PJM Relay Subcommittee
Protective Relaying Philosophy and Design Standards

Revision: 03
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Prepared by:
PJM Relay Subcommittee

PJM Relay Subcommittee
Protective Relaying Philosophy and Design Standards

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At the time the Protective Relaying Philosophy and Design Standards were revised in October 2002, the PJM Relay Subcommittee had the following membership:

Steve Boutilier	BG&E	Ken Seiler	PJM
Tom Domin	PPL	J. D. Wardlow	Chairman - PSEG
Carl Kinsley	Conectiv	Richard Webster	PECO
Dave Powell	First Energy	Keith Wilson	Pepco

The PJM Relay Subcommittee also wishes to acknowledge the contributions made by the following former members and guests:

Richard Brackbill	First Energy	Evan Sage	BG&E / Pepco
Jace Gill	PPL	Chuck Thompson	Conectiv
Tom Groscup	First Energy		

Definition of Terms

Shall – indicates a requirement.

Should – Functionally required, but alternate solutions are acceptable, provided that the functional intention is satisfied.

Approval

Approval Date: 6/19/03
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Approvals:

PJM Relay Subcommittee

Revision History

Revision 03 (6/19/03)

The PJM Relay Subcommittee intends to revise or reaffirm these relay philosophy and design standards every four years.

PREVIOUSLY ISSUED: February 1990

REVISED: May 1993

REVISE/REAFFIRM: 1997

APPROVED BY: Planning and Engineering Committee

This document is the third revision of the Relay Subcommittee Protective Relaying Philosophy and Design Standards.

Introduction

Target Users

The target users for this PJM Relay Subcommittee document for ***Protective Relaying Philosophy and Design Standards*** are:

- Generation Developers' respective engineering, construction and operations staff.
- Transmission Owners' respective engineering and construction staff.
- PJM Members.
- PJM Staff.

References

There are other PJM documents that provide both background and detail on other topics.

1. MAAC A3 "Special Protection System Criteria"
2. MAAC B6 "Requirements for Isolation of Disturbance Monitoring Equipment"
3. MAAC B8 "Underfrequency Load Shedding Requirements"

What You'll Find In This Document

- A table of contents.
- This introduction.
- Sections containing the specific guidelines, requirements, or procedures including Generation Developer and PJM OI actions.

Section 1: Subject Introduction

Welcome to the *Subject Introduction* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- An introduction to the scope and applicability of these standards.
- Protection system definition.

Introduction

This document establishes the minimum design standards and recommended design philosophy for the protection systems associated with bulk power facilities within the Mid-Atlantic Area Council (MAAC) Region. The facilities to which these protective relay philosophy and design standards apply are generally comprised of all large (100 MW and above) unit-connected generators under automatic load control or other generators where failures may have an effect on the interconnected system, as well as all interconnection and major (230 kV and above) transmission lines and associated transmission facilities. Appendices H & J apply to smaller facilities. Further interpretation of applicability follows:

A. Compliance with Section IA and associated Table I of the NERC Planning Standards is mandatory for all facilities identified in the MAAC Bulk Transmission Facilities and Major Generation Facilities lists. The MAAC Bulk Transmission Facilities and Major Generation Facilities lists include certain transmission facilities below 230 kV. The requirements of this document will not specifically apply to these facilities if it is demonstrated that compliance with Section IA and associated Table I of the NERC Planning Standards is not violated. This demonstration is the responsibility of the facility owner.

B. Where a protection system does not presently meet the requirements of Section IA and associated Table I of the NERC Planning Standards, action shall be taken by the facility owner to bring the protection system into compliance.

C. The requirements set forth in this document will in some cases be more restrictive than the NERC 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 protection systems designed after the adoption date of this document shall conform to these philosophy and design standards. It is recognized that some facilities existing prior to the adoption of these philosophy and design standards do not conform. It is the responsibility of the facility owners to consider retrofitting those facilities to bring them into conformance as changes or modifications are made to these facilities. As previously implied, retrofits are mandatory if the failure to implement those results in non-compliance with Section IA and associated Table I of the NERC Planning Standards.

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 standards. 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 standards as an interpretation of a specific section and finally upon revision of the document.

Section 2: Protective Relaying Philosophy

Welcome to the *Protective Relaying Philosophy* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Philosophy on design objectives and criteria
- Equipment and recording considerations.

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 design considerations must be adhered to:

- Two sets of protective relay schemes (primary and backup) designed and set such that necessary protection will be maintained for an outage or failure of either protective system.
- Independent ac current and voltage sources to the primary and back-up relay schemes. Independent Voltage Transformers (VT's) are preferred. However, VT's with independent secondary windings are acceptable**.** (Approved schemes for independent a.c. voltage sources are included in Appendix G.)
- Independently protected dc control circuits associated with the primary and back-up relay schemes.
- Dual breaker trip coils. (See Appendix A)

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 must 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.

2.4 Fault Analysis

Fault Recording devices must be installed at all EHV substations (345 kV and above), major 230 kV substations and at generating stations with large generating capacity (in aggregate, 500 MW and greater). Note that modern protective relays often include fault-recording capability and their use may preclude the requirement for stand-alone fault recorders. Sufficient power system quantities shall be monitored and recorded to assess the proper or improper performance of the bulk power system during faults. Typical quantities monitored are provided in Appendix B of this document.

- New fault recording equipment shall have a minimum of three cycles of pre-fault data.
- These recorders shall be time synchronized to a reference traceable to the National Institute of Standards and Technology (NIST)

2.5 Dynamic Disturbance Recorders

Dynamic disturbance recording equipment shall be installed at strategic locations on the interconnected bulk electric transmission system within the MAAC region to provide sufficient data to enable verification of power flow and dynamics simulations of a disturbance at the bulk power system level. Dynamic recording capability shall be installed at selected 500 kV switchyards and 500/230 kV substations so that dynamic quantities are monitored and recorded. These recorders shall be time synchronized to a reference traceable to the National Institute of Standards and Technology (NIST).

Section 3: Generator Protection

Welcome to the *Generator Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Generator stator and rotor protection.
- Abnormal operating conditions.

Generator Protection

This section defines the minimum protection requirements necessary to satisfy PJM/MAAC protection guidelines for generators. In general, the generator manufacturer should be consulted for specific protection requirements. It should be recognized that incorporated in generating units are protective devices such as stator temperature, cooling medium temperature, voltage regulator control, over speed protection, etc., which should be provided but are beyond the scope of this document. It should further be recognized that details associated with effective application of protective systems to generators represents an area too broad to be covered in this document. The reader is referred to the following publications for additional guidance:

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

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

For units below 100MW and not connected at 230 kV or above, see Appendix H to 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 Phase Fault Protection

Phase fault protection requires a primary current differential relay scheme and an independent back-up differential relay scheme, employing independent current sources and independently protected dc control circuits. The backup scheme often consists of the overall generator and unit transformer differential. A simultaneous trip of the generator breakers, excitation system and turbine valve is required.

3.1.3 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. Two independent schemes are required with independent current or voltage sources and independently protected dc control circuits. At least one of the schemes shall provide protection for 100 percent of the stator winding. The relays must coordinate with other protective devices and the generator voltage transformer fuses. A simultaneous trip of the generator breakers, excitation system and turbine valves is required.

Smaller units (between 100 and 500 MW) are exempt from the redundancy requirement. For generators grounded through an impedance which is low enough to allow fault currents detectable by differential relays (typical on older units), no dedicated ground fault protection is required.

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. The generator shall be equipped with rotor field ground fault protection. Tripping of the generator is acceptable but not mandatory. At a minimum, the protection shall initiate an alarm and upon receipt of this alarm, the generator should be shut down as quickly as possible.

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. A primary relay scheme and an independent back-up relay scheme are required, using independent current and voltage sources and independently protected dc control circuits.

Tripping of the generator output breaker(s) is required. A simultaneous trip of the excitation system and turbine valves is recommended.

Smaller units (between 100 and 500MW) are exempt from the requirement for redundant loss of field protection.

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. This protection requires a negative sequence time overcurrent relay with sufficient sensitivity to detect unbalanced conditions exceeding the continuous rating of the generator. The protection shall initiate an alarm at an appropriate level. For higher levels, tripping the generator output breakers is required and a simultaneous trip of the excitation system and turbine valves is recommended.

Smaller units (between 100 and 500MW) require dedicated unbalanced fault protection, but are exempt from the requirement to protect for unbalanced load currents.

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. Detailed stability studies are required to determine if out-of-step protection is required. If the apparent impedance locus during an unstable swing is expected to pass through the step-up transformer or generator impedance, out-of-step protection is generally necessary because the condition will be undetectable by line relaying. The generator shall be tripped within the first slip cycle.

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. Two independent schemes must be normally in service whenever field is applied, using independent potential sources and independently protected DC control circuits. An alarm and a simultaneous trip of the generator breakers, excitation system and turbine valves are recommended. A multi-setpoint (or inverse time) overall Volts/Hertz tripping characteristic is also recommended. Operation of the scheme shall result in an alarm at a low level of overexcitation followed, if no action is taken, by simultaneous tripping of the generator breakers and the excitation system after an appropriate time delay. A simultaneous trip of the turbine is also recommended. 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.

Smaller units (between 100 and 500MW) are exempt from the requirement for redundant volts/Hertz protection.

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. Anti-motoring protection, which initiates an alarm followed by a simultaneous trip of the generator breakers, excitation system, and turbine valves, is recommended.

The recommended practice is to use the reverse power relay as the means for opening the generator breakers following a routine manual or automatic trip of the turbine valves. Typical protection consists of a reverse power relay set with a short time delay, acting in conjunction with closed turbine valve logic to initiate a trip. Due to inherent reliability problems with valve-position switches, this scheme should be backed up by a second, fully-redundant reverse power relay acting independently of the valve position switches but with a longer time delay for security against tripping during transient power swings.

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 set at 57.5 Hz with a five-second tripping delay are required unless the turbine manufacturer states that this protection is unnecessary. (The turbine manufacturer should be consulted for comprehensive requirements.) For security, two underfrequency relays connected with “AND” tripping logic and connected to separate voltage sources are required. A sequential trip of the turbine valves, excitation system and generator breakers is recommended.

Smaller units (between 100 and 500MW) are exempt from the two-relay security requirement.

3.4 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; therefore, current-actuated fault detection may lack sufficient sensitivity to allow the breaker failure scheme to operate. For these conditions, current fault detectors shall be augmented with breaker auxiliary switches using "OR" tripping logic.

3.5 Excitation System Tripping

When it is necessary for a protective relay to trip the excitation system, redundant tripping shall be used if available. This may include the tripping of two field breakers (e.g., the main field and the exciter field breakers), or the tripping of a single field breaker with simultaneous activation of the static de-excitation circuit.

Smaller units (between 100 and 500MW) are exempt from the redundancy requirement.

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. Protection for this condition shall be provided for all gas and/or air circuit breakers used for generator synchronizing.

3.7 Protection During Start-Up or Shut-Down

During start-up or shutdown, the generator may be operated at less than rated frequency. If this is the case, adequate protection during such periods shall be provided. Since some relays are frequency-sensitive, each of the relay's operating characteristics vs. frequencies must 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. Protection designed specifically for this condition is required and shall trip all associated generator breakers. Consideration should also be given to potential damage from accidental energizing from the low-voltage side of the unit auxiliary station service transformer.

3.9 Synchronizing Equipment

Each generator should be equipped with a scheme that supervises manual synchronizing, where employed. If required for system restoration, the synchronizing equipment shall be configured in a manner which will allow the generator breakers to close in on a dead system.

3.10 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. The generator leads shall be included within a second differential zone if either (1) the conductors are not segregated into bus ducts for their entire exposure or, (2) the generator is not grounded through a high impedance to limit ground faults to levels undetectable by current differential relays. When two schemes are required, independent current sources and independently protected dc control circuits are required. A simultaneous trip of the generator breakers, excitation system and turbine valves is required.

Section 4: Unit Power Transformer and Lead Protection

Welcome to the *Unit Power Transformer and Lead Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Transformer fault protection and redundancy requirements.

Unit Power Transformer and Lead Protection

This section defines the minimum protection requirements necessary to satisfy PJM/MAAC protection guidelines for unit power transformers larger than 100 MW or connected at 230 kV and above. It should be recognized that details associated with effective application of protective systems to transformers represents an area too broad to be covered in this document. The reader is referred to the following publication for additional guidance:

C-37.91 Guide for Protective Relay Applications to Power Transformers.

4.1 Transformer Fault Protection

Primary protection for the transformer shall consist of either current differential relays or a sudden pressure relay.

Back-up protection for the transformer shall consist of current differential relays whose zone of protection may also include other equipment such as the transformer leads, the generator, the unit auxiliary transformer and its leads.

4.2 Transformer High-Side Lead Protection

The transformer high-side leads shall be protected by primary and backup differential relays or equivalent high-speed protection.

4.3 Overexcitation Protection

Overexcitation protection is required and is often provided by the generator overexcitation protection. See GENERATOR PROTECTION: Overexcitation.

4.4 Redundancy Requirements

Primary and back-up protection requires independent current sources and independently protected dc control circuits.

SECTION 5: Unit Auxiliary Transformer and Lead Protection

Welcome to the *Unit Auxiliary Transformer and Lead Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Unit Auxiliary Transformer and Lead fault protection and redundancy requirements.

Unit Auxiliary Transformer and Lead Protection

This section defines the minimum protection requirements necessary to satisfy PJM/MAAC protection guidelines for unit auxiliary transformers associated with generators larger than 100 MW or connected at 230 kV and above. It should be recognized that details associated with effective application of protective systems to transformers represents an area too broad to be covered in this document. The reader is referred to the following publication for additional guidance:

C-37.91 Guide for Protective Relay Applications to Power Transformers.

5.1 Transformer and Low-Side Lead Protection

Primary protection for the transformer and low-side leads shall consist of current differential relays. Transformer and low-side lead back-up protection shall consist of a current differential scheme or high-side overcurrent relays or sudden pressure relay with transformer low-side overcurrent relays.

If the transformer low-side neutral is grounded through an impedance which limits fault currents to levels not detectable by differential relays, transformer neutral overcurrent relaying shall be provided. Back-up protection in this case is not required.

5.2 Transformer High-Side Lead Protection

Transformer high-side leads shall be included in a current differential scheme (the unit differential). Back-up differential protection is also required for the transformer high-side leads (or any other equipment connected directly to the generator) if: (1) the phase conductors are not segregated in bus duct for their entire exposure, or (2) ground faults are not limited to levels not detectable by the unit differential relays.

5.3 Redundancy Requirements

Primary and back-up protection requires independent current sources and independently protected dc control circuits.

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

Welcome to the *Start-up Station Service Transformer and Lead Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Start-up Station Service Transformer and Lead fault protection and redundancy requirements.

Start-up Station Service Transformer and Lead Protection

This section defines the minimum protection requirements necessary to satisfy PJM/MAAC protection guidelines for start-up station service transformers associated with generators larger than 100 MW or connected at 230 kV and above. It should be recognized that details associated with effective application of protective systems to transformers represents an area too broad to be covered in this document. The reader is referred to the following publication for additional guidance:

C-37.91 Guide for Protective Relay Applications to Power Transformers.

6.1 Transformer and Low-Side Lead Protection

Primary protection for the transformer and low-side leads shall consist of a dedicated transformer and lead differential relay. Transformer and low-side lead back-up protection shall consist of a current differential scheme or high-side overcurrent relays or sudden pressure relay with transformer low-side overcurrent relays.

If the transformer low-side neutral is grounded through an impedance which limits fault currents to levels not detectable by differential relays, transformer neutral overcurrent relaying shall be provided. Back-up protection for this case is not required.

6.2 Transformer High-Side Lead Protection

The transformer high-side leads shall be protected by primary and back-up current differential or other high-speed relaying systems.

6.3 Redundancy Requirements

Primary and back-up protection requires independent current sources and independently protected dc control circuits.

SECTION 7: Line Protection

Welcome to the *Line Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Line protection and redundancy requirements.

Line Protection

This section defines the minimum protection requirements necessary to satisfy PJM/MAAC protection guidelines for transmission lines. Details associated with effective application of protective systems to transmission lines represents an area too broad to be covered in this document. The reader is referred to the following publication for additional guidance:

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

Requirements covered in this section apply to lines listed in the MAAC Compliance Facilities List. It is not mandatory that these requirements be applied to those lines included in the listing that are operated at a nominal voltage which is below 230 kV--provided that compliance with Section IA and associated Table I of the NERC Planning Standards is met with the applied protection. Demonstration of such compliance is the responsibility of the transmission owner.

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. As such, independent primary and backup line protection systems are a requirement for all lines covered by this standard. 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 be such that, with high probability, operation will not occur for faults external to the line or under non-fault conditions.

7.1 Primary Protection

7.1.1 The primary line protection shall provide high-speed simultaneous tripping of all line terminals. On network lines, this will typically require the use of a pilot relay system.

7.1.2 The relays shall have sufficient speed so that they will provide the clearing times for system reliability as defined in the NERC Planning Standards, Section I.A—System Adequacy and Security – Transmission Systems and associated Table 1

7.2 Back-up Protection

7.2.1 The back-up protection shall be independent of the primary relays with:

A. Independent current transformer (CTs). For dead tank breakers, both primary and back-up relays shall be connected to independent CTs located on the "bus" side of the breaker so that breaker faults will be detected by the primary and backup relays of both zones adjacent to the breaker.

B. An independent voltage source. One of the following is acceptable:

1. Independent voltage transformers (VTs).

2. Independent secondary windings of the same VT.

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

C. Independently protected dc control circuits.

D. Relays from the same manufacturer are acceptable for both the primary and backup systems, however, use of different models is preferred.

7.2.2 Back-up protection must always include a non-pilot tripping scheme for phase and ground faults.

7.2.3 Back-up protection shall have sufficient speed to provide the clearing times necessary to maintain system stability as defined in the NERC

Planning Standards, Section I.A—System Adequacy and Security – Transmission Systems and associated Table 1.

A. 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.

B. 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.

C. Backup pilot – The backup protection may require the inclusion of a pilot 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. (See Appendix E) When backup pilot is required, logic must be provided to alarm for a failure that disables both primary and backup pilot tripping—in order that the line can be promptly removed from service or other action taken if requirements of Table 1 are violated.

7.3 Restricted Ground Fault Protection

A scheme must be provided to detect ground faults with high fault resistance. The relay(s) selected for this application shall be set at 600 primary amperes or less. (These relays may serve as the overreaching non-pilot ground tripping function.)

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

Relays requiring polarizing voltage may not operate for close-in multi-phase faults when a line is energized if the relays are supplied from line-side voltage transformers. Such faults typically occur when grounds are left connected to the line following line maintenance.

These faults must be detected by the primary or back-up line protection relays. If this cannot be achieved, a specially designed scheme must be provided to detect and clear such faults.

7.5 Out-of-Step Protection – Transmission Line Applications

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

1. Block Automatic Reclosing – The use of out-of-step relays to block automatic reclosing in the event tripping is caused by instability.

2. Block Tripping – the use of out-of-step relays to block tripping of phase distance relays during power swings.

3. 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. ***However, any proposed use of out-of-step relays in any transmission line application shall be subject to review by the PJM Relay Subcommittee.***

7.6 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 applied on the PJM system in the past. Due to the complex nature of the protective systems involved with single-phase tripping schemes, any planned application of such a scheme on lines covered by this standard are subject to review and approval by the PJM Relay Subcommittee.

SECTION 8: Substation Transformer Protection

Welcome to the *Substation Transformer Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Substation transformer protection and redundancy requirements.

Substation Transformer Protection

The following section defines the minimum protection requirements necessary to satisfy PJM / MAAC protection guidelines for substation transformers. However, the effective application of protective relays and other devices for the protection of power transformers is a subject too broad to be covered in detail in this document. The reader is referred to the following publications for guidance:

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

Substation transformers tapped to lines shall have provisions to automatically isolate a faulted transformer and permit automatic restoration of the line. If the transformer is connected to a bus, the need to automatically isolate the transformer and restore the bus will depend on the bus configuration and the importance of the interrupted transmission paths. The following protective schemes shall be provided:

8.1.1 A primary current differential scheme.

8.1.2 A back-up current scheme, preferably differential, utilizing separate current transformers,

or

a pressure-actuated device which operates for a rapid change in gas or oil pressure. In cases where a separate tap changer compartment exists, either a separate pressure-actuated device for that compartment, or a back-up current scheme, must be used.

The back-up scheme shall have an independent tripping circuit.

If the transformer current differential zone is extended to include the bus between breakers on the high or low sides of the transformer, then the current circuit from each breaker shall 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

The following are acceptable schemes for isolating a faulted 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 will be required.

8.2.1 When a high-side interrupting device, such as a circuit breaker or a circuit switcher, is used, either:

(1) a direct transfer trip scheme and a motor-operated disconnect switch,

or

(2) a second circuit switcher,

or

(3) a ground switch and a motor-operated disconnect switch combination must be provided for the contingency of a stuck high-side interrupting device. Where carrier direct transfer trip is used, it is recommended connecting it to a phase other than that used for the ground switch. Once the motor-operated disconnect switch opens to isolate the high-side interrupting device, then the line shall be capable of being restored. If the high-side interrupting device is a circuit switcher which is not fully rated to interrupt all high-side and low-side faults, then, to prevent damage to the circuit switcher, remote terminal protection must be capable of detecting and clearing all faults above the circuit switcher rating.

8.2.2 When a high-side interrupting device, such as a circuit breaker or a circuit switcher, is NOT used, either:

(1) Two independent direct transfer trip schemes to trip the remote terminals and a motor-operated disconnect switch to isolate the faulted transformer must be used. Once the transformer is isolated, the remote terminals shall be capable of being restored.

or

(2) The combination of a direct transfer trip scheme and a motor-operated disconnect switch to isolate the faulted transformer from the system must be used. A ground switch shall be provided as back-up to the direct transfer trip. Once the motor-operated disconnect opens to isolate the faulted transformer, the line shall be capable of being restored. Where carrier direct transfer trip is used, it is recommended connecting it to a phase other than that used for the ground switch.

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 (8.2.1.1 and 8.2.2.1) are preferred over ground switches.

Whenever direct transfer trip is referred to in this document, either a dual channel direct transfer trip scheme, or a scheme with equivalent security, such as a digital system or a fiber optic channel, is acceptable.

8.2.3 The use of transformer primary isolation switch auxiliary contacts in the transformer protection scheme can result in a degradation to dependability. Recommendations regarding the use of auxiliary switches follow. Note that the recommendations represent "good engineering practice" and are not specifically mandated. Note also, however, that if the single-contingency failure of an auxiliary switch contact or of the mechanical assembly which drives it, could result in non-compliance with Section 1A and associated Table 1 of the NERC Planning Standards, then the design is unacceptable.

(1) Other than as noted below, transformer primary isolation switch auxiliary contacts should preferably not be used in the transformer protection scheme in such a manner that if the auxiliary switch (e.g.., 89a/b) contact falsely indicates that the isolation switch is open, the required tripping of local breakers, the breaker failure initiation of local breakers, or the direct transfer tripping of remote breakers would be defeated. The use of auxiliary switches in the protection scheme should preferably be limited to local trip seal-in, direct transfer trip termination, etc. Trip (local or remote) logic of the form T = 94+T*89a is permissible. Trip logic of the form T = 94*89a is not recommended.

(2) If the transformer is tapped in such a manner that it is switchable

between two lines, there may be no alternative other than to use auxiliary switch contacts to determine which equipment to trip. In this case, redundancy requirements extend to the auxiliary switches, which should preferably be electrically and mechanically independent. Further, the auxiliary switches should preferably be mechanically connected to the operating shaft of the main switch rather than to the motor-operator shaft, to avoid false position indication in the event the motor-operator has been left decoupled from the switch.

(3) 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 Overexcitation

Overexcitation protection shall be provided on transformers connected to the 500 kV system. 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. An EHV Engineering Committee report entitled "Conemaugh Project - Relay Protection for 500 kV Transmission System, January 1971" discusses, in Appendix D, the development of PJM autotransformer overvoltage protection requirements.

It is recommended, but not required, that the relay be connected to the secondary side of the transformer.

8.4 Transformer Leads

Transformer high and low side leads must be included in two independent instantaneous protection schemes.

A "blind-spot" protective system must also be provided if any operating condition such as an open high-side disconnect defeats the transformer lead protection.

SECTION 9: Bus Protection

Welcome to the *Bus Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Bus protection and redundancy requirements.

Bus Protection

The following section defines the minimum protection requirements necessary to satisfy PJM / MAAC protection guidelines for substation busses. However, the effective application of protective relays and other devices for the protection of power system busses is a subject too broad to be covered in detail in this document. The reader is referred to the following publications for guidance:

ANSI/IEEE C37.97 Guide for Protective Relay Applications to Power System Busses

ANSI/IEEE C37.110 Guide for the Application of Current Transformers Used for Protective Relaying Purposes

9.1 The following protective schemes shall be provided:

9.1.1 A primary current differential or high impedance voltage differential protection scheme.

9.1.2 An independent back-up protection scheme consisting of:

(1) A second differential scheme, employing current transformers and tripping circuits that are completely independent from the primary scheme.

or

(2) Protection by remote line section relaying, when the broad objectives for system protection, as outlined in Section 2.1, are satisfied and the requirements in NERC Planning Standards Section I.A. and Table I are not violated.

SECTION 10: Shunt Reactor Protection

Welcome to the *Shunt Reactor Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Shunt reactor protection and redundancy requirements.

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.

The following section defines the minimum protection requirements necessary to satisfy PJM / MAAC protection guidelines for shunt reactors. However, the 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. The reader is referred to the following publications for guidance:

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

10.1 Reactor Protection

Shunt reactors tapped to lines shall 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. The following protective schemes shall be provided:

10.1.1 A primary current differential scheme.

10.1.2 A back-up current scheme, preferably differential, utilizing separate current transformers,

or

a pressure-actuated device which operates for a rapid change in gas or oil pressure.

The back-up scheme shall have an independent tripping circuit.

10.1.3 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

The following are acceptable schemes for isolating a faulted reactor 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 will be required.

10.2.1 When a high-side interrupting device, such as a circuit breaker or a circuit switcher, is used, either:

(1) Direct transfer trip and a motor-operated disconnect switch,

or

(2) A second circuit switcher,

or

(3) or a ground switch and a motor-operated disconnect switch combination must be provided for the contingency of a stuck high-side interrupting device. Where carrier direct transfer trip is used, it is recommended connecting it to a phase other than that used for the ground switch. Once the motor-operated disconnect switch opens to isolate the high-side interrupting device, then the line shall be capable of being restored. If the high-side interrupting device is a circuit switcher which is not fully rated to interrupt all high-side and low-side faults, then, to prevent damage to the circuit switcher, remote terminal protection must be capable of detecting and clearing all faults above the circuit switcher rating.

10.2.2 When a high-side interrupting device, such as a circuit breaker or a circuit switcher, is NOT used, either:

(1) Two independent direct transfer trip schemes to trip the remote terminals and a motor-operated disconnect switch to isolate the faulted reactor must be used. Once the reactor is isolated, the remote terminals shall be capable of being restored.

or

(2) The combination of a direct transfer trip scheme and a motor-operated disconnect switch to isolate the faulted reactor from the

system must be used. A ground switch shall be provided as back up to the direct transfer trip. Once the motor-operated disconnect opens to isolate the faulted reactor, the line shall be capable of being restored. Where carrier direct transfer trip is used, it is recommended connecting it to a phase other than that used for the ground switch.

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 (10.2.1.1 and 10.2.2.1) are preferred over ground switches.

Whenever direct transfer trip is referred to in this document, either a dual channel direct transfer trip scheme or a scheme with equivalent security, such as a digital system or a fiber optic channel, is acceptable.

10.2.3 The use of reactor isolation switch auxiliary contacts in the reactor protection scheme can result in a degradation to dependability. Recommendations regarding the use of auxiliary switches follow. Note that the recommendations represent "good engineering practice" and are not specifically mandated. Note also, however, that if the single-contingency failure of an auxiliary switch contact or of the mechanical assembly which drives it, could result in non-compliance with Section 1A and associated Table 1 of the NERC Planning Standards, then the design is unacceptable.

(1) Other than as noted below, reactor isolation switch auxiliary contacts should preferably not be used in the reactor protection scheme in such a manner that if the auxiliary switch (e.g., 89a/b) contact falsely indicates that the isolation switch is open, the required tripping of local breakers, the breaker failure initiation of local breakers, or the direct transfer tripping of remote breakers would be defeated. The use of auxiliary switches in the protection scheme should preferably be limited to local trip seal-in, direct transfer trip termination, etc. Trip (local or remote) logic of the form T = 94+T*89a is permissible. Trip logic of the form T = 94*89a is not recommended.

(2) If reactor 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 reactor 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 reactor maintenance.

SECTION 11: Shunt Capacitor Protection

Welcome to the *Shunt Capacitor Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Shunt capacitor protection and redundancy requirements.

Shunt Capacitor Protection

Shunt capacitors are provided on the transmission system to provide reactive capacity and are generally connected to station buses.

The following section defines the minimum protection requirements necessary to satisfy PJM / MAAC protection guidelines for shunt capacitor banks. However, the effective application of protective relays and other devices for the protection of shunt capacitors is a subject too broad to be covered in detail in this document. The reader is referred to the following publications for guidance:

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

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

11.1 Primary and back-up phase and ground overcurrent relays each connected to separate current transformers with independent tripping circuits, or other means of providing independent / redundant fault protection for the primary leads connecting the bank to the fault interrupting device.

11.2 A primary and a back-up bank unbalance detection scheme which will prevent the imposition of more than 110 percent of rated voltage on the individual capacitor cans in the event of multiple can failures. The capacitor bank should be designed such that a single can failure would not cause more than 110 percent of rated voltage on the remaining cans (necessitate removing the bank from service). Each scheme shall be provided with an independent tripping circuit. Where potential sensing is used in both primary and back-up schemes, independent potential sources are required, except for voltage differential schemes, where loss of potential results in tripping of the bank.

11.3 In the case of externally fused banks, the fuse size is 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 rupture.

SECTION 12: Breaker Failure Protection

Welcome to the *Breaker Failure Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Breaker failure protection and redundancy requirements.

Breaker Failure Protection

The following section defines the minimum protection requirements necessary to satisfy PJM / MAAC protection guidelines for breaker failure protection. However, the effective application of protective relays and other devices for breaker failure protection is a subject too broad to be covered in detail in this document. The reader is referred to the following publication for guidance:

"Summary Update of Practices on Breaker Failure Protection", an IEEE Power System Relaying Committee Report, IEEE Power Apparatus & Systems Transactions, vol. PAS-101, no.3, pp. 555-563, March 1982.

12.1 Local breaker failure protection is required.

12.2 It is required that local breaker failure initiate direct transfer trip when one or more of the following conditions exist:

12.2.1 Speed is required to assure system stability.

12.2.2 Remote back-up protection is unacceptable because of the number of circuits and area affected.

12.2.3 Sensitivity of remote relay schemes is inadequate due to connected transformers, connected generators or line end faults or because of the strong infeed from parallel sources.

Whenever direct transfer trip is referred to in this document, either a dual channel direct transfer trip scheme or a scheme with equivalent security, such as a digital system or a fiber optic channel, is acceptable.

12.3 The following criteria shall apply to all stuck breaker schemes:

12.3.1 Failure of a single component must not disable both breaker tripping and the stuck breaker scheme.

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

12.3.3 Consideration of pickup and dropout times of auxiliary devices used in a scheme must ensure adequate coordination margins. The minimum acceptable margin between normal fault clearing and the initiation of stuck breaker clearing is 28 ms.

12.3.4 A dedicated local breaker failure scheme must be used for each breaker. The scheme shall trip and block closing of all fault-interrupting devices necessary to isolate the faulted breaker. If a lockout relay is not used for this purpose, the breaker failure tripping scheme must not automatically reset until the faulted breaker has been isolated (via disconnect switches) from the system.

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

12.3.6 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 a 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 BFI = 94+BFI*89a is permissible. Breaker failure initiation logic of the form BFI = 94*89a 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.)

12.3.7 A "retrip" feature (retrip the principal breaker at initiation of the breaker failure timer) shall be an integral part of the breaker failure protection. It is recognized that some combinations of fault detector settings and scheme logic will preclude the necessity of this feature.

12.4 Pole disagreement tripping shall be installed on circuit breakers capable of individual pole operation.

12.4.1 This protection will be designed to open all poles if the position of one pole fails to agree with the position of either of the other two.

12.4.2 An alarm specifically for "breaker pole disagreement" will be initiated by the above scheme.

12.4.3 This disagreement circuit will trip only the affected circuit breaker.

12.5 Live tank circuit breakers shall have a specially designed high- speed scheme to detect an external phase-to-ground flashover of the columns.

12.6 Current transformer support columns shall have a specially designed high-speed scheme to detect an external phase-to-ground flashover of the column if the CTs would be in a blind spot during the flashover.

SECTION 13: Phase Angle Regulator Protection

Welcome to the *Phase Angle Regulator Protection* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Phase angle regulator protection and redundancy requirements.

Phase Angle Regulator Protection

13.1 Phase angle regulators, which are installed in series with transmission circuits to control power flow, consist of two sets of windings. There are primary and secondary series windings, also known as “excited” windings. There are primary and secondary shunt windings also called “exciting”, or tap changer windings. Protection for the phase angle regulator shall be provided with the following protective equipment:

a. A primary current differential scheme must include the series and shunt (tap changer) windings utilizing dedicated current transformers and tripping circuits.

b. A back-up current differential scheme must include the series and shunt (tap changer) windings with separate current transformers and tripping circuit.

c. Primary and back-up overcurrent schemes for the neutral connection of the primary and secondary shunt (exciting) windings utilizing dedicated current transformers.

d. Primary and back-up overcurrent schemes to detect an out-of-step tap changer position.

e. Individual pressure actuated devices which operate for a change in gas or oil pressure shall be provided for each winding tank.

For further information on the protection of phase angle regulators please refer to the document titled, “Protection of Phase Angle Regulating Transformers”, dated October 21,1999, issued by the IEEE Power System Relaying Committee.

SECTION 14: Transmission Line Reclosing

Welcome to the *Reclosing of Transmission Lines* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Transmission line reclosing requirements.

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

14.2 Definitions

14.2.1 Reclosing

Automatic closing of a circuit breaker by a relay system without operator initiation.

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.

14.2.2.1 High-Speed Autoreclosing

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.

14.2.2.2 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.

14.2.3 Delayed Reclosing

Reclosing after a time delay of more than 60 cycles.

14.2.4 Reclosing Through Synchronism Check Relay

A reclosing operation supervised by a synchronism check relay which permits closing 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.

14.2.5 Single Shot Reclosing Relay

A device which can initiate one reclose operation. If the reclose is unsuccessful, no further attempts to reclose can be made until a successful manual closure is effected.

14.2.6 Multiple Shot Reclosing Relay

A device which can initiate one or more reclose operations at preset time intervals. If unsuccessful on the last operation, no further attempts to reclose can be made until a successful manual closure is effected.

14.2.7 Dead Time

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

14.2.8 Initiating terminal

The first terminal closed into the deenergized line.

14.2.9 Following terminals

The terminals, which reclose following the successful reclosure of the initiating terminal.

14.3 Reclosing Considerations

14.3.1 Shaft Torque

The effect on the turbine generator shaft due to the torque produced as a result of line breaker reclosing should be considered. Turbine generator shaft damage could occur due to oscillations created by reclosing operations on nearby transmission lines. An appropriate time delay should be used for the reclosure of transmission line breakers close to generating units. (See section 14.5.3)

14.3.2 Circuit Breaker Capability

Reclosing times and sequences should be selected with regard to circuit breaker capability.

14.3.3 Cable Transmission Lines

Reclosing shall not be used on transmission lines consisting entirely of cable, since cable faults are permanent. 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 and blocked for cable faults.

14.3.4 Reclose Blocking

a. Reclosing of transmission line circuit breakers shall be blocked while a direct transfer trip signal is being received.

b. The operation of the breaker failure relay scheme on a breaker shall block reclosing on adjacent breakers. If the failed breaker can be automatically isolated, the reclose function may be restored to the adjacent breakers.

c. The operation of a transformer or bus protective relay scheme may also be a reason for blocking reclosing.

14.3.5 Switching Surge

Reclosing shall not be used where transient voltage analysis studies indicate that reclosing may produce switching surges exceeding the equipment design levels.

14.4 High Speed Autoreclosing Considerations

14.4.1 Deionization

When utilizing high speed autoreclosing, a consideration is the dead time required to deionize the fault arc. Based on voltage level, the minimum dead time required can be determined from the following equation:

$$T = 10.5 + (kV/34.5) \text{ cycles}$$

Where kV is the rated line-to-line voltage.

14.4.2 Effect on Stability

High Speed Autoreclosing into a permanent fault may adversely affect system stability. Stability studies should be performed before applying High Speed Autoreclosing on transmission line circuit breakers. If these stability studies indicate that reclosing following a specific type of fault or system condition would result in an unacceptable situation, adaptive reclosing may be used. Most adaptive 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.

14.4.3 Out-of-Step Conditions

Refer to Section 7.5, Out of Step Protection – Transmission Line Applications, for reclosing under this condition.

14.4.4 Reclose Initiation

High Speed Line reclosing shall be initiated only if a pilot relaying scheme is in service.

14.5 Prevailing Practices

14.5.1 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.

14.5.2 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.

14.5.3 Lines Electrically Close to Generating Stations

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.

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

Welcome to the *Supervision and Alarming of Relaying and Associated Control Circuits* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Supervision and alarming of relaying and associated control circuits.

Supervision and Alarming of Relaying and Associated Control Circuits

15.1 Philosophy

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.

15.2 Design Standards

The following circuits or conditions should be indicated visually at the stations and reported remotely from unattended stations. Some functions can be grouped together when reporting the alarm condition to the remote site based on the availability of alarm points. Facilities should be provided to indicate the specific trouble at the local site:

a. Battery low voltage condition.

b. Blown fuse on protective relaying dc control circuit.

c. Primary and back-up relays must be monitored for loss of ac potential.

d. Alarm condition of protective relay pilot channels, as described in Section 15.3.

e. Relay trouble alarms where internal alarm features are provided.

15.3 Relaying Communication Channel Monitoring and Testing

Any relaying communication channel shall be monitored so as to alarm when channel problems are detected. Schemes utilizing a signal that is "on" continuously shall be monitored continuously. Schemes that use an "on-off" signal shall be tested automatically at least once a day, preferably at reduced and full power levels.

SECTION 16: Underfrequency Load Shedding

Welcome to the *Underfrequency Load Shedding* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Underfrequency load shedding requirements.

Underfrequency Load Shedding

16.1 Per MAAC Under-Frequency Load Shedding Program Requirements (Document B-8), load-shedding schemes are required for dropping 30 percent of the utility load in response to a system underfrequency condition in accordance with the following program:

Amount of Load to be Dropped	Minimum Frequency Set Point ≥
10%	59.3 Hz
10%	58.9 Hz
10%	58.5 Hz

Note: Load may be shed in more than three steps provided the above schedule is maintained.

16.2 The load-shedding scheme shall be distributed in application as opposed to centralized.

16.3 Loads tripped by the load-shedding scheme shall require manual restoration (local or remote).

16.4 The underfrequency detection scheme shall be secure for a failure of a potential supply, and shall incorporate a 0.1 second (maximum) time delay. Longer time delays have been used to override the frequency decay associated with de-energized motor load. However, other techniques are preferred; for example, supervision of the underfrequency relay with a current detector, or the use of two underfrequency relays supplied from independent sources and connected such that both must operate to produce a trip.

16.5 Underfrequency relays shall be selected with the capability of maintaining +/- 0.2 Hz stability for set point and +/- 0.1 seconds for time delay.

SECTION 17: Special Protection Schemes

Welcome to the *Special Protection Schemes* section of the ***PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards.*** This section presents the following information:

- Special Protection Schemes.

Special Protection Schemes

17.1 Special Protection Schemes (SPS's) are occasionally employed in response to some abnormal condition or configuration of the electric system. Usually, the intent of these schemes is to protect equipment from thermal overload or system instability following contingencies on the electric system.

17.2 SPS'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.

17.3 The decision to employ an SPS should take into account the complexity of the scheme and the consequences of misoperation as well as its benefits. The use of an SPS, like any protection scheme, entails the risk that it will misoperate. However, the results of an SPS misoperation are usually more severe than those of more conventional protection schemes. The most severe consequences of the misoperation of SPS's are documented in the annual NERC major disturbance reports.

17.4 For SPS's which are only needed under certain conditions, controls shall be established to ensure that the scheme is deactivated when the conditions requiring its use no longer exist.

17.5 When the SPS is armed, there shall be indication in a manned facility.

17.6 For greater detail on SPS's refer to "MAAC Special Protection System Criteria (Document A-3)"

APPENDIX A

Use of Dual Trip Coils

Dual trip coils must be applied at new installations to meet dependability requirements mandated by this document. (See Section 2.2.4) The intent of this requirement is to assure that a failed trip coil will not result in the failure of a breaker to operate when it is called upon to clear a fault.

Several issues are important to consider when dual trip coils are applied:

1. In some designs, if the coils are energized simultaneously but with voltages of opposite polarity the action of the trip mechanism may be defeated. In such cases, trip tests to verify that connections to the trip coils are proper are recommended.

2. Undesirable breaker failure operations are possible if the primary trip path is open and tripping is initiated through slower operating backup relays. If this is a concern, it can be addressed in several ways:

   - Energize both sets of trip coils with both primary and backup relays or at least with the relaying system that 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 set of relays is not clear, it would be necessary to initiate the retrip of both sets of trip coils.

   - Apply "cross-trip" auxiliary relays in the breaker tripping control scheme. These relays 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

Fault Recorder Quantities

The following quantities are desired at each switchyard fault recorder location:

1. Time code (reference traceable to NIST).
2. A minimum of three cycles pre-fault information.
3. Phase-to-neutral voltage for each of the three phases (the three phase voltages may be rectified on to one channel). It is desirable to have the voltages available from two different sources.
4. Minimum of one phase current for each significant line. Each phase current should be monitored at least twice at each location.
5. Phase current for one phase of each generator, if the phase current is not available from a fault recorder in the plant.
6. Neutral (residual) current on each line.
7. Transmit and receive indication for each pilot channel associated with a protective relay scheme.
8. Breaker position (if not available on a sequence-of-events recorder).
9. Tertiary current for each transformer. (Summation)
10. Zero sequence voltage.
11. Transmit and receive indication for each direct transfer trip scheme (if not available on a sequence-of-events recorder).

The following quantities are desired for each generator 500 MW and above:

1. Frequency.
2. Generator field current or field voltage.
3. Generator watts.
4. Generator vars.
5. Generator neutral voltage (off neutral grounding transformer) or current.
6. Phase-to-neutral terminal voltage for each of the three phases. (The three phase voltages may be rectified on to one channel.)
7. Three-phase terminal amps.

The following types of starting elements may be used:

1. Zero sequence current (tertiary or residual).
2. Undervoltage (three phase).
3. Rate of change of current.
4. Zero sequence voltage.
5. Negative sequence voltage.
6. Under/over frequency.

See Section 2.4, as well as MAAC Document B-6 *MAAC Requirements for Installation of Disturbance Monitoring Equipment* for requirements for fault recorders at substations.

Dynamic Disturbance Quantities

Quantities recorded (either directly or readily derivable) shall include, but are not limited to the following:

1. Bus Voltage
2. Line Current
3. MW and MVAR flow
4. Frequency

See Section 2.5, as well as MAAC Document B-6 *MAAC Requirements for Installation of Disturbance Monitoring Equipment* for requirements for dynamic disturbance recorders at substations.

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 checkback 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 Requirements

- Carrier/Audio Tone systems – Dual-channel systems must be applied. Single-channel operation is allowed only for testing or while repairs are underway subsequent to a channel failure.

- 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.

Audio tone systems, which were designed for use on an analog multiplexed system, should be carefully evaluated for compatibility when interfaced with a digital communication system. When incompatible, false trips have been experienced in conjunction with the momentary loss and subsequent reestablishment of the digital system.

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 500 kV lines (and other lower voltage but still critical lines) for distribution load increases the likelihood of interruptions (natural or by human error) to the bulk power path.

Distribution station transformer low voltage leads and bus work are 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 Relaying Philosophy and Design 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 use, 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. As such, the communication channels associated with dual pilot relaying systems must possess a degree of independence similar to that provided for the primary and backup protection and controls in the substation. 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 shall remain functional.

Several factors need to be considered when evaluating the level of independence of communication 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.

Per NERC Planning Standards (III A S2), "Transmission protection systems shall provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A Standards on Transmission Systems and associated Table I." In addition to NERC requirements, dual pilot relaying may be required to meet section IV.B of the MAAC Reliability Principles and Standards: Stability must be maintained for "Single phase-to-ground fault with a stuck breaker or other cause for delayed clearing." Dual pilot relaying is also 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.

Some companies apply dual pilot relaying to prevent system instability for a multi-phase fault with delayed clearing. (See MAAC Reliability Principles and Standards section V.G.) Dual pilot relaying may also be applied on bulk power lines as a general practice. If dual pilot channels are used, but not required to meet above performance criteria, channel independence should be justified based on benefits and cost.

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.

Dual independent paths can be achieved by using two separate carrier systems, one connected to the center phase and one connected to an outer phase. If attenuation of the carrier signal is a consideration due to the use of an outer phase, other arrangements should be considered.

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.

Another disadvantage of power line carrier is that repair or maintenance on associated wave traps require 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.

Two completely independent microwave/fiber 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 common-mode failures is limited to equipment generally considered to be at extremely low risk of failure (e.g., a single communications battery or common microwave tower), a single microwave/fiber system is acceptable. The system must include full redundancy in the RF/fiber path (e.g., using a "ring" topology) and in the electronic RF/multiplex equipment. When so-configured, no single path failure or electronic component failure will result in the unavailability of both pilot protection schemes for longer than the switching time from normal to alternate facilities (nominally milliseconds).

C. Leased Telephone Circuits

Two separate leased telephone circuits that are physically separate and terminate at different central offices are acceptable, but not recommended for use with dual pilot protection systems. It is often difficult, if not impossible, to ascertain the degree of independence that may exist, since the leased circuit path may be switched and re-routed by the telephone company without knowledge of the power company.

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.

D. 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. The following examples illustrate factors that should be considered:

a) <u>Two permissive tripping schemes, one fiber optic shield wire</u>
This scheme is unacceptable for dual pilot protection since 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.

b) <u>Two permissive tripping schemes, two independent fiber optic shield wires</u>
Although this scheme offers some improvement over that mentioned in (a), outside interference such as an aircraft could cause the loss of both shield wires during a fault. This scheme is acceptable for dual pilot protection, but not recommended.

c) <u>Two unblocking schemes, one fiber optic shield wire</u>
Once again, in the case of a broken shield wire, both channels would be disabled if the fault took longer than 300 ms to develop. In addition, as in (a), using two fibers in the

shield wire may result in the loss of both channels when the shield is damaged with uncertain repair time. This scheme is unacceptable for dual pilot protection

d) Two unblocking schemes, two independent fiber optic shield wires
This arrangement is similar to (c), but with the repair problem of (a) alleviated. This scheme is acceptable for dual pilot protection, but not recommended.

e) Underbuilt optical fiber cable
It is possible, although unlikely, that an underbuilt fiber cable will break and cause a fault on the protected circuit. Use of an underbuilt fiber optic cable in conjunction with an over head fiber optic cable, or use of two underbuilt fiber optic cables, is acceptable for dual pilot protection. However, as in (b), outside interference such as an aircraft could cause the loss of both fiber paths during a fault.

The general philosophy to be followed when applying dual pilot fiber optic communication channels with common failure mode:

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

   If at least one of the pilot schemes is a blocking scheme, then independent fiber paths are not required, since loss of the channel will not disable high speed tripping of the blocking scheme. (It should be noted, however, 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 even more degradation in security. However, blocking schemes using dedicated fiber offer a tremendous improvement in security over those using power line carrier.)

   Similarly if at least one of the pilot schemes is a current differential scheme, which reverts to a sensitive overcurrent element or otherwise provides for high speed tripping for the entire line on loss of channel, then independent fiber paths are not required.

   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

   Associated transmission line must 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. Where there is a requirement for dual pilot protection, the overall communications architecture must be such that no single failure either of a fiber path or of the multiplexing equipment will result in the unavailability of both pilot protection schemes for longer than the switching time from normal to alternate facilities (nominally milliseconds).

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.

E. 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 shall 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 recognize these relay limitations when performing load flow studies, and the system operator must also know these limitations so as not to allow loading of sufficient magnitude as to invite relay tripping.

To ensure consistency throughout PJM, the members have adopted a uniform methodology to calculate and report the transient load limits of overcurrent and distance relays used on the PJM bulk power system. 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, & 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.

<u>OVERCURRENT RELAYS</u>

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

<u>Overcurrent Relay Example</u>: 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 √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

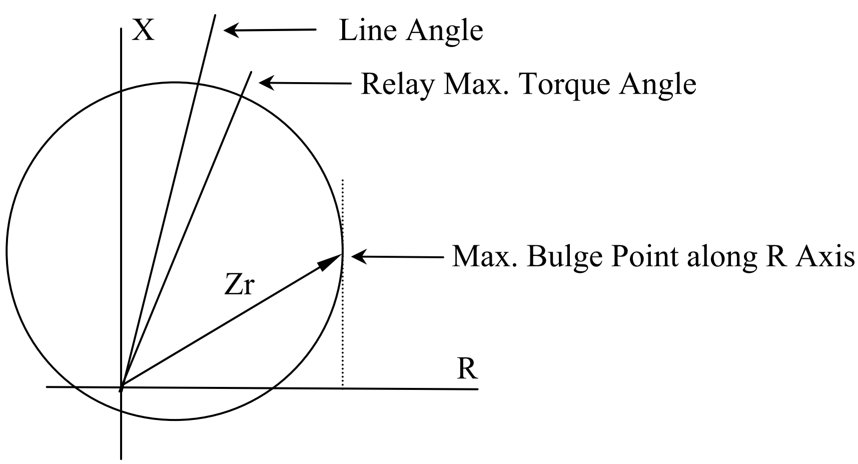


Figure F-1 Mho Relay Characteristic showing Maximum Bulge Point

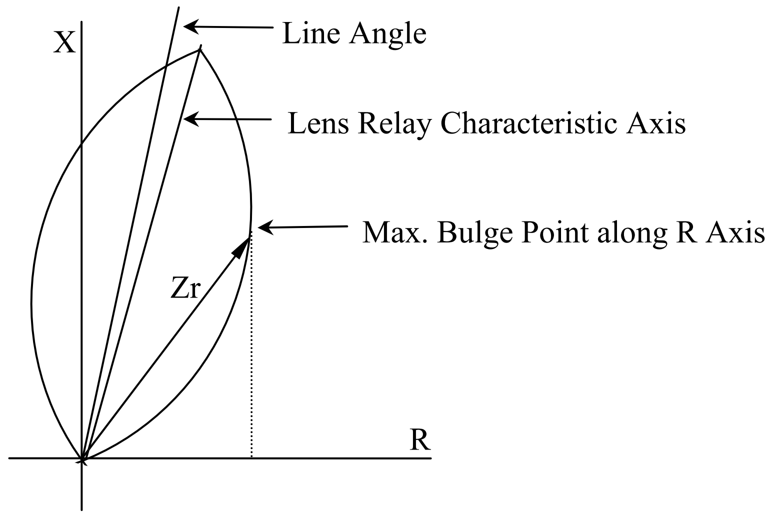


Figure F-2 Lens Relay Characteristic showing Maximum Bulge Point

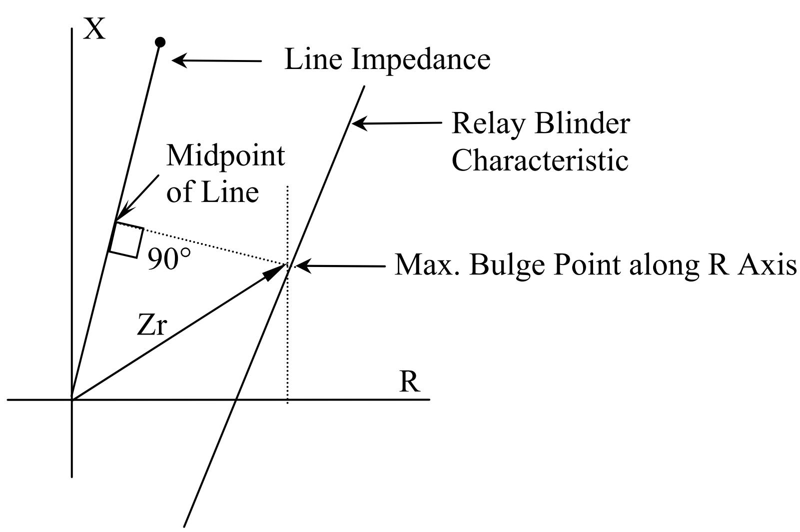
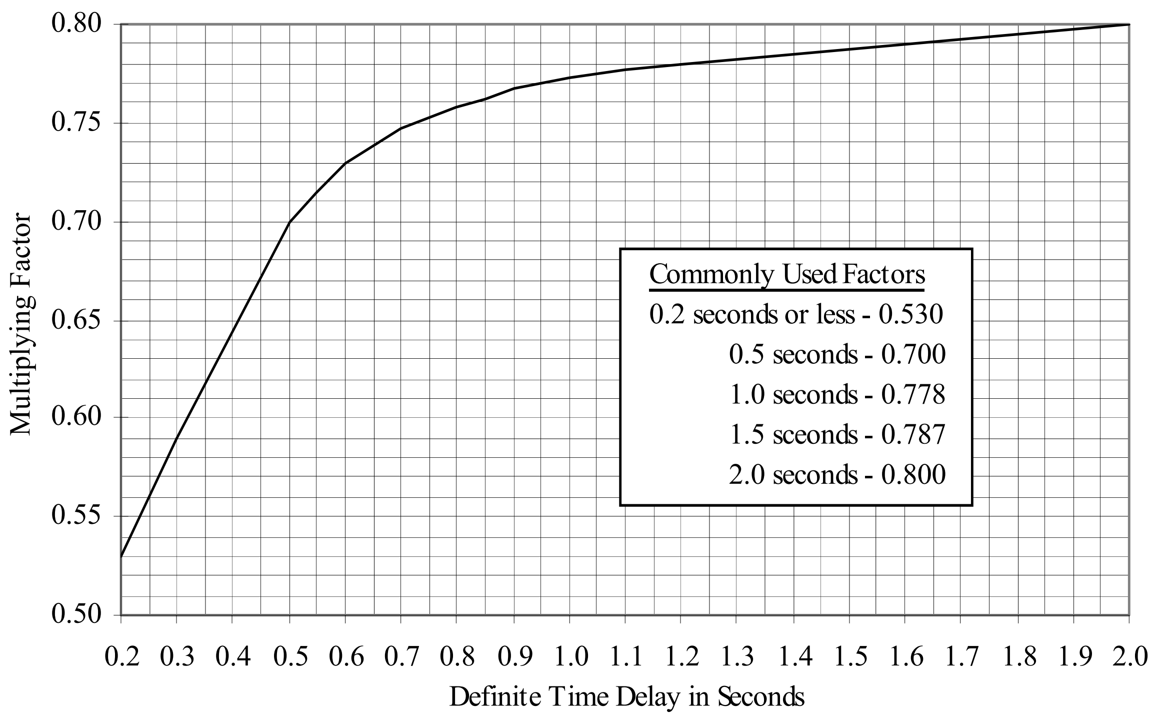


Figure F-3 Straight Line / Blinder Relay Characteristic showing Maximum Bulge Point

<u>Mho Distance Relay Example</u>: 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



<u>Figure F-4 Definite Time Relay Transient Load Limit Adjustment Factor</u>

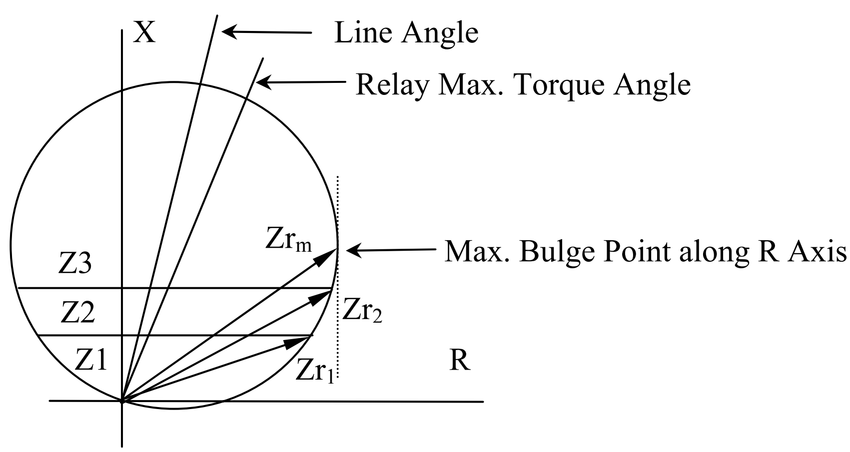
REACTANCE RELAYS

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) must 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 shall 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



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

DRTLL must be computed for All Three Zones

Using Zr = Zr_1, Zr_2, & Zr_m with corresponding Kt time delay factors for each Zone

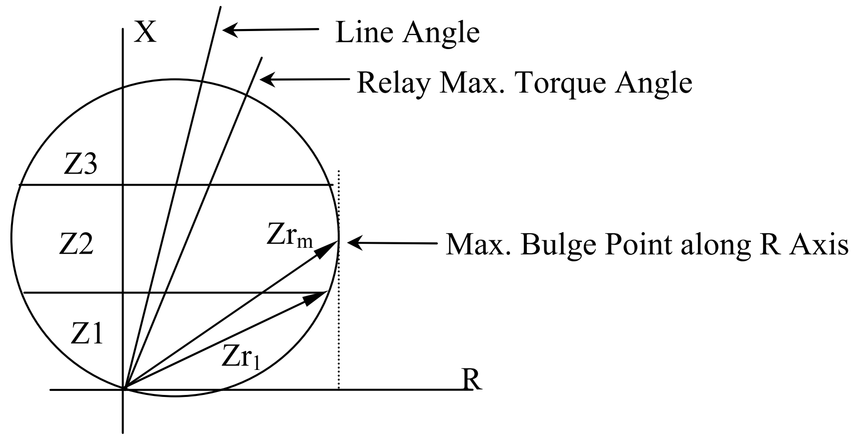


Figure F-5B Reactance Relay Characteristics with Maximum Bulge Point in Zone 2 Area

DRTLL must be computed for Zones 1 and 2 only

Using $Zr = Zr_1$, & Zr_m with corresponding Kt time delay factors for each Zone

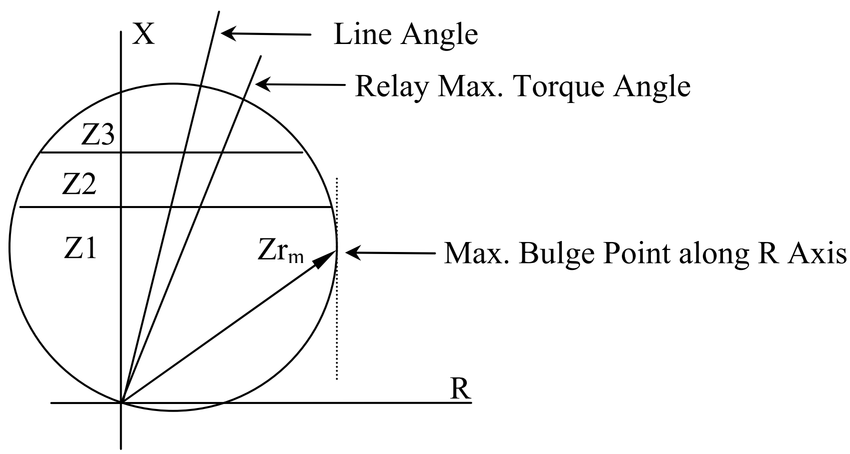


Figure F-5C Reactance Relay Characteristics with Maximum Bulge Point in Zone 1 Area

DRTLL must 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 = 3318 MVA

Zone 3 = 0.93 x 0.787 x $(230)^2$ / 11.90 = 3254 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 shall 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 shall be used.

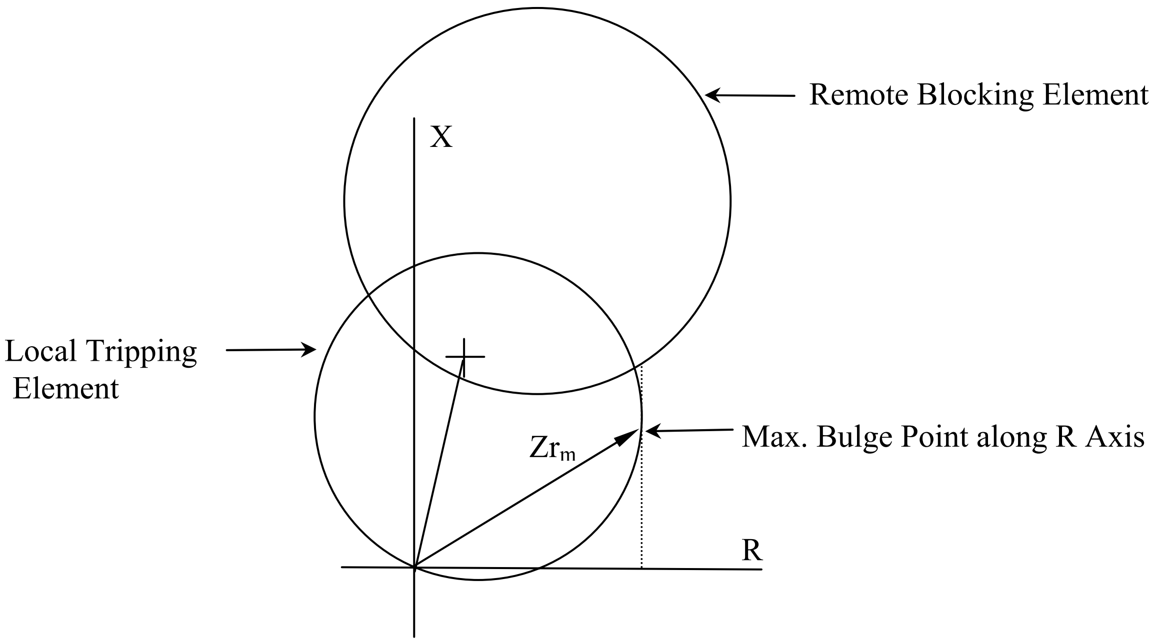


Figure F-6A Blocking Scheme where the Tripping Element Maximum Bulge Point Falls Outside the Remote Relay Blocking Characteristic.
Use Zr_m to calculate DRTLL with Kt = 0.53

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.

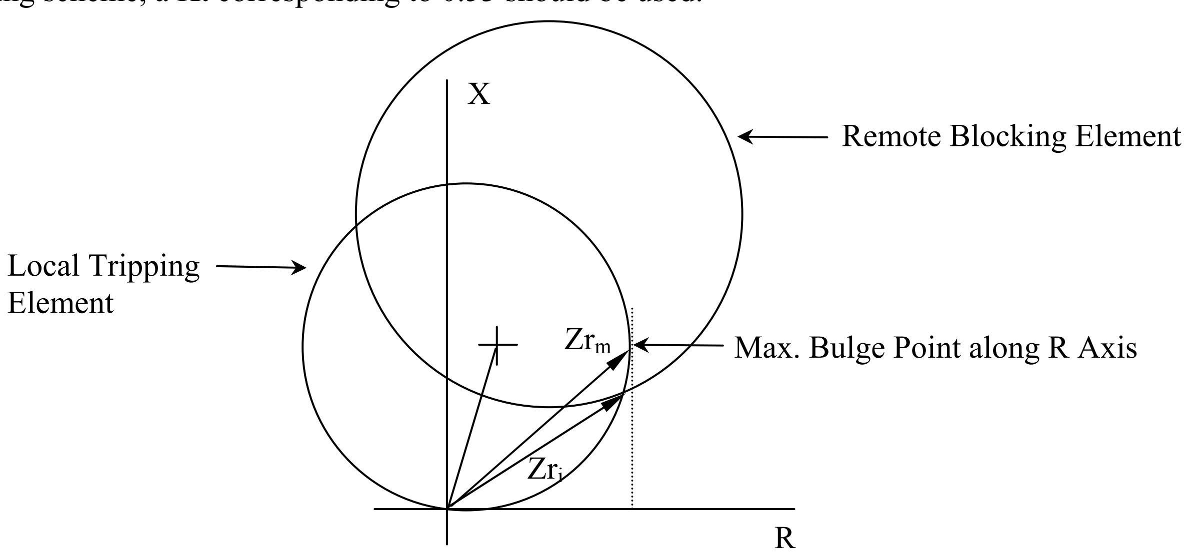


Figure F-6B Blocking Scheme where the Tripping Element Maximum Bulge Point Falls Inside the Remote Relay Blocking Characteristic.
Use Zr_i to calculate DRTLL with Kt = 0.53

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} shall 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 shall be used.

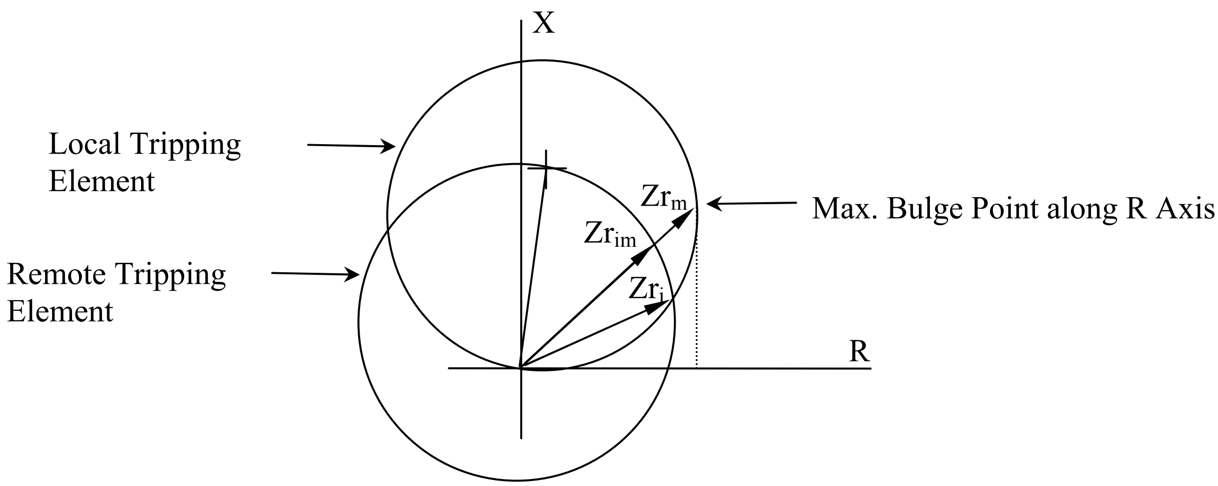


Figure F-7A Permissive Scheme where the Tripping Element Maximum Bulge Point Falls Outside the Remote Relay Tripping Characteristic.

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 shall be used to calculate the DRTLL. Again, since the pilot scheme is a high speed-tripping scheme, a Kt corresponding to 0.53 shall be used.

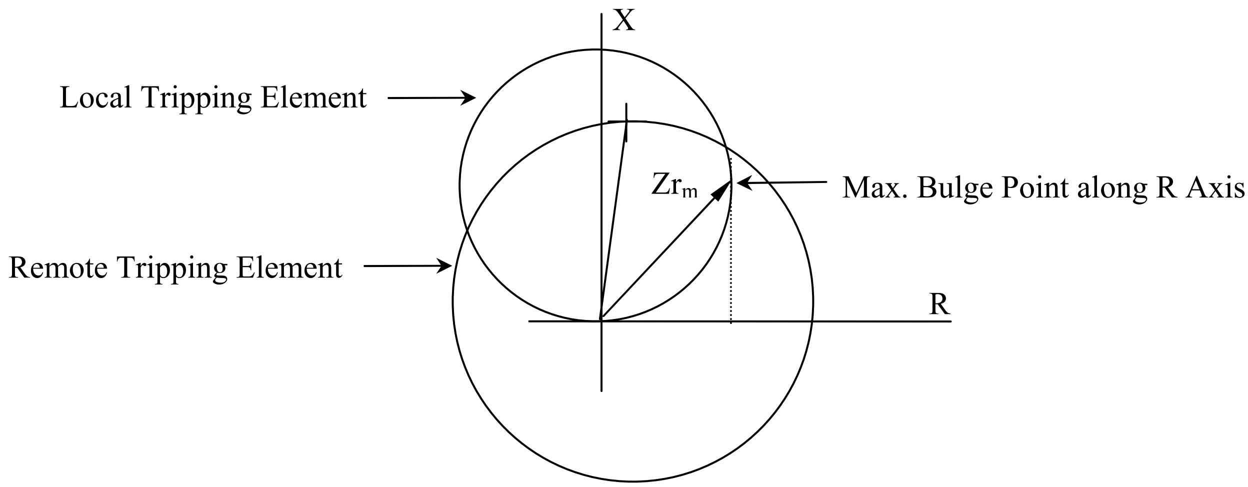


Figure F-7B Permissive Scheme where the Tripping Element Maximum Bulge Point Falls Inside the Remote Relay Tripping Characteristic.
Use Zr_m to calculate DRTLL with Kt = 0.53

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

$$\text{POTT} = 0.93 \times 0.530 \times (230)^2 / 8.60 = 3032 \text{ MVA}$$
$$\text{Zone 2} = 0.93 \times 0.700 \times (230)^2 / 11.90 = 2894 \text{ MVA}$$

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

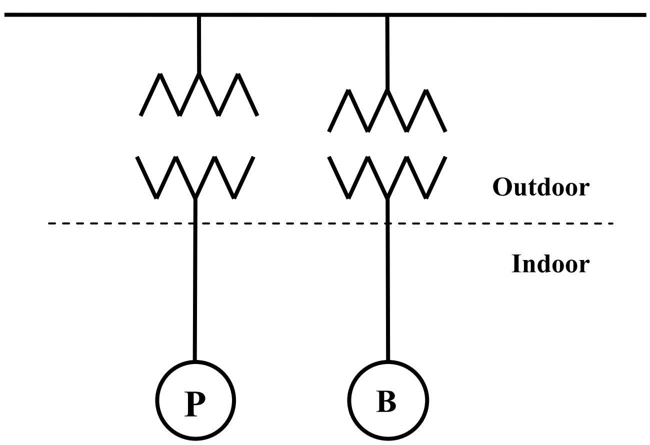
APPENDIX G

Voltage Transformers

For new protection scheme designs:
Independent ac voltage sources must be adhered to for the primary and the back-up relay schemes. Independent Voltage Transformers (VTs) are preferred. However, VTs with independent secondary windings are acceptable.

The following are examples of acceptable VT applications:

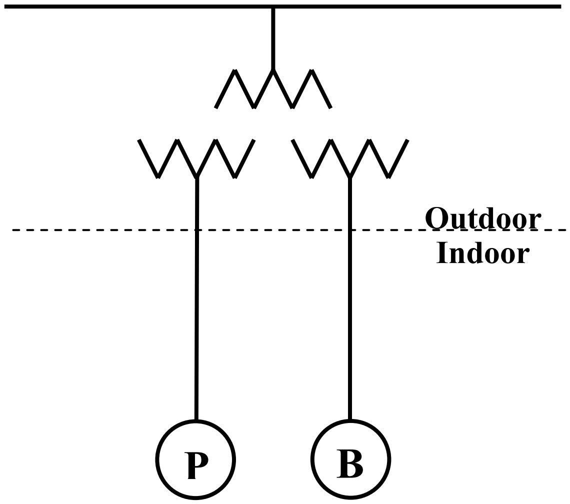
1. Two Independent Sets of Potential Transformers/Devices



"P" Indicates Primary Relays

"B" Indicates Backup Relays

2. One Set of Potential Transformers/Devices with two independent secondary windings leads



"P" Indicates Primary Relays

"B" Indicates Backup Relays

APPENDIX H

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

GENERAL

The protection outlined in sections 3, 4, 5 and 6 of the PJM Protective Relaying Philosophy and Design 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 makes it difficult to outline a single standard 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 P1547 (Draft) Standard for Distributed Resources Interconnected 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 it's 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 must 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/MAAC specified underfrequency set point on generators (20MW and greater) is 57.5 Hz with a 5 second time delay. This setpoint is 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 57.5 Hz-5 second setting 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 at 57.5 Hz in 5 seconds. Where a generator (20MW 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 shall 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 shall 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 shall 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 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 shall 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 10MVA 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 shall 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

Accepted PJM Bulk Power Three Terminal Line Applications

CATEGORY I – TEMPORARY INSTALLATION

This category applies when an acceptable long-term reinforcement was already identified but can not be installed in time and consequently the reliability of the PJM system may be compromised. Examples include construction delays, unusual combinations of system demand and long term transmission equipment forced outages.

A Category I temporary three terminal line installation will only be considered if it passes the following criteria:

MAAC criteria

The system must be studied with the three terminal line and pass all MAAC planning and operating criteria and the RTEP Generator Deliverability tests.

The meaning of "temporary"

The three terminal line configuration must be removed when the planned permanent reinforcement is placed in service.

500 kV applications

Three terminal lines are not permitted on the 500 kV system.

Category I Protection requirements

Coordination review

The affected Transmission Owner(s) must conduct a detailed relay coordination review 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, etc.

Primary line protection

Designing for simultaneous high-speed (pilot) clearing of faults at all locations on the three-terminal line is mandatory. Designing for sequential clearing of faults is not acceptable. Temporary relay settings/equipment changes may be necessary at the two existing terminals to meet this requirement.

Backup line protection

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.

Backup pilot protection

The backup line protection may be pilot (high-speed, communications-dependent) or non-pilot (stepped-distance, ground time overcurrent) depending on the specific circumstances, upon the results of fault and stability studies, etc. Each affected Transmission Owner will evaluate proposed installations on a case-by-case basis. If a backup high-speed pilot scheme is required, the associated communications must be designed and installed with sufficient independence from the primary communications (above) that no single event will result in the simultaneous loss of both high speed pilot relaying functions. (The severing of multiple fibers on the same transmission structure is considered a single event). Sequential clearing to provide successful fault clearing is not acceptable.

CATEGORY II – PERMANENT INSTALLATION

Three-terminal lines may be considered for long term installation on the PJM system when a substation site at the proposed three terminal tap point is deemed unnecessary by PJM, cost prohibitive, environmentally unacceptable, or requires condemnation proceedings.

A category II permanent three terminal line installation will only be considered if it passes the following criteria:

MAAC criteria

The system must be studied with the three terminal line and pass all MAAC planning and operating criteria and the RTEP Generator Deliverability tests.

The system must continue to provide reasonable operation without significant degradation of the PJM system due to a Category II three terminal line. Daily system operating flexibility to perform equipment maintenance outages during typical intermediate load levels, as tested in the MAAC Reliability Assessment Section IIB analysis, shall not be compromised due to the use of Category II three terminal line.
A three terminal line, proposed by PJM (or PJM participant) to avoid ampere capacity reinforcements, or to avoid construction of a new substation must be studied at all load levels to assure the integrity of the MAAC system.
The stability of the system must be tested for fault locations anywhere on the three terminal line to assure compliance with MAAC Reliability Principles and Standards Section II, and Section IV tests at all load levels.

500 kV applications

Three terminal lines are not permitted on the 500 kV system.

Four terminal lines

Four terminal lines are not permitted on any 230 kV or above transmission facility.

CATEGORY II PROTECTION REQUIREMENTS

Coordination review

The affected Transmission Owner(s) must conduct a detailed relay coordination review, 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, etc.

Primary line protection

Designing for simultaneous high-speed (pilot) clearing of faults at all locations on the three-terminal line is mandatory. Designing for sequential clearing of faults is not acceptable.

Backup line protection

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.

Backup pilot protection

The backup line protection may be pilot (high-speed, communications-dependent) or non-pilot (stepped-distance, ground time overcurrent) depending on the specific circumstances, upon the results of fault and stability studies, etc. Each affected Transmission Owner will evaluate proposed installations on a case-by-case basis. If a backup high-speed pilot scheme is required, the associated communications must be designed and installed with sufficient independence from the primary communications (above) that no single event will result in the simultaneous loss of both high-speed pilot-relaying functions. (The severing of multiple fibers on the same transmission structure is considered a single event). Sequential clearing to provide successful fault clearing is not acceptable.

Protection methods

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. More-reliable protection has become available in recent years, especially electronic current differential relays communicating over digital media, either direct (relay-to-relay, using optical fiber) or multiplexed on a dedicated optical fiber. Modern current differential relays are often configurable for three-terminal application. Impedance-based pilot schemes may also be acceptable provided the above criteria are met. In all cases where a pilot scheme is required, digital communication channels between the three terminals must be used. No portions of these channels may be metallic (telephone cable, coaxial cable, etc) other than between relays and multiplex equipment (where used) within a control house. External audio-tone interfaces are not acceptable. When multiplexing schemes are used, they must be evaluated with respect to the characteristics of the proposed protection (e.g., susceptibility to mal-operation due to variances in path delay) on a case-by case basis.

Installation and maintenance

In order to assure the integrity of the protection schemes, the primary and backup protection facilities for all three terminals of the transmission line must be installed and maintained by transmission or protection system owners regulated by the PJM and MAAC relay compliance process.

Note: All existing transmission facilities and Queue A IPPs are grandfathered prior to implementation of the above business rules for 3 terminal lines. The above will apply to all subsequent transmission facilities specified in Baseline transmission enhancements, Queue B new transmission, etc.

Appendix J

Requirements for the Application of Triggered Fault Current Limiters

The following document describes the concerns and lists requirements 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.

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 REQUIREMENTS

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.

Requirements 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 must 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 rating 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.

Requirements

The FCL owner must 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 shall be the maximum asymmetrical current available based on the calculated X/R ratio, and shall 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 must 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 shall be added to the short circuit current of the breaker for determination of interrupting duty.

The utility must supply the FCL owner with sufficient modeling information of the utility system to allow the FCL owner to make the analysis described in 2.2.2.1.

The FCL owner must 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.

Requirements If changes are made to the FCL owner's electrical system, the FCL owner must re-apply the requirements outlined in section 2.2. 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.

Requirements The FCL owner must 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.

Requirements The FCL owner shall 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.

Requirements Routine testing of FCL trigger levels, firing logic, and firing circuitry must be conducted at least every four years. Documentation of this testing shall be available upon request by the utility. The utility shall 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.