PRC-023 Reference

Determination and Application of Practical Relaying Loadability Ratings

North American Electric Reliability Council

Prepared by the
System Protection and Control Task Force
of the
NERC Planning Committee

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Introduction

This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023.

The function of transmission protection systems included in the referenced reliability standard is to protect the transmission system when subjected to faults. System conditions, particularly during emergency operations, may make it necessary for transmission lines and transformers to become overloaded for short periods of time. During such instances, it is important that protective relays do not *prematurely* trip the transmission elements out-of-service preventing the system operators from taking controlled actions to alleviate the overload. Therefore, protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability reliability standard has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers.

While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

The following protection functions are addressed by Reliability Standard PRC–023:

1. Any protective functions which could trip with or without time delay, on normal or emergency load current, including but not limited to:
   - 1.1. Phase distance
   - 1.2. Out-of-step tripping
   - 1.3. Out-of-step blocking
   - 1.4. Switch-on-to-fault
   - 1.5. Overcurrent relays
   - 1.6. Communications aided protection schemes including but not limited to:
     - 1.6.1. Permissive overreaching transfer trip (POTT)
     - 1.6.2. Permissive underreaching transfer trip (PUTT)
     - 1.6.3. Directional comparison blocking (DCB)
     - 1.6.4. Directional comparison unblocking (DCUB)
2. The following protection systems are excluded from requirements of this standard:
   - 2.1. Relay elements that are only enabled when other relays or associated systems fail.
     - 2.1.1. Overcurrent elements that are only enabled during loss of potential conditions.
     - 2.1.2. Elements that are only enabled during a loss of communications.
   - 2.2. Protection systems intended for the detection of ground fault conditions.
   - 2.3. Generator protection relays
   - 2.4. Relay elements used only for Special Protection Systems, applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.

Requirements Reference Material

R1 — Phase Relay Setting

Transmission Owners, Generator Owners, and Distribution Providers shall use any one of the following criteria to prevent its phase protective relay settings from limiting transmission system capability while maintaining reliable protection of the electrical network for all fault conditions. The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees: [Risk Factor: High]

R1.1 — Transmission Line Thermal Rating

Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

$$Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a 30 degree power factor angle

V_{L-L} = Rated line-to-line voltage

I_{rating} = Facility Rating

Set the tripping relay so it does not operate at or below 1.5 times the highest Facility Rating (I_{rating}) of the line for the available defined loading duration nearest 4 hours. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.5 \times I_{rating}}$

R1.2 — Transmission Line Established 15-Minute Rating

When the original loadability parameters were established, it was based on the 4-hour facility rating. The intent of the 150% factor applied to the facility ampere rating in the loadability requirement was to approximate the 15-minute rating of the transmission line and add some additional margin. Although the original study performed to establish the 150% factor did not segregate the portion of the 150% factor that was to approximate the 15-minute capability from that portion that was to be a safety margin, it has been determined that a 115% margin is appropriate. In situations where detailed studies have been performed to establish 15-minute ratings on a transmission line, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

Set the tripping relay so it does not operate at or below 1.15 times the 15-minute winter facility ampere rating (I_{rating}) of the line. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{rating}}$

R1.3 — Maximum Power Transfer Limit Across a Transmission Line

Set transmission line relays so they do not operate at or below 115% of the maximum power transfer capability of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

R1.3.1 — Maximum Power Transfer with Infinite Source

An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line

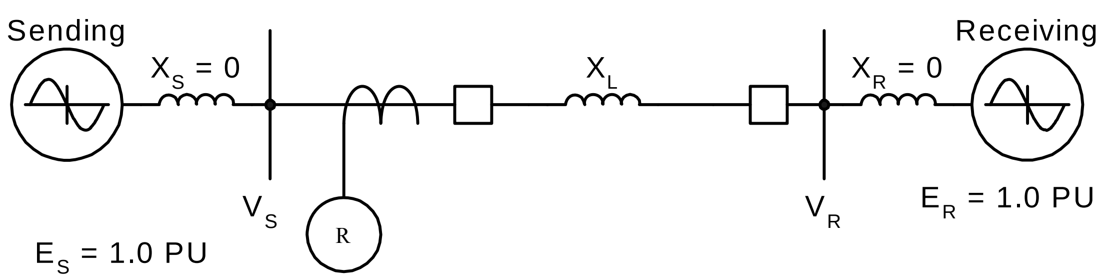

Figure 1 – Maximum Power Transfer

The power transfer across a transmission line (*Figure 1*) is defined by the equation[1]:

$$P = \frac{V_S \times V_R \times \sin\delta}{X_L}$$

Where:

P = the power flow across the transmission line

V_S = Phase-to-phase voltage at the sending bus

V_R = Phase-to-phase voltage at the receiving bus

δ = Voltage angle between V_S and V_R

X_L = Reactance of the transmission line in ohms

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[1] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

The theoretical maximum power transfer occurs when δ is 90 degrees. The real maximum power transfer will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.0 per unit
- An infinite source is assumed behind each bus; i.e. no source impedance is assumed.

The equation for maximum power becomes:

$$P_{\max} = \frac{V^2}{X_L}$$

$$I_{real} = \frac{P_{max}}{\sqrt{3} \times V}$$

$$I_{real} = \frac{V}{\sqrt{3} \times X_L}$$

Where:

P_{max} = Maximum power that can be transferred across a system

I_{real} = Real component of current

V = Nominal phase-to-phase bus voltage

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times V}{\sqrt{3} \times X_L}$$

$$\boxed{I_{total} = \frac{0.816 \times V}{X_L}}$$

Where:

I_{total} is the total current at maximum power transfer.

Set the tripping relay so it does not operate at or below 1.15 times I_{total} (where $I_{total} = \frac{0.816 \times V}{X_L}$). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

R1.3.2 — Maximum Power Transfer with System Source Impedance

Actual source and receiving end impedances are determined using a short circuit program and choosing the classical or flat start option to calculate the fault parameters. The impedances required for this calculation are the generator subtransient impedances (*Figure 2*).

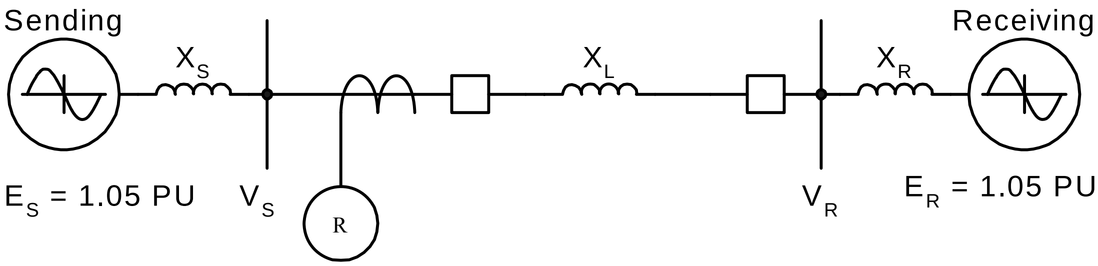


Figure 2 – Site-Specific Maximum Power Transfer Limit

The recommended procedure for determining X_S and X_R is:

- Remove the line or lines under study (parallel lines need to be removed prior to doing the fault study)
- Apply a three-phase short circuit to the sending and receiving end buses.
- The program will calculate a number of fault parameters including the equivalent Thévenin source impedances.
- The real component of the Thévenin impedance is ignored.

The voltage angle across the system is fixed at 90 degrees, and the current magnitude (I_{real}) for the maximum power transfer across the system is determined as follows[2]:

$$P_{\max} = \frac{(1.05 \times V)^2}{(X_S + X_R + X_L)}$$

Where:

P_{max} = Maximum power that can be transferred across a system

E_S = Thévenin phase-to-phase voltage at the system sending bus

E_R = Thévenin phase-to-phase voltage at the system receiving bus

δ = Voltage angle between E_S and E_R

X_S = Thévenin equivalent reactance in ohms of the sending bus

X_R = Thévenin equivalent reactance in ohms of the receiving bus

X_L = Reactance of the transmission line in ohms

V = Nominal phase-to-phase system voltage

[2] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in Appendix A.

$$I_{real} = \frac{1.05 \times V}{\sqrt{3}\left(X_S + X_R + X_L\right)}$$

$$I_{real} = \frac{0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

The theoretical maximum power transfer occurs when δ is 90 degrees. All stable maximum power transfers will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. A number of conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.05 per unit
- The source impedances are calculated using the sub-transient generator reactances.

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2} \times I_{real}$$

$$I_{total} = \frac{\sqrt{2} \times 0.606 \times V}{\left(X_S + X_R + X_L\right)}$$

$$\boxed{I_{total} = \frac{0.857 \times V}{(X_S + X_R + X_L)}}$$

Where:

I_{total} = Total current at maximum power transfer

Set the tripping relay so it does not operate at or below 1.15 times I_{total}. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

This should be re-verified whenever major system changes are made.

R1.4 — Special Considerations for Series-Compensated Lines

Series capacitors are used on long transmission lines to allow increased power transfer. Special consideration must be made in computing the maximum power flow that protective relays must accommodate on series compensated transmission lines. Capacitor cans have a short-term over voltage capability that is defined in IEEE standard 1036. This allows series capacitors to carry currents in excess of their nominal rating for a short term. Series capacitor emergency ratings, typically 30-minute, are frequently specified during design.

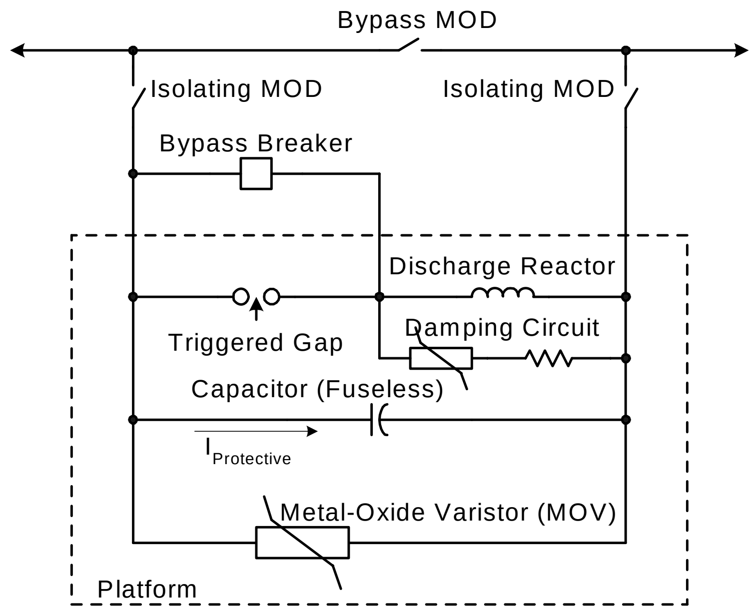


Figure 3 – Series Capacitor Components

The capacitor banks are protected from overload conditions by spark gaps and/or metal oxide varistors (MOVs) and can be also be protected or bypassed by breakers. Protective gaps and MOVs (*Figure 3*) operate on the voltage across the capacitor ($V_{protective}$).

This voltage can be converted to a current by the equation:

$$\boxed{I_{protective} = \frac{V_{protective}}{X_C}}$$

Where:

$V_{protective}$ = Protective level of voltage across the capacitor spark gaps and/or MOVs

X_C = Capacitive reactance

The capacitor protection limits the theoretical maximum power flow because I_{total}, assuming the line inductive reactance is reduced by the capacitive reactance, will typically exceed $I_{protective}$. A current of $I_{protective}$ or greater will result in a capacitor bypass. This reduces the theoretical maximum power transfer to that of only the line inductive reactance as described in R1.3.

The relay settings must be evaluated against 115% of the highest series capacitor emergency current rating and the maximum power transfer calculated in R1.3 using the full line inductive reactance (uncompensated line reactance). This must be done to accommodate situations where the capacitor is bypassed for reasons other than $I_{protective}$. The relay must be set to accommodate the greater of these two currents.

Set the tripping relay so it does not operate at or below the greater of:

1. 1.15 times the highest emergency rating of the series capacitor. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.
2. I_{total} (where I_{total} is calculated under R1.3 using the full line inductive reactance). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{total}}$

R1.5 — Weak Source Systems

In some cases, the maximum line end three-phase fault current is small relative to the thermal loadability of the conductor. Such cases exist due to some combination of weak sources, long lines, and the topology of the transmission system (*Figure 4*).

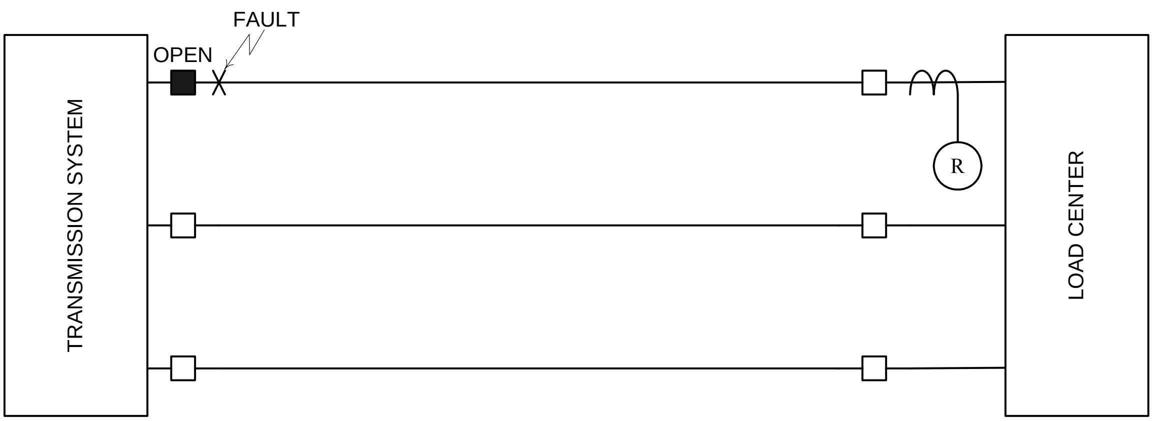


Figure 4 – Weak Source Systems

Since the line end fault is the maximum current at one per unit phase to ground voltage and it is possible to have a voltage of 90 degrees across the line for maximum power transfer across the line, the voltage across the line is equal to:

$$V_{S-R} = \sqrt{{V_S}^2 + {V_R}^2} = \sqrt{2} \times V_{LN}$$

It is necessary to increase the line end fault current I_{fault} by $\sqrt{2}$ to reflect the maximum current that the terminal could see for maximum power transfer and by 115% to provide margin for device errors.

$$I_{max} = 1.15 \times \sqrt{2} \times 1.05 \times I_{fault}$$

$$I_{max} = 1.70 \times I_{fault}$$

Where:

I_{fault} is the line-end three-phase fault current magnitude obtained from a short circuit study, reflecting sub-transient generator reactances.

Set the tripping relay on weak-source systems so it does not operate at or below 1.70 times I_{fault}, where I_{fault} is the maximum end of line three-phase fault current magnitude. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.70 \times I_{fault}}$

R1.6 — Generation Remote to Load

Some system configurations have generation remote to load centers or the main transmission busses. Under these conditions, the total generation in the remote area may limit the total available current from the area towards the load center. In the simple case of generation connected by a single line to the system (*Figure 5*), the total capability of the generator determines the maximum current (I_{max}) that the line will experience.

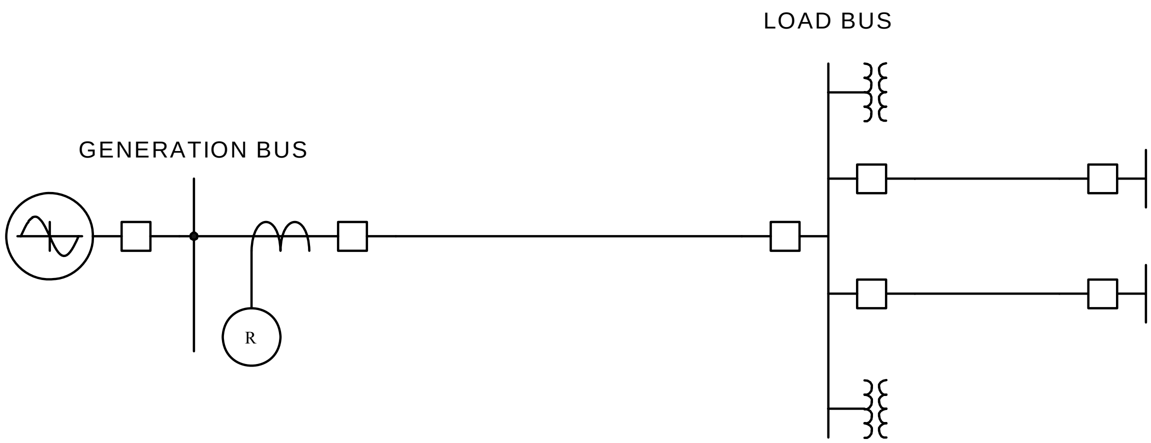


Figure 5 – Generation Remote to Load Center

The total generation output is defined as two times[3] the aggregate of the nameplate ratings of the generators in MVA converted to amps at the relay location at 100% voltage:

$$MVA_{\max} = 2 \times \sum_{1}^{N} \frac{MW_{nameplate}}{PF_{nameplate}}$$

[3] This has a basis in the PSRC paper titled: "Performance of Generator Protection During Major System Disturbances", IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003. Specifically, page 8 of this paper states: "…distance relays [used for system backup phase fault protection] should be set to carry more than 200% of the MVA rating of the generator at its rated power factor."

$$\boxed{I_{\max} = \frac{MVA_{\max}}{\sqrt{3} \times V_{relay}}}$$

Where:

V_{relay} = Phase-to-phase voltage at the relay location

N = Number of generators connected to the generation bus

Set the tripping relay so it does not operate at or below 1.15 times the I_{max}. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

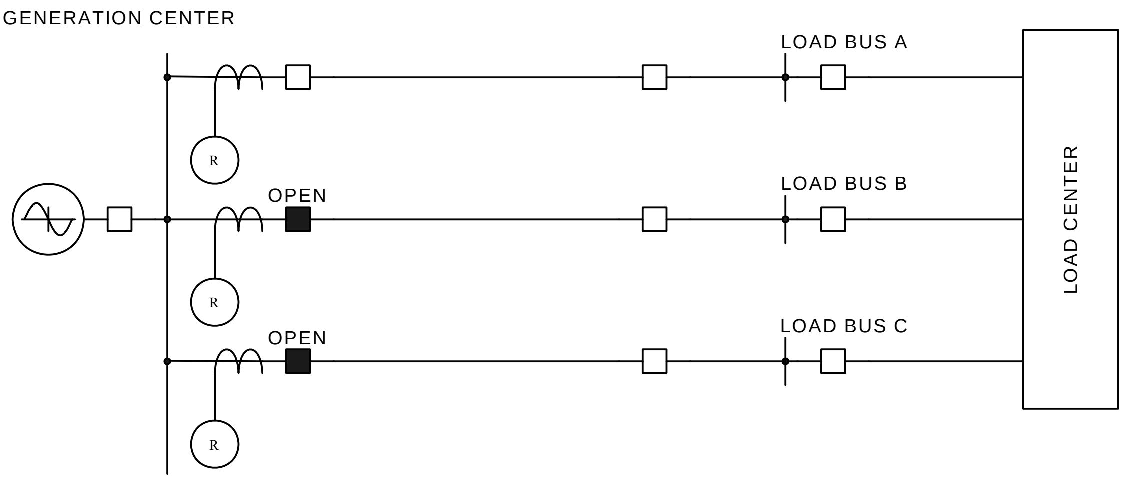


Figure 6 – Generation Connected to System – Multiple Lines

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

The same general principle can be used if the generator is connected to the system through more than one line (*Figure 6*). The I_{max} expressed above also applies in this case. To qualify, all transmission lines except the one being evaluated must be open such that the entire generation output is carried across the single transmission line. One must also ensure that loop flow through the system cannot occur such that the total current in the line exceeds I_{max}.

Set the tripping relay so it does not operate at or below 1.15 times I_{max}, if all the other lines that connect the generator to the system are out of service. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \frac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

R1.7 — Load Remote to Generation

Some system configurations have load centers (no appreciable generation) remote from the generation center where under no contingency, would appreciable current flow from the load centers to the generation center (*Figure 7*).

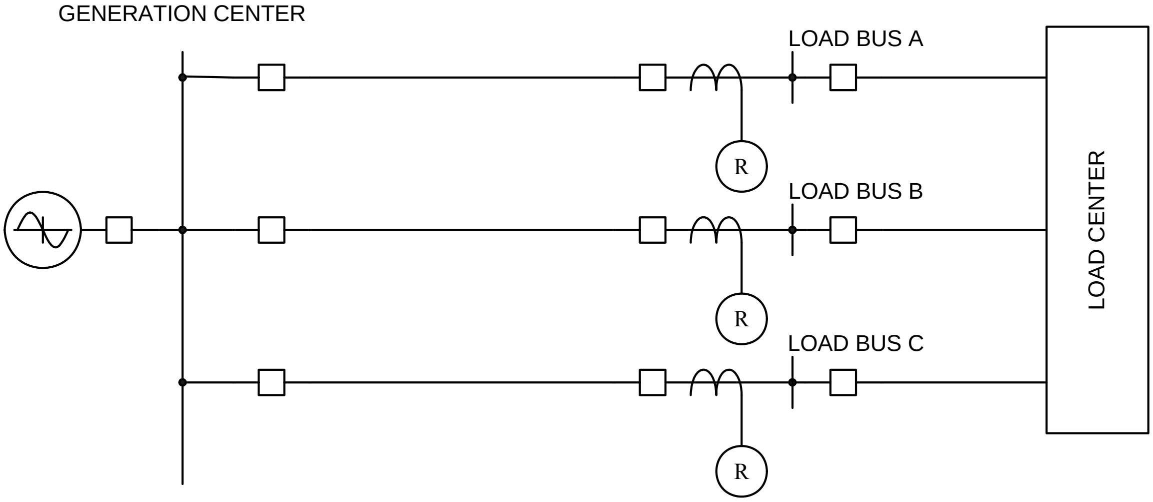


Figure 7 – Load Remote to Generation

Although under normal conditions, only minimal current can flow from the load center to the generation center, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions. To qualify, one must determine the maximum current flow (I_{max}) from the load center to the generation center under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

R1.8 — Remote Cohesive Load Center

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system.

For the system shown in *Figure 8*, the total maximum load at the load center defines the maximum load that a single line must carry.

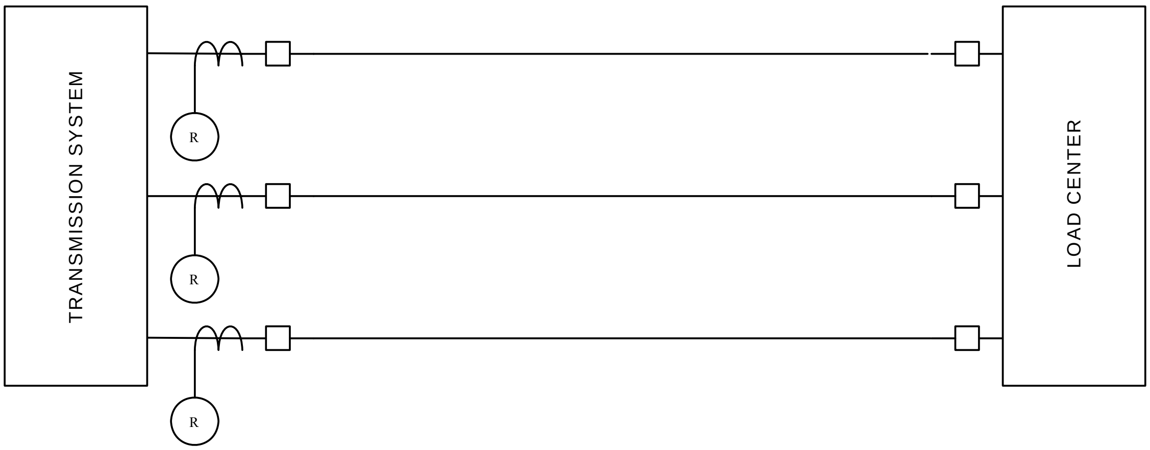


Figure 8 – Remote Cohesive Load Center

Also, one must determine the maximum power flow on an individual line to the area (I_{max}) under all system contingencies, reflecting any higher currents resulting from reduced voltages, and ensure that under no condition will loop current in excess of $I_{maxload}$ flow in the transmission lines.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

R1.9 — Cohesive Load Center Remote to Transmission System

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system. For the system shown in *Figure 9*, the total maximum load at the load center defines the maximum load that a single line must carry. This applies to the relays at the load center ends of lines addressed in R1.8.

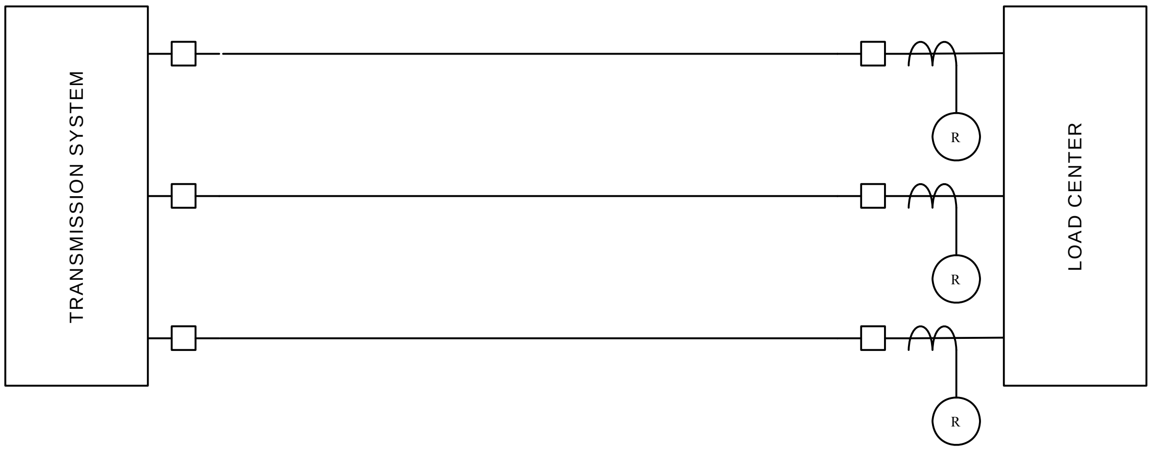


Figure 9 – Cohesive Load Center Remote to Transmission System

Although under normal conditions, only minimal current can flow from the load center to the electrical network, the forward reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions, including all potential loop flows. To qualify, one must determine the maximum current flow (I_{max})from the load center to the electrical network under any system contingency.

Set the tripping relay so it does not operate at or below 1.15 times the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

Example: $Z_{relay30} = \dfrac{0.85 \times V_{L-L}}{\sqrt{3} \times 1.15 \times I_{\max}}$

R1.10 — Transformer Overcurrent Protection

The transformer fault protective relaying settings are set to protect for fault conditions, not excessive load conditions. These fault protection relays are designed to operate relatively quickly. Loading conditions on the order of magnitude of 150% (50% overload) of the maximum applicable nameplate rating of the transformer can normally[4] be sustained for several minutes without damage or appreciable loss of life to the transformer.

4 See ANSI/IEEE Standard C57.92, Table 3.

R1.11 — Transformer Overload Protection

This may be used for those situations where the consequence of a transformer tripping due to an overload condition is less than the potential loss of life or possible damage to the transformer.

1. Provide the protective relay set point(s) for all load-responsive relays on the transformer.
2. Provide the reason or basis for the reduced load capability (below 150% of transformer nameplate or 115% of the operator-established emergency rating, whichever is higher) .
3. Verify that no current or subsequent planning contingency analyses identify any conditions where the recoverable flow is less than the reduced load capability (150% of transformer nameplate or 115% of the highest operator-established emergency rating, whichever is higher) and greater than the trip point.

If an overcurrent relay is supervised by either a top oil or simulated winding hot spot element less than 100° C and 140° C[5] respectively, justification for the reduced temperature must be provided.

R1.12 a — Long Line Relay Loadability – Two Terminal Lines

This description applies only to classical two-terminal circuits. For lines with other configurations, see R1.12b , *Three (or more) Terminal Lines and Lines with One or More Radial Taps*. A large number of transmission lines in North America are protected with distance based relays that use a mho characteristic. Although other relay characteristics are now available that offer the same fault protection with more immunity to load encroachment, generally they are not required based on the following:

1. The original loadability concern from the Northeast blackout (and other blackouts) was overly sensitive distance relays (usually Zone 3 relays).
2. Distance relays with mho characteristics that are set at 125% of the line length are clearly not "overly sensitive," and were not responsible for any of the documented cascading outages, under steady-state conditions.
3. It is unlikely that distance relays with mho characteristics set at 125% of line length will misoperate due to recoverable loading during major events.
4. Even though unintentional relay operation due to load could clearly be mitigated with blinders or other load encroachment techniques, in the vast majority of cases, it may not be necessary.

5 IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

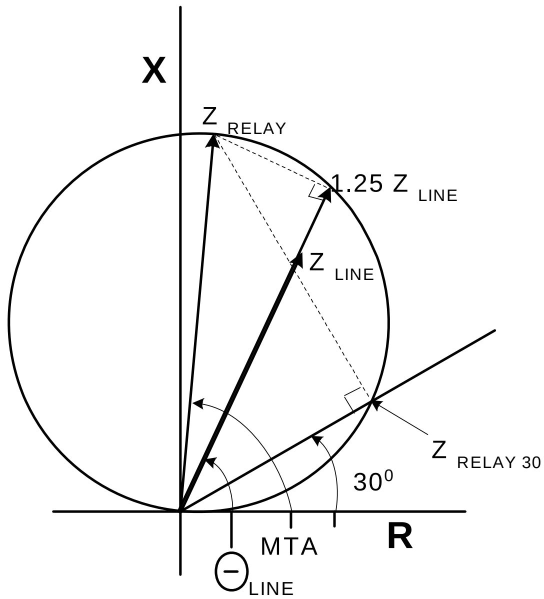


Figure 10 – Long Line relay Loadability

It is prudent that the relays be adjusted to as close to the 90 degree MTA setting as the relay can be set to achieve the highest level of loadability without compromising the ability of the relay to reliably detect faults.

The basis for the current loading is as follows:

V_{relay} = Phase-to-phase line voltage at the relay location

Z_{line} = Line impedance

Θ_{line} = Line impedance angle

Z_{relay} = Relay setting at the maximum torque angle

MTA = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

I_{trip} = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 per unit voltage at a 30 degree phase angle between the voltage and current before reaching the relay trip point

For applying a mho relay at any maximum torque angle to any line impedance angle:

$$Z_{relay} = \frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{line}}{\cos(MTA - \Theta_{line})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(\,MTA - \Theta_{line}\,)}{\sqrt{3} \times 1.25 \times Z_{line} \times cos(\,MTA - 30°\,)}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{line})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{line} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{line}}\right) \times \left(\frac{\cos(MTA - \Theta_{line})}{\cos(MTA - 30°)}\right)}$$

R1.12 b — Long Line Relay Loadability — Three (or more) Terminal Lines and Lines with One or More Radial Taps

Three (or more) terminal lines present protective relaying challenges from a loadability standpoint due to the apparent impedance as seen by the different terminals. This includes lines with radial taps. The loadability of the line may be different for each terminal of the line so the loadability must be done on a per terminal basis:

The basis for the current loading is as follows:

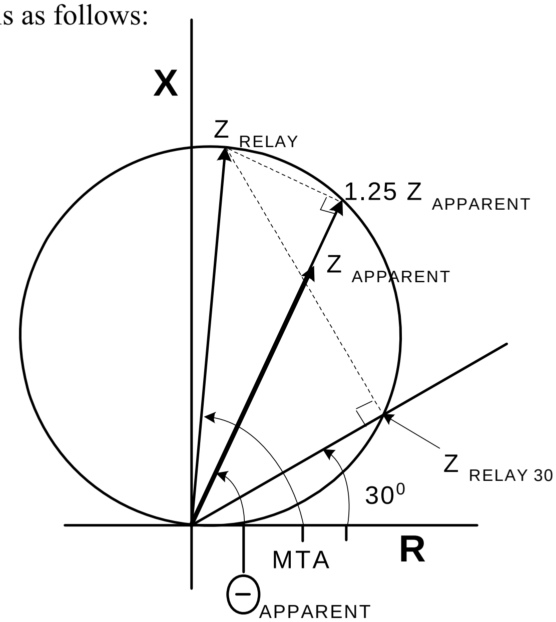


Figure 11 – Three (or more) Terminal Lines and Lines with One or More Radial Taps

V_{relay} = Phase-to-phase line voltage at the relay location

$Z_{apparent}$ = Apparent line impedance as seen from the line terminal. This apparent impedance is the impedance calculated (using in-feed where applicable) for a fault at the most electrically distant line terminal for system conditions normally used in protective relaying setting practices.

$\Theta_{apparent}$ = Apparent line impedance angle as seen from the line terminal

Z_{relay} = Relay setting at the maximum torque angle.

MTA = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

I_{trip} = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree phase angle between the voltage and current before reaching the trip point

For applying a mho relay at any maximum torque angle to any apparent impedance angle

$$Z_{relay} = \frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}$$

The relay reach at the load power factor angle of 30° is determined from:

$$Z_{relay30} = \left[\frac{1.25 \times Z_{apparent}}{\cos(MTA - \Theta_{apparent})}\right] \times \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3} \times Z_{relay30}}$$

$$I_{trip} = \frac{V_{relay} \times cos(MTA - \Theta_{apparent})}{\sqrt{3} \times 1.25 \times Z_{apparent} \times cos(MTA - 30°)}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by:

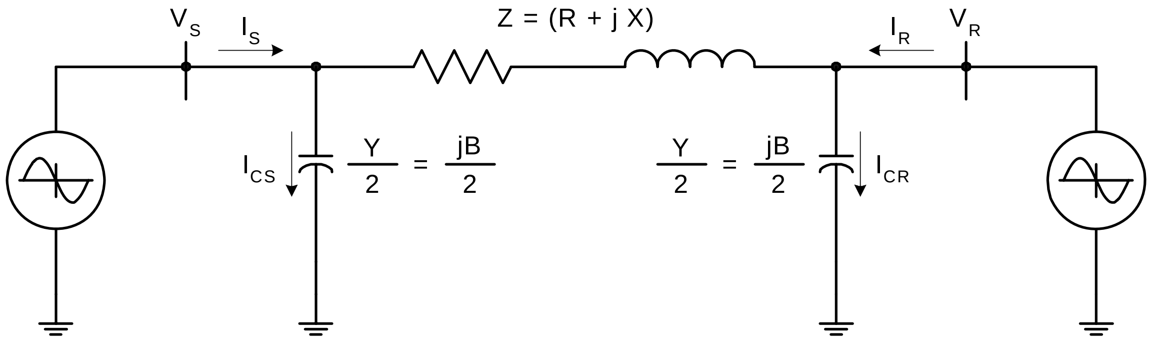
$$I_{relay30} = \frac{0.85 \times I_{trip}}{1.15}$$

$$I_{relay30} = \frac{0.85 \times V_{relay} \times \cos(MTA - \Theta_{apparent})}{1.15 \times \sqrt{3} \times 1.25 \times Z_{apparent} \times \cos(MTA - 30°)}$$

$$\boxed{I_{relay30} = \left(\frac{0.341 \times V_{relay}}{Z_{apparent}}\right) \times \left(\frac{\cos(MTA - \Theta_{apparent})}{\cos(MTA - 30°)}\right)}$$

Appendices

Appendix A — Long Line Maximum Power Transfer Equations



Lengthy transmission lines have significant series resistance, reactance, and shunt capacitance. The line resistance consumes real power when current flows through the line and increases the real power input during maximum power transfer. The shunt capacitance supplies reactive current, which impacts the sending end reactive power requirements of the transmission line during maximum power transfer. These line parameters should be used when calculating the maximum line power flow.

The following equations may be used to compute the maximum power transfer:

$$P_{S3-\phi} = \frac{V_S^{\;2}}{|Z|}\cos\left(\theta^\circ\right) - \frac{V_S V_R}{|Z|}\cos\left(\theta + \delta^\circ\right)$$

$$Q_{S3-\phi} = \frac{V_S^{\;2}}{|Z|}\sin\left(\theta^\circ\right) - V_S^{\;2}\,\frac{B}{2} - \frac{V_S V_R}{|Z|}\sin\left(\theta + \delta^\circ\right)$$

The equations for computing the total line current are below. These equations assume the condition of maximum power transfer, δ = 90º, and nominal voltage at both the sending and receiving line ends:

$$\boxed{I_{real} = \frac{V}{\sqrt{3}|Z|}\left(\cos\left(\theta^\circ\right) + \sin\left(\theta^\circ\right)\right)}$$

$$\boxed{I_{reactive} = \frac{V}{\sqrt{3}|Z|}\left(\sin\left(\theta^\circ\right) - |Z|\frac{B}{2} - \cos\left(\theta^\circ\right)\right)}$$

$$I_{total} = I_{real} + jI_{reactive}$$

$$\boxed{I_{total} = \sqrt{I_{real}^{\;2} + I_{reactive}^{\;2}}}$$

Where:

P = the power flow across the transmission line

V_S = Phase-to-phase voltage at the sending bus

V_R = Phase-to-phase voltage at the receiving bus

V = Nominal phase-to-phase bus voltage

δ = Voltage angle between V_S and V_R

Z = Reactance, including fixed shunt reactors, of the transmission line in ohms*

Θ = Line impedance angle

B = Shunt susceptance of the transmission line in mhos*

* The use of hyperbolic functions to calculate these impedances is recommended to reflect the distributed nature of long line reactance and capacitance.

Appendix B — Impedance-Based Pilot Relaying Considerations

Some utilities employ communication-aided (pilot) relaying schemes which, taken as a whole, may have a higher loadability than would otherwise be implied by the setting of the forward (overreaching) impedance elements. Impedance based pilot relaying schemes may comply with PRC-023 R1 if all of the following conditions are satisfied

1. The overreaching impedance elements are used only as part of the pilot scheme itself – i.e., not also in conjunction with a Zone 2 timer which would allow them to trip independently of the pilot scheme.
2. The scheme is of the permissive overreaching transfer trip type, requiring relays at all terminals to sense an internal fault as a condition for tripping any terminal.
3. The permissive overreaching transfer trip scheme has not been modified to include weak infeed logic or other logic which could allow a terminal to trip even if the (closed) remote terminal does not sense an internal fault condition with its own forward-reaching elements. Unmodified directional comparison unblocking schemes are equivalent to permissive overreaching transfer trip in this context. Directional comparison blocking schemes will generally not qualify.

For purposes of this discussion, impedance-based pilot relaying schemes fall into two general classes:

1. Unmodified permissive overreaching transfer trip (POTT) (requires relays at all terminals to sense an internal fault as a condition for tripping any terminal). Unmodified directional comparison unblocking schemes are equivalent to permissive overreach in this context.
2. Directional comparison blocking (DCB) (requires relays at one terminal to sense an internal fault, and relays at all other terminals to not sense an external fault as a condition for tripping the terminal). Depending on the details of scheme operation, the criteria for determining that a fault is external may be based on current magnitude and/or on the response of directionally-sensitive relays. Permissive schemes which have been modified to include “echo” or “weak source” logic fall into the DCB class.

Unmodified POTT schemes may offer a significant advantage in loadability as compared with a non-pilot scheme. Modified POTT and DCB schemes will generally offer no such advantage. Both applications are discussed below.

Unmodified Permissive Overreaching Transfer Trip

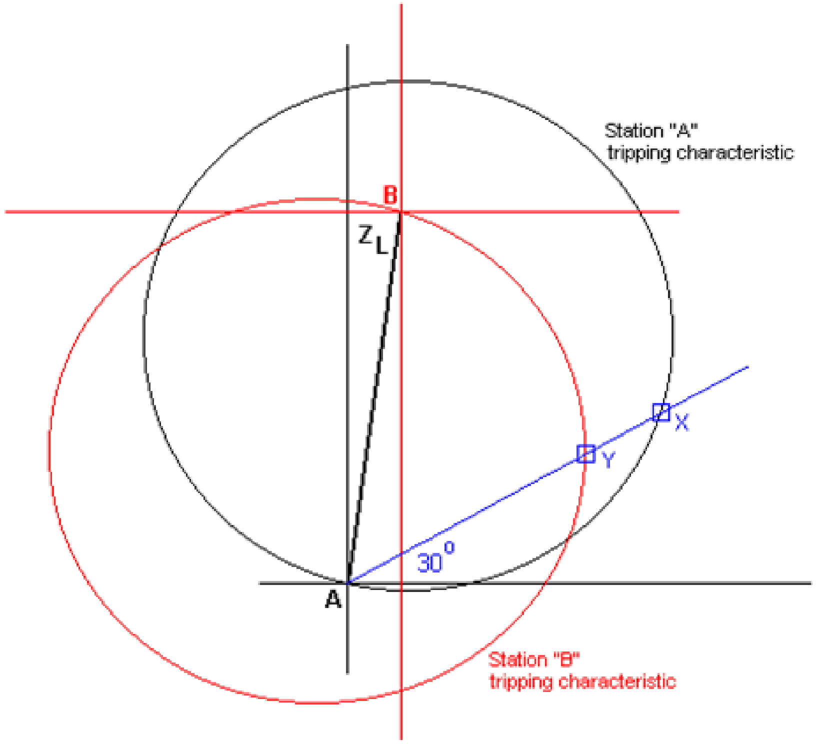


Figure 1 Permissive Overreaching Transferred Trip (unmodified)

In a non-pilot application, the loadability of the tripping relay at Station “A” is determined by the reach of the impedance characteristic at an angle of 30 degrees, or the length of line AX in Figure 1. In a POTT application, point “X” falls outside the tripping characteristic of the relay at Station “B”, preventing tripping at either terminal. Relay “A” becomes susceptible to tripping along its 30-degree line only when point “Y” is reached. Loadability will therefore be increased according to the ratio of AX to AY, which may be sufficient to meet the loadability requirement with no mitigating measures being necessary.

Directional Comparison Blocking

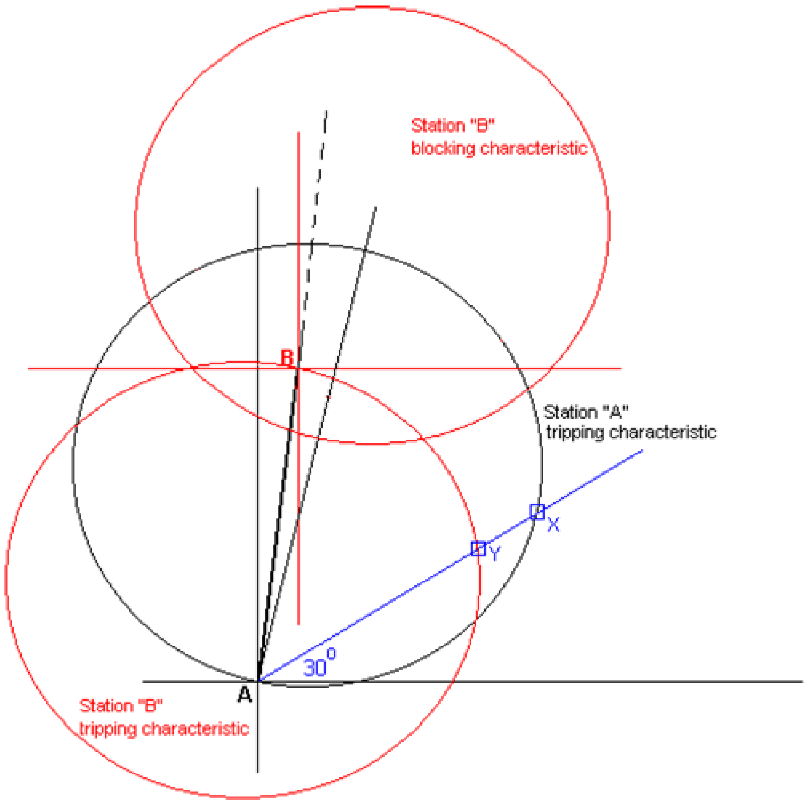


Figure 2 Directional Comparison Blocking with reverse-looking blocking elements

In Figure 2, blocking at Station “B” utilizes impedance elements which may or may not have offset. The settings of the blocking elements are traditionally based on external fault conditions only. It is unlikely that the blocking characteristic at Station “B” will extend into the load region of the tripping characteristic at Station “A”. The loadability of Relay “A” will therefore almost invariably be determined by the impedance AX.

Appendix C — Related Reading and References

The following related IEEE technical papers are available at:

http://pes-psrc.org

under the link for "Published Reports"

The listed IEEE Standards are available from the IEEE Standards Association at:

http://shop.ieee.org/ieeestore

The listed ANSI Standards are available directly from the American National Standards Institute at

http://webstore.ansi.org/ansidocstore/default.asp

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1. *Performance of Generator Protection During Major System Disturbances*, IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003.
2. *Transmission Line Protective Systems Loadability*, Working Group D6 of the Line Protection Subcommittee, Power System Relaying Committee, March 2001.
3. *Practical Concepts in Capability and Performance of Transmission Lines*, H. P. St. Clair, IEEE Transactions, December 1953, pp. 1152–1157.
4. *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines*, R. D. Dunlop, R. Gutman, P. P. Marchenko, IEEE transactions on Power Apparatus and Systems, Vol. PAS –98, No. 2 March-April 1979, pp. 606–617.
5. *EHV and UHV Line Loadability Dependence on var Supply Capability*, T. W. Kay, P. W. Sauer, R. D. Shultz, R. A. Smith, IEEE transactions on Power Apparatus and Systems, Vol. PAS –101, No. 9 September 1982, pp. 3568–3575.
6. *Application of Line Loadability Concepts to Operating Studies*, R. Gutman, IEEE Transactions on Power Systems, Vol. 3, No. 4 November 1988, pp. 1426–1433.
7. IEEE Standard C37.113*, IEEE Guide for Protective Relay Applications to Transmission Lines*
8. ANSI Standard C50.13*, American National Standard for Cylindrical Rotor Synchronous Generators.*
9. ANSI Standard C84.1, *American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)*, 1995
10. IEEE Standard 1036, *IEEE Guide for Application of Shunt Capacitors*, 1992.
11. J. J. Grainger & W. D. Stevenson, Jr., *Power System Analysis*, McGraw- Hill Inc., 1994, Chapter 6 Sections 6.4 – 6.7, pp 202 – 215.
12. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 2004.
13. August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, approved by the NERC Board of Trustees, February 10, 200