monitoring features can include such capabilities as outlined in Figure 3. Note that self-monitoring typically does not check the condition of the output contacts.

The availability and attractiveness of self-monitoring can justify the replacement of a device prior to its end-of-life. That is, it may be better to replace an existing fully functional device with one that has self-monitoring capabilities in order to reduce labor requirements and costs as well as to reduce the possibility of human error during maintenance. The device would therefore be replaced at its end-of-useful life because a better solution (self-monitoring) became available prior to the device’s expected, or planned, end-of-life.

Component Failure	Monitoring Capability	Detail
RAM Failure	Yes	Static RAM read/write error
ROM Failure	Yes	EPROM program memory checksum error
Analog to Digital Failure	Yes	Analog to digital converter error
DSP System Failure	Yes	The watch-dog repeatedly attempts to re-start the DSP for diagnostic purposes.
µP Failure	Yes	Microprocessor exception or self-test error
Watchdog Failure	Yes	Microprocessor watchdog circuit timed out
Default Setting Loaded	Yes	Relay using default setting.
Password access Lost	Yes	Password access lost. No changes
Group Override	Yes	Setting group override in effect
Settings Change	Yes	Setting change made by a user
Active Setting Group Change	Yes	Active setting group changed
Self-Test	Yes	The most comprehensive self testing of the relay is performed during a power-up. During both startup and normal operation, the CPU polls all plug-in modules and checks that every one answers the poll.
Critical Failure Alarm	Yes	The relay has form-C contacts and is energized under normal operating conditions. The critical failure alarm will become de-energized if the relay self test algorithms detect a critical failure.
Output Override	Yes	One or more output contacts have logic override condition
Output contact Monitoring - Active Voltage Monitor Circuit	Yes	This circuit is connected across form-A contacts. The voltage monitor circuit limits the trickle current through the output circuit. The state of the operands can be used as indicators of the integrity of the circuits in which form-A contacts are inserted.
Clock Error	Yes	Real-time clock not set

Figure 3 - Self Monitoring Capabilities (Courtesy of EPRI)

1.11) Lack of Support, Spares or Parts by Vendors

Devices have a finite life cycle in terms of product support. It is difficult for vendors to support a product for the entire physical life of a device which might be upwards of 25 or 30 years. Vendors may offer a lengthy warranty but will replace a failed device with a newer one if it is not feasible to replace the failed device with an identical one (either at the device or component level). The warranty period is typically less than the actual expected life of the device and does not ensure or guarantee a like-for-like replacement in the event of a failure.

Because manufacturers cannot always control the availability of parts necessary to maintain a device in production, there is typically an “end-of-life” process to support the application, design and installation of products in the field after production has ceased. A process of implementing and communicating this “end-of-life” to customers consists of several steps. The first step is a “Discontinuation Notice” to advise the community that a particular product will become unsupported in some upcoming time frame, typically one or two years. During that time customers can issue “last time buys” of the product with normal lead times and standard warranties. Following the time specified in the “Discontinuation Notice” will be the actual “Cancellation” of the product. At the time of cancellation the product is no longer available for standard purchase - although individual units may be available if required to complete a station or support a complete replacement. For an extended time after the cancellation these individual units and repair support is typically available along with application and documentation support. The time following cancellation that this support is available is typically the warranty period or ten years, whichever comes last. Finally, after this extended support time the unit is no longer supported in an official capacity. Documentation is archived and information will be difficult to obtain.

A utility may not wish to continue the use of a particular device after it is no longer supported or parts/replacements are no longer available. It is conceivable, therefore, that a device can reach its end-of-useful life, long before the expected end-of-life, based on the level of support available from the manufacturer. Spare devices may not be available from the vendor, internal inventory, or are incompatible with recently installed devices. Also there may be a lack of spare parts/components for repairs (for example, cards/modules become obsolete or unavailable, specific components are no longer produced, etc.)

Ensuring the availability of spares is a serious matter to consider in terms of optimizing expense, storage space, availability, system reliability, cost of upgrading if spare not available, etc. A spare supply policy can have a significant impact on what devices are kept running and what devices are replaced at an early point in their life.

1.12) Firmware Changes

A volume of protection and control related devices may reach their end-of-useful life sooner than their expected life if firmware changes and upgrades are considered. Many utilities specify a certain version of a device and perform tests on that device and subsequently order a volume of those exact same devices. The utility may consider that a firmware upgrade constitutes a change in the device performance or operating characteristics. Does a device reach its end-of-useful life due to firmware changes? If firmware changes become frequent in nature or they begin to require massive integration efforts, then the device may have reached its end-of-useful life due to firmware changes. IEEE Std C37.231™-2006 provides some useful techniques for monitoring firmware changes which can be helpful in tracking performance [7].

There may also be a lack of interoperability between various devices due to firmware incompatibilities, vendor related issues, communications issues, device vintage, etc. Replacing existing (operable) devices could allow for more seamless integration and inter-communication rather that upgrading firmware.

In addition, firmware changes may require extensive testing, outages, and commissioning and therefore the incremental cost of installing new devices may be more attractive than maintaining the existing devices[3].

1.13) Cost of Maintenance, Repair, and Operation Compared with Replacement.

A clear indicator of the end-of the useful life of a device is an increase in maintenance costs. This is similar to any repairable consumer product. At some point in time a device needs to be replaced due to an excessive need for repairs. The excessive need for repair could be on only one unit out of a batch of units but could cause sufficient concern to warrant the complete replacement of all units and hence, an end-of-useful life.

In addition to the frequency of repair, the cost of repair is also a serious factor to consider. Increasing repair costs due to lack of qualified personnel, long turnover times, and lack of parts may contribute to an accelerated end of life.

The cost of operating a device is a third factor in determining the end-of-useful life. Some older devices, for example, may require manual resetting of targets (thereby requiring operators to visit, record, and reset targets);

[3] For an example of firmware design and its impact in the automotive industry, refer to http://www.edn.com/design/automotive/4423428/Toyota-s-killer-firmware--Bad-design-and-its-consequences

replacement of batteries; and of course, excessive maintenance. These may contribute to a decision to replace existing (functionally operative) devices for newer devices requiring less operating costs. This is a common consumer decision with regards to appliances and automobiles. Do we continue to repair a device over and over again, or do we replace it? Does the cost of replacement outweigh the cost of maintenance and repair? This type of analysis is called a "cost-benefit analysis" in the business world[4]. Replacing a device and accepting an early end-of-useful life may save money and time in the long run. Unfortunately this is often the case with many mass-produced consumer goods, where it is easier to replace a device (end-of-useful-life) than to repair it [8].

1.14) Documentation and Loss of Knowledge Base

Another reason why a device may have reached its end-of-useful life is that the utility personnel no longer have the expertise to maintain or repair the device and that documentation may no longer exist (or the documentation associated with a particular firmware version does not exist). This may become more of a problem in the future as maintenance cycles become extended and documentation becomes increasingly digitized. Information[5] and skills will actually be harder to retain.

Compound this with staff attrition and job changes; utility acquisitions and mergers; internal downsizing and reduction of storage space; GREEN initiatives to reduce paper; and the changing technology from paper to floppy discs to CD ROMs to USB and hard drives and now to cloud storage; etc. How does the utility cope with maintaining critical information on equipment for 20 years or more to prevent loss of knowledge and expertise on device operation, parts, maintenance and performance? These issues will undoubtedly result in, or at least contribute to, the premature expiration of device usefulness in some situations.

In addition, the increasing use of contract personnel and outsourcing of internal design and construction responsibilities can accelerate the shortening of useful life due to the fact that the contractor, outsourced, temporary personnel simply do not have the historical background, data and documentation to inform them why something was done the way it was; and when things went into service; and the device performance history. It is easier for an outsider to package a design and replace a system, or number of components, than to try to maintain or extend the life or specific devices - especially from an external perspective from the utility.

1.15) Hazard Reduction

Requirements continuously change in order to reduce hazards in the workplace. As a result there may be circumstances that arise after a device is placed into service which require the device to be changed out (shorten its useful life).

Hazardous issues which may provide impetus for replacing a device prior to its expected end-of-life include:

- Lack of sufficient barriers or interlocks when performing maintenance.
- The presence of hidden and dangerous energy sources, such as energized capacitors and springs.
- The presence of toxic materials (PCB's, asbestos, mercury, lead, benzene, etc.).
- Lack of proper clearing times needed for arc flash protection.
- Lack of ability to change setting groups to allow faster clearing times when linemen are working on or near energized power lines.
- Lack of high impedance fault detection for energized lines lying on the ground.

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[4] Refer to the wiki page at https://en.wikipedia.org/wiki/Cost%E2%80%93benefit_analysis for a starting point to learn about cost-benefit analysis.

[5] Consider for example the demise of the 5 1/4 or 3 1/2 inch floppy disk. Older devices came with paper copies of manuals which are frequently purged during documentation down-sizing operations.

- The device(s) may be located in hazardous areas with such dangers as: exposure to moving parts; exposure to possible steam leaks; unacceptable noise levels; elevated heights; confined space; unacceptable temperatures; radiation exposure; etc.

A device may need to be replaced prior to the end of its end-of-life due to these and other concerns. Each utility and state/province/federal government will have its own measure of what is considered to be hazardous in the work place, but it usually involves some level of actual or perceived potential injury to personnel. Power system relays are generally not considered to be hazardous if used according to manufacture specifications but a couple of examples below are instances where they could be:

1) Some electromechanical relays were built with capacitors, wire or other components that contained Polychlorinated Biphenyl, PCB, and insulating fluids. These components have been known to leak and/or off gas PCBs at significant levels and potentially expose employees to this carcinogenic and mutagenic compound. The environmental issues associated with PCBs have resulted in many of these older relays being systematically removed from power systems and being retired.

2) Spurious assertion of trip outputs during non-fault conditions or not tripping for a fault condition may be considered a hazard at some utilities. One utility had a condition where a family of new relays was needlessly asserting breaker failure outputs that resulted in clearing the bus at critical stations. This situation was viewed as a hazard, and the relays were removed from the system.

3) Although not a relay issue, the test switches built into some digital relays have created concerns with their usage. Some test switches do not automatically short circuit incoming current transformer, CT, circuits when the test plug is inserted into the test block. These test blocks require the maintenance personnel to install a number of “test jumpers” in the test plug to continue the shorting function after the plug is inserted in the block. Some utilities have had CTs become open circuited when the test plug was not configured properly and then inserted into the test block. This has led to burned blocks and damaged relays and as a result, some utilities have viewed these types of test blocks as a hazard to personnel. This has led to the early retirement of relays containing these particular test blocks.

4) Maintenance may require access to the proximity of hazardous ac or dc voltages and currents. Also, Maintenance can expose workers to danger from possible high voltages or currents during fault conditions. Maintenance sometimes requires access to rear panel terminals and/or possible hazardous practices of removing connections to facilitate testing. Some older relays, for instance, require that the front cover be removed to access settings and test points while the device is energized.

It is possible that, in extreme circumstances, a manufacturer may recall a device due to possible hazardous concerns such as occurs in the automotive industry from time-to-time. This is of great concern not only from an operational point of view but also from a publicity and litigation perspective as well.

The diligent consideration of hazardous issues may result in a device reaching its end-of-useful life well before its expected end-of-life.

1.16) Operational Issues

Operational issues related to the functionality of a device can lead to a lower life expectancy if, for example:

1. The device does not have operator control or functionality required for the application (distributed generation or interface to local municipal utility, for example). Perhaps with emerging smart grid applications or increased DG penetration there may be operational (control and metering) features that are now required but not previously available. These issues could lead to the device being replaced prior to its end of life.

2. In addition to control and metering information, the device may lack certain capabilities necessary to provide for operator and control data. Financial information, asset management information may be required but not available (consider 61850 and CIM[6] and how data can be used for non-technical purposes as well as technical). Smart meters, though not a protection and control device per se, are an example where an existing device is replaced (before its end-of-life) with another device having data capabilities for operational information.

3. It is possible that device functionality no longer aligns with corporate policies (reliability, connectivity with neighboring utilities, performance, etc.) and therefore must be replaced.

4. Reorganization from a regional-based operation to a centralized operation may require replacing equipment due to the need for remote access, control and data accessibility.

1.17) Reduce Outage Scheduling and Customer Outages

Utilities are now trying to work smarter and reduce the number of outages taken on power equipment in order to reduce customer interruptions, scheduling issues and reduced system security. This is becoming more important recently with the increasing number of generators being added to the transmission system. With their mandate and objective to generate power and maximum revenue, taking equipment out of service multiple times due to uncoordinated outage requests (one for P&C, one for lines, one for this, one for that, etc.) is no longer practical. It therefore makes sense to schedule the maximum amount of work - from all disciplines - during each and every outage and reduce equipment outages to a bare minimum.

This pressure to reduce outages impacts the scheduling of work programs but also has an impact on equipment end-of-life. If a protection or control upgrade is scheduled for a certain date but the power equipment it protects (or controls) is coming out of service prior to that date, it makes much more practical sense to do the P&C work when the power equipment is already out of service. This reduces the number of outages, scheduling requests and trip tests. It may also reduce the amount of time spend traveling (reducing travel hazards) for operators (less switching) and facilitate multidiscipline interaction.

Obviously this requirement by some utilities to reduce outages can impact end-of useful life as devices may be replaced sooner than expected. This will have to be taken into consideration during the planning stages for the P&C equipment end-of-useful-life assessment [9].

1.18) Cyber Security Implications

A device may be replaced due to lack of cyber security features. Even though it may be adequate for the function for which it is intended, the lack of sufficient security features may warrant replacement of the device. This may also be an example of a change (useful life less than design life) due to regulatory requirements.

Even if the device has sufficient cyber security features the usefulness of those features may be an issue as well. Consider the need to update/change passwords on an annual basis. Some utilities are using a user-based account system to update device passwords. Without this remote access capability the operating/maintenance cost of the device may be a factor in upgrading to a newer version to provide such capability to meet the need of securing local/remote access.

A further cyber security concern that may have an impact on the useful life of a device is that of its software vulnerability. Does the device have a back-door vulnerability that may allow unauthorized access? Does the user software require remote access for a license key or help files? Does the software perform routine Internet checks

[6] Common Information Model

for new versions, upgrades, or patches (consider Windows updates)? These issues may warrant the replacement of a device due to security concerns.

Security concerns leading to an end-of-useful life may also arise from lack of conformance to NERC CIP requirements which includes many other concerns aside from those listed above.

1.19) Environmental Implications

A device may have reached its end-of-useful life due to environmental issues. For example, the utility may have a policy against PCBs, asbestos, or lead solder. Some devices may contain these substances and the corporation, due to environmental concerns, policy or public pressure, may need to eradicate these from its system. In older stations, for example, the presence of ebony-asbestos relay panels may be considered a motivation for replacing the panel and equipment - even if the equipment is functioning properly and reliably.

Humidity, seismic activity, and temperature are also factors that may contribute to a less-than-ideal life for protection and control devices. Environmental issues need to be carefully examined, as a bulk order for protection or control devices may be allocated to different sites. Devices installed in air conditioned control buildings would not likely be limited to the same life expectancy as those installed in the basement of a 60 year old substation or in a breaker mechanism box. The end-of-useful life of the devices in the breaker mechanism box certainly would be shorter than those in the air conditioned control room (due to: vibration; dust; temperature swings; humidity swings; greater potential for EMC; and possible UV exposure, for example). These factors need to be considered in determining the useful life of a device. Not all locations can be considered the same

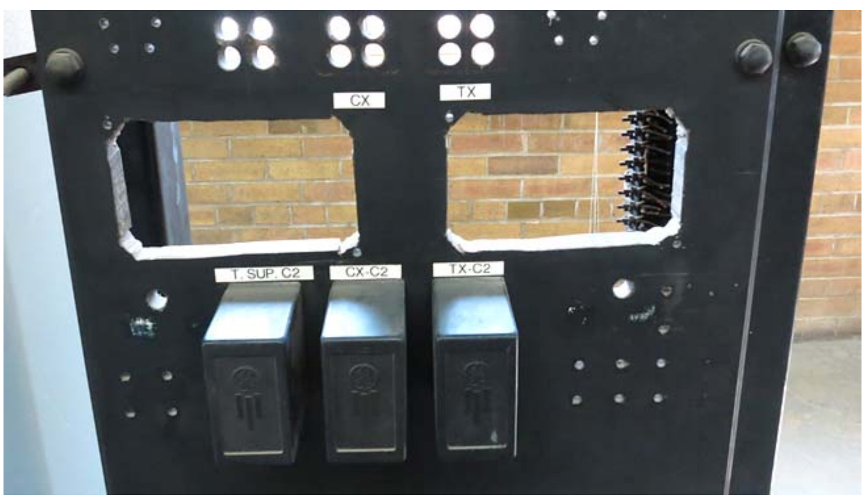

Figure 4 - Ebony-Asbestos Relay Panel

Environmental issues can lead to reduced expected life expectancy, that is, cause an end-of-life that is lower than that for which it was expected to achieve. Factors such as: cycling (on/off/on); air flow; and the normal state of the device (energized/de-energized) are normal operating environmental conditions, however when not taken in to consideration during the design or implementation stage of the application can lead to an end-of-useful life significantly shorter than that for which device was expected.

The Arrhenius equation for aging is shown below, where AF = aging factor; E_a is the "activation energy" of the component being aged; and k is Boltzmann's constant.

$$AF = e^{-\frac{E_a}{k}\times\left(\frac{1}{T_1}-\frac{1}{T_0}\right)}$$

This equation shows the relationship between an elevation in *temperature* and the impact on life expectancy. A device ages, by the aging factor (AF), when it is exposed to higher than designed for temperature. It therefore reaches an end-of-life sooner than what it was originally intended or designed for. Electrolytic capacitors, for example, "typically double their stress and failure rate for every 10°C increase in operating temperature" [10].

A further development on the Arrhenius equation is that of the Hallberg Peck relationship which also shows the impact of *humidity*.

$$AF = \left[\frac{RH_0}{RH_1}\right]^3 e^{-\frac{E_a}{k}\times\left(\frac{1}{T_1}-\frac{1}{T_0}\right)}$$

This equation shows that there is a cubic relationship between an elevation in humidity and the impact on life expectancy. A device ages, by the aging factor (AF) when it is exposed to higher than designed-for temperature and/or humidity. It is not the intent of this report to go into the details of specific aging factors, but to point it out to make the reader aware of these issues.

With the extreme weather conditions, some utilities have experienced flooding and high levels of humidity. Unfortunately, the impact of high levels of humidity on the performance and longevity of protection devices is not well known, or generally even considered. Nevertheless, humidity does impact the age of a device and must be factored into a consideration of the device's useful life.

1.19.1 Storage Considerations

Storage is important factor to consider in terms of: how the device was handled; how long has it been in storage; and under what conditions was it stored? Many of the issues related to temperature and humidity may impact the useful life a device during storage. Most manufacturers carefully package their devices to protect them until the time of installation; nevertheless, storage is an important consideration when determining the end-of-useful life.

Storage is also an important consideration with respect to the aging of electronic components. Aluminum electrolytic capacitors age when they are not subject to energization. The aging process is due to breakdown of the dielectric which occurs when the capacitor is unenergized. When an electrolytic capacitor is energized the dielectric is healed ("reformed") and restored. Degradation in the dielectric leads to an increase in leakage current. Therefore, the longer capacitors remain in storage without being energized or "reformed" the leakage current, when they are energized, can become greater than the rated value. This may lead to failure when the device is eventually energized. Texas Utilities Comanche Peak Steam Electric Station states that the shelf life of electrolytic capacitors is 16 years with appropriate re-forming, otherwise only 5 years without appropriate re-forming [11, 12].

One manufacturer clearly states that "To avoid deterioration of electrolytic capacitors, power up units that are stored in a de-energized state once per year, for one hour continuously" [13].

The leakage current of a capacitor is essentially the presence of parallel resistor across the capacitor as shown inFigure 5. This resistor is ideally and normally extremely high but due to the degradation of the dielectric can become much smaller thereby leading to an increased current flow and possible damage.

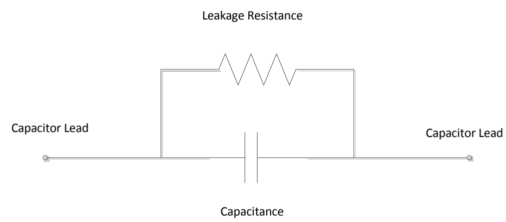

Figure 5 - Simplified Capacitor Model

Storage time and operating temperature can accelerate the dielectric degradation process and create a shorter useful life for the device.

1.19.2 Silver Migration

An environmental issue faced by some older devices is that of *silver migration* (electromigration of silver). Silver migration is the diffusion of metal alloys from one location (typically a terminal post) across a surface to another location (terminal). It is not clearly understood what causes this but is conjectured to be a result of ultraviolet radiation as it occurs somewhat more predominately near sunlit surfaces. Figure 6 shows silver migrating from one terminal to another terminal. Silver migration is a serious issue and has resulted in the need to replace entire relay cases. Silver migration is an example of how an environmental issue can lead to an end-of-useful life that is less than desirable. Proper conformal coatings are required to help prevent this from occurring. Silver migration has also been identified as a problem in the railroad and telephone industries [14,15]

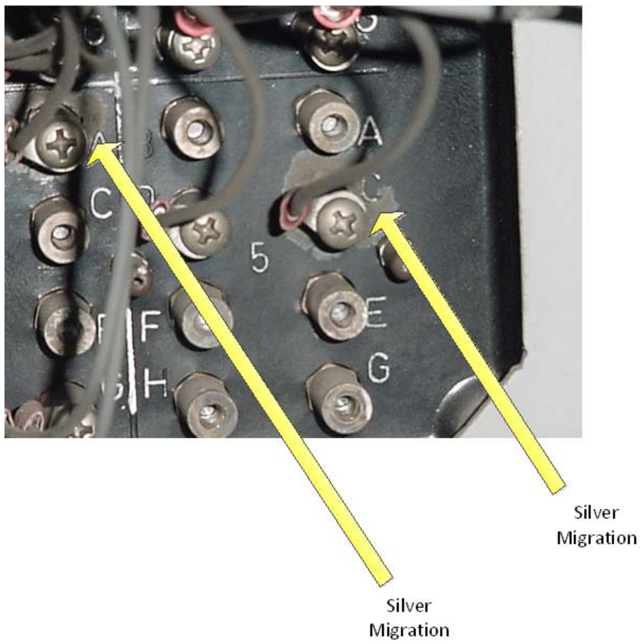

Figure 6 - Example of Silver Migration

1.19.3 Tin Whiskers

Another environmental issue leading to a reduced end-of-life is that of *tin whiskers*. Tin whiskers are small filaments of tin (or alloys) that can grow to be millimeters in length and bridge between traces on a circuit board, pins on a sub connector, relay contacts, and various other metallic surfaces[7]. Tin whiskers have also played a role in the failure of other devices such as GPS receivers [16]. For more information on tin whiskers with graphics, details on their formation, and damage caused as a result of their presence, refer to [17 and 18]. A downloadable spreadsheet providing a "Tin Whisker Risk Assessment" is available from the URL link provided in the References [19].

Figure 7 shows a tin whisker growing between two pins on a 14 pin DIP package IC. In this case the whisker actually grew long enough to short the two pins of the IC. The pins on this IC were tin plated with a spacing of 0.1". Figure 8 shows a whisker (possibly zinc in this case) growing between a relay base and relay coil.

[7] For videos showing whisker growth see: http://www.engin.brown.edu/faculty/Chason/research/whisker.html

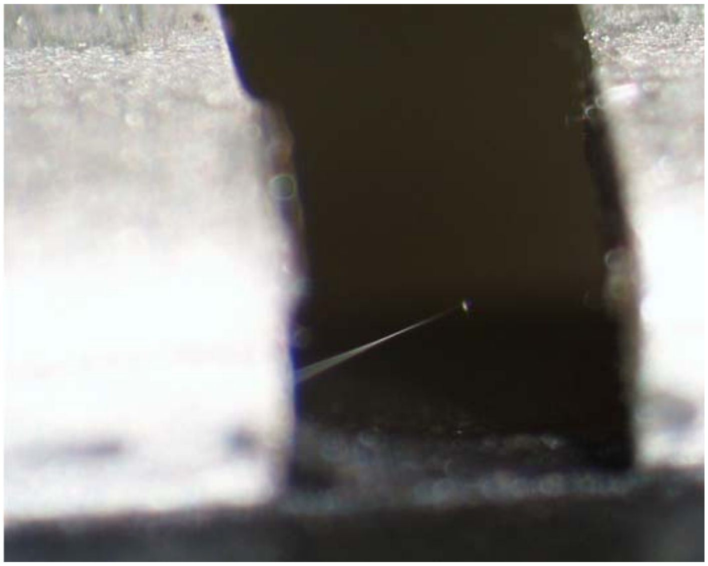

Figure 7 – Whisker Growing between Two Pins of 14 Pin DIP IC (Photo Courtesy of Kinectrics Inc.)

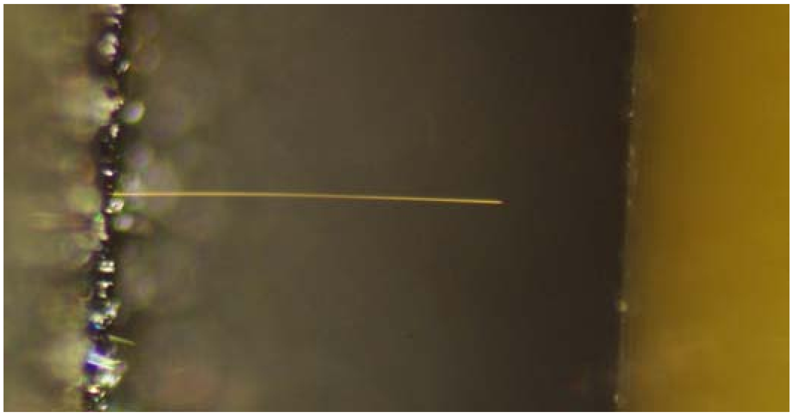

Figure 8 – Whisker Growing between Relay Base (left) and Coil (right) (Photo courtesy of Kinectrics Inc.)

1.19.4 Other Environmental Issues

Other environmental issues that could lead to a shorter useful life - if the device is not suitably qualified include:

- Vibration, which can be caused by seismic activity, road traffic, blasting, and lead to lead to "wire chafing, loosening of fastener, intermittent contact closure/opening, seal deformation of enclosed components component failure, optical misalignment and cracking [20].
- UV radiation from the sun.

- EMI (surge withstand, dielectrics, fast transient, etc.)
- Moisture (rain, snow, frost) in outdoor locations
- Humidity from damp control room basements with cable entrances and sump pumps.
- Dust ingress
- RF radiation

Some very old devices are susceptible to vibration, dust, moisture, contact contamination, as well as other contaminants hostile to electronic or electromechanical equipment.

1.20) Improper Application

To an extent, improper application has been covered indirectly in other discussions in this report; however it is important to realize that improper application can result in a less than ideal life expectancy. If the application design and product selection were not properly identified then the device may require replacing in advance of its end-of-life due to improper application – the wrong device for the application.

Possible improper application issues include:

1. Output contact ratings are not correct for the application.
2. Humidity, temperature, vibration, altitude rating, or EMC ratings are not appropriate for the application or installation location. For instance, the wear and tear example of an electromechanical plunger type relay described in Section 1.23 could be considered an incorrect application.
3. Potential for smoke damage to equipment/contacts in areas susceptible to forest fires.
4. Setting ranges are not adequate for the application.
5. Performance requirements or networking capabilities not sufficient.
6. Using an overly complex device for a simple role. This may not appear to be a problem but in terms of replacing the device it makes it more complicated. Also, maintenance, settings documentation, procedures, functionality may be overly excessive for the specific application.

Any number of the above issues, and more, are sufficient to render the device unsuitable for future use. The issue comes down to proper planning to a great extent. This highlights the need for proper design and device selection at the start of a project in order to help avoid end-of-useful life issues in the future.

The NERC Misoperations Report (April 1, 2013) provides the following suggestions for helping to avoid possible trouble arising out the improper application of devices [21]:

> "Applications requiring coordination of functionally different relay elements should be avoided. If these applications cannot be avoided, the coordination should be studied and tested thoroughly. This type of coordination is virtually always problematic, and is the cause of numerous misoperations reported in the study period. Some examples to avoid include:
>
> - Mixture, in the same scheme, of distance elements and overcurrent elements
> - Distance and directional overcurrent elements at opposite line terminals that use different directional polarization methods, particularly in the same pilot scheme
> - Overcurrent elements that use different measurement methods, such as phase vs. residual ground vs. negative-sequence current measurement"

Proper application of a device is critical.

1.21) Application beyond Design Parameters

Akin to improper application, it is also possible that the device may be applied in conditions that exceed its design parameters and therefore could lead to an earlier end-of-useful life. Manufacturers typically give extensive operating parameters for their devices including: voltage, humidity, temperature, EMC levels, altitude, shock/vibration, dust, etc. If a device is operated outside of these ranges, it could degrade the life expectancy, similar to when a transformer is operated above its rating for extended periods of time.
An example of a protection and control device applied beyond it design limits could be:

- The operation of the device in a humid environment or located above a heater, or near a window.
- The device could be installed at a site whose elevation exceeds the device's rating.
- The device is used with a battery charger that has an excessively high float level.
- The device operates more times than it is designed to operate.

The device operates a load that exceeds its contact ratings.

1.22) Early Adoption

Early technology adoption (trendsetting) may be a driver for a shortened end-of-useful life. Technologies may be deployed before they have been fully tested or "proofed". The Rogers's Bell (Figure 9) curve is a Gaussian-based distribution showing the demographics of technology adopters over time [22]. Care (type testing/pilots/environmental testing/etc.) should be taken when adopting new technologies.

Early adopters, also called "Lighthouse Customers" by the industry[8], may face near-term issues with products from software, firmware, and hardware-related teething pains. This may necessitate early retirement of the device due to performance issues.

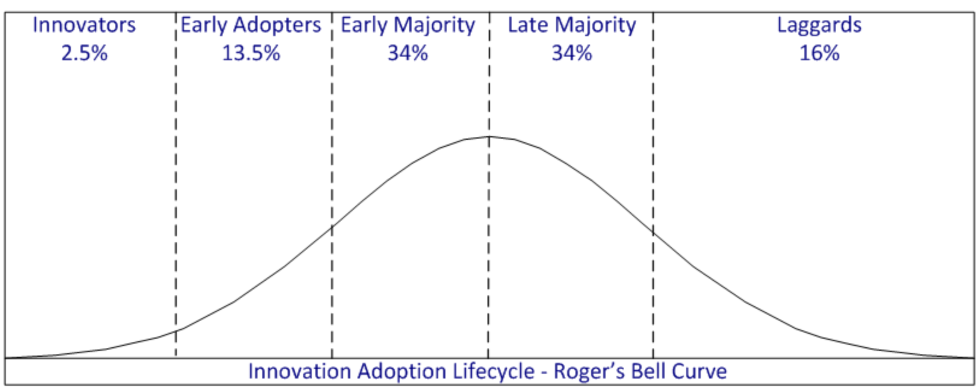

Figure 9 - Innovation Adoption Life Cycle

Early adoption of new technology may have associated risks as well as the touted benefits. The Gartner Hype Cycle depicts a graph, similar to a damped wave with overshoot, illustrated in Figure 10. On the "y" axis is the visibility of a new product and the abscissa shows product maturity. When a new product is deployed, there is a "trigger" that pushes the new product out in to market place. As the product is promoted, the expectations begin to increase

[8] Presumably so called as they provide a warning to later adopters?

and eventually peak. The product then may fail to realize some of the promised benefits and the then enters the "trough of disillusionment". This trough then gradually reverses as the product matures and the adopters begin to see the promoted benefits and rewards. Eventually the product matures and becomes accepted by the mainstream [23]. This illustrates that new products may come with inflated expectations until there finally comes user maturation with greater acceptance. During this development cycle the product evolves and performance stabilizes.

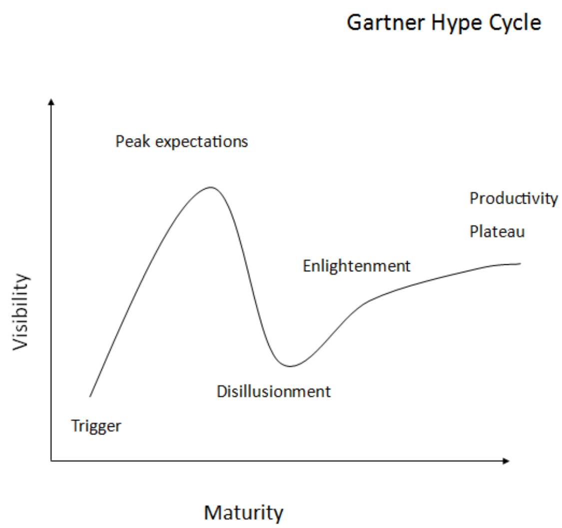

Figure 10 - Gartner Hype Cycle

Early adopters of new products, or technologies, must be aware of the inherent potential for life-cycle impact including possible shorter life issues. This is a well-known, common and industry wide phenomenon.

1.23) Wear and Tear and Mechanical Failure

As mentioned in the introduction of this report, the manufacturer-based rating for the number of operations is a possible indicator of actual end-of-life. This is related to wear and tear and operational life due to mechanical/electrical failure characteristics (no device will last forever).

An example of a failure that led to the early end-of-life of a device is given below and illustrated in Figure 11:

> One utility experienced a problem with a plunger type relay used in under voltage applications that were not designed for continuous AC energization operation. The mechanical wear as a result of this continuous operation caused fretting and sticking of the device. The resulting increase in maintenance and other alternatives do not resolve the problem and the device had to be replaced [24,25].

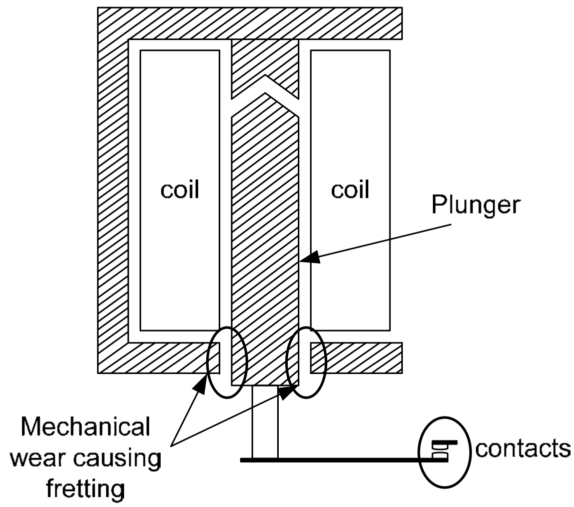

Figure 11 - Illustration of Mechanical Wear Which Resulted in End-of-Useful Life [24]

Typical concerns with electromechanical contacts are their ratings. Manufacturers specify the rating of their device contact by means of voltage, current making (or breaking) and L/R ratings. Switching devices may fail due to: overheating; overcurrent; overvoltage; excessive *di/dt;* or excessive *dv/dt* [26]. Contact arcing through time, or misapplication, can result in degradation of contact resistance and/or welding of contacts. This may necessitate the repair or replacement of a device. This is an example of where proper design and application would ensure the longevity of a device by possibly installing contact protection (snubber circuit) or increasing the rating of a device (over specify). For example, the inclusion of a simple snubber circuit during the design of an application can help prevent contact damage due to arcing, reduce possibility of EMI, and subsequently help extend the useful life of a device. Snubber circuits can be a simple RC circuit, diode, or varistor to mention only a few [27, 28].

1.24) Human Factors

Although this may be a minor issue, human factors may also contribute to the early demise of a device in respect to its end-of-useful life. There may be occasions when accessibility and usability may be factors in the usefulness of a device and therefore its longevity. Consider for example:

- Ease-of-use – Does the device have mechanical interfaces (knobs/dials/terminals/etc.) and are they easily (and safely) accessible? Does the device require the use of specialized tools for accessing it (physically, or via software, or via communications ports)? Is the documentation easy to read, understand, and is it well organized? Are the on-panel indicators and displays clear? Are the controls/interfaces confusing? A bad design or poor documentation can lead to operator error or create a personnel hazard which could impact the life of the device if performance is impacted.
- Software usability – is the software such that it makes the life of the user easier? Is it intuitive to use? Does the way it is designed help reduce the possibly of errors? Does it allow for the self-checking and verification of data? Does the software conform to company policies? (Perhaps the software accesses remote servers for help files, software updates or license validation – in contradiction to NERC CIP or company policy requirements. Obviously this could lead to a shortened life if the equipment must be replaced due to internal or external policy violation.

These human factor issues should be addressed at the design and purchasing stage, nevertheless, circumstances sometimes arise where these issues must be considered retroactively.

1.25) Disposal

It may be prudent to retire a device prior to its end-of-life due to pending legislative changes such as those requiring increased diligence, cost and procedures with respect to disposal (for example, lead solder or NERC CIP requirements for disposing of critical cyber assets). However, as a good corporate citizen, utilities will want to dispose of equipment properly regardless of pending legislative changes. Devices containing the following hazardous materials are strictly controlled with respect to their disposal [29]:

- Lead paint, lead solder
- PCBs (found in some capacitors)
- Asbestos insulation
- Mercury (relays, LCD displays, batteries, etc.)
- Phosphorus displays
- Flame retardant materials
- Cadmium in batteries
- Beryllium (printed circuit boards, monitors, relays)

However, disposal is no longer simply limited to hazardous materials. Now one must also consider devices containing critical cyber asset information or data and dispose of this equipment in a controlled manner. This ensures that confidential information stored in the device is not left for non–authorized personnel to view and exploit, The following excerpt is from NERC CIP-007-3a Section R7 [30].

> R7. Disposal or Redeployment — The Responsible Entity shall establish and implement formal methods, processes, and procedures for disposal or redeployment of Cyber Assets within the Electronic Security Perimeter(s) as identified and documented in Standard CIP-005-3.
>
> R7.1. Prior to the disposal of such assets, the Responsible Entity shall destroy or erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.
>
> R7.2. Prior to redeployment of such assets, the Responsible Entity shall, at a minimum, erase the data storage media to prevent unauthorized retrieval of sensitive cyber security or reliability data.
>
> R7.3. The Responsible Entity shall maintain records that such assets were disposed of or redeployed in accordance with documented procedures.

The disposal of devices is an important consideration in determining the useful end-of-life of a device in so far as how long the process may take and what is required as well as the cost in time and labor. Device disposal cost and considerations should be examined at the time of evaluation, design and purchase. It is hoped that with the awareness from documents such as this one, including the list of things to remember found in the appendix, that obscure items like “disposal” will also be considered in the product life cycle.

2) Motivation for Determining End-of-life

The following are a number of issues that provide motivation for determining the actual end-of-life of devices.

2.1) Impact of End-of-Life on Reliability and Redundancy

Redundancy is designed into many protection schemes to provide adequate protection coverage in case of component failure. This redundancy plays a large role in the reliability of the scheme. The system dependability is maintained as long as confidence in the viability of the installed equipment remains high. As this equipment approaches end-of-life, the loss of a component effectively removes the redundancy and its inherent reliability. This in turn creates a higher level of uncertainty for the health of the remaining equipment. Improvements in the predictability and management of the end-of-life help maintain a high level of reliability and dependability of the protective system. It might also be noted that this impact can vary depending on whether the affected relay is a single-function device such as an electromechanical relay or a multifunction device such as a microprocessor relay. Older electromechanical schemes may rely on partial redundancy from a collection of relays. For example, the loss of a ground relay is covered by the protection provided by the phase relays. Other schemes may consist of two multifunction relays or a combination of mixed multifunction and single-function relays. The impact of losing a component in each scheme on redundancy will vary but the impact on the overall reliability will remain the same.

2.2) End-of-Useful-Life Needed for Asset Management

Asset managers require a thorough knowledge of the characteristics of their assets in order to schedule changes/upgrades and also to determine the economic impact of a change. If scheduling and equipment/resource forecasts are predicted based on the end-of-physical life (wear out as per bathtub curve) then rate cases, labor and reliability issues can become a significant issue to contend with.

Of course it is impossible to determine when new functional requirements regarding device performance may be necessary to comply with some technical or regulatory directive, nevertheless, it is prudent in the planning stages to consider that a device may reach its end-of-useful life significantly sooner than its expected end-of-life.

Asset management requires a comprehensive understanding of the life of equipment – sometimes referred to as a “health index”. It is not necessary for the sake of this document to enter into the details of asset condition assessment, however it is enough to say that end-of-life features prominently in any asset management strategy and taking the end-of-life to mean the end of a device’s physical life is not necessarily the most prudent course of action to take.

As an example, microprocessor based devices have an expected life of 20 years or less due to technical obsolescence. The primary equipment they protect often has a life of 40 years or more. Therefore asset managers may wish to plan for replacement of protection and control equipment based on the life of a primary asset.

2.3) Impact of End-of-Life on Regulatory Compliance

It is difficult to know if technology drives the regulatory bodies to draft new policies or if the system operating requirements drive the technology. Regardless, due to the need for a highly reliable system regulatory requirements will continue to impose themselves upon the industry. These requirements will also drive the need for newer technologies. We currently see this already with requirements for DG integration, energy storage, smart grids and smart metering. Technology will continue to play an important role as conservation, hazard reduction, and environmental considerations are addressed by legislators.

NERC standards either requiring or influencing the end-of-life of older generations of relay manufacturing technologies include PRC-023 Transmission Relay Loadability Standard, NERC PRC-005-02 Relay Maintenance Standard, and NERC CIP 7. NERC PRC-023 was created to address relay loadability which has been cited as a factor in major system disturbances since 1965 including the 2003 blackout. The standard improvements are intended to be permanent and enforceable [31]. Some relay technologies including electromechanical distance relays cannot be set to meet this standard for all applications particularly those providing protection of long transmission lines where the zone coverage required drops below the rating of the circuit. Newer distance relays with load encroachment blinders often can be applied to meet the NERC PRC–023 standards. PRC–005-02 the relay maintenance standard requires that electromechanical relays to be tested more frequently than common micro-processor relays because they do not have self-monitoring capabilities. NERC CIP 7 requires the use of strong passwords for micro-processor relays when possible. Utilities prioritizing on cyber security would be motivated to replace early versions of micro-processor relays that do not support strong passwords.

2.4) Technological Advances

The current focus on technology and what it can do for the power system will inevitably drive the industry to earlier adoption and deployment of innovative solutions resulting in more end-of-useful life considerations. Consider the impact of blackouts and terrorist attacks and how this has driven the industry to adopt synchrophasors and disturbance records and cyber security considerations. These have led to advances in technological requirements and the need to either replace or integrate new devices far ahead of existing, planned replacement cycles.

Of course none of this is predictable and one cannot enter these societal issues into an end-of-life equation, but nevertheless they significantly impact the useful life of protection and control equipment. It would be prudent for each utility to at least be aware of, if not involved in, the regulatory processes that impact the operation of their industry as this will impact equipment end-of-life.

2.5) Performance (Need for Calibration)

One possible indicator of a device nearing its end-of-useful life is its performance with respect to routine maintenance. If the set points or calibration response is drifting, or not consistent from one maintenance interval to the next, this may be an indicator the device is ending its useful life. Components in the device could be aging or becoming more susceptible to environmental issues. Obviously to determine if the device is behaving inconsistently, the need for accurate record keeping and the ability to track performance is essential.

This metric of monitoring performance may become more difficult to evaluate and interpret as maintenance intervals become extended (due to less maintenance data), nevertheless, it is a sure indicator that there may be issues with the device and that the device may need to be retired[9].

3) Determining End-of-Useful Life

In order to develop an effective end-of-useful life assessment for a device, proactive studies need to be undertaken. Each device type should be studied regarding the issues summarized in this report and evaluated in terms of what the end-of-useful life could be. Anecdotal evidence using internal data and experience would be highly valued.

Up to this point the report has discussed many of the issues that may contribute to a shorter useful life - compared with an expected design or device life. Now the report shall attempt to provide some tools to evaluate quantitatively the impact of these factors (*F*). Specific factors include:

[9] Tracking of performance in light of reduced maintenance intervals may provide an impetus for an industry-wide database on device performance. Even though one particular utility may only maintain their device every 8 years for instance, using a combined force of many dozens of utilities would provide great insight to the performance of specific devices and help all utilities in their end-of-useful-life assessment.

1. *F(manufacturer)* - What are the end-of-life factors that are impacted by the manufacturer?

    a. Viability of manufacturer. What is the likelihood the manufacturer will be around for the next 10 years? How long have they been in existence? How long have they been making protection and/or control devices?

    b. Past performance experience of manufacturer. Has the manufacturer been responsive to issues? How has their quality control been? What is the turnaround time for repairs? Do they charge for repairs?

    c. Support: Is support available? What is the quality of support? What is the timeliness of support?

    d. Spares: Are spares available? Do they have the correct firmware? Is the appropriate configuration software available and functional and will it run on present generation computers?

    e. Firmware upgrades: How frequently is the firmware updated? How severe are the firmware changes? How difficult is it to upgrade the firmware?

    f. Hardware issues: Have there been any hardware issues? How severe have they been? Do they require a return to the manufacturer? Does the relay need to be removed? How long does service take?

    g. Recent experience with other products from same manufacturer. Use experience with other products as a baseline or indication of what to expect. Is the device a mature product?

    h. Are there possible issues arising from early adoption?

    i. Are there quality related issues with the manufacture or components used in the manufacture of the device?

2. *F(performance)* - What has been the performance of the device?

    a. Past history of reliability of device based on own experience (MTBF determined by vendor or utility?)

    b. Past history of reliability based on the utility's own experience with similar devices. Many devices have similar characteristics and performance can be generalized in the event of a lack of specific information.

    c. Actual performance (as observed during routine testing/as-found information) can be used as input to developing an accurate end-of-useful life model for a particular device.

    d. Number of false operations and unscheduled maintenance can be a motivation to replace a device before its design life. Similarly, self-reporting indications of internal problems (memory checksum, power supply etc.) may also be indicators of that useful life may not be equal to design life.

3. *F(company)* - What are the company (utility) factors impacting end-of-useful life?

    a. Fiscal outlook of the utility and likelihood of possible rate increases may impact device end-of-useful life. If a utility is constrained by financial resources they may implement changes in their design and maintenance programs to accommodate financial policies.

b. Future direction of the company in terms of replacement/upgrades in other areas (RTUs replacement, breaker replacements, control through IED, etc.) may cause a device to have a shorter life. If a utility has a fleet of a certain type of breaker and they wish to upgrade short circuit rating, they may replace the associated protection and control equipment the same time, even though such equipment is still perfectly functional.

c. Does the company (utility) have staff and resources to support the products in the field?

d. Operating requirements to reduce the number of outages

4. *F(industry) - What industry factors impact end-of-useful life?*

   a. Utility industry experience

   b. Other/Comparative industry experience (NASA/GM/AT&T/etc.) – The utility industry is not the only one using networking equipment for example.

   c. Anticipated standards under development can influence the end-of-useful life of a device and shorten it from its anticipated design specification. Standards are constantly being developed and revised. The impact of a change, especially a regulatory one, can have a significant effect on the end-of-useful life of a device.

   d. Trends in other areas of the industry will have repercussions on the expected, or planned, device longevity. For example: the growth of Ethernet speed may render some devices obsolete before their expected end-of life; the typical manufacturing life of electronic components may shorten the design life of a product; global acceptance of 61850 is making great inroads in the utility industry and may be a reason for replacing some devices before their actual end-of life; etc.

   e. Monitor performance. The use of an industry-wide database containing historical information regarding the performance of protection and control devices would be of great use to the industry

5. *F(device) - What are the non-performance-based factors impacting end-of-useful life?*

   a. Risk assessment (could include redundancy)

   b. Determining the life of vulnerable component(s) such as electrolytic capacitors can help determine useful life, as in routinely done in the nuclear industry.

   c. Disposal related issues: Are there special requirements (or pending requirements) for disposing of the device (hazardous waste, NERC CIP, time necessary to remove, special tools needed, etc.)

   d. Ergonomic issues, human factors: what are the ergonomic issues surrounding the device?

   e. Wear and tear and mechanical factors – are there mechanical issues arising from operation movement that can impact-end-of useful life?

   f. Environment (Hot vs. moderate, humid vs. dry) can lead to shorter life expectancy. Empirical data exists showing how life expectancy is depleted due to elevated temperature or humidity. This can be factored into an expected useful-life analysis

   g. Does the device impact system reliability?

The above factors can be integrated into a checklist for scoring purposes; however, it is difficult to quantify certain things or to place a weight upon them. For example, vendor support may be good, fair or poor; however, vendor support may not be as critical as the actual performance of the device. If the device functions well with little trouble, then vendor support may be of little consequence. In addition, the evaluation of the parameters above *must* be made by someone who is aware of the issues. It would be of little value to have somebody in purchasing describe the efficacy of customer support, or device performance, and assign some numeric scale value to that, for example.

Nevertheless, there are ways of quantifying subjective information and it may be possible to derive an algorithm using the above factors, with suitable weighting, to determine an effective end-of-useful life.

Expected end-of-life can be defined by the MTBF or warranty period as specified by the manufacturer. Some manufacturers state that their devices have a certain MTBF, or provide a warranty for a certain duration or explicitly state that their device will last and/or be supported for a certain number of years. However, in terms of end-of-useful life it would be beneficial to define a heuristic by which the utility itself can estimate the useful life of a device for their planning budgeting, forecasting and staffing purposes.

Possible ways to determine a numerical end-of-useful life estimate might include:

- Examine subjectively/objectively the concerns and issues and assign some weighting factors.
- Scaling the issues and concerns and issues from 0-10, for example.
- Use a live-to-fail policy based on performance trends and historical data.
- Determine a percent of end-of-useful life metric based on various factors.

Examining the above life-factors elucidated in this document, one may come up with a very simple equation based on a totally subjective analysis. The following equation is presented as one option: a de-rating factor which is proportional the sum of the above factors, each of which factors is weighted according the intrinsic value placed it by the utility.

$$F(derating) = \delta\,[\alpha_1 F(performace) + F\alpha_2(company) + \alpha_3 F(industry) + \alpha_4 F(device) + \alpha_5 F(manufacturer)]$$

Where:

F(derating) is the end-of-useful life de-rating factor (this is what we are interested in)

> δ = Overall importance of determining end-of-useful life (value from 0 to 1). For example, if useful life is of only modest interest to the utility, then a factor of 0.1 may be appropriate for δ.

For the sake of illustration, consider an individual or team has examined each of the above life factors for a particular device and determined the following:

Table 1 – Example of Rating Factors for Illustration Purposes

	Factor	From 0-10	Comment
1	*F(performance)*	9	The device has performed well (or a similar device that we have experience with has been a solid performer).
2	*F(company)*	10	Company is doing well with clear direction and solid management and staff.
3	*F(industry)*	8	There are some trends in the industry that may impact how we do business down the road.
4	*F(device)*	9	There are no or few non-performance based issues with this device.
5	*F(manufacturer)*	9	The manufacturer has a good reputation and provided timely and consistent support.
	Total	45 (out of 50)	This value is normalized in the analysis by dividing the total by 50.

Table 2 – Example of Weighting Factors for Illustration Purposes

	Factor	Co-eff	Weight	Comment
1	*F(performance)*	a_1	0.9	The impact of past performance is considered critical
2	*F(company)*	a_2	0.6	The impact of company-related factors is considered to be modest
3	*F(industry)*	a_3	0.75	The impact of industry factors is considered important
4	*F(device)*	a_4	0.9	The impact of the device factors is critical
5	*F(manufacturer)*	a_5	0.8	The impact of manufacturer performance is important

Then, for this hypothetical example:

$$F(derating) = 0.1 * \left[\frac{0.9 * 9 + \ 0.6 * 10 + 0.75 * 8 + 0.9 * 9 + 0.8 * 9}{50}\right]$$

or, a de-rating factor of 0.0885. Therefore, if at design time the expected life of the device was given as 30 years, then using a de-rating factor, as derived above, an estimate for the useful life would be 30*(1-0.0885) or 27.345 years. (Recall that the “50” in the denominator is for normalizing the Rating Factors in Table 1.)

If the useful life is an important consideration and a factor 0.4 is used instead of 0.1 for δ, then the de-rating factor would be 0.2832 and the estimated useful life would be 21.5 years. This number (21.5 years) could then be used (instead of 30 years) in the planning process for capital replacement, staffing levels, and rate case support.

The above analysis and equations are not scientifically determined but provide one way of quantifying end-of-useful life. Of course if the end-of-useful life is being determined at the beginning of the product life cycle then factors such as performance and industry experience would not be available and may have to be removed from Table 1and Table 2 though the manufacturer's stated MTBF or utility experience with similar products could be used as a basis for the performance factor in this case). The factors can be adjusted to develop unique or comparative models.

Also, it is important to keep in mind that the expected life (30 years, as used in this example) is often of questionable origin in actuality. Expected life is used as the basis for financial planning as well as equipment replacement (without consideration of useful-life). Expected life (*not* useful life) can be based on:

a. The design expectations for the device or application.
b. The financial deprecation life of the device.
c. Life, or mortality, tables, such as used in the insurance industry.
d. Maximum support period provided by the manufacturer (a new product will have a finite production and support life).
e. Maximum warranty periods provided by the manufacturer.
f. Expected operational life (rated number of operations divided by expected number of operations per year, for example).
g. Past experience with other similar devices.
h. Past experience with a previous generation of devices (perhaps expecting the life of a microprocessor device to be the same as that of an electromechanical device).
i. Expected life based on other equipment associated with the protection (for example, expecting a transformer protection to last the same length of time as the transformer itself).
j. Industry guidelines
k. Other user defined parameters.

This **expected** life of a device (not to be confused with its **useful** life) is important to establish, regardless of what method is chosen. It is assumed that most users would already have some idea of the expected life of a device. It is the intent of this report, as has been discussed, to make this expected life more realistic in terms of the issues and factors that have been discussed to this point and determine a reasonable and realistic end-of-useful life for the device[10].

4) Other Methods of Determining End-of-Useful Life

4.1) Sample Testing

The nuclear industry is currently faced with the challenge to extend the life of their existing and aging fleet of plants. The initial design life is being extended however it is critical to assess the reliability of existing devices. In this case one approach taken has been to perform sample testing on specific devices. This approach enables the planner to determine if specific equipment can function past its deigned life. Stress testing, including environmental and electrical effects, can be used to determine if a device will continue to function for some additional to-be-determined period of time.

[10] For an interesting perspective on life and death and life after death as related to lead acid batteries, please see "The Meaning of Life" at http://www.mpoweruk.com/reliability.htm.

A similar approach can be used to determine the useful life of a device for typical utility applications. A sample of existing devices (if available) can be tested to determine their expected-end-of life (which may be shorter or longer than their designed life). These tests are typically environmental-type test using heat and or humidity to perform an Arrhenius type of analysis.

4.2) Probabilistic Risk Assessment

Another approach can be the use of probabilistic risk assessment that has been used to determine the expected life of the International Space Station (ISS) [32]. Figure 12 is the index item from the NASA technical reports server describing a paper using PRA for the end-of-life assessment on the International Space Station [33].

1. International Space Station End-of-Life Probabilistic Risk Assessment

Document ID: 20140004798

NTRS Full-Text: Click to View [PDF Size: 343 KB]

Author: Duncan, Gary

Abstract: Although there are ongoing efforts to extend the ISS life cycle through 2028, the International Space Station (ISS) end-of-life (EOL) cycle is currently scheduled for 2020. The EOL for the ISS will require de-orbiting the ISS. This will be the largest manmade object ever to be de-orbited, therefore safely de-orbiting the station will be a very complex problem. This process is being planned by NASA and its international partners. Numerous factors will need to be considered to accomplish this such as target corridors, orbits, altitude, drag, maneuvering capabilities, debris mapping etc. The ISS EOL Probabilistic Risk Assessment (PRA) will play a part in this process by estimating the reliability of the hardware supplying the maneuvering capabilities. The PRA will model the probability of failure of the systems supplying and controlling the thrust needed to aid in the de-orbit maneuvering.

Publication Year: 2014

Document Type: Conference Paper

Report/Patent Number: JSC-CN-30995

Date Acquired: May 08, 2014

Figure 12 – Document Search Index Item on PRA on EOL re ISS from NASA

It is not within the scope of this document to explain the details of PRA, but many useful resources can be found on the Internet. The NASA Technical Reports Server[11] has many useful tutorials and papers on PRA as do many other worthy sites.

4.3) Economic Analysis

An economic analysis may be a viable approach to help determine whether a device should be replaced before its end-of-life or not. An economic analysis considers such things as alternatives, stakeholders, costs and of course, benefits.

The following is an excerpt from DoD Instruction Number 7041.3 [34]

> *E3.1… Economic analysis is a systematic approach to the problem of choosing the best method of allocating scarce resources to achieve a given objective. A sound economic analysis recognizes that there are alternative ways to meet a given objective and that each alternative requires certain resources and produces certain results. To achieve a systematic evaluation, the economic analysis process employs the following two principles:*
>
> - *E3.1.1. Each feasible alternative for meeting an objective must be considered, and its life-cycle costs and benefits evaluated.*
> - *E3.1.2. All costs and benefits are adjusted to "present value" by using discount factors to account for the time value of money. Both the size and the timing of costs and benefits are important.*

[11] http://ntrs.nasa.gov/search.jsp

Economic analysis is another tool that can be used to help to make the decision whether to replace a device before its end-of-life or not. For a tutorial on Economic Analysis, reference [35] provides an introduction including a non-technical example.

4.4) Failure Analysis

By performing a failure analysis, the root cause of the failure can be determined and perhaps mitigated in other devices, thereby extending their useful life. One device failure can help prevent other failures as well as extending the life of the remaining fleet. It is important for the user to examine and understand why a device fails.

As an example, failure analysis was used to estimate the end-of-useful life of a particular relay having trouble with "jaws" used to connect the current and voltage signals from the case to the relay - the "jaws" were fatiguing and cracking with age.

The utility underwent an extensive program to replace the jaws on vulnerable devices. The data obtained from this replacement process was analyzed by means of a Weibull analysis to determine if the failures were a random process or indication of early wear-out.

In this case, the Weibull analysis, Figure 13, provided a good fit to a straight line which indicates a single-mode failure in this case. The slope of the line (Beta) reveals if the failures are due to infant mortality, random failures, or wear-out. In this case the slope (2.766) indicates wear out. The intercept at 63.2% indicates the characteristic life of the device, that is, 63.2% of the jaws are expected to fail by this time, which in this case is 3232.75 days or about 8.85 years. The points shown in the graph represent the individual samples used in the analysis. Weibull analysis is particularly suited for cases with low sample sizes.

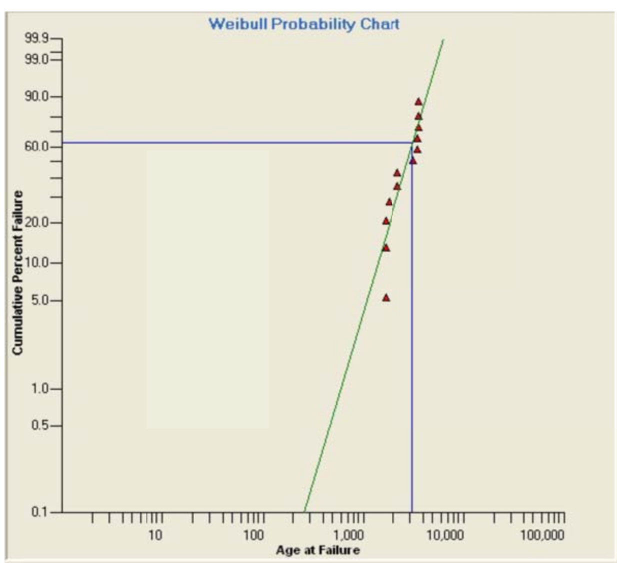

Figure 13 - Weibull Analysis of Jaw Failures

In this analysis, the data is somewhat questionable because exact in-service dates were not available and the out-of-service data used was not necessarily when the jaws failed (cracked) but when the failure or fatigued state was discovered (this uncertainty in the dates is also made evident by the undulation/curve in the plotted data points on the graph).

The Weibull plot can be used to determine the number of failures expected at certain levels. For example, with 10% failure, what is the expected life of these devices? By using the graph it can be seen that 10% of the jaws will fail before 2000 days, or 5.5 years from in-service.

The advantage of Weibull analysis is that a good prediction can be made with a small sample set. By randomly eliminating all but 5 samples from the above analysis, the same conclusion was reached, however the characteristic life was a bit longer.

> *"The primary advantage of Weibull analysis is the ability to provide reasonably accurate failure analysis and failure forecasts with extremely small samples. Solutions are possible at the earliest indications of a problem…" [36].*

Weibull analysis is one tool that can be used for determining end-of-useful life based on a failure analysis using actual data. In this example, the failure of the jaws was repairable, however, in many cases failures are not as easy to resolve and the device may have to be replaced (earlier than planned).

5) Life Extension

How can the end-of-useful life of a device be extended? There are several methods explained below, however, one can infer various solutions by examining the issues *causing* a shortening of useful life and then ameliorate those causes where possible.

5.1) Replace Aging Components

One method for extending the useful life of a device is to replace aging/aged components, for example in nuclear industry [37].

> "Capacitors also may exhibit tendencies to leak, drift, or make electronic noise, as a result of varying environmental conditions (e.g., shifts in temperature, humidity levels, or both). Extreme temperature conditions can be problematic for capacitors that contain aluminum electrolytes. At lower temperatures, capacitance falls off rapidly. At higher temperatures, the electrolyte may be lost through evaporation, thereby accelerating leakage. This may result in premature circuit damage or malfunction."

> "Capacitors are energy storage devices that are widely used in electronic and electrical power circuits. Operating experience has shown that capacitors have finite lifetimes. Placing these capacitors in a periodic preventative maintenance program that accounts for both time in storage and time in service can address the adverse effects of aging capacitors in equipment circuitry and prevent equipment failures."

Of course a precursor to replace aging components is to know which components are most vulnerable to aging in the first place. This may be a difficult task without the use of laboratory testing or extensive data on past performance of similar devices. Nevertheless, it is not an impossible task and there are components that age faster than others. Component activation energy, used in aging analysis, is one indicator that can be used to rate devices in terms of vulnerability to aging. Activation energy tables are readily available and provide a quick overview of what components age faster than others. Refer to MIL HDBK 217 for one source of activation energies related to electronic components [38].

5.2) Like-for-Like

A like-for-like replacement of an existing device involves finding a similar product to replace the existing end-of-useful life device. This has the advantage of simplifying the replacement process but it may be difficult to find a device that has the same characteristics years after the device under consideration has been in-service

5.3) Reverse Engineer

Reverse engineering of a device is a possible solution to replacing or upgrading an existing device that has come to its end-of-useful life. This option is often used in the nuclear industry due to the volumes of paper work and approvals necessary to qualify a new product that is not identical in form fit and function to the original device. Reverse engineering is typically a very expensive proposition but is certainly one that can be considered to extend the life of existing devices.

5.4) Keep Better Records

In order to better understand and track the performance of devices, and even for the sake of simple reliability indicators, good record keeping must be implemented to record in-service dates; out-of-service dates and repair times. In addition to better date records, better recording capabilities in terms of why a device was taken out of service; what was done to it; and what changes were made to the device would go a long way towards understanding device performance and thereby being better able to monitor and predict device failures as well as longevity. With modern technology it is trivial to track devices using bar codes, RFID, QRC codes. Bluetooth, or many other technologies commonly used in the retail industry.

Many documents already exist describing reliability and performance monitoring which also provide detailed information for record keeping.

5.5) Implement Servicing as per Manufacturer Service Bulletins

Manufacturer service bulletins are intended to address specific issues pertaining to devices. It is understood that by following these bulletins that the life of the device will be either maintained at its original predicted longevity or will be extended past its original design life.

Some manufacturer will state that their device MTBF is contingent up application of all manufacturer service bulletins. If manufacturer service bulletins are not being implemented (or only on a limited scale) the expected useful life of the device may be reduced. It is prudent to consider this important factor in maintaining the optimal useful life.

In order to ensure that the end user is aware of any impact on useful life, one option would be to state in the purchase order that the manufacturer is required to inform the utility on the impact of expected life, or MTBF, if the manufacturer’s service bulletins are not implemented.

5.6) Device Self-Monitoring

Self-monitoring is the ability of a device to examine its own performance and to determine if there are any abnormal conditions in its hardware or software. Self-monitoring is widely used in most modern microprocessor devices, however, the implementation and what is being monitored is not well defined or specified. Simple self-monitoring can be the verification of checksums in a memory chip.

The advantage of self-monitoring is that failures or anomalies in performance can be detected immediately and some action taken. This action can be an alarm, event record, self-healing or going into a safe operating (or non-operating) mode. Note that self-monitoring typically does not address the condition of the output contacts.

Self-monitoring can extend the useful life of a device as corrective action can be taken as soon as the anomaly is detected rather than waiting for a misoperation or failure to operate or the next routine maintenance cycle to detect the problem. Issues can be resolved and the equipment performance restored to normal. In some cases the device is also able to heal itself by performing a self-reset, reboot, re-calibrations, or reloading of data, for example.

5.7) Involve Multi-party Teams

Many players are involved in the process of specifying, purchasing, designing, installing and maintaining a particular device. On top of that there is the industry involvement/awareness, standards development (internal and industry), P&C, IT, fault analysis, failure reporting, firmware updates, manufacturer interface, and settings etc. involved with a particular device. It is very difficult for one person to have a handle on all the aspects of a specific device and therefore a team approach is highly recommended for determining the end-of-useful life for a device. This will ensure that all aspects are covered and provide a greater sense of certitude regarding the expected life of a device.

5.8) Be Proactive

In regards to extending useful life, it is vital to plan ahead and consider what conditions could occur that tend towards reducing the life of a device and then consider what to do in the event that any of these conditions do occur. One obvious issue mentioned is the impact of storage/shelf life on unenergized devices. It is a known that the life of electrolytic capacitors degrade the longer they remain unenergized. Therefore, knowing this fact and the fact that manufacturers recommend energizing devices in storage for one hour per year is a simple and obvious way to be proactive in extending device longevity (a greater end-of-useful life).

Having a specifically appointed and responsible person or team with the authority to investigate, evaluate and make recommendations is a good step in ensuring a greater life for P&C devices. An overall analysis of what the issues are is a proactive process. This cannot be optimized by leaving things until the issues causing short life expectancy become critical or imminent.

5.9) Documentation

Documentation (manuals) and document of activities plays a vital role in the process of ensuring an optimal end-of-life for P&C devices. In-service date, failures, device history, rationale, issues must be recorded and made available.

Keep user manuals and equipment documentation available and in formats that provide for easy access. Document activities related to each device with as much detail as possible. This will help in providing the necessary data for failure and life analysis.

5.10) Inter-Utility Cooperation

A common database of utility experience would go a long way towards ensuring device longevity. Not only could typical problems, issues and experience be listed but remediation and recommendations also could be provided to contributing utilities. Of course this could be contentious and open various legal issues, but such a solution could be implemented given proper care and coordination. Such forums exist already to a limited extent: in NERC with respect to compliance issues and reporting [39] also in the North American Transmission Forum [40] and nuclear users groups etc. However, specific utility related P&C issues are not centrally available or coordinated at this time.

5.11) Components

There can be little guarantee against the possibility that somewhere in the production cycle of electronic devices that a counterfeit or used component was purchased inadvertently, however, tendering specifications can explicitly state that only new components can be used in the manufacture of devices. Also, inspections can be made by the utility or manufacturer whenever a new or different supplier is used for a specific component [3].

5.12) Provide Feedback to Manufacturer based on End-of-Useful Life.

By providing feedback to manufacturers on their device performance, the manufacturer may be in a better position to provide effective end-of-life information to their clients. Overall trends may be better understood in the context of the entire manufactured population of devices rather than a smaller subset purchased by an individual utility. Also, manufacturers have the experience and incentive to optimize the performance of their devices. Often utilities do not have the resources to investigate issues and trends in specific devices.

Feedback to manufacturers should include specific details of device performance and failure(s) as well as dates associated with commissioning, maintenance and removal from service. Serial numbers, model numbers of both the main devices and associated modules (if any) as well as firmware version would be helpful in their analyses.

5.13) Equipment Coordination

Consider the impact of coordinating multiple activities on the useful life of a device. If a relay, RTU and breaker are going to be replaced at some time, then consider the benefit of replacing all associated equipment at the same time. This can be done on a scheme basis, such as breaker/relay, or on a station-centric approach where the entire station is upgraded at the same time.

By coordinating the work of replacing multiple devices, then the life of the P&C equipment, in the context of the station, is maximized. This obviously depends on the definition given to end-of-life and what is expected from a piece of equipment, however if the entire station is said to be expected to operate for a given number of years and all the equipment in the station is upgraded at the same time (station centric) then, any one device can be said to have reached its maximum life in the context of the station replacement program.

5.14) Redefine the Problem or Change the Parameters

One way to extend the life a device with respect to its expected life is to redefine what is meant by expected life and lower the expectations. If a device is expected to function for 30 years and it is replaced after 20 (its end-of-useful life) for any one or more of the reasons mentioned in this document, the device seems to have failed and come short of its expected performance. However, if the device was initially only given a 20 year life due to foresight; planning; basing life on the number of operations; or the life of operating system; or the expected support from the vendor; or by means of some equation similar to the one presented in this document, then the device would have fulfilled its duty and the application of the device would have been a success.

It may, therefore, benefit the prudent asset manager/planner to carefully consider how to specify the actual life of a device. In an environment where new products are constantly being introduced and older products obsoleted, a re-definition of expected device age may be beneficial and more practical than simply applying an arbitrary, historical, or book value, of expected life. Firmware support, for example, may on average be no longer than 16-20 years and so a life expectancy based on expected firmware support that may be appropriate. Similarly, the operating system used to access the device and configure settings may have a finite life and the life of a device may be closely tied with that system. Basing the life expectancy of device on accounting principles or historical values may no longer be the wisest or most appropriate benchmark to use. It may be that with the use of internal self-monitoring capabilities and the extension of maintenance periods (NERC PRC-005-002) that a device's life may be considered to be from its initial installation to the time at which it first requires re-calibration (if calibration periods are on the order of 12 years, a device will likely not last long enough to be calibrated a second time anyways).

Another issue to consider is the way in which a replacement program will be carried out. It may be unlikely that a utility would go around to all stations in its operating territory and replace a single type of device at each station because it has met its end-of-useful life. A more likely scenario would be that devices are replaced on a station-by-station basis or in parallel with other work programs, such as breaker replacements.

5.15) Failure Modes and Effects Analysis (FMEA) or Fault Tree Analysis (FTA)

By conducting a FMEA or FTA (or similar failure analysis) it may be possible to determine why a device is failing (or failed) and identify the root cause. Having done so, remediation could help extend the life of the remaining un-failed devices and also provide valuable input into extending the life of other similar devices [41].

FTA, for example, is used to determine the underlying basic events that lead to a specific "top" event. The top event could be "Why has a device reached an early end-of-useful life?"

FTA is a tool used to [42]:

a. Understand the logic leading to a top event – why did this happen?
b. Prioritize contributors leading to the top event – what caused this?
c. Help be proactive in preventing the top event – what can be done to prevent this?
d. Monitor the performance of the system – how are things doing today?
e. Used to minimize and optimize resources – what can we improve upon to better manage this risk?
f. Assist in system design to select best alternatives – what is the best solution for fixing this problem or designing this system?
g. As a diagnostic tool to identify and correct causes of the top event – what caused this to happen?

Failure analysis tools are a valuable means by which to identify early end-of-life issues and therefore a first step in helping to remediate these issues to provide for longer equipment life.

5.16) Cocooning

Cocooning is the process of regulating the environment of a device or component in order to keep it within the manufacturer's specifications during operation – and thereby maximize the life of a device. The following conditions may be required [43]:

1. The device may require a regulated power supply.
2. The device may require a regulated temperature environment.
3. The device may require shock mounting and or vibration isolation.
4. The device may require humidity regulation.
5. The device may require special shielding.

6. Additional manufacturer specifications.

Whatever requirements it takes to make the device continue to function in an environment that is specified by the manufacturer, would be part of the cocooning process. Cocooning has been used to successfully prolong the life of devices in some applications; however the cost can be significant.

6) Other issues

There are two important perspectives: forward looking to determine what end-of-life may be (predictive) and backwards looking to determine what end-of-life is. Examine overall device performance – is the device still functional in spite of reaching end-of-life? Look at positive side as well – maybe device performance is better than expected.

6.1) Device Criticality

The criticality of the application for which the device is intended may be a significant factor in determining its end-of-useful life. In a critical application a device may need to be replaced significantly earlier than if the application was somewhat benign and the failure of the device of little consequence. It is not practical to take a chance to run to end of life a device that is in a critical application, a shorter, end-of-useful life must be considered – replace the device while it is still working rather than when it fails unexpectedly.

How does risk of failure impact relay replacement (end-of-useful life)? One driving factor for criticality may be the impact on customers. The effect of a device failure on customer supply can be quantified and used as a metric to weigh the importance of replacing a device in a priority manner before it reaches its end of actual life. Does the device function in a scheme to protect a critical facility like a hospital or military installation/vessel or research facility? Will a failure of the device result in system instability or possible hazardous issues? Could a failure of the device compromise national security? Will a failure of the device compromise the good will and reputation of the utility?

A criticality score can be derived from various metrics. One such scoring system involves a combination of the importance of the scheme, bus and substation. Other scoring systems can be developed and customized internally by the utility or be based on established industry practices [44].

6.2) Cost of Not Replacing

The need to optimize one's investment as well to as weigh off the alternative driving factors to replace a device must be balanced. One way to consider the decision to replace a device prior to its actual end of life is to examine the social-economical-technical impact of replacing early (end of useful life) or at the end of its actual life.

The following factors are important in making a decision to replace a device:

- The embarrassment that might occur if a device is not replaced and it fails.
- The impact of doing nothing.
- The time it takes to replace the device or the time taken to deal with issues if the device is not replaced.
- Fines from regulatory bodies (NERC).
- Must do – no choice
- The cost of replacing versus the cost of not replacing:
    - Cost of disposal
    - Cost of type testing

- Cost of design changes
- Cost of training on new devices
- Cost of documentation and procedure changes
- Cost of spares
- Cost of removal and installation
- Impact of outages and reduced security during replacement
- Cost of new test equipment perhaps (think of a migration from electromechanical to IEC 61850)
- Administrative costs of updating systems, going for tenders, tender review, etc.

These issues, among others, should be considered in making a decision to replace a device or to leave it or to find a way to make it last longer.

6.3) What to do if Replacement is Required

If a device comes to its end-of-useful life, then a decision must be made to replace it or try to extend the life - if possible. A process for making this decision could include:

- Prioritize the work to be done – How important is it? When does it need to be done? What resources are needed?
- Estimate the cost of replacing the device. Consider parts, outages, labor, and contingencies.
- Test replacement device(s). Test the replacement device prior to considering a replacement. Does it have the required functionality? Does it fit? Does it have the same power requirements? Does it have the same CT/PT burdens and input ranges? Does it operate the same re outputs/inputs? Is the network compatible? Can the user interface software be supported in the current computer equipment? Is additional training required for this device? Will it function in the same environment? Are there any special requirements that the previous device did not need?
- Work with the manufacturer for the best solution.
- Replace the existing device with additional capabilities and play with it to see and test its capabilities
- Watch for scope creep – it is easy to get sidetracked and do additional work or “nice-to-haves”
- Replace with like-for like? Consider replacing the failed device on a like-for-like basis. What are the implications? Does it matter?

7) Utility and Industry Examples

7.1) Pacific Gas and Electric

The following is a list of several examples from Pacific Gas and Electric (PG&E) where devices were replaced before their actual end-of-life for various reasons [45].

1. Line protection scheme is required to change to line current differential from existing POTT or non-pilot protection in order to adequately protect the line or provide relay coordination. PG&E has a proliferation of new photo-voltaic (PV) interconnections. These new interconnections many times require a new switching station, bisecting an existing line and creating a short line section requiring line current differential protection for coordination. Existing relays at the remote terminals will require replacement to match the new line current differential relays at the new switching station, regardless of the age of the relays. Since the PV interconnections are third party driven projects, they may be unforeseen and relays recently replaced by the utility may be impacted by a third party interconnection forcing replacement of relays prior to end of useful life. PG&E is in the process of updating its protection design standards to use the same relay type for all applications, which will help alleviate this problem. Current PG&E protection design standards use different relay models for POTT and line current differential protection.

2. Installation of a drop in place control building which replaces all protection and control at one substation with latest design standards. Relays at remote line terminals will have to match for line current differential protection, requiring replacement of relays at remote terminals. For other pilot schemes, such as POTT or Blocking, relays may be replaced depending on policy/tolerance for mixing different relay manufacturers/models in a pilot scheme. For PG&E mixing relay types is not recommended on the two ends of pilot protection scheme. It may be tolerated with different microprocessor relay type at the remote terminal as an exception, but not with electromechanical relays.

3. Bus configuration is changed at a substation. For example, converting from Double-Bus Single Breaker (DBSB) to a breaker-and-a-half (BAAH) bus configuration for increased reliability. For PG&E a bus configuration change will require installation of a new drop in place control building. All of the existing relays in the old control building will be retired. Some of those existing relays being retired may have been fairly new and installed due to other capacity, reliability or third party driven work that could not wait for the BAAH project. PG&E also installs new drop in place control buildings for SCADA automation purposes, and for those jobs all of the existing relays in the old control building will be retired similar to the BAAH projects.

4. Unacceptable relay performance – excessively high failure and misoperation rates. This problem is typically associated with relays near end of useful life; however in one instance PG&E specified a new standard relay type that was determined to have unacceptable performance within one year of application. Approximately 40 relays were installed before PG&E stopped purchasing the poor performing relay type due to excessively high failure rates and misoperations. The continued high failure and misoperation rates for those devices already installed caused them to be nominated for replacement prior to the end of their useful life. Manufacturer support for the relay type in question was limited due to a plant closure where the relay was manufactured as a result of a merger/buy-out with another relay manufacturer.

7.2) Bonneville Power Administration

The following is a list of several examples from Bonneville Power Administration (BPA) where devices were replaced before their actual end-of-life for various reasons.

1) A station upgrade from a ring bus configuration to a full breaker and one half scheme was undertaken. New breakers were added as well as a bus protection, new control panels and the replacement of line relays. The new line protection relays were mounted on new panels installed in a new location and put into service incrementally as each HV bay position was cut over and put into service. The relays were replaced to keep them as up-to-date as possible with internal standards. Other relays were also replaced, such as the breaker failure, to make them current with latest standards and make their behavior consistent with other devices in other bays of that particular substation - even though the particular relays were not necessarily at end of their useful life. This philosophy was also used in the case of the line-oriented lockout relays. These relay replacements ensured that consistent behavior existed throughout the substation. Similarly, reclosing relays were replaced where previously existing reclosing relays were breaker oriented but the new standard specified lead-breaker/follow-breaker reclosing - which is quite different. Again, the same reasoning was used in the replacement of the reclosing relays, that is, to obtain consistent performance and ensure that performance conformed to the current standards.

2) Identical relays with identical schemes protecting each end of a transmission line are often required. Although it might be possible to have different schemes at each end of a line, this can be confusing for field staff and for the proper functioning of the scheme. Line terminal protections are often updated to meet a new standard at one end of the line. They might also be updated to conform to what one utility is using at the end of a particular line - despite the relays not being at end of their useful life.

3) Another reason why devices may be upgraded prior to their end-of-useful life is in the case where a new control HMI is updated that requires reading the active file of a relay to obtain status information. Newer relays with downloadable data files might be needed and therefore older, yet still functional, devices must be replaced.

4) Obsolete TDM communications of leased telephone circuits are being removed by the telephone companies and new technologies are required for communication. This may require the early end-of-life of a device in order to replace it with one having newer telecommunication capabilities.

5) There is an integral relationship between breakers, relays and SCADA alarms. They are each closely interrelated and interdependent when in service. BPA has many substations where it is unlikely that the useful life of these three types of devices is the same or are in sync with each another. If one device needs to be replaced now then possibly 5 years later a different device may need replacing because it is at its expected end-of-life. Replacing devices individually and incrementally was found to be expensive partly due to the need to replace wiring that was just previously installed a few years ago. The new direction is to now integrate multiple replacements, and replace breakers, relays and sometimes SCADA systems at the same time when feasible. This is more efficient but clearly involved replacing some devices prior to the end of their expected life – thus their end-of-useful life is shorter than expected.

Obviously, good planning can go a long ways to optimizing the life of a device. Many utilities, such as BPA, are now using smarter approaches to asset (P&C) replacements to minimize outage time; reduce personnel and material costs as well as the potential for mistakes.

7.3) National Aeronautics and Space Administration

The value of performing a failure analysis is clearly stated in the following extract from a National Aeronautics and Space Administration (NASA) report.

> "FAILURE analysis at the Kennedy Space Center (KSC) is performed on both flight hardware and ground support equipment for all of the programs that operate at the center…The fundamental goal of the analysis is to determine the root cause of the failure in order to prevent future failures. The majority of failures can typically be attributed to one or more of the following causes: failure due to fabrication problems; failure due to environmental problems; failure due to maintenance and processing problems; and failure due to design problems. The proper fabrication of hardware is of fundamental importance to the success of the component. Several failures have been analyzed where a part has received an inadequate heat treatment, improper coating, or unauthorized material substitution. The failures that occur due to fabrication problems typically become evident early in the materials evaluation. Whereas many problems can be prevented through a quality assurance program, some problems are not apparent until failure occurs under service conditions." [46]

For the sake of emphasis, "The majority of failures can typically be attributed to one or more of the following causes: failure due to fabrication problems; failure due to environmental problems; failure due to maintenance and processing problems; and failure due to design problems." It is obvious that if we can learn from mistakes in terms of a less-than-ideal life expectancy of devices in the area of protection and control, as in the space industry, that life expectancy can be understood and lengthened by taking proper care:

1. In the fabrication – that is, site acceptance testing perhaps, proper adherence to environmental testing at the factory,
2. Environmental problems – understanding what the specific location and environmental conditions for the application are (that is, do not assume all site locations for the equipment are the same).
3. Failure due to maintenance and processing problems.
4. Failure due to design.

8) Additional Suggestions for Manufacturers and Utilities

The following are some suggestions for extending the useful life of P&C equipment.

8.1) Ideas from the Aerospace Industry

The following are suggestions to help extend useful life from the aerospace industry, but find application in the protection and control world as well [47]. Many of these apply specifically to manufacturers.

1) Optimize use of devices – can one device be used for multiple applications?
2) Can a modular design be used?
3) Can one device with multifunction capabilities be provided?
4) Can the use of toxic materials be reduced or eliminated?
5) Can the product design be such that future replacement be considered (future proof the design)?
6) Can the maintenance requirements be minimized?
7) Ensure high quality assurance.
8) Ensure that inferior or counterfeit parts are not used.
9) Extend product lifetime.
10) Consider environmental impact of materials used.
11) Consider how easy/hard it would be to replace devices.
12) Consider ability to upgrade.

Other considerations in addition to the above could be:

1) Engage customer feedback on performance and maintenance and needs
2) Consider bulk purchase of parts
3) Consider an integrated supply chain where parts are obtained from a minimum of suppliers
4) Consider the possibility to self-manufacture critical components.
5) Simplify the design to reduce parts and complexity.
6) Provide portable software to different hardware platforms.
7) Provide modularity in design to facilitate partial replacement.
8) Keep firmware versions the same in all similar devices and don't change unless absolutely necessary.
9) Pool resources (such as spare parts) with other manufacturers..

8.2) Ideas from the Federal Aviation Administration

The following is an excerpt of suggestions from a Federal Aviation Administration (FAA) Software Engineering Resource Center paper that deals with software intensive COTS (Commercial Off The Shelf) devices (compare with microprocessor relays). This checklist can be used to help extend useful life of devices. Many of these items emphasize the need for up-front thinking and planning [48].

- "Do not rely on vendor claims; verify with operational demonstrations.
- Bring the users into the operational demonstrations, not just the vendors.
- Establish a technology watch to track vendors and products.
- Be forward looking…Unanticipated changes in hardware platforms may occur.
- Understand that your leverage occurs before the contract with the vendor is signed.
- Negotiate all prices up front.
- Understand that profits are what motivate vendors. Whether they are cooperative or not depends to a large degree on anticipated profits.
- Distinguish between essential requirements and those that can be negotiated. Successful use of COTS solutions requires the capability to modify requirements.
- Use mature products.
- Skill level and experience are important. This includes people on the acquirer's side who are determining essential requirements as well as the COTS integrators.
- Expect to spend time in training. In choosing a system integrator, look not only at experience in the application domain but also with COTS integration in general and with the specific products to be integrated. Do they have a mature COTS integration process?"

8.3) Ideas from the Medical Field

The following is an example of end-of-useful life assessment from the Medical field, specifically "Life Cycle Guidance for Medical Imaging Equipment in Canada – 2013" The following recommendations were produced as a result of a recent (2013) study examining life cycle issues surrounding medical imaging equipment. These recommendations focus on the planning process and more details can be obtained by reviewing the original documentation [49]. Although these recommendations and their associated details refer to medical imaging technology, in many respects this can also be useful for the power industry, and specifically, protection and control.

The following are the recommended guidelines for the planning stage of installing medical imaging technology. For the sake of copyright and space limitations, only one section is included in below. Refer to [49] for further details.

1. Establish a formal process
2. Establish criteria for lifecycle planning
3. Considerations for Initial Purchase of Equipment

"During the initial purchase process, it is wise to determine when an original equipment manufacturer (OEM) equipment platform was first established and how long the technology platform will continue to be developed and supported (including upgrading) with regard to hardware, software and service support. It can also be beneficial to understand (a) the hardware / software updates to be provided as part of the original purchase, as well as those involving additional cost; and (b) the hardware / software considered optional, how long these will be available, and at what cost. This knowledge will be helpful when evaluating each device for equipment lifecycle planning."

1. Considerations for replacing equipment
2. Considerations for upgrading equipment
3. Considerations for adopting new/emerging technologies

Appendix - Checklist

The following checklist is by no means exhaustive, nor can many of the issues discussed in this report be distilled to a simple yes or no type of evaluations. Nevertheless, this will provide some guidance in helping to identify issues that may result in a less-than-ideal end of useful life.

Item	Issue	Comments	Notes	Category Factor Rating
1	Manufacturer	How viable is the manufacturer? Will they be around in 10 years? Is support available? What is the quality of support? What is the timeliness of support? Are spares available? Do they have the correct firmware? Is the appropriate configuration software available and runnable? How frequently is the firmware updated? How severe are the firmware changes? Have there been any hardware issues? How severe have they been? Do they require a return to the manufacturer? Does the relay need to be removed? How long does service take? Recent experience with other products from same manufacturer. Use experience with other products as a baseline or indication of what to expect. Is the device a mature product? Are there any possible issues associated with early adoption?		
2	Human Factors	What human factors issues impact the life of the installed or proposed devices? Are there any ergonomic issues with the device?		
3	Impending Government regulations - NERC	What regulations are now being discussed or balloted that may impact the device life?		
4	Hazards	What hazards are there that may impact the life of the installed or proposed devices?		
5	Security	Does the device meet existing or pending cyber sectary requirements (both internal and industry-based)		
6	Environment	Do the devices require any special disposal procedures? Are there any hazardous products associated with the device?		
7	Common sense	Does the device use specialized parts or software that may become obsolete?		

8	Performance	What is the past history of reliability of device based on own experience (MTBF determined by vendor or utility?) What is the past history of reliability based on the utilities own experience with similar devices? What has been the actual performance (as observed during routine testing/as-found information)? Have there been any false operations or unscheduled maintenance on the device?		
9	Company	What is the fiscal outlook of the utility and likelihood of possible rate increases may impact device end-of-life? What is the future direction of the company in terms of replacement/upgrades in other areas (RTUs replacement, breaker replacements, control through IED, etc.) may cause a device to have a shorter life? Does the company (utility) have staff and resources to support the product(s) in the field?		
10	Industry	Is there any industry experience on this device? Is there any other (comparative) industry experience (NASA/GM/AT&T/etc.)? The utility industry is not the only using networking equipment for example. Are there any anticipated standards under development that can influence the end-of-life of this device? Are there any trends in other areas of the industry will have repercussions on the expected, or planned, device longevity?		
11	Device	Risk assessment (could include redundancy) Are there any vulnerable component(s) such as electrolytic capacitors? Are there special requirements (or pending requirements) for disposing of the device (hazardous waste, NERC CIP, time necessary to remove, special tools needed, etc.)? Are there mechanical issues arising from operation movement that can impact-end-of useful life? Are there environment issues regarding the application of the device (hot vs. moderate, humid vs. dry) which can lead to shorter life expectancy? Does the device impact system reliability?		

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DATA REQUEST

AG 2-5 Refer to Kentucky Power's response to AG DR 1-1. Which Kentucky wholesale customers are invited to the Annual Stakeholder Summit?

RESPONSE

Kentucky Power invites all of its wholesale transmission customers to this annual meeting. At present, the City of Vanceburg is the only wholesale transmission customer.

Witness: Kamran Ali

DATA REQUEST

AG 2-6 Refer to Kentucky Power's response to AG DR 1-6, wherein, when asked whether any work subject to the Application had begun, Mr. Wohnhas responded that "Construction has not started for the components listed within this application." Confirm that the Company has not begun any permitting processes applicable to the work subject to this Application.

RESPONSE

The Company objects to this data request on the grounds that it is vague and ambiguous. Without waiving this objection , Kentucky Power states as follows: Confirmed.

Witness: Ranie K. Wohnhas

DATA REQUEST

AG 2-7 Refer to Kentucky Power's response to AG DR 1-8, wherein when asked to explain, in detail, the procedure by which PJM review projects designated as Supplemental, the Company merely referred to testimony that is not responsive to the request. Refer also to Kentucky Power's response to AG DR 1-21 (c), wherein the Company answered in the affirmative that PJM reviews the need underlying a Supplemental Project.
a. Explain, in detail, the process and depth of the process by with PJM reviews the need underlying a Supplemental Project and the Supplemental Project itself. Any response should include a description of when during PJM's review of Supplemental Projects that PJM conducts a no harm analysis. A mere reference to testimony is not an adequate response.

RESPONSE

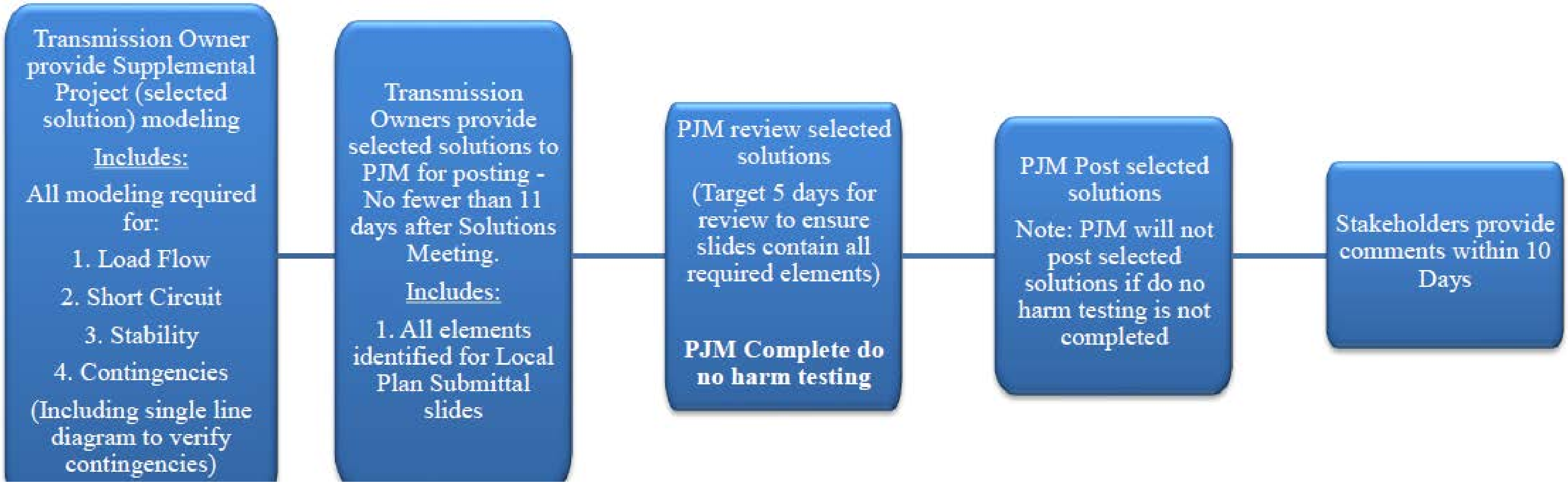
The Company objects to this request on the basis that it seeks information equally available to the Attorney General. Specifically, the process by which PJM and stakeholders review Supplemental Projects in the context of PJM's Transmission Expansion Advisory Committee ("TEAC") as part of PJM's Regional Transmission Expansion Plan ("RTEP") process is regulated by the Federal Energy regulatory Commission; the Attorney General has access to the requested information and from time to time participates.

Without waiving these objections, the Company reiterates that it is responsible for determining the need for Supplemental project components that are required in addition to PJM's approved Baseline project components.

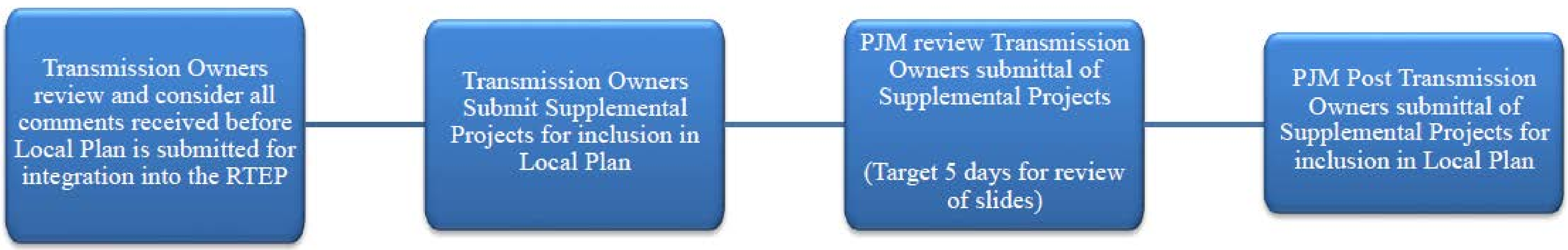
AEP first reviews all assumptions, criteria, and models used to identify needs and solutions with PJM stakeholders. Following the presentation of a need, Kentucky Power will submit and review a solution for that need. PJM then reviews the solutions and performs a do-no-harm analysis. However, PJM does not make the do-no-harm analysis available to the public for review. Should the proposed solution create any adverse effects, Kentucky Power must address these issues as part of the Supplemental project before proceeding through the remainder of the RTEP process. The do-no-harm analysis is followed by a stakeholder comment period where transmission owners review and consider the comments that they receive. Finally, projects are submitted to PJM for inclusion in the Local Plan, are assigned a PJM supplemental number, and are posted for inclusion in the RTEP and future RTEP analyses. See KPCO_R_AG_2_7_Attachment_1 for a visual representation of this process taken from PJM Planning Committee meeting materials presented in October of 2019. The materials in their entirety can be found using the following link: https://www.pjm.com/committees-and-groups/committees/pc.aspx

See KPCO_R_AG_2_7_Attachment_2 for a copy of the publicly available slides from the Sub-regional RTEP meeting where the elements of this project were reviewed.

Finalize Selection of Supplemental Projects for Inclusion in the Local Plan



Submission of Supplemental Projects for Inclusion in the Local Plan



PJM Submittal Slide

Hazard Station Rehab Work

Operating Company: KPCo

Project Type: Supplemental

Project Category: Equipment Material/Condition/Performance/Risk

Project Location: Hazard, KY
Estimated Total Cost: $20,000,000
Estimated Trans Cost: $20,000,000
Estimate Type: Class IV
Current Status: Scoping
Projected ISD: 12/31/2019
AEP Project Number(s): A15702041, TP2011063, TP2013064
PJM Project Number(s):
PLMP Risk Level: High

Project Sponsor:Will Burkett
Revision Date: 10/23/2017
Revision Number: 0
PJM Submission Date: 10/24/2017
SRRTEP/TEAC Date:

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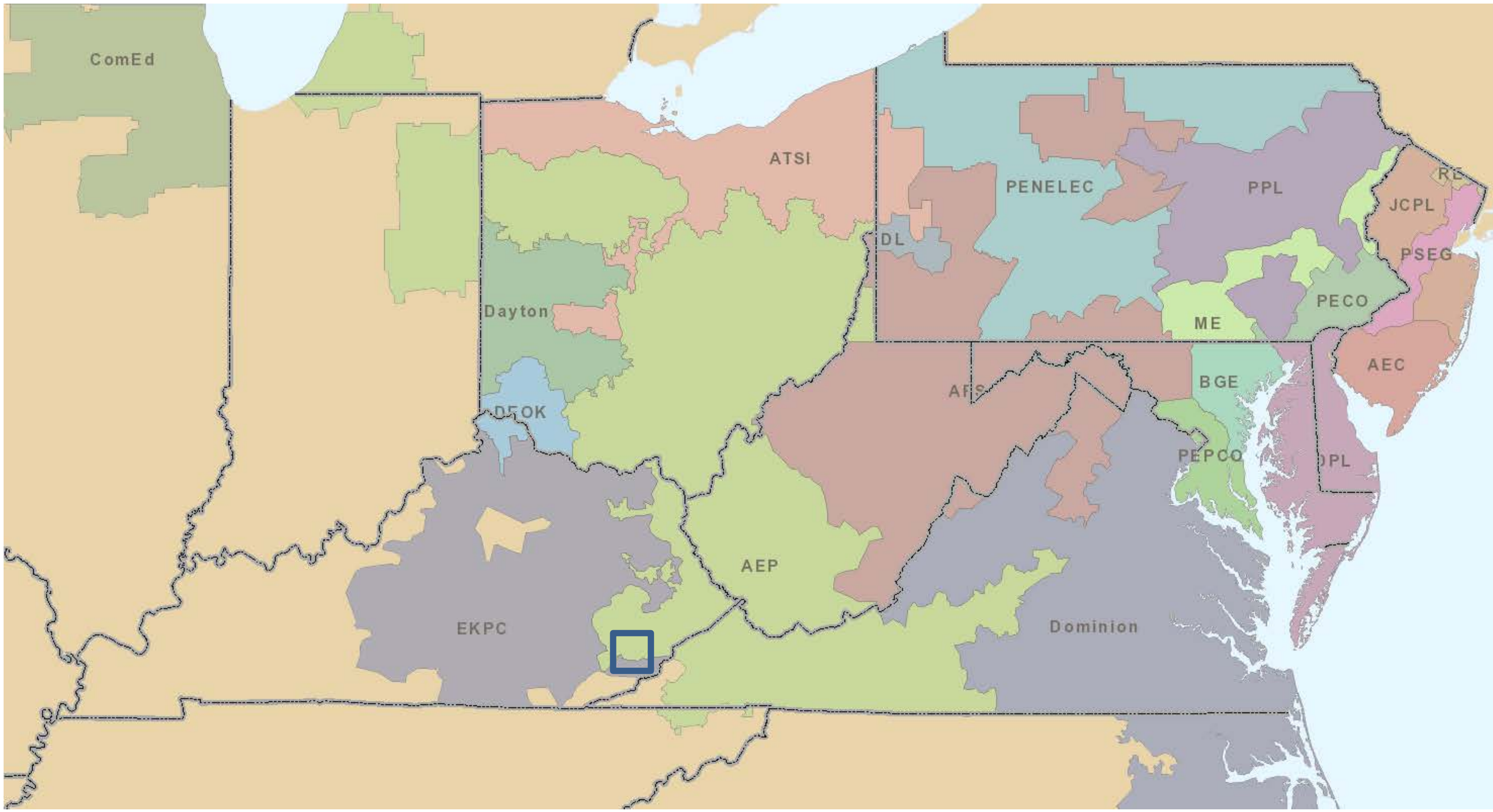
Project Location



PJM Submittal Slide

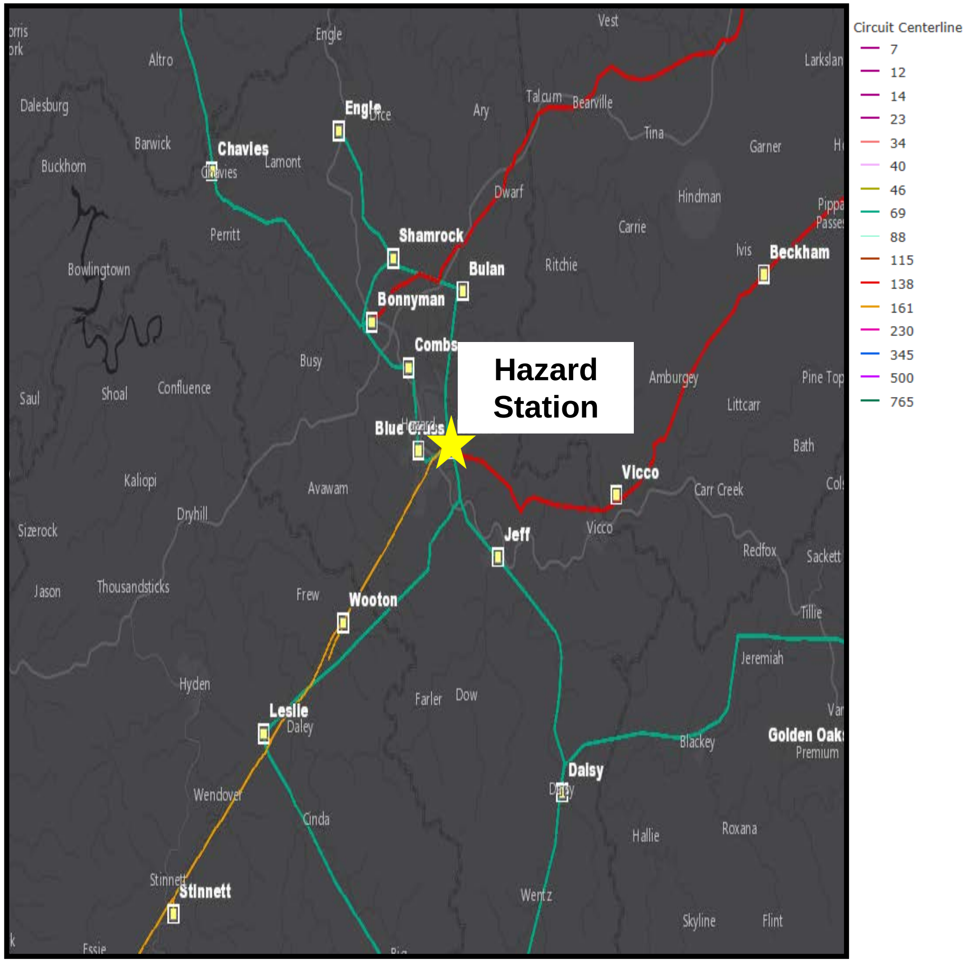
Project Description

Hazard Station: 1400 E. Main St, Hazard, KY

Hazard Station

Install a new 3000A 40 kA 138 kV circuit breaker at Hazard station on the line exit towards Beckham station. A 138 kV circuit switcher will be added to the high side of transformer #4. 138 kV capacitor bank and switcher BB will be replaced with a new switcher and 43.2 MVAR capacitor bank. 138/69 kV transformers #1 and #2 will be replaced by new 138/69 kV 130 MVA transformers with 138 kV circuit switchers on the high side and 3000A 40 kA 69 kV breakers on the low side. 69 kV circuit breakers S, E, and F will be replaced with 3000A 40 kA 69 kV circuit breakers with a bus tie 3000A 69 kV circuit breaker being installed between the existing 69 kV box bays. 69 kV capacitor bank and switcher CC will be replaced with a new switcher and 28.8 MVAR capacitor bank. 69 kV capacitor bank and switcher AA will be retired. 161 kV circuit breaker M towards Wooton will be replaced by a 161 kV 3000 A 40 kA breaker. A 3000A 40 kA 138 kV circuit breaker will be added to the low side of 161/138 kV transformer #3. Safety and access issues associated with existing equipment platforms and drainage issues at the station will also be addressed.

Estimated Transmission Cost: $20 M



PJM Submittal Slide

Project Justification

Planning Criteria Violations:

N/A

Equipment Material/Condition/Performance/Risk:

Circuit breakers S and E at Hazard station are FK type breakers all over 40 years old. Circuit breaker F at Hazard is a CG type breaker. These are oil breakers that have come more difficult to maintain due to the required oil handling. In general, oil spills occur often during routine maintenance and failures with these types of breakers. Other drivers include PCB content, damage to bushings and number of fault operations exceeding the recommendations of the manufacturer. Breakers S, E, and F have experienced 82, 184, and 193 fault operations respectively, well above the manufactures recommendation of 10.

Circuit breaker M will need to be relocated in association with the baseline project to replace the existing 161/138 kV transformer at Hazard station (b2761). The breaker is 29 years old and has experienced 21 fault operations, which exceeds the manufacturer recommendation of 10.

Transformer #1 and #2 show dielectric breakdown (insulation), accessory damage (bushings/windings) and short circuit breakdown (due to amount of through faults). Transformer #1 also shows signs of corrosion on radiators as well as oil leaks.

Circuit Switcher BB a MARK V unit which have presented AEP with a large amount of failures and mis-operations. AEP has determined that all MARK V's will be replaced and upgraded with the latest AEP cap-switcher design standard. Capacitor bank BB will need to be relocated in association with the baseline project to replace the existing 161/138 kV transformer at Hazard station (b2761).

Capacitor switcher CC has oil leaks on all three phases and cannot be repaired. Capacitor bank CC was a non standard design and its components (fuses and cans) have begun to fail.

Safety concerns associated with existing equipment platforms at the station will also be addressed. The majority of the platforms at the station were field designed with thought of access, not safety, adequate clearances, or structural integrity in mind. Drainage issues at the station will also be addressed.

Operational Flexibility and Efficiency

A 138 kV circuit breaker will be added at Hazard station on the line exit towards Beckham station, along with a circuit switcher and low side breaker on transformer # 1 to separate three dissimilar zones of protection.

138 kV circuit switchers will be added to transformer #2 and #4, as well as low side breakers on transformer #2, #3, and #4 to separate four dissimilar zones of protection.
Transmission Operations has requested a 69 KV bus tie circuit breaker be installed to improve operational flexibility to the 69 kV networks served out of Hazard. The 69 kV tie breaker will also help facilitate the retirement of Capacitor AA which: is currently located off the line to Bonnyman, is beginning to show issues, and requires its VBM type cap switcher replaced.

Infrastructure Resilience:

N/A

Customer Service:

N/A

Other:

N/A

PJM Submittal Slide

Alternates Considered

Alternate #1

Rebuilding the station in the clear was evaluated. Lack of a suitable site in close proximity to the station due to the mountainous terrain and nearby population would have resulted in significant rerouting of the six transmission circuits and the four distribution circuits located within the existing station. It was determined that this would not be a cost effective alternative. Beyond the cost implications, relocation of the circuits and station would have been extremely challenging, if not infeasible, from a siting perspective.

Conceptual Cost: $35 million

Alternate #2

Constructing the 69 kV portion of the yard into a 69 kV ring bus was evaluated. It was determined that this alternative was not physically possible at the existing station site without extended outages. This alternative was determined to be not feasible due to constructability aspects.

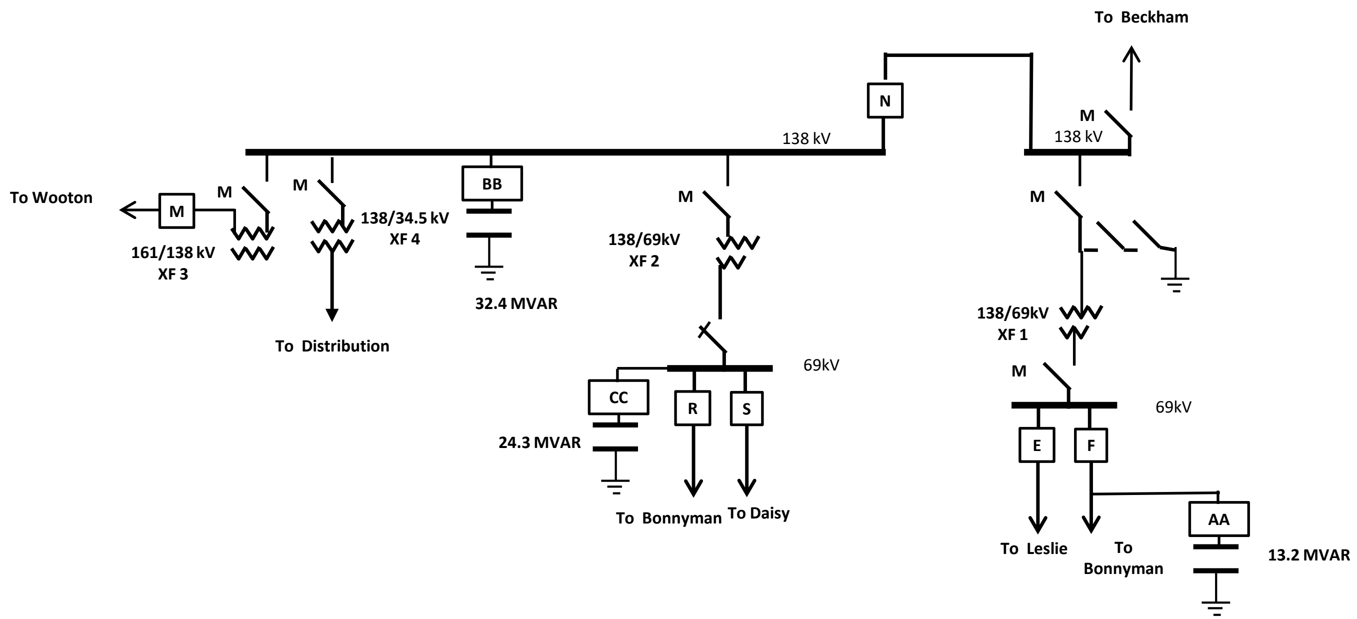
PJM Submittal Slide

System Electrical Diagram

PJM Submittal Slide

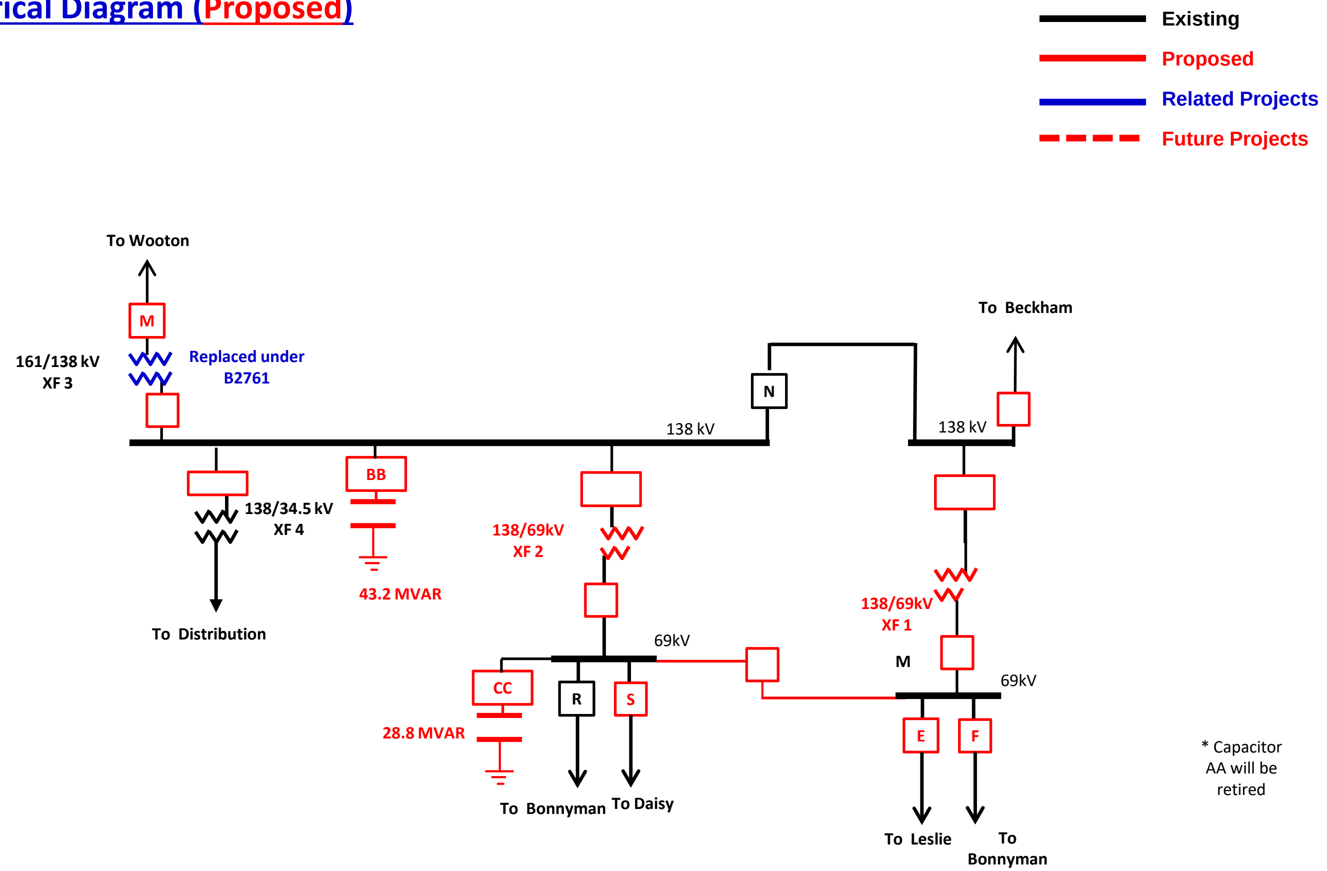
System Electrical Diagram (Existing)

Existing
Proposed
Related Projects
Future Projects



PJM Submittal Slide

System Electrical Diagram (Proposed)



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Hazard 161/138/69/34.5/12 kV Station

Station Characteristics

Station	Station ID	OpCo	Owner	Hist. Station Perf. Score (%)	Hist. Cust. Impacts (%)	Trans. CB Score (%)	Trans. XF Score (%)	Dist. CB Score (%)	Dist. XF Score (%)	Relay Score (%)	RTU Score (%)	DLF Load	DLF Customers
HAZARD	813	KPCO	T	0.00%	13.73%	46.50%	2.05%	6.35%	0.04%	3.00%	2.88%	16.85%	8.60%

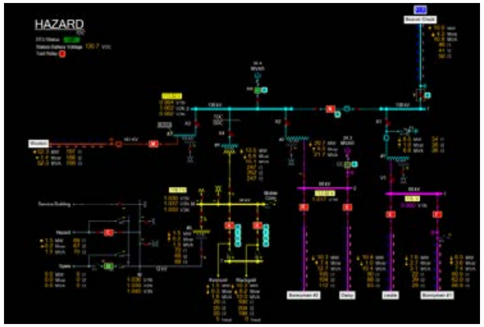
Customer Impacts

Station CMI	Station CI	IEEE SAIDI	SAIDI (%)	IEEE SAIFI	SAIFI (%)	IEEE CAIDI	CAIDI (%)
149,752	4,422	0.89	0.38	0.026	1.46	33.87	0.46

Number of Outages	Outage Causes
5	(2) WEATHER – LIGHTNING - NO EQUIPMENT FAILURE INVOLVED
	WEATHER – LIGHTNING - ANY TYPE OF CUTOUT (Replaced 2012)
	SCHEDULED COMPANY
	EQUIPMENT FAILURE - ANY AEP STATION SERVICE TRANSFORMER (Repaired 2014)

Customer Load and Risk Totals

Peak Load	%	Customer Count	%
25.7	2.54	2,187	1.30



Station Configuration:

- **APR recommends replacing the following legacy equipment per PCE standards: GE CD31D 138kV CCVT on the Beaver Creek Circuit and the GE CF02 & Westinghouse wave traps on the high side of 1 BANK TRANSM,**
- Consider replacing the following arresters with station class arresters: the 138kV, 34.5kV, 11kV, & neutral terminals of 3 BANK, the high & low side of 5 BANK DISTRI, the low side & tertiary of 2 BANK TRANSM, and the low side & tertiary of 1 BANK TRANSM. **A new set of station class surge arresters are needed on the 69kV bus side of the UG termination of power cable originating from the low side of 2 BANK TRANSM.** Consider removing any bus surge arresters, including the 12kV Main Bus and 34.5 kV Main Bus.
- Consider installing circuit switchers on the high sides of #4 transformer, 1 BANK TRANSM and 2 BANK TRANSM. The current MOAB/Ground SW configuration on 1 BANK TRANSM creates a fault in the station to signal the remote end breakers to open; this is a known safety hazard in legacy station designs. Adding circuit switchers to all banks will enable improved protection for these assets.
- APR suggests installing low side circuit breakers or load break capable MOABs to replace the low-side hookstick switches for #4 transformer and 5 BANK DISTRI to enable the switchman to be away from the device when switching and the resulting arc occurs.
- APR suggests installing a low side circuit breaker or load break capable MOAB to replace the low-side GOAB for 2 BANK TRANSM to enable the switchman to be away from the device when switching and the resulting arc occurs.
- APR suggests researching the age of the UG connection from the low sides of 2 BANK TRANSM & #4 transformer as well as all feeder exits from the 12kV bus; any UG power cable older than 50 years should be considered for immediate replacement.
- Consider installing a fuse cutout on the high side of the LTC can on the 12kV Main Bus to enable proper protection of the distribution bus should the transformer can experience an internal fault.

Hazard 161/138/69/34.5/12 kV Station

Station Steel and Foundations:

- ***Consider replacing all 161/138kV steel structures.*** The existing 161/138kV steel appears to be in poor condition. Many of the foundations are in good condition and can be reused with adaptors as needed.
- The remaining station steel is adequate and should not require replacement.
- Replacing the foundations of breakers being replaced should be considered based on outage availability; special consideration should be made for foundations that currently extrude well above grade. All foundations appear to be in good condition for reuse with proper steel adaptors.
- AEP structural engineers should be consulted for final determination on the reuse of equipment foundations, especially those of the replaced transformer banks.

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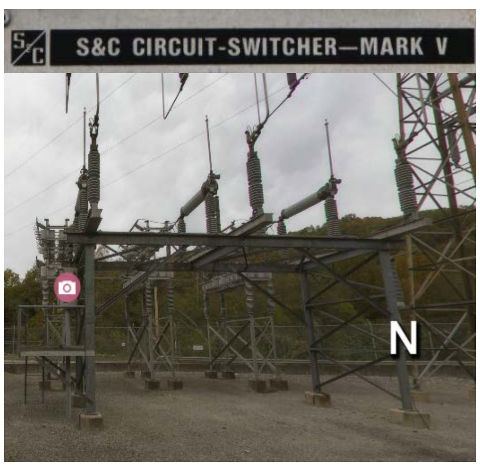
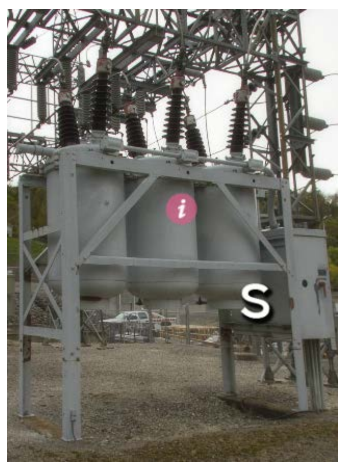
Hazard Circuit Breakers

Circuit Breaker Health						
Owner	Name of Circuit Breaker	Interrupting Medium	Manufacturing Year	Voltage Level	Total Score*	Fault Ops
D	KENMONT A	Vacuum Oil	1989	34.5 kV	5.29	221
D	BLACKGOLD B	Vacuum	2011	34.5 kV	-6.04	22
D	HAZARD C	Oil	1969	12 kV	17.1	354
T	LESLIE E	Oil	1974	69 kV	13.7	184
T	BONNYMAN #1 F	Oil	1985	69 kV	4.42	193
T	WOOTON M	SF6	1988	161 kV	4.60	21
T	BEAVER CREEK N	SF6	1988	138 kV	5.03	105
T	BONNYMAN #2 R	Oil	1959	69 kV	23.7	101
T	DAISY S	Oil	1960	69 kV	22.5	82
T	CIRCUIT SWITCHER BB	SF6	1993	138 kV	7.69	0
T	CIRCUIT SWITCHER CC	SF6	1989	69 kV	-0.72	3

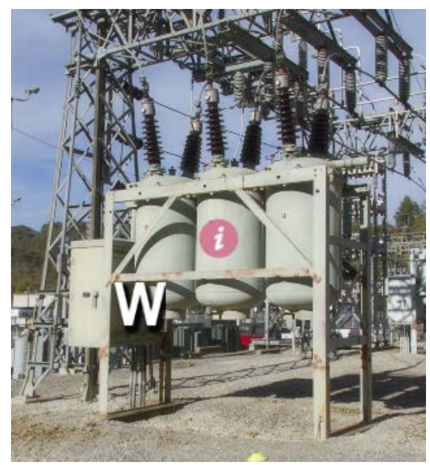
*Total scores of 11 or above warrant immediate review and appropriate actions be taken.



138kV Circuit Switcher BB



69kV Bonnyman #2 CB R



69kV Daisy CB S

12kV Hazard CB C

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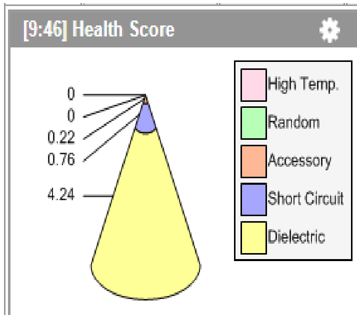
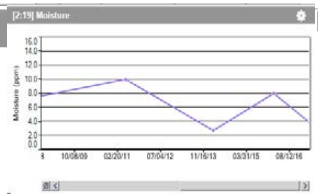
Hazard 138/69-13.09 kV 1 BANK TRANSM

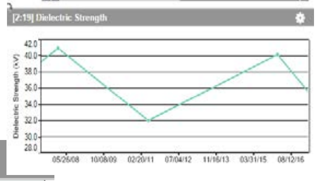
Transformer Health

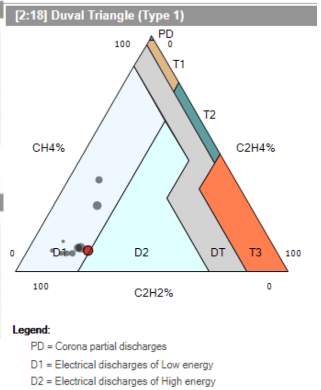
Owner	Name of Transformer	Manufacturing Year	Voltage Level	Health Score**
T	1 BANK TRANSM	1973	138/69-12 kV	5.22

** Health scores of 3 or above warrant immediate review and appropriate actions be taken.







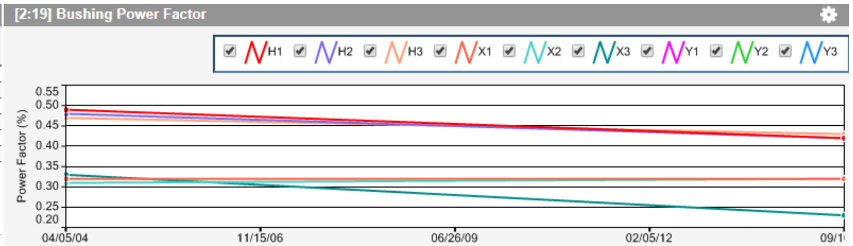


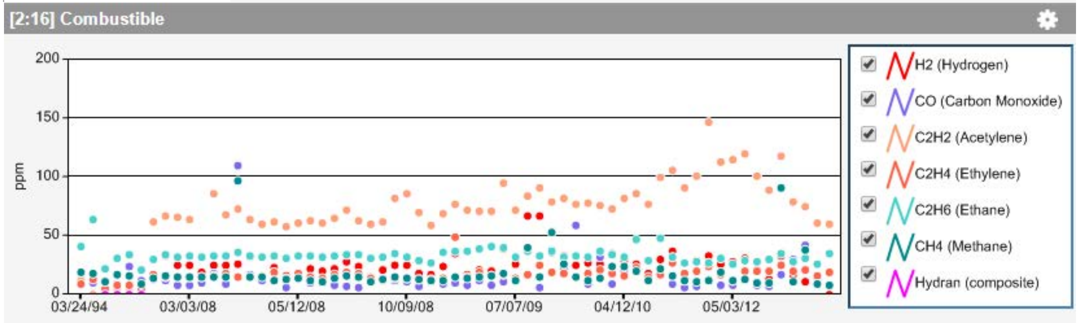
Combustible

Gas	Gas Name	PPM	IEEE Condition
C2H2	Acetylene	60	4

[2:19] Latest Reads

Location	Power Factor	Reading Date
H1	0.42	09/16/14
H2	0.42	09/16/14
H3	0.43	09/16/14
X1	0.32	09/16/14
X2	0.32	09/16/14
X3	0.23	09/16/14





Summary:

The short circuit strength health score contribution is caused by the amount of relatively low intensity electrical through fault events. Bushing health has improved from the downward trending power factor levels, now below 0.5. Despite the recent downward trend in moisture content, the dielectric strength of the oil began a decline. In addition, a high concentration reaching the IEEE Condition 4 Level for acetylene has driven up the dielectric score; however, the current acetylene level has improved from the historical measured values.

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

Hazard 138/69-12 kV 2 BANK TRANSM

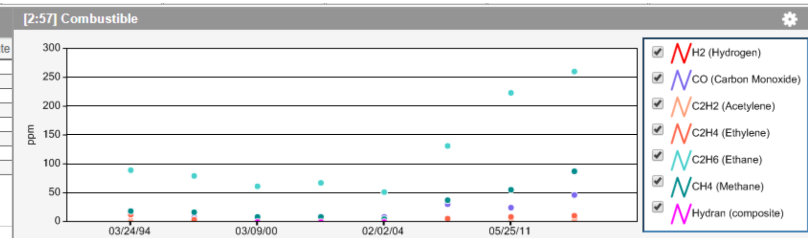
Transformer Health

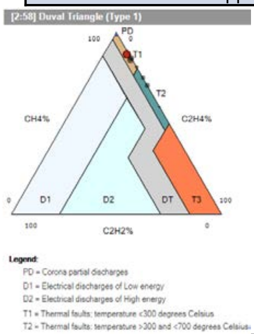
Owner	Name of Transformer	Manufacturing Year	Voltage Level	Health Score**
T	2 BANK TRANSM	1974	138/69-12 kV	3.45

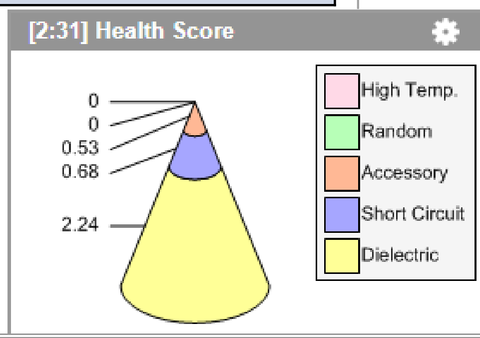
** Health scores of 3 or above warrant immediate review and appropriate actions be taken.

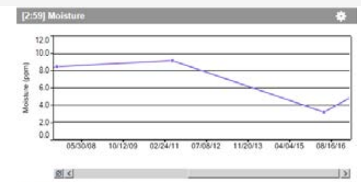
[2:57] Latest Reads

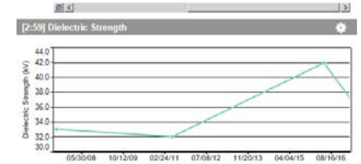
Gas	ppm	Reading Date
C2H2	1	02/23/16
C2H4	11	02/23/16
C2H6	261	02/23/16
CH4	88	02/23/16
CO	47	02/23/16
H2	6	02/23/16
HYD	0	02/02/04
TDCG	9	02/02/04









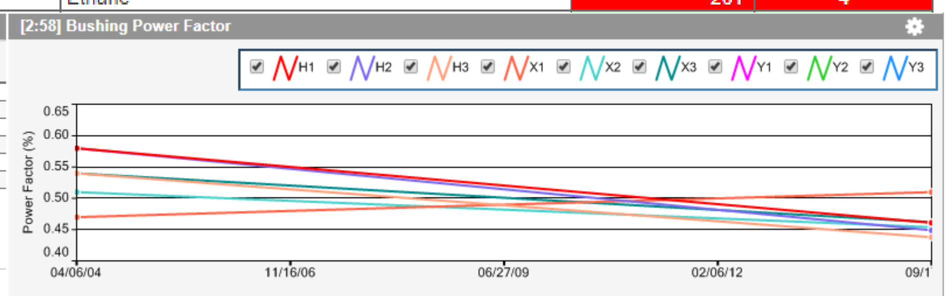


Combustible

	Gas	Gas Name	PPM	IEEE Condition
	C2H2	Acetylene	1	1
	C2H4	Ethylene	11	1
	C2H6	Ethane	261	4

[2:58] Latest Reads

Location	Power Factor	Reading Date
H1	0.46	09/17/14
H2	0.45	09/17/14
H3	0.44	09/17/14
X1	0.51	09/17/14
X2	0.45	09/17/14
X3	0.46	09/17/14



Summary:
Short circuit strength breakdown caused by the large amount of thermal through fault events, some between 300°C and 700°C, has lead to an increased health score and major upward trending to gassing of the unit. The dielectric score has been impacted by the high concentrations of the combustible gas ethane which is at the highest IEEE Condition level 4. Bushing power factor readings have recently improved, but all remain near or above .5 which has negatively impacted the accessory health score. Moisture content is currently trending up with resulting downward trending to the dielectric strength. Increasing moisture content is a resultant of water ingress and/or break down of paper insulation of TF windings.

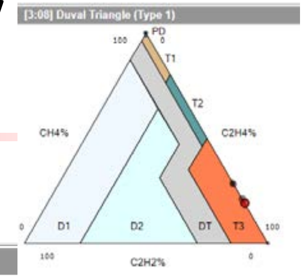
AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

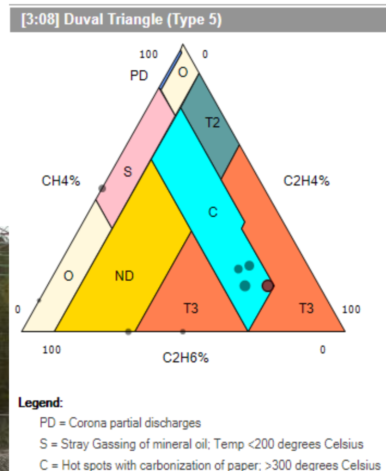
Hazard 161/138/34.5-11 kV 3 BANK A TRANSM

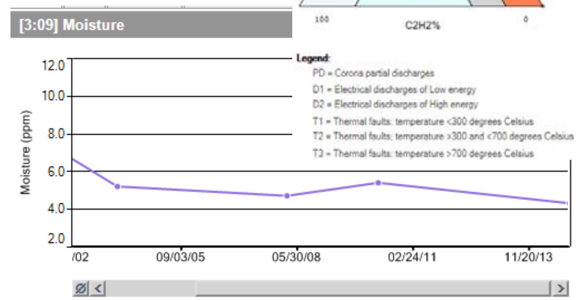
Transformer Health

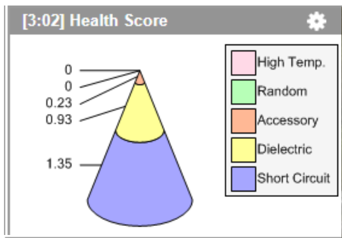
Owner	Name of Transformer	Manufacturing Year	Voltage Level	Health Score**
T	3 BANK A TRANSM	1941	161/138/34.5-11 kV	2.51

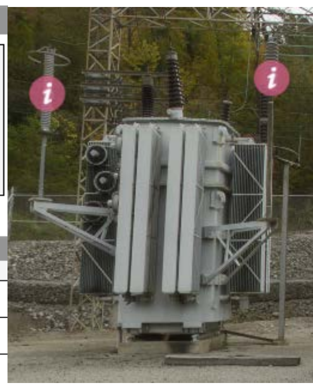
** Health scores of 3 or above warrant immediate review and appropriate actions be taken.

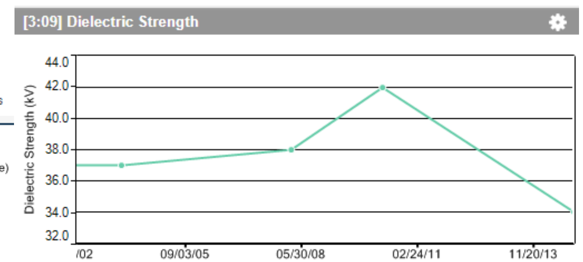






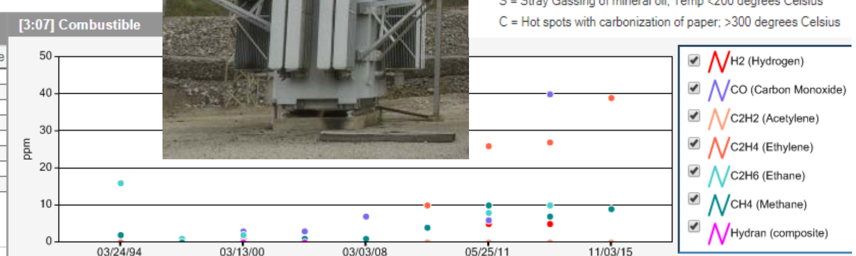






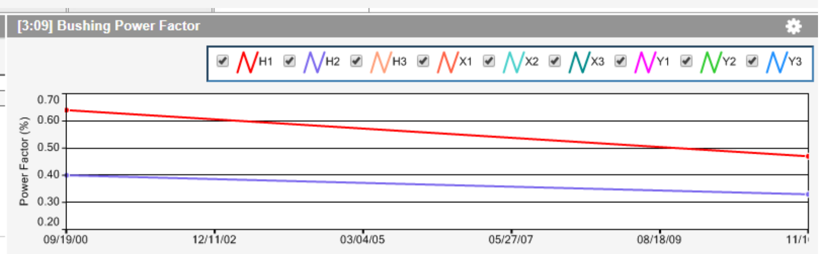
[3:07] Latest Reads

Gas	ppm	Reading Date
C2H2	0	11/03/15
C2H4	39	11/03/15
C2H6	9	11/03/15
CH4	9	11/03/15
CO	39	11/03/15
H2	0	11/03/15
HYD	0	03/01/04
TDCG	8	03/01/04



[3:09] Latest Reads

Location	Power Factor	Reading Date
H1	0.47	11/10/11
H2	0.33	11/10/11



Summary:

Short circuit strength breakdown caused by the large amount of significant thermal through fault events in excess of 700°C, has lead to an increased health score, upward trending to gassing of the unit, and carbonization of the insulating paper. This is indicative of the unit nearing the end of its useful life. The dielectric strength continues to decline despite the improved moisture content levels. Bushing power factor readings have recently improved to below 0.5.

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

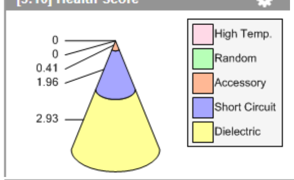
Hazard 161/138/34.5-11 kV 3 BANK B TRANSM

Transformer Health

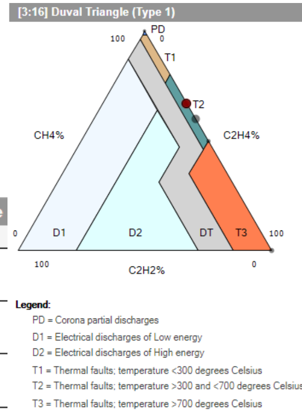
Owner	Name of Transformer	Manufacturing Year	Voltage Level	Health Score**
T	3 BANK B TRANSM	1941	161/138/34.5-11 kV	5.30

** Health scores of 3 or above warrant immediate review and appropriate actions be taken.

[3:10] Health Score



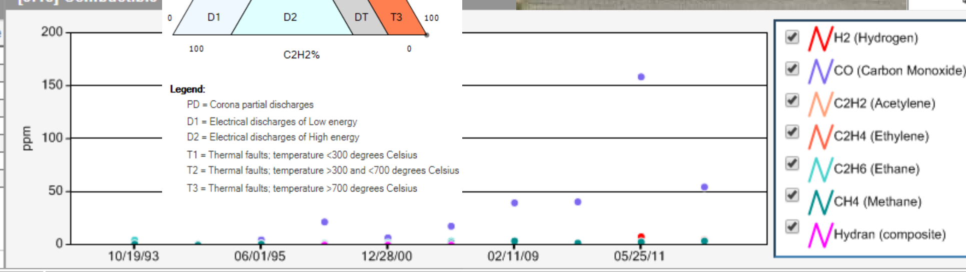
[3:16] Duval Triangle (Type 1)



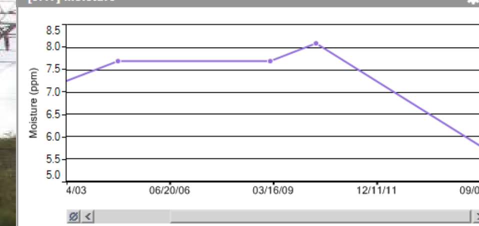
[3:15] Latest Reads

Gas	ppm	Reading Date
C2H2	0	11/04/14
C2H4	2	11/04/14
C2H6	3	11/04/14
CH4	4	11/04/14
CO	55	11/04/14
H2	5	11/04/14
HYD	0	02/01/05
TDCG	12	02/01/05

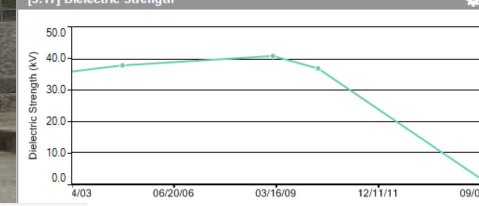
[3:15] Combustible



[3:17] Moisture



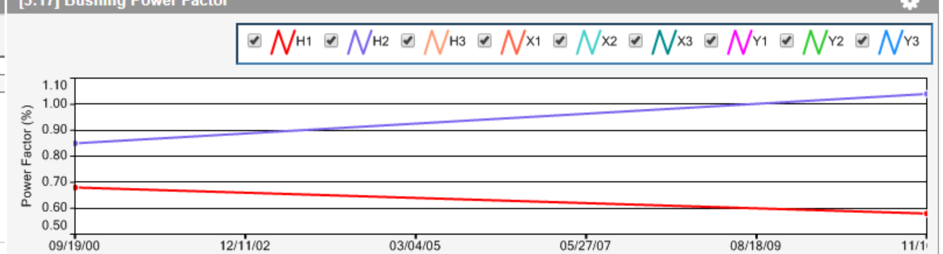
[3:17] Dielectric Strength



[3:17] Latest Reads

Location	Power Factor	Reading Date
H1	0.58	11/10/11
H2	1.04	11/10/11

[3:17] Bushing Power Factor



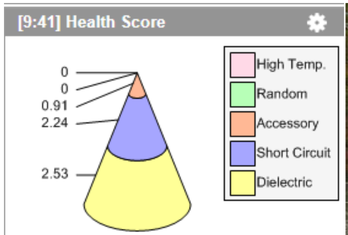
Summary:
Short circuit strength breakdown caused by the large amount of significant thermal through fault events between 300°C and 700°C with some in excess of 700°C, has lead to an increased health score, gassing of the unit, and major periods of overheating. Despite the decreasing moisture content, the dielectric strength of the unit has continued to deteriorate. Bushing power factor readings have been consistently well above 0.5 which has negatively impacted the accessory health score.

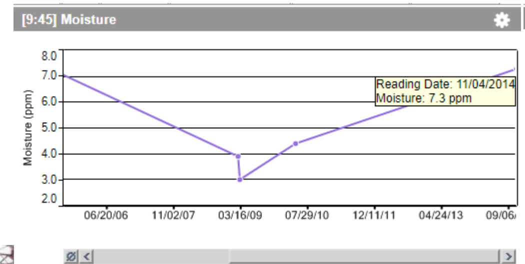
Hazard 161/138/34.5-11 kV 3 BANK C TRANSM

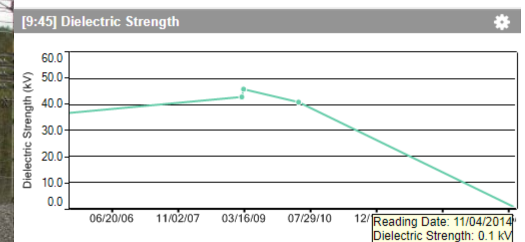
Transformer Health

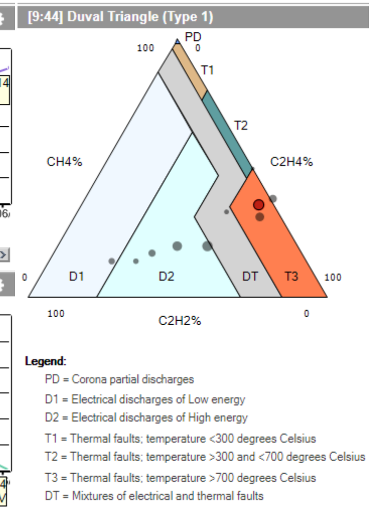
Owner	Name of Transformer	Manufacturing Year	Voltage Level	Health Score**
T	3 BANK C TRANSM	1941	161/138/34.5-11 kV	5.68

** Health scores of 3 or above warrant immediate review and appropriate actions be taken.



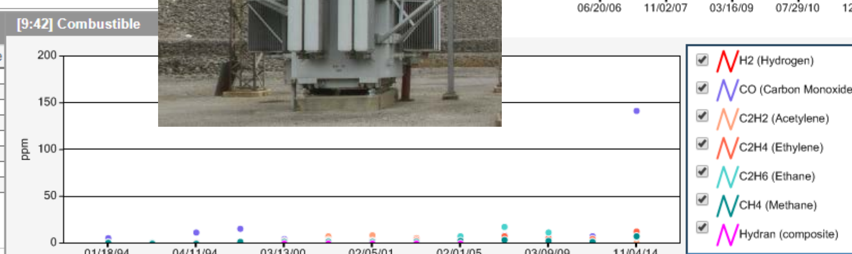






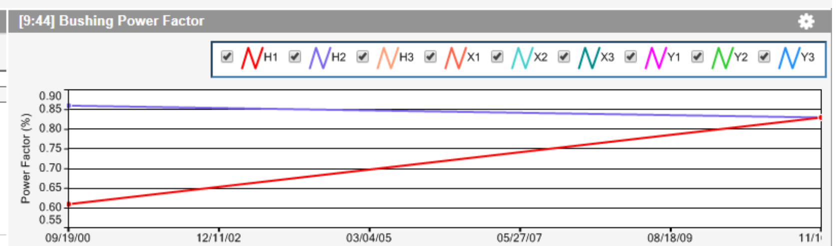
[9:42] Latest Reads

Gas	ppm	Reading Date
C2H2	1	11/04/14
C2H4	13	11/04/14
C2H6	7	11/04/14
CH4	8	11/04/14
CO	142	11/04/14
H2	12	11/04/14
HYD	0	02/01/05
TDCG	10	02/01/05



[9:44] Latest Reads

Location	Power Factor	Reading Date
H1	0.83	11/10/11
H2	0.83	11/10/11



Summary:

Short circuit strength breakdown caused by the large amount of significant thermal and electrical through fault events in excess of 700°C, has lead to an increased health score, gassing of the unit, and major periods of overheating. Moisture content is currently trending up with resulting downward trending to the dielectric strength. Increasing moisture content is a resultant of water ingress and/or break down of paper insulation of TF windings. Bushing power factor readings have been consistently well above 0.5 which has negatively impacted the accessory health score.

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

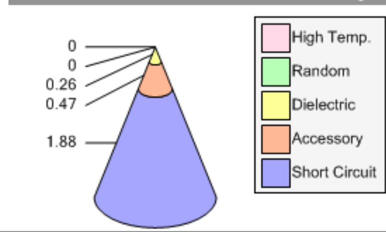
Hazard 161/138/34.5-11 kV 3 SPARE TRANSM

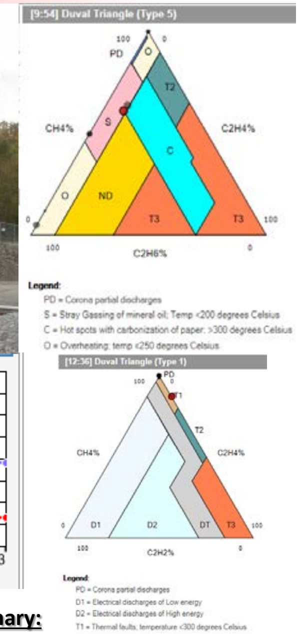
Transformer Health

Owner	Name of Transformer	Manufacturing Year	Voltage Level	Health Score**
T	3 SPARE TRANSM	1941	161/138/34.5-11 kV	2.61

** Health scores of 3 or above warrant immediate review and appropriate actions be taken.

[9:51] Health Score

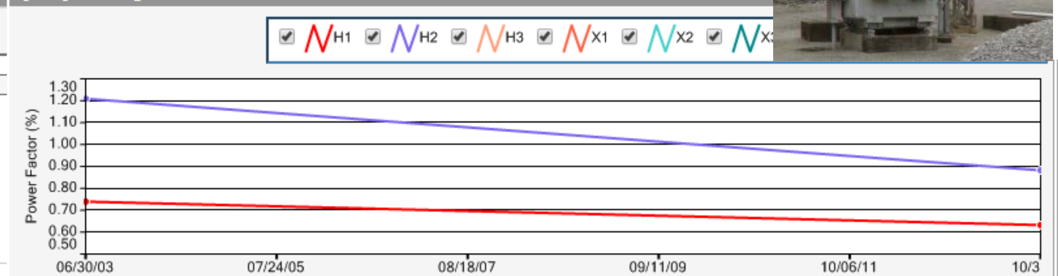




[9:55] Latest Reads

Location	Power Factor	Reading Date
H1	0.63	10/31/13
H2	0.88	10/31/13

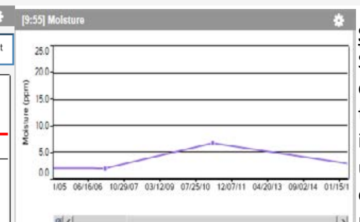
[9:55] Bushing Power Factor

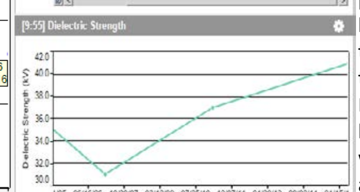


[9:53] Readings

CO	CO2	Source	Reading Date
125	779	Offline	02/23/16
37	352	Offline	03/16/11
9	285	Offline	02/07/07
7	223	Offline	03/05/03
10	348	Offline	05/08/02
21	287	Offline	05/12/97
16	344	Offline	03/11/96
8	760	Offline	03/24/94

[9:53] CO/CO2 Ratio





Summary:
Short circuit strength breakdown caused by significant thermal and through fault events has lead to an increased health score, gassing of the unit, and major periods of overheating. The CO/CO2 ratio in particular is now over the warning level. Moisture content is currently trending down with resulting upward trending to the dielectric strength. Bushing power factor readings have been consistently well above 0.5 which has negatively impacted the accessory health score.

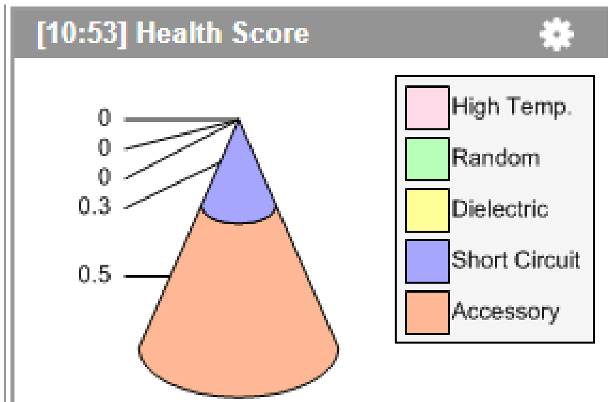
AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

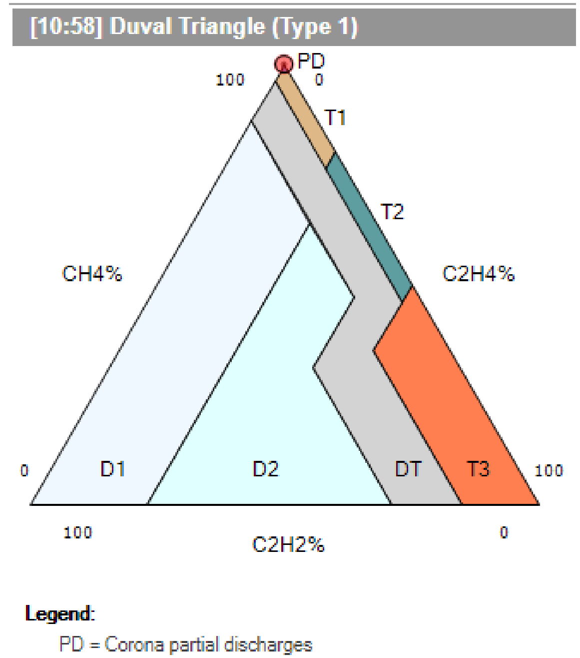
Hazard 138/34.5 kV #4 transformer

Transformer Health

Owner	Name of Transformer	Manufacturing Year	Voltage Level	Health Score**
D	#4 transformer	2011	138/34.5 kV	0.80

** Health scores of 3 or above warrant immediate review and appropriate actions be taken.

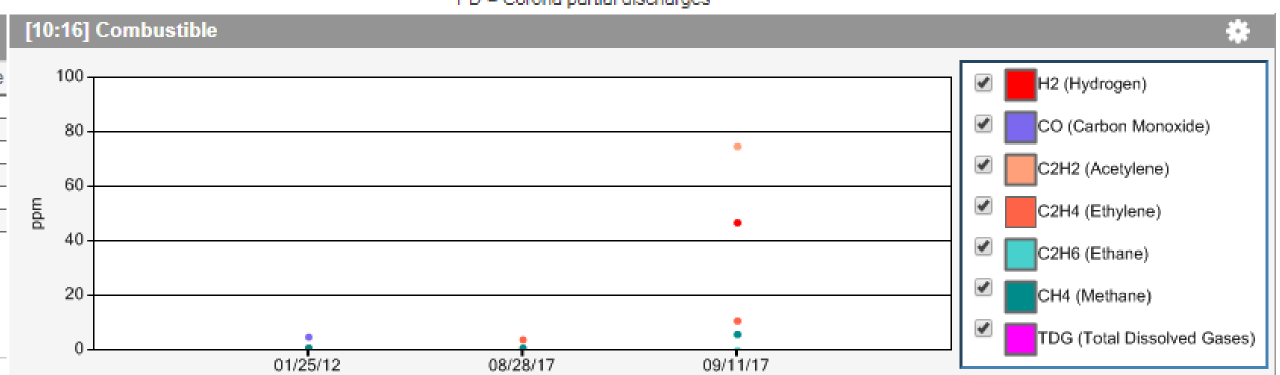




Summary:
Despite the young age of this unit, the LTC oil DGA (seen below) shown below shows large concentrations of the combustible gas acetylene at more than double the IEEE Condition 4 Level. The LTC only has 1,544 operations per IPS since it was put in service.

[10:16] Latest Reads

Gas	ppm	Reading Date
C2H2	75	09/11/17
C2H4	11	09/11/17
C2H6	0	09/11/17
CH4	6	09/11/17
CO	5	01/25/12
H2	47	09/11/17



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

Hazard 34.5/12 kV 5 BANK DISTRI

Transformer Health

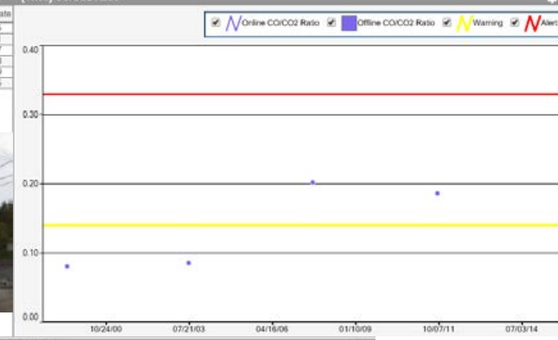
Owner	Name of Transformer	Manufacturing Year	Voltage Level	Health Score**
D	5 BANK DISTRI	1994	34.5/12 kV	1.37

** Health scores of 3 or above warrant immediate review and appropriate actions be taken.

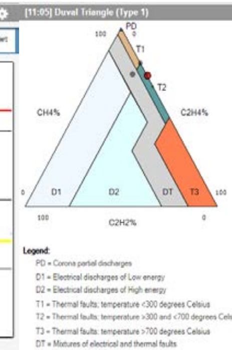
[11:03] Readings

CO	CO2	Source	Reading Date
402	2,652	Offline	11/03/15
243	1,298	Offline	09/13/11
337	1,659	Offline	08/06/07
254	2,962	Offline	07/07/03
248	3,054	Offline	07/07/99
0	28	Offline	05/04/95

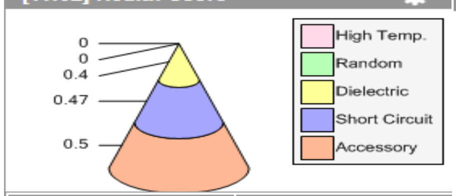
[11:03] CO/CO2 Ratio



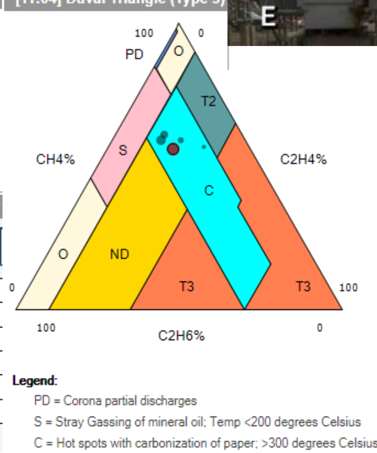
[11:05] Duval Triangle (Type 1)



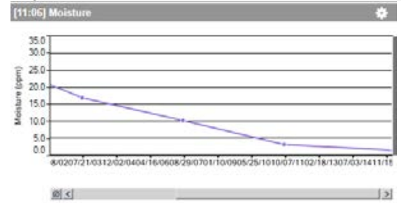
[11:02] Health Score



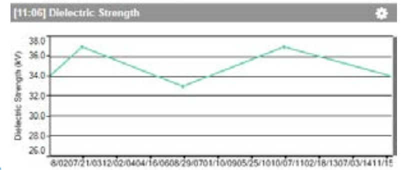
[11:04] Duval Triangle (Type 5)



[11:06] Moisture



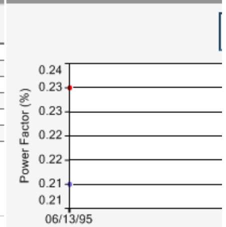
[11:06] Dielectric Strength



[11:05] Latest Reads

Location	Power Factor	Reading Date
H1	0.23	06/13/95
H2	0.21	06/13/95
H3	0.21	06/13/95
X1	0.21	06/13/95
X2	0.21	06/13/95
X3	0.21	06/13/95

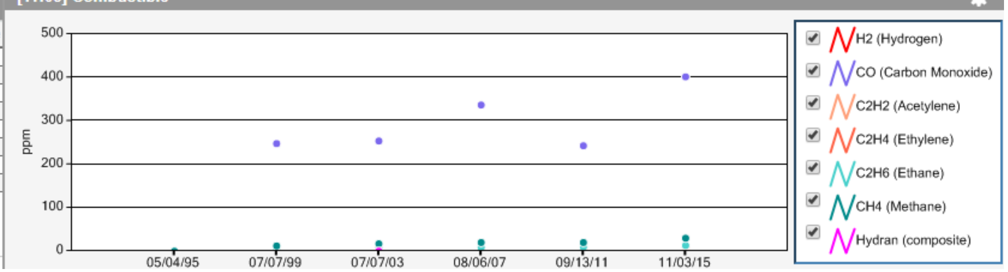
[11:05] Bushing Power Factor



[11:03] Latest Reads

Gas	ppm	Reading Date
C2H2	0	11/03/15
C2H4	11	11/03/15
C2H6	13	11/03/15
CH4	30	11/03/15
CO	402	11/03/15
H2	4	11/03/15
HYD	0	07/07/03
TDCG	11	07/07/03

[11:03] Combustible



Summary:

Short circuit strength breakdown caused by the large amount of significant electrical and thermal through fault events between 300°C and 700°C, has lead to an increased health score, upward trending to gassing of the unit (especially CO and CO2 with a ratio consistently above the warning level), and carbonization of the insulating paper. Despite the decreasing moisture content, the dielectric strength of the unit has recently begun to deteriorate. This needs to be further investigated as these warning signs can indicate that the bank is nearing the end of its useful life.

Hazard Control House

Relay Health				
Total Relay Count	Average Relay Score	Highest Relay Score	Total Station Score Ranking	Normalized Score
144	1.99	2.93	39	0.90

RTU Health			
Total Number of RTUs	Highest Ranked RTU at the station	Average RTU Score	Normalized Score
3	2.93	2.39	0.87

Relay Data:

- There are 113 electromechanical type relays, consisting of the following manufacturers: ABB, GE, Tyco, and Westinghouse.
- There are 24 microprocessor type relays, consisting of the following manufacturers: GE and SEL.
- There are 7 static type relays, consisting of the following manufacturers: ASEA, Beckwith, GE, H&H, and LaMarche.

RTU Data:

- There are currently 3 RTUs installed at Hazard Substation of the following types: TLG DC/RCOM, GE IBOX, and Cooper SMP 16/CP.

Panels 1C-3C

Existing Control House

Reviewed by:	Jomar Perez
Date:	10/23/17

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

Hazard 161/138/69/34.5/12 kV Station

Circuit Breakers and Circuit Switchers

- The 12kV CB C, 34.5kV CB A, 69kV CBs E, F, R & S at Hazard Substation are oil filled breakers without oil containment. These breakers, in addition to the all other circuit breakers in the station (not including CB D and Circuit Switchers BB and CC), have significantly exceeded the designed number of fault operations. Based on the health scores being well over the threshold of 11 in addition to the above mentioned notices, **APR recommends replacing circuit breakers C, E, R, and S.**
- The spare 12kV CB D is a sister unit of CB C. Consider replacing CB D at this time as the availability of replacement parts for this unit will become much harder to find as many of these sister units are being retired across the AEP system.
- Circuit Switcher BB is a MARK V unit which have presented AEP with a large amount of failures and mis-operations resulting in large amounts of customer interruptions. Due to the critical functionality as the interrupting device for the capacitor bank, AEP has determined that all MARK V's, regardless of scoring, will be replaced and upgraded with the latest AEP capswitcher design standard. **APR recommends replacing Circuit Switcher BB.**
- Consider replacing the 600A hookstick disconnects for CB C and D with standard 1200A hookstick switches.
- Consider replacing the 600A hookstick disconnects on CBs E, R, and S with standard 2000A GOAB switches. Consider replacing the 600A bus side disconnects for CS CC and CB F with 2000A GOABs if bus outages are required. When possible, GOABs should replace existing hooksticks on the transmission system to enable easier operation of visible disconnect points.

Transformers

- Considering the health scores in excess of 3.0 and supporting documentation on previous slides, **APR recommends replacing 1 BANK TRANSM, 2 BANK TRANSM, AND 3 BANK B & C TRANSM.**
- The remaining phase and spare of bank 3 are not currently scoring above the replacement threshold; however, given their age, sister unit condition, and indications that these units are nearing the end of their useful lives as illustrated on previous slides, **APR recommends the replacement of 3 BANK A & SPARE TRANSM.**
- Though recently put into service, #4 transformer's LTC oil has high concentrations of acetylene at more than double the IEEE Condition 4 Level. **APR recommends that oil processing be done on the LTC's oil.**
- 5 BANK showing numerous signals that it could be nearing the end of its useful life, but the health score does not reflect those indications. The dielectric strength of the oil is not recovering despite improved moisture levels and the concentrations of combustible gases are indicating that carbonization of the insulating paper could be occurring. **APR recommends that TFS perform additional analysis on this unit to determine if it needs to be considered for replacement despite scoring below the 3.0 threshold.**

Relaying

- Hazard Substation currently deploys 144 relays, implemented to ensure the adequate protection and operation of the substation. Currently, 113 of the 144 relays (78% of all station relays) are of the electromechanical type which have significant limitations with regards to fault data collection and retention. In addition, two static relays, ASEA RXIB and GE SBC-31, are scoring at 2.28, above the 1.96 threshold for immediate replacement consideration. **APR recommends the replacement of these 115 relays in a new DICM**. Due to the large amount of relays requiring replacement and lack of space in the existing control house, a DICM will reduce the duration of construction outages as well as reduce the overall project cost associated with P&C crew labor. There are 24 microprocessor based relays and 5 static relays panels in the existing control house not requiring replacement; the project team will need to determine if these should be maintained or replaced in the DICM.

RTUs

- One existing RTU installed at Hazard Substation is a legacy TLG DC/RCOM unit. **APR recommends replacing or retiring this legacy DC/RCOM RTU.**
- Another existing RTU installed at Hazard Substation is a current standard Cooper SMP 16/CP unit. APR **does not recommend** any action be taken with the Cooper RTU.
- Another existing RTU installed at Hazard Substation is a GE IBOX which at this time has no direct replacement. **APR recommends that the project team consider replacing or retiring this GE IBOX RTU if all functionality can be attained by current standard equipment.**

Open Conditions from Operations

- Tr MA alarm. Defective contactor on Tr 3 to cooling group 2. Cooling has been placed in manual. Leak exist between supply cylinder line and transformer. Leak is possibly near gauge. Defective conductor to mechanical relief device. Joey Day toggled off and info tagged TS 16 and they will investigate further at a later date. Joey Day & Mike Hollifield report they found a discrepant conductor to the mechanical relief device. This conductor is isolated and TS #16 (pressure relief device) is acknowledged w/Info tag placed. Joey Day reports repairs can only be completed when the bank is out of service. No ERT. **By recommending the replacement of all phases and spare for 3 BANK, APR addresses this need.**

Platforms

all platforms in the yard need to be replaced or at the least repaired. None were engineered but field designed with the thought of access, not safety or durability in mind. They all have lumber decks that are old and dangerous. Most don't allow room for anything other than standing, not room for maintenance or room in front of cabinets to step back incase of electrical flash or failures. The moab platform below has no railing. The right hand illustration is at the 12kv cb, very flexible, no middle bracing, your head is level with bottom of bushings and you have no quick way to get away if you have an issue when closing breaker except to jump.

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Platforms #4 Transformer platform doesn't allow room to open cabinet door fully and doesn't extend around transformer

AEP AMERICAN® ELECTRIC POWER

Drainage Issues

Water coming from service building parking lot in the left picture and water coming from a combination of the sloped 69kv bay which slopes back to the parking lot and then is funneled along the fence line is creating ruts in the station.

DATA REQUEST

AG 2-8 Refer to Kentucky Power’s response to AG DR 1-17. Based on the answer provided, fully explain how Kentucky Power protects the interest of its customers regarding transmission planning when those interests are at odds with affiliates or the rest of the AEP East transmission system.

RESPONSE

Kentucky Power states that the interest of its customers regarding transmission planning, which in material terms corresponds to the Company's obligation to provide adequate, efficient, and reasonable electric service to its customers, is the ultimate guiding principle in the Company's transmission planning activities. These transmission planning activities require a high level of coordination, not only within the context of the AEP East Transmission System, but at the regional level in the context of PJM and potentially other transmission organizations.

Kentucky Power actively participates in meetings with the AEP Transmission organization to review the projects planned for its service area. Among other things, AEP Transmission regularly reviews and discusses transmission projects planned or underway with Kentucky Power management. During these briefings, Kentucky Power examines the reasons for the projects, the scope of work, and the project management processes to ensure that the projects are reasonable and necessary to reliably serve customers. Kentucky Power also reviews proposed transmission investments as part of the capital planning process. Kentucky Power senior management also engages as a part of the AEP ongoing review of AEP Transmission investments. In addition, Kentucky Power arranges for presentations by AEP Transmission to discuss AEP Transmission projects in Kentucky with the Kentucky Public Service Commission.

All AEP affiliated transmission owners follow the same established and detailed protocol to evaluate and select Supplemental Projects. This assures that all AEP-affiliated transmission owners are applying consistent criteria in evaluations. However, Kentucky Power ultimately determines the mix of Supplemental Projects needed to maintain the reliability of its transmission grid. AEP affiliates do not have any input into Kentucky Power's decision making process. Please refer to the Company's response to AG 1-17.

Witness: Ranie K. Wohnhas and Kamran Ali

Kentucky Power Company
KPSC Case No. 2019-00154
Attorney General's Second Set of Data Requests
Order Dated October 14, 2019

DATA REQUEST

AG 2-9 Refer to Kentucky Power's response to AG DR 1-18, wherein when requested to explain the standards that were referenced in Mr. Ali's testimony, Mr. Ali merely provided a link to the entirety of PJM's 3000+ page Open Access Transmission Tariff. Confirm that the industry and RTO standards that were referenced in Mr. Ali's testimony, page 6, we restated to have been "set forth in the PJM Operating Agreement."

RESPONSE

The Company objects to this data request to the extent it purports to request a legal conclusion. Without waiving this objection, the Company states that the PJM's Operating Agreement and Open Access Transmission Tariff ("OATT") are both regulated and approved by the Federal Energy Regulatory Commission ("FERC"), and neither can be appropriately viewed in isolation from the other. Compliance with the requirements in PJM's OATT is a requirement of PJM's FERC-approved Operating Agreement.

PJM's minimum design standards are also known as "Designated Entity Design Standards". These were developed by the Designated Entity Design Standards Task Force (DEDSTF) to govern the minimum standards that any entity must design to when developing competitive transmission projects in PJM. Schedule 6 of the PJM Operating Agreement describes the process for acquiring and maintaining Designated Entity Status. Although the Designated Entity Design Standards were developed specifically for competitively solicited projects, Kentucky Power ensures that its own design standards are consistent with the PJM standards.
Information on the DEDSTF and the on-going review of standards can be found using the following link: https://www.pjm.com/committees-and-groups/subcommittees/dedss.aspx

Witness: Kamran Ali

DATA REQUEST

AG 2-10 Refer to KPCo's response to AG-1, Item 9, subpart c.
a. Identify and explain in detail any part of the current CPCN application where the Company declined to upgrade certain equipment or declined to pursue a certain solution because such upgrade or solution would not be considered cost-effective.
b. Explain how KPCo balances the cost-effectiveness portion of this equation against the other factors.

RESPONSE

The Company objects to this data request to the extent it is overly broad and not reasonably calculated to lead to the discovery of admissible evidence relevant to the Application. Without waiving these objections, the Company states as follows:

a. The Company determined that, based on current circumstances, Circuit Breaker R is not required to be replaced or upgraded at the present time. The Company will continue to monitor the condition and performance of this breaker and, as needs are identified, and as opportunities are identified to address those needs, the Company will present any solutions through the PJM process as applicable. Also see the Company's response to Staff 2-11 for a description of project alternatives that were evaluated by the Company.

b. The Company considers many factors including but not limited to historical performance reviews, engineering analysis, field condition reports, and planning load flow analysis. Based on this information, Kentucky Power determines whether a transmission asset should be rebuilt, replaced or retired. The Company then works on developing the most efficient and cost-effective solutions to rebuild or replace the asset.

Witness: Michael G. Lasslo and Kamran Ali

DATA REQUEST

AG 2-11 Refer to KPCo's response to AG-1, Item 23, discussing how:
[a]ll of the equipment to be installed as part of the Project has a long useful life expectancy, often measured in decades. Such long useful life expectancies are consistent with the Company's experience with comparable equipment and facilities, which in some cases can exceed their expected life expectancies by many years, and in some cases decades.
a. Refer further to the Application, page 11. Fully explain the Company's approach of noting equipment possibly exceeding its useful life expectancy by decades as a positive outcome in the response above, while in the Application for this project it described such equipment that has exceeded its useful life and is no longer supported by the manufacturer as in need of immediate replacement.
b. At what point do manufacturers stop supporting equipment? How long do third-party suppliers support equipment with non-OEM parts?
c. Explain whether there is any difference between the terms "useful life expectancy" and "projected operating life."

RESPONSE

a. There is no contradiction between the two statements. Kentucky Power's transmission system currently includes, and has included in the past, multiple examples of assets that have exceeded their useful life expectancy (which in this context can be understood to be its projected operating life). The Company performs maintenance with the intent of maximizing the useful life of its equipment to the extent practicable. Although age is a useful indicator of the remaining useful life of an asset, relying solely on expected life estimates is not a reasonable strategy for managing equipment reliability. If a comprehensive review of performance, condition and risk indicates that an asset is not a candidate for replacement, the Company will continue to utilize that asset, even if the age exceeds what is typically expected for that class of asset. However, if equipment is found to pose an unreasonable risk of service disruption to connected customers, the Company will act to proactively replace this equipment.

b. Manufacturers typically continue to support equipment until there is a major design change or a technological advancement. This varies depending on the manufacturer and type of equipment. As an example, circuit breaker manufacturers have historically changed their base design roughly every 10-15 years. These manufacturers may continue to supply parts for a limited time, typically in the range of 3-5 years. In general, third party non-OEM suppliers will provide "minor" parts (compressors, motors, some relays, interrupter parts such as baffles, arcing tip, and moving contacts) for a fairly long time (about 25 years) or until it is no longer profitable for them to support the equipment and carry the items in stock. For "major parts", most non-OEMs will not support these more intricately designed parts. Non–OEM companies are often forced to reverse engineer the parts and often lack the specific design knowledge to do so without the support of the original manufacturer or supporting design documents. For these reasons, most non-OEM suppliers only offer a limited number of parts. Other types of equipment change on a more frequent basis, primarily due to the technology involved. For example, protective relaying and SCADA devices used by Kentucky Power today have a manufacturer warranty of 10 years, and revenue meter manufacturers typically have warranties of 5 or 10 years. Non-OEM serviceability is very limited and often involves the replacement of control cards or other major components with components from other working devices of the same make and model.

c. In the context of the Company's description of the need for the project, the two terms can be used interchangeably. The Company notes that equipment can, and often does, continue to be used to provide service to customers even after the equipment exceeds its projected useful life and until retired. Conversely, the fact that equipment has not reached its projected operating life does not mean that it is not necessary and/or cost-effective to replace or upgrade the component. One concept does not negate the other.

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director of Regulatory & Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Ranie K. Wohnhas

Ranie K. Wohnhas

Commonwealth of Kentucky	)	
	)	Case No. 2019-00154
County of Boyd	)	

Subscribed and sworn before me, a Notary Public, by Ranie K. Wohnhas this 24th day of October, 2019.

Pamela Howard

Notary Public #619486

My Commission Expires 3-18-2023

VERIFICATION

The undersigned, Kamran Ali, being duly sworn, deposes and says he is the Managing Director of Transmission Planning, American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Kamran Ali

Kamran Ali

State of Ohio	)	
	)	Case No. 2019-00154
County of Franklin	)	

Subscribed and sworn before me, a Notary Public, by Kamran Ali this 15TH day of October, 2019.

Notary Public

My Commission Expires 06·06·2022

NOTARIAL SEAL
STATE OF OHIO

Andrea Marea Cuthbert
NOTARY PUBLIC - OHIO
MY COMMISSION EXPIRES
06-06-2022

VERIFICATION

The undersigned, Michael G. Lasslo, being duly sworn, deposes and says he is the Reliability Manager for Kentucky Power, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Michael G. Lasslo

Michael G. Lasslo

Commonwealth of Kentucky)
) Case No. 2019-00154
County of Perry)

Subscribed and sworn before me, a Notary Public, by Michael G. Lasslo this 22nd day of October, 2019.

Ellis R. McKnight

Notary Public

My Commission Expires JUNE 21, 2022