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Automatic Relay Setting

By

Donald M. MacGregor, Ph.D. (Electrocon International, Inc, USA)

A. T. ("Tony") Giuliante, Fellow of IEEE (ATG Exodus, Inc., USA)

Russell W. Patterson, P.E. (Tennessee Valley Authority, USA)

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Dr. Donald M. MacGregor **A. T. Giuliante** **Russell W. Patterson**

Abstract

Precise relay setting rules can be formulated for any protection scheme and embodied as a setting algorithm in a larger environment for protection system simulation. Automating these rules saves engineering time by simplifying routine data-handling. Since different companies use different relay elements or setting parameters, the algorithms need to be flexible and accessible to a user for modification.

This paper examines a specific case that involves overcurrent and distance elements in a Permissive Overreach Transfer Trip scheme. This scheme uses direct tripping from zone 1 and permissive tripping from a forward pilot element, with two time-delayed zones for a backup stepped-distance scheme. The permissive signal is echoed to allow sequential tripping after one breaker opens. A reverse pilot element blocks the echo signal for external faults.

The algorithm sets the distance reaches from the network connections and impedances, and sets overcurrent element pickup values using fault studies, following established utility practice. Detailed reports identify possible conflicts in the setting rules. Settings can be saved in the system database, which includes a library of relays with actual tap names and ranges. Approved settings can then be transferred to the relay electronically.

An operating margin measures how close a relay element is to its operating limit for a particular fault. For solid faults, overcurrent elements use the multiples of pickup and distance elements use the relative distance of the apparent line impedance from the characteristic. For resistive faults, the maximum fault resistance seen by zones 1 to 3 is presented graphically as a function of distance.

The settings are validated with a stepped-event simulation of the permissive tripping sequence, using detailed relay models. This will find any primary-backup miscoordinations.

1. Introduction

Modern numerical relays provide many protection functions in a single package. The internal logic involves a large number of distance, directional and overcurrent elements. The protection engineer must choose electrical parameters (such as distance reach and current pickup taps) that make the relay both reliable and secure against unwanted operation. A protection simulation environment can assist the engineer by automating the application of the setting rules and simplifying routine data-handling. The algorithms do not attempt automatic relay coordination; they set one element at a time and warn where setting rules conflict.

The process demonstrated uses a Permissive Overreach Transfer Trip (POTT) scheme for a 161kV transmission line at the Tennessee Valley Authority. The setting rules are based largely on the standards and experience at that utility. First, the user searches the system database and chooses a relay. Next, the user selects a setting algorithm for the specific relay model. The user is prompted for the maximum load current, the load angle, and the minimum pickup to avoid operation for unbalanced currents. Then the impedance reaches and pickup currents or voltages are computed from the primary network values and converted to the named relay tap settings. The user can test these settings while they are in temporary memory or can save them in the system database. The database can hold groups of alternative settings for trial purposes and for varied network conditions.

When all the relays protecting the line of interest have provisional settings, a system simulation checks the overall tripping logic and detects any miscoordinations.

2. Protection Simulation

The protection simulation environment allows a user to compute settings and send them to a relay or to read settings from a relay and test them in the modeled system. The components are:

- A network model (buses, generators, lines, shunts, and transformers) and a short-circuit analysis with high-level commands for faults and outage contingencies [1]. Currents and voltages are treated as steady-state phasors.

- A library of detailed relay models [2]. A relay model consists of instantaneous overcurrent, time overcurrent, directional, distance, voltage, timer, and recloser elements, with auxiliary elements for internal logic and pilot (teleprotection) schemes. Special code for each relay model interprets the setting names and evaluates the comparators using a steady-state phasor analysis [3]. As a result, element response is always based on the actual relay logic. Actual settings are modeled so that the relay model is "set" in the same way as the physical device.

- Rules for locating relays. An integrated database [4] with an interactive editor contains the CTs and VTs connecting the relays to the network, and specifies the protected equipment and its logical breakers.

- A macro facility. The macro language has many commands associated with a high-level language, such as IF-THEN-ELSE, DOWHILE, and DO loops tailored to power system applications. For example, DOXFMRS and DOLINES find the transformers and lines at a bus, and DOPATH and DOREMOTE search through a meshed network with load-tap buses. Standard functions (e.g. SIN, ABS, and POLAR) and special protection functions (e.g. OPERATING_CYCLES and GET_TOC_TIME) are installed. Support for defining and looping through sets of buses, branches, and relay elements is provided. The engineer can access all information in the database (e.g. line impedances) and quantities developed by the programs (e.g. fault currents and source impedances). The relay setting rules are encoded using the macro language and can be modified by a user. Settings for a 38kV stepped-distance scheme have been obtained in this way for several years [5].

- Import/export facilities to communicate with a physical relay indirectly via relay vendor databases, or to send settings to a field engineer. Many numerical relays have their own setting software and can store relay settings in a database. The independent simulation environment complements this by modeling together the entire network and its protective devices from multiple vendors. Settings can often be transferred to the relay vendor's database product for subsequent electronic transmittal to the relay, making paper setting sheets unnecessary.

3. Setting Rules

The setting rules below provide distance zones and overcurrent pickups in primary network values or other convenient units and apply to any type of relay. Tap settings for a specific relay are derived separately within the setting algorithm. This paper presents each rule and an example of its results.

Figure 1 shows an actual case involving two coupled 161kV lines with equal lengths; line #1 is tapped at Ackerman station. It demonstrates an example of a POTT operation for a close-in phase-A-ground fault at Sturgis. Zone 1 opens the local breaker at Sturgis; the directional overcurrent element operates at Red Hills with the permissive signal.

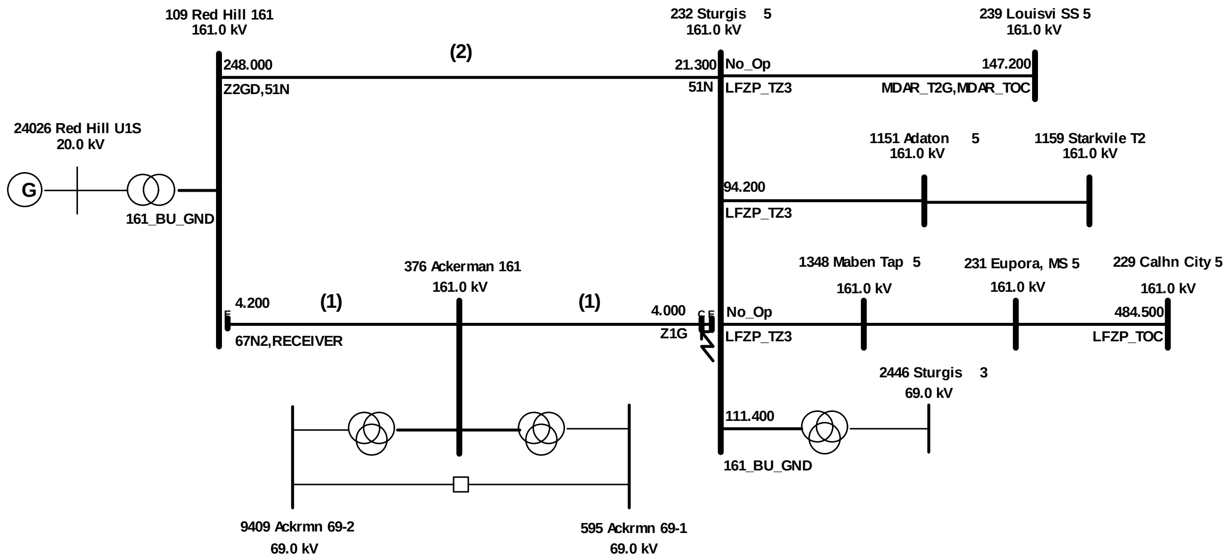


Figure 1 – One-line diagram of protected region.

The impedances in primary ohms are:

	Positive Sequence	Zero Sequence
Red Hills - Ackerman #1	3.77 @ 85.3 deg	9.37 @ 77.5 deg
Ackerman - Sturgis #1	3.77 @ 85.3 deg	9.37 @ 77.5 deg
Red Hills - Sturgis #2	7.57 @ 85.5 deg	19.03 @ 77.9 deg
Each tapped transformer at bus 376	34.5 @ 90.0 deg at 16lkV	28.2 @ 85.2 deg at 161kV

The computed positive-sequence source-impedance ratio for this case ranges from 1.3 to 4.4 depending on fault location; this is a "medium" line [6].

Here, the scheme uses phase and ground distance relay elements with backup ground and negative-sequence overcurrent elements. A simplified operating logic for any zone is shown in Figure 2.

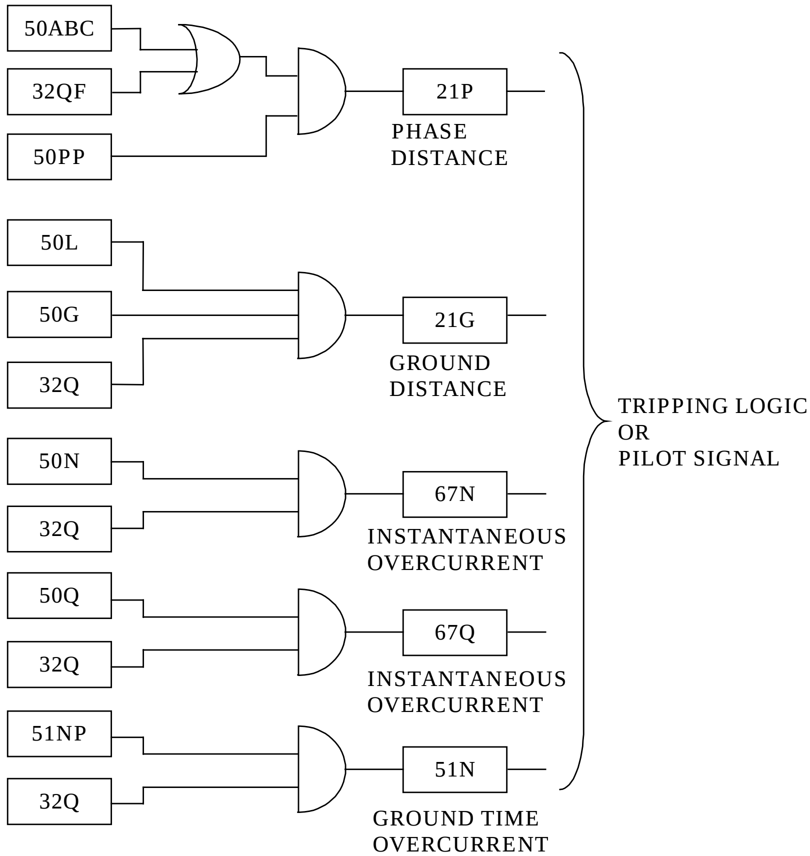


Figure 2 – Supervised Distance and Overcurrent Relay Elements.

At each line terminal, zone 1 elements (21P1, 21G1, 67N1 or 67Q1) trip instantaneously for internal faults within their set points, and forward directional pilot elements (21P2, 21G2, 67N2 or 67Q2) cover the entire line with some overreach. For internal faults, each forward pilot element will transmit a permissive signal to the other terminal. When this signal is received, the local forward pilot elements that have operated trip the corresponding breakers, at buses 109 and 232 in Figure 1. External faults at a terminal will suppress the transmitter functions and inhibit pilot tripping.

The pilot scheme is a POTT scheme with "echo keying" logic. A second pilot zone reaches in the reverse direction. A permissive signal received at a terminal, e.g. Sturgis, is echoed (after a precautionary delay), unless any of the reverse elements at Sturgis (21P3, 21G3, 67N3, or 67Q3) have detected an external fault. If the breaker at Sturgis is already open (for maintenance or other reasons) and a close-in fault occurs there, the relay at the opposite terminal (Red Hills) will send a permissive signal to Sturgis, and this signal will be echoed back to Red Hills after a set delay (typically 2 cycles). Receipt of the echo signal will allow the breaker at Red Hills to open and clear the fault.

In one type of relay, the pilot zones also serve as zones 2 and 3 and provide time-delayed backup for the adjacent lines. Another type uses zone 1 for instantaneous tripping, uses dedicated forward and reverse pilot zones, and uses zones 2 and 3 exclusively for time-delayed backup in a stepped-distance scheme.

3.1 MHO Distance Elements

The R-X diagram in Figure 3 shows the mho characteristics of zone 1 and the forward and reverse pilot elements.

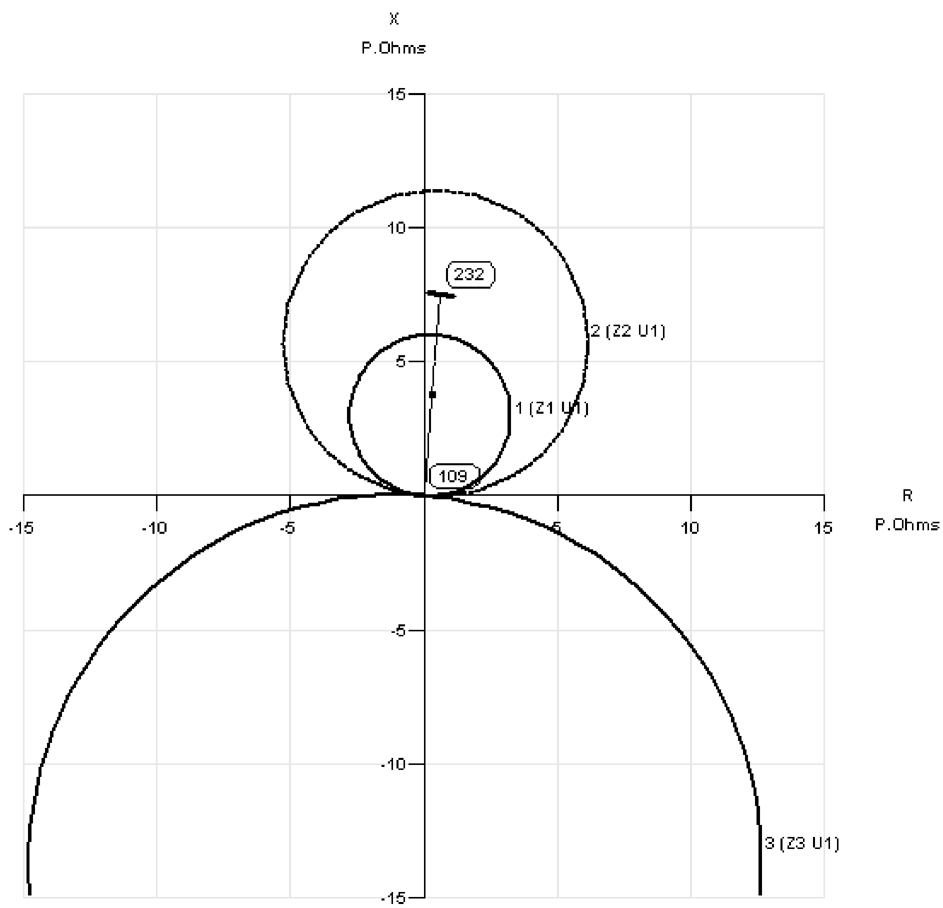


Figure 3 – Mho distance characteristics.

All distance elements are set from the line impedances. Then all phase zones are checked for load encroachment. The user supplies the maximum forward and reverse load currents and worst load angle, from separate load flow computations. If the load restriction is too severe, additional load encroachment or blinder elements may be needed.

3.1.1 Zone 1

Zone 1 reaches 80% along the protected line. Specifically, the total positive-sequence and zero-sequence line impedances Z1 and Z0 are found from the database. The maximum torque angle (MTA) equals the zone 1 line angle arg(Z1), and the set reach is 80% of the magnitude of Z1. Then the phase zone is further limited to 66 percent of the apparent impedance at maximum forward load current and a specified power angle, typically 30 degrees.

The zero-sequence compensation factor [7] multiplying the neutral current is:

$$k_0 = \left(Z_0/Z_1 - 1\right)/3$$

To avoid overreach due to mutual coupling, the reach of the zone 1 ground distance element is also limited to 80% of the least apparent impedance for a single-line-ground fault on the remote bus. The calculation is run first with all lines in service and then with coupled lines grounded one at a time, and with intermediate infeed removed. The apparent impedance is defined in section 4.

The supervising phase fault detector is useful to prevent instantaneous operation on loss of potential. It is desirable to set it above expected load current while maintaining a margin below expected fault current to allow the distance elements to operate reliably.

In relays with a separate fault detector (50PP1) for zone 1, the recommended setting (based on experience) is the lower of:

(a) 0.8 times the least fault current for solid faults 80% along the line, with sources out one at a time behind the relay bus, and

(b) 0.33 times the fault current for the same faults with the remote breaker open, for sequential tripping.

To prevent zone 1 from tripping with a loss of potential under load, this pickup must also be set at least 10 percent above the maximum load current from temporary overloads and heavy loads under reduced system voltage.

The single-phase and ground-fault detectors (50L and 50G level 1 or 2) are allowed to operate with load currents. This is because both 50L and 50G must operate to trip a ground distance zone, and the 50G residual elements do not operate with load except under abnormal conditions such as a breaker with one phase open.

In relays with only one fault detector for all zones, current sensitivity for remote faults takes priority, including those in the reverse pilot zone or zone 3. The setting may necessarily be below the maximum load current. These relays have separate elements to block the distance elements under loss of potential.

3.1.2 Forward Pilot Zone and Zone 2

These are set from line impedances and subsequently checked for infeed and mutual coupling.

Both of these zones cover the lesser of

(a) 150 percent of the protected line and

(b) 66 percent of the apparent impedance at maximum forward load current and a specified power angle.

Where zone 2 provides time-delayed direct tripping, it must not overreach a downstream zone 1. An additional constraint limits zone 2 to the protected line (or the longest path of a multiterminal line) plus 20 percent of the shortest adjacent line.

To avoid tripping for faults on the secondary winding of a tapped transformer, zone 2 should not overreach the primary bus by more than 20 percent of the transformer reactance.

Where separate fault detectors 50PP2, 50L2 and 50G2 for zone 2 are available, they are set at the least relay current (with one source removed) for remote-bus faults with fault resistance of 40 primary ohms.

The zone 2 timer is set at 20 cycles. Downstream zone 1 elements and breaker-failure protection at the line-end bus (about 15 cycles delay) are allowed to operate first.

3.1.3 Reverse Pilot Zone

A reverse pilot zone blocks echoing of a permissive signal for external faults. Both phase and ground elements should cover 150 percent of the largest apparent impedance calculated for line-end faults (on the line-side of an open remote breaker) behind the relay. This setting allows the reverse zone to operate for all external faults seen by the forward pilot zone at the other end of the protected line. A graphical coordination check is shown in section 4, Figure 7.

The phase-distance element must not operate under load alone. This limit is set as 66 percent of the apparent impedance due to maximum load current from the protected line into the relay bus, with a specified power angle.

For the fault detectors (such as 50PP3, 50L3 and 50G3), minimum settings are allowed because: (a) zone 3 direct tripping is delayed by 75 cycles, giving ample time for Loss of Potential Logic to assert and block tripping of distance elements, and (b) the zone 3 distance elements are set to avoid operation under maximum load conditions.

3.1.4 Zone 3 of Stepped Distance Scheme

A forward zone 3 should see 1.2 times the impedance to the most distant bus at a depth of 2, but the phase element is also limited by forward load as above. Both phase and ground elements are limited to cover 80 percent of the reactance of tapped transformers. The timer is set at 75 cycles.

Certain relay models allow zone 3 to have a reverse offset. Where this is used, it is set at 25% of the shortest adjacent line behind the relay, to detect local bus faults.

Example of Distance Zone Setting Algorithm Report:

```
*****************************************************************

    Setting MHO DISTANCE elements for Permissive Overreach

*****************************************************************

Substation: RED HILLS STEAM PLANT
Line:       Sturgis 161-kV line No. 1
Maximum load current 3000 primary amps
Highest power factor angle (deg) of the load    = 30
Worst Load: 30.9854 Primary Ohms at  30 Degrees
Load Power = Sqrt(3) * Base kV/1000 * Max load current /_ power factor angle
 836.556 MVA    724.479 MW    418.278 MVAR
***********************************************************
Relay on 109 376 Ckt 1 RED HILLS STEAM PLANT - ACKERMAN 161-kV SUB 161 kV
```

```
Base kV 161    Base ohms 259.210
************************************************************

*** Zone 1 =  0.8 * shortest protected line ***
Total primary line ohms 7.543
Zone 1 path 109 376 1 to 232
Setting     0.8 *  0.02910 =     0.0233 pu      6.03 Ohm

MTA =   85.3 deg

Adjusting ground zone 1 for mutual coupling

Case                                            Apparent line ohms

SLG on zone 1 bus; infeed removed               9.701 @  83 deg
Infeed removed; line out 109 232 2              7.543 @  85 deg
Infeed removed; line grounded 109 232 2         7.159 @  89 deg

Reducing zone 1 ground to  0.8 * 7.159 = 5.73 ohm

*** Zone 2 = Longest protected line +  0.2 * shortest adjacent line
Zone 2 path 109 376 Ckt 1 to 232 109 Ckt 2

*** Zone 3 = 1.2 * longest path to depth 2
Zone 3 path 109 376 1 to 229

Checking Transformer Overreach for zone 3
 4 remote XFMR buses at bus  376 161 kV
Zone reach into XFMR   132.7 % of XFMR
*** Reducing zone ohms from 47.8517 to 30.3402.  New reach   80.0 %
*** Warning: Zone 3 with transformer limit underreaches farthest zone 2 bus 229
***  Zone 3 setting rules cannot be met

*** Zone 3 reverse offset = 0.25 * zone 1

*** Forward pilot zone =  1.5 * longest protected line

*** Reverse pilot zone =  1.5 * longest line behind relay

Phase and ground MHO elements: desired primary ohms
                     Without XFMRS  With XFMRS  With XFMRS and LOAD
Zone 1 Phs       forward      6.03      6.03      6.03
Zone 1 Gnd       forward      5.73      5.73      5.73
Zone 2           forward     10.69     10.40     10.40
Zone 3           forward     47.85     30.34     30.34
Pilot            forward     11.31     11.31     11.31
Pilot            reverse     27.25     27.25     27.25
MTA (deg) for all zones  85.3


******************************************************************

    Setting Fault Detectors for Permissive Overreach

******************************************************************

Minimum allowed fault-detector pickup = 200 Primary A

Zone 1 fault detectors: no load;
0.80000 * min current from solid faults 0.8 along line
50PP1  Phase-phase  Primary A 4282.21
50L1   Single phase Primary A 2141.52
50G1   3*Izero      Primary A 2345.51
```

```
Zone 1 fault detectors: no load;
0.33000 * min current from solid faults 0.8 along line with remote breaker open
50PP1  Phase-phase  Primary A 2263.65
50L1   Single phase Primary A 1131.83
50G1   3*Izero      Primary A 1048.90

Zone 1 fault detectors: no load; maximum recommended settings:
50PP1  Phase-phase  Primary A 2263.65
50L1   Single phase Primary A 1131.83
50G1   3*Izero      Primary A 1048.90


Zone 2 fault detectors: no load;  40-ohm faults
50PP2  Phase-phase  Primary A 827.912
50L2   Single phase Primary A 54.3842
50G2   3*Izero      Primary A 163.153
 *** 50L2 below minimum  200; using minimum
 *** 50G2 below minimum  200; using minimum

Zone 3 fault detectors are set at the minimum allowed:
50PP3  Phase-phase  Primary A 200
50L3   Single phase Primary A 200
50G3   3*Izero      Primary A 200

Checking load current for IOC 50PP1

Maximum load current through the relay, in amps   = 3000
Maximum load current through the relay, in percent= 836.556
Maximum phase-phase load current in amps          = 5196
Maximum PP load current * 1.10000                 = 5715.60
50PP1 Primary A increased to 5715.60
50PP2 and 50PP3 do not require adjustment above load
```

3.2 Quadrilateral Elements

In the TVA application, Zones 1 to 3 use polarized mho phase and ground elements only and use the directional overcurrent elements to extend the protection for resistive faults. Some relays also provide optional quadrilateral (quad) ground elements. These are particularly useful to cover resistive faults on short lines with strong sources, where the mho characteristic may not expand sufficiently [3, 8].

The mho and quad elements have equal reaches in the line-angle direction. Typically, the quad element resistive reaches are set at 20 primary ohms. For the quad characteristic, the constant-reactance line is tilted automatically in the line impedance plane. The tilt eliminates overreach or underreach for resistive faults with outward or inward load current. One type of relay [8, 9] uses negative-sequence current polarization without additional settings. Another type [7] uses zero-sequence polarization and an extra tap setting T which is defined as the phase difference

$$T = \arg(\text{total fault } I_0) - \arg(\text{local relay } I_0)$$

Here I_0 is the zero-sequence current due to a single-line-ground fault at the zone 1 reach point. T is a function of fault location and the network impedances and is typically between zero and -10 degrees. The angle T is zero for a homogeneous system (where the zero-sequence source impedance angles at the line ends are both equal to the line angle). If T is set exactly, the reach is independent of load. If T varies along the line, T should be set at the largest negative value from a fault study, tilting the reactance line down to the right in the system impedance plane. Then any error in T causes underreach rather than overreach, increasing security.

3.3 Directional Instantaneous Overcurrent (IOC) Elements

These elements (67N and 67Q) detect the direction and magnitude of residual and negative-sequence current. They provide sensitive protection for resistive faults that are missed by the mho elements. They contain IOC pickup settings (tap 50N with $3I_0$ for 67N, or tap 50Q with $3I_2$ for 67Q) and the negative-sequence directional elements 32Q.

The following setting rules automatically monitor all three unbalanced fault types: single-line-ground (SLG), line-line (LTL) and double-line-ground (DLG).

3.3.1 Level 1 IOC for Instantaneous Direct Tripping

Level 1 (High Set) elements 67N1 and 67Q1 are set with a safety margin of 1.3 times the maximum current for a fault at the remote bus or on coupled branches, with infeed branches outaged. Monitors record the maximum zero- and negative-sequence currents at the relay over all faults with the outage contingencies chosen.

3.3.2 Level 2 IOC for Pilot Signaling and Time-Delayed Backup

Level 2 elements (67N2 and 67Q2) are backup controls for the pilot signal or time-delayed zone 2 tripping. They are set as 0.5 times the minimum relay current for a 40-ohm ground fault at the remote bus. The following report presents the 3I0 and 3I2 fault currents for the four types of faults. SLGR refers to a single-line-to-ground fault with 40-ohm fault resistance (primary ohms).

Example of Overcurrent Element Settings

```
******************************************************************

   Ground and Neg-Seq Overcurrent Elements for Permissive Overreach

*****************************************************************

Minimum allowed IOC pickup for all levels = 100 Primary A


 Level 1 IOC     Max     1.30000* Max
 50N1 Primary A 4294.91     5583.39
 50Q1 Primary A 5582.18     7256.83

 Level 2 IOC:  40-ohm faults at remote bus 232

              Fault          3I0       3I2

                TPHR         0.0       0.0
                LTLR         0.0    1275.9
                DLGR       403.4     464.6
                SLGR       405.5     458.3


 Level 2 IOC at RED HILLS STEAM PLANT to ACKERMAN 161-kV SUB
 Desired setting = 0.50000 * min relay amps for 40-ohm faults at remote bus 232
```

```
Level 2 IOC         Min    0.50000 * Min
50N2 Primary A   403.387     201.694
50Q2 Primary A   458.263     229.132
```

3.3.3 Level 2 IOC Settings with Tapped Transformers

If the protected line has tapped transformers, level 2 must be increased to 1.25 times the highest current due to faults on the transformer secondary. The fault study applies three-phase, phase-phase and phase-ground faults on the secondary side; one does not need to know the transformer connection.

Example of limits due to transformers:

```
 4 tapped transformers at bus 376; adjusting Level 2

Faults on tapped XFMRs; remote breaker closed
Faults on tapped XFMRs; remote breaker open at 232

Solid faults on tapped XFMR secondaries
 Level 2 IOC        MAX    1.25000 * MAX
 50N2 Primary A   1454.83     1818.53
 50Q2 Primary A   2976.65     3720.81
```

The following summarizes the adjusted neutral and negative-sequence pickup settings.

	Level 2 IOC elements (Primary A)	
	Without XFMRS	With XFMRS
50N2	201.69	1818.53
50Q2	229.13	3720.81

3.3.4 Level 3 IOC Settings

The local level-3 reverse IOC settings (taps 50N3 and 50Q3) should have at most half of the remote level-2 values, to block echo signals for external faults (Figure 4). These settings are secure, since zone 3 sees at least as much line current as its remote level 2 element.

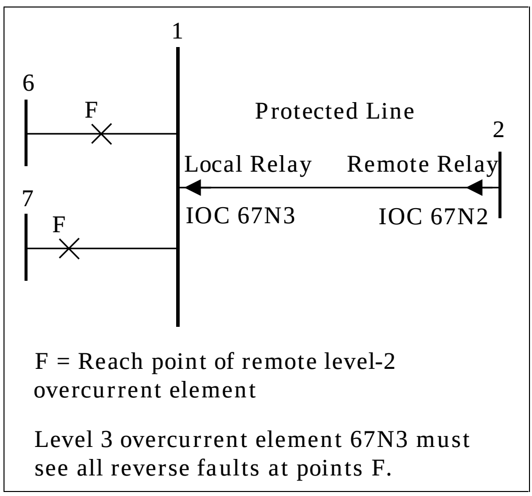


Figure 4 – Coordinating definite-time overcurrent elements.

3.4 Backup Directional Ground Time-Overcurrent (TOC) Element

Element 51N provides current-dependent time-delayed clearance of high-resistance faults along the protected line. It provides backup protection for remote elements, and supplements zone 2 when the pilot scheme is out of service. A suitable time delay is 30 cycles for a solid fault at the remote bus and a pickup setting of 0.1 times the relay current for this fault. The curve shape is chosen separately for coordination with neighboring TOC elements. A "Very Inverse" curve is typical for a looped system without fuses.

Figure 5 shows the operating time for 40-ohm faults along the protected line from Red Hills to Sturgis.

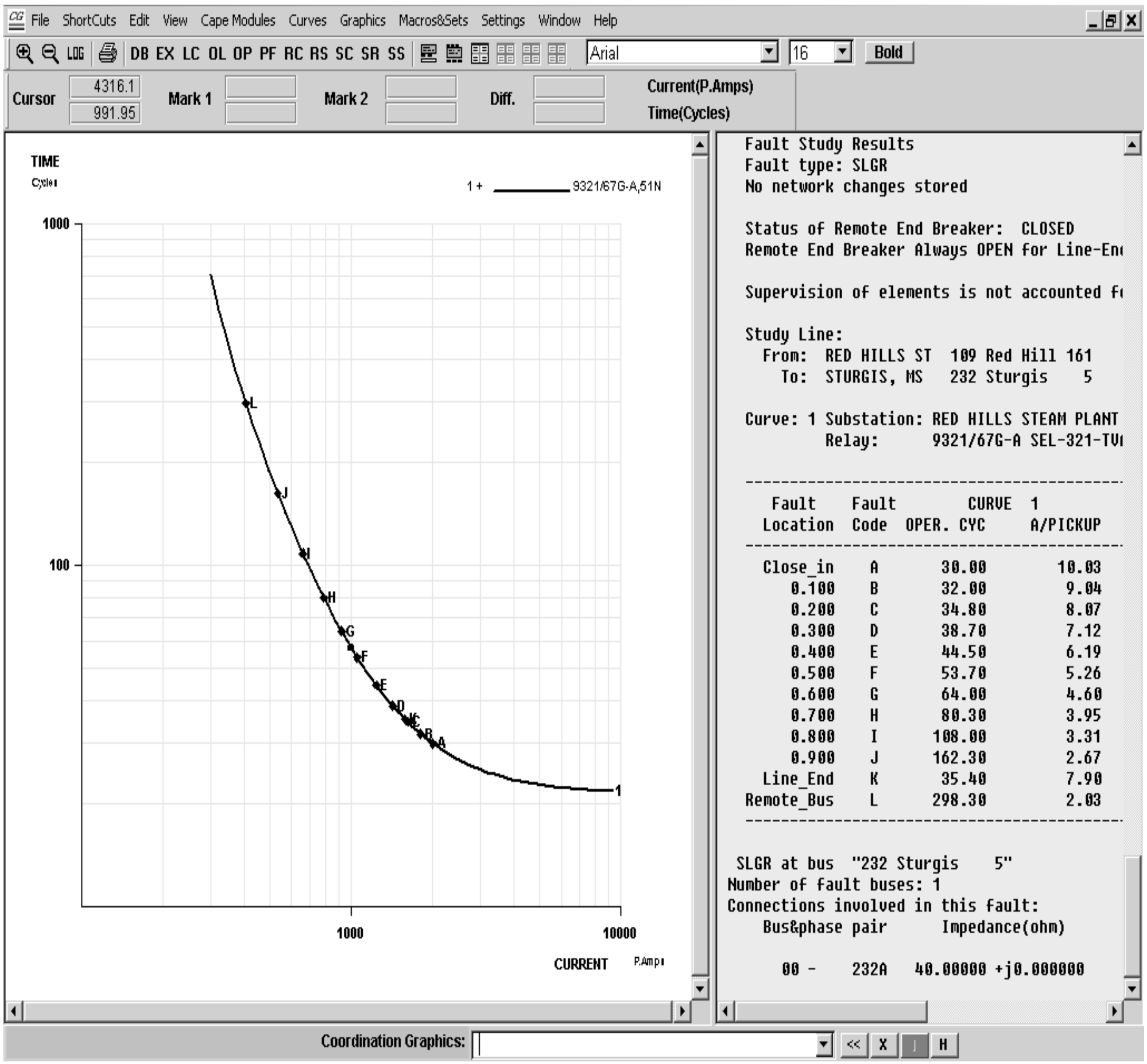


Figure 5 – Time-overcurrent characteristic with sliding 40-Ohm faults.

3.5 Current Direction

A fault on a coupled external line can reverse the zero-sequence voltage and make the relays at both ends of the line see the fault as forward [6, 10]. In other cases, the current direction may reverse. The setting algorithm reports the direction seen by the relay for

(a) Sliding faults on the relay line with coupled lines all in service,

(b) Sliding faults on the relay line with lines in the group of coupled lines grounded one at a time, and

(c) Sliding faults on all coupled lines with all lines in service.

Generic zero-sequence and negative-sequence directional elements are used to measure the direction as in reference [10]. The user is shown where the current may reverse and is warned where an external fault appears as internal.

The following output from the setting algorithm verifies that internal faults remain as forward (F) at both ends of the line when a coupled line is grounded.

```
Fault directions at end buses 109 and 232 of line 109 376 1 to 232
-----------------------------------------------------------------

Fault type: Single-Line-Ground

  Faults on relay line; all lines in service
   Relay branch  109 376 1  Fault branch 376 232 1    Internal
                 0 seq                   -seq
      Dist     Left end  Right end   Left end  Right end
   1  0.25        F        F                F        F
   2  0.50        F        F                F        F
   3  0.75        F        F                F        F

 Line Grounding "109 Red Hill 161"  to  "232 Sturgis    5" Ckt 1
   Relay branch  109 376 1  Fault branch 376 232 1    Internal
                 0 seq                   -seq
      Dist     Left end  Right end   Left end  Right end
   1  0.25        F        F                F        F
   2  0.50        F        F                F        F
   3  0.75        F        F                F        F
```

The following output from the setting algorithm shows the direction measured for external faults on a coupled branch. At least one end must see the external fault as reverse (R); otherwise a warning would be shown. Normal current reversal occurs when the fault location changes on the parallel line.

```
  Faults on coupled branches; all lines in service
   Relay branch  109 376 1  Fault branch 109 232 2    External
                 0 seq                   -seq
      Dist     Left end  Right end   Left end  Right end
   1  0.25        R        R                R        F
   2  0.50        F        R                R        F
   3  0.75        F        R                F        R
```

3.6 Negative-Sequence Directional Element 32Q

This element supervises all zones for the ground distance elements (forward or reverse) and also supervises the phase mho elements except when a three-phase fault is detected. One type of relay [10] has a fixed pickup for the torque product

$$\text{Torque} = \text{Re}\left(V_2 \, \text{conjg}\,(I_2)\,\exp(\text{-jMTA})\right)$$

from relay negative-sequence voltage V_2 and current I_2. When the product is negative (for a forward fault), the relay bit 32QF is asserted. For a reverse fault, the relay bit 32QR is asserted.

Another type [11] increases the torque limit for high fault current by measuring an impedance component instead:

$$Z_2 = \text{Re}\left(\left(V_2/I_2\right)\exp\left(\text{-jMTA}\right)\right)$$

The angle MTA is a tap setting, usually set equal to the +/- sequence line angle arg(ZL1). Z_2 changes abruptly from a negative value for close-in forward faults to a positive value for reverse faults. Directionality is assured by computing the least negative Z_2 for forward faults, and the least positive Z_2 for reverse faults. Then the forward and reverse impedance pickups Z2F and Z2R are set between these limits, with

$$\text{Z2R} \ \geq \ \text{Z2F} + 0.5 \ / \ (\text{rated current})$$

in secondary ohms.

The 50QF and 50QR pickup settings ($3I_2$) must allow the most sensitive supervised IOC, TOC or distance element to operate [12]. The required minimum 3I2 values are computed from line-line, single-line-ground, and double-line-ground faults at the operating limits of the supervised elements.

The tap setting (a2) equals the least allowed magnitude of (I_2/I_1) for operation, to avoid operation due to untransposed lines with load current. If an unbalance factor a2 is supplied, the algorithm must warn the user where the desired 50QF or 50QR are less than a2 * (max load current). Alternatively, 50QF and 50QR are set from the fault studies and the unbalance factor is set as:

$$\text{a2} = \min\ (\text{50QF, 50QR}) \ / \ (\text{max load current})$$

This value is chosen because any larger a2 value would cause the maximum load current to raise the threshold $3I_2$ above the required 50QF setting.

Example of Setting Algorithm Report:

```
************************************************************************

  Setting Negative-Sequence Directional Element for Permissive Overreach

************************************************************************

Substation RED HILLS STEAM PLANT
  Maximum load current 3000 primary amps
  Branch impedance (pu)       0.015 @  85 deg
  Total line ohms (primary) 7.54279
```

```
 CTR 400 VTR 1400
 Primary (network) quantities for forward faults
|Zsourcen|  Re(V2/I2/_-MTA)    |I2|  Contingency
 12.4908    -12.485        3106.60  All lines in service
 13.4036    -13.398        2565.09  Midline fault at 0.25000
 14.5186    -14.512        2166.46  Midline fault at 0.50000
 15.9117    -15.904        1857.16  Midline fault at 0.75000
 17.6934    -17.683        1607.01  Midline fault at 1
 18.3737    -18.336        2140.20  Line out 109 232 2
 38.8598    -38.823        750.487  Line out 109 24026 1
Negative V2/I2 component of least magnitude for forward faults -12.485 primary ohms
(-3.567 secondary ohms).

 Primary (network) quantities for reverse faults
|Zsourcen|  Re(V2/I2/_-MTA)    |I2|  Contingency
 38.7379    38.6949        1001.71  All lines in service
 23.1619    23.1450        1697.76  Line out 109 232 2
 38.7379    38.6949        752.850  Line out 109 24026 1
Positive  V2/I2 component of least magnitude for reverse faults 23.1450 primary ohms
(6.613 secondary ohms).

Default settings
Rated amps            5
Total line ohms       7.54279
Total secondary ohms  2.15524
Default Z2F = 0.5 * total secondary ohms= 1.07762
Default Z2R = Z2F + 0.5/(rated amps)    = 1.17762

Default values lie within required range (-3.567, 6.613) secondary ohms

Primary 3*I2 (A)           2133.70
TOC_FACTOR chosen as       0.10000
Primary pickup (3*I2)      213.370
CTR                        400
Secondary pickup (3*I2)    0.53343 relay A

Settings chosen with fixed a2 and max load 3000 A
a2  (min I2/I1)            0.10000
50QF & 50QR 3I2 pickup     2.25000

Alternative settings for IOC pickup and max load 3000 A
a2  (min I2/I1)            0.02371
50QF & 50QR 3I2 pickup     0.53343
```

Table 1 is a summary of the setting rules. The automatic process is exploited by including more thorough fault studies than would be practicable manually. For example, to set the largest allowed fault detector pickup requires about 50 sets of fault calculations, and setting the overcurrent elements uses about 70 sets of fault calculations, with various lines temporarily outaged.

Table 1

Summary of Rules for Distance and Overcurrent Settings

Phase DIST zone 1	80% along the protected line; all phase zones are checked for max load.
Ground DIST zone 1	Min of 80% along the protected line and 80% of apparent impedance due to mutual coupling for a remote A-G bus fault, with infeed removed and a coupled branch grounded.

Fault detector for zone 1	0.8 times the least fault current for solid faults 80% along the line. 0.33 times the fault current for the same faults with the remote breaker open. Phase pickup 10% above max load current.
Forward pilot zone	150% of the protected line. Phase element limited to 66% of the apparent impedance at maximum load current and a power angle of 30 degrees.
Time-delayed zone 2	Max of (150% of the protected line) and (protected line + 20% of shortest adjacent line) Phase element limited to 66% of the apparent impedance at maximum load current and a power angle of 30 degrees. Must not overreach a downstream zone 1. Must not overreach the primary bus of a tapped XFMR by more than 20% of the transformer reactance.
Fault detector for zone 2	Least relay current (with one source removed) for remote-bus faults with fault resistance 40 primary ohms.
Zone 2 timer	20 cycles.
Reverse pilot zone	150% of the largest apparent impedance calculated for line-end faults (on the line-side of an open remote breaker) behind the relay. Phase element limited to 66% of the apparent impedance due to maximum load current from the protected line into the relay bus, with a power angle of 30 degrees.
Fault detector for reverse pilot zone	Minimum setting.
Time-delayed forward zone 3	1.2 times the impedance to the most distant depth-2 bus. Phase element limited to 66% of the apparent impedance at maximum load current and a power angle of 30 degrees. Must not overreach the primary bus of a tapped XFMR by more than 80% of the transformer reactance.
Zone 3 timer	75 cycles.
Fault detector for zone 3	Minimum setting.

Zone 3 reverse offset	25% of zone 1.
Quad element resistive reach	20 primary ohms.
Level 1 IOC	1.3 times the maximum current for a fault at the remote bus with infeed branches outaged.
Level 2 IOC	0.5 times the relay current for a 40-ohm ground fault at the remote bus.
	At most 1.25 times the highest current due to faults on the transformer secondary.
Level 3 IOC	Half of the remote level-2 pickup.
Ground TOC with “Very Inverse” curve	30 cycles delay for a solid fault at the remote bus and a pickup setting of 0.1 times the relay current for this fault.
Negative-Sequence Directional Element	Z2F = 0.5 * (secondary line ohms); Z2R = Z2F + 0.5/(rated current)
	Forward and reverse pickups (3I2) allow the most sensitive supervised element to operate.
	Min (Ineg/Ipos) tap = pickup / (max load current)

4. Checking the Settings

Settings must allow for fault resistance, imprecise network data, and instrument-transformer error. The operating margin defined below shows how close an operating relay is to its limit, or how close a non-operating relay is to an incorrect operation. Where the calculations involve only a single element, the fault studies are performed by the setting algorithm to warn the user of setting conflicts.

Overcurrent elements use the multiples of pickup to measure the safety margin, and the pickup taps are computed directly from the desired margin in the fault studies above.

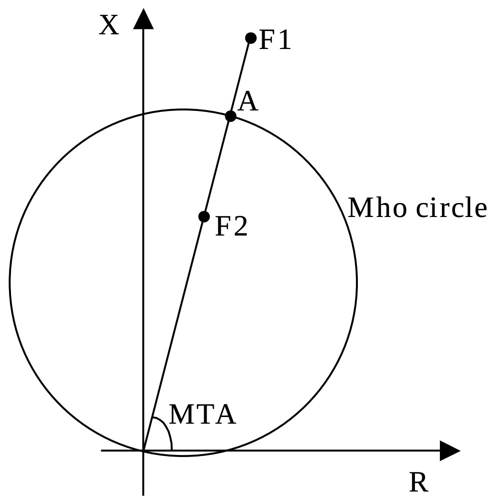
Distance elements are set directly from the line impedances and need additional fault studies (performed by the setting algorithm) to test for infeed and mutual coupling.

4.1 Reach Margin for Distance Elements

Here the reach margin is defined in the positive-sequence line-impedance plane (Figure 6) for a solid fault on one of the protected lines as

Margin = Set reach / (Set reach + distance from boundary) [Fault beyond characteristic]

Margin = Set reach / (Set reach - distance from boundary) [Fault within characteristic] using the shortest distance from the apparent impedance point to the boundary of the operating region.



$$\text{Margin} = \frac{\text{Diameter}}{\text{Diameter + dist A to F1}} \quad \text{Fault beyond characteristic}$$

$$\text{Margin} = \frac{\text{Diameter}}{\text{Diameter} - \text{dist A to F2}} \quad \text{Fault within characteristic}$$

Figure 6 – Operating margins of mho distance characteristic in line impedance plane.

The set reach depends on the tap settings. For a quadrilateral, the reach is measured from the origin to the reactance line. For a mho circle (Figure 6), the reach is the diameter. By design, this circle passes through the set reach point at the MTA. Although the actual characteristic expands away from this angle, solid faults on the protected lines have apparent impedance angles within a few degrees of the MTA setting, so useful margin estimates for solid faults can be based on a fixed set reach. This simplification makes the margin calculation independent of the particular relay comparator. To test *resistive* faults, the dynamic characteristic is plotted using the actual relay operating equations [3].

The phase elements are tested for three-phase faults and the apparent impedance is computed as:

$$\text{Impedance} = \left(V_b\text{-}V_c\right)/\left(I_b\text{-}I_c\right)$$

where the relay phase voltages relative to local ground are (V_a, V_b, V_c) and the line currents at the relay are (I_a, I_b, I_c).

For the ground elements, the apparent impedance is computed. For phase-A-ground element, the apparent impedance is:

$$\text{Impedance} = V_a/\left(I_a + 3I_0\, k_0\right)$$

where k_0 is the zero-sequence compensation factor [7] as approximated by the relay tap settings.

These impedances equal the apparent positive-sequence ohms between the relay and its local zero-voltage point and therefore give the apparent fault location on the line.

Applications of the reach margins are described in the following sections.

4.1.1 Zone 1 and 2 on Protected Line

With solid faults at the end bus of the protected line, the zone 1 reach margin should be 0.8 or less. For the forward pilot zone or zone 2, the reach margin should exceed 1.2 for the same faults.

This check is part of the setting algorithm. The report warns that the forward pilot zone and zone 2 set as above both underreach for ground faults:

```
  Margins for zone 1 phase (underreaching)

          Line    Fault  Reach    App P.Ohm  MHO margin
     109 -   232   TPH    6.03      7.54     0.80  Underreach

  Margins for zone 1 ground (underreaching)

          Line    Fault  Reach    App P.Ohm  MHO margin
     109 -   232   SLG    5.73     11.52     0.50  Underreach

  Margins for zone 2 (overreaching)

          Line    Fault  Reach    App P.Ohm  MHO margin
     109 -   232   TPH    9.06      7.54     1.20  Overreach
     109 -   232   SLG    9.06     11.52     0.79  Underreach    ** Warning **

  Margins for forward pilot zone (overreaching)

          Line    Fault  Reach    App P.Ohm  MHO margin
     109 -   232   TPH   11.31      7.54     1.50  Overreach
     109 -   232   SLG   11.31     11.52     0.98  Underreach    ** Warning **
```

Here the automatic procedure cannot set an optimum value, and the engineer must choose compromise settings for forward pilot operation and for time-delayed tripping. Zone 1 (phase or ground) is critical and should already have been set to prevent overreach. To increase zone 2 to cover the line, or to relax the load restrictions or the tapped transformer limit, the user will change the setting factors in the algorithm and repeat the calculation.

4.1.2 Zone 2 Coverage of Downstream Line

For zone 2 stepped distance elements, the algorithm applies a fault at each of the downstream zone 1 limits, with infeed branches removed to maximize the zone 2 reach. The parallel line in this network is treated as any other downstream line. If the zone 2 reach margin (as defined above) exceeds 0.8, the fault is close to the zone 2 characteristic, so there is a risk that the local zone 2 will misoperate for faults beyond zone 1 of the downstream relay. The coordination can be maintained by increasing the local zone 2 time delay [6].

In this application, zone 2 is short enough to coordinate with every downstream zone 1, even with intermediate sources removed.

```
Margins for maximum zone 2 overreach in downstream zone 1
Overreaching zone of relay on 109 376 1 must not reach ends of downstream zone 1

Solid faults 0.80000 along lines from remote bus 232
All infeed branches in service
 Remote line     Fault   Reach      App P.Ohm        MHO margin

 232 109 2 to 109  TPH   11.31    7.079 @-102 deg    Reverse fault       OK
 232 109 2 to 109  SLG   11.31   10.650 @-104 deg    Reverse fault       OK

 232 239 1 to 239  TPH   11.31   57.577 @  85 deg    0.18  Underreach    OK
 232 239 1 to 239  SLG   11.31   69.714 @  82 deg    0.15  Underreach    OK
 .... etc.

Solid faults 0.80000 along lines from remote bus 232
All infeed branches outaged
 Remote line      Fault  Reach      App P.Ohm        MHO margin
 Outage branches at 376
 Outage branches at 232

 232 109 2 to 109  TPH   11.31   13.596 @  85 deg    0.77  Underreach    OK
 232 109 2 to 109  SLG   11.31   13.978 @  85 deg    0.74  Underreach    OK

 232 239 1 to 239  TPH   11.31   20.132 @  83 deg    0.52  Underreach    OK
 232 239 1 to 239  SLG   11.31   20.522 @  83 deg    0.51  Underreach    OK
 .... etc.
```

4.1.3 Zone 3 Coverage of Depth-2 Buses

For a forward zone 3, the setting algorithm applies a fault at each bus at a depth of 2, with all branches in use and with branches out one at a time behind the relay, to check minimum source conditions. Warnings appear in the following example because zone 3 has been limited by tapped transformers.

Margins for zone 3 at depth 2: all lines in service

```
        Line        Fault  Reach  App P.Ohm  MHO margin
 109 376 1 to 239   TPH    30.34    69.58     0.44  Underreach    ** Warning **
 109 376 1 to 239   SLG    30.34    85.82     0.35  Underreach    ** Warning **
 109 376 1 to 36    TPH    30.34    54.37     0.56  Underreach    ** Warning **
 109 376 1 to 36    SLG    30.34    84.83     0.36  Underreach    ** Warning **
 109 376 1 to 229   TPH    30.34   120.92     0.25  Underreach    ** Warning **
 109 376 1 to 229   SLG    30.34   169.84     0.18  Underreach    ** Warning **
 109 376 1 to 590   TPH    30.34    88.00     0.34  Underreach    ** Warning **
 109 376 1 to 590   SLG    30.34   105.63     0.29  Underreach    ** Warning **
```

4.1.4 Reverse Pilot Reach

The reverse pilot zone must cover the overreach region of the forward pilot zone at the opposite end of the line, in order to block all echoed signals. This coordination check is made graphically after both relays have been set. The expanded characteristics in Figure 7 show the operating limits for all faults, both solid and resistive. Circle R1 for Zone 2 lies well inside circle R2 for the expanded reverse pilot characteristic, so the reverse zone provides ample coverage for 161kV line-ground faults beyond the protected line at Sturgis (232).

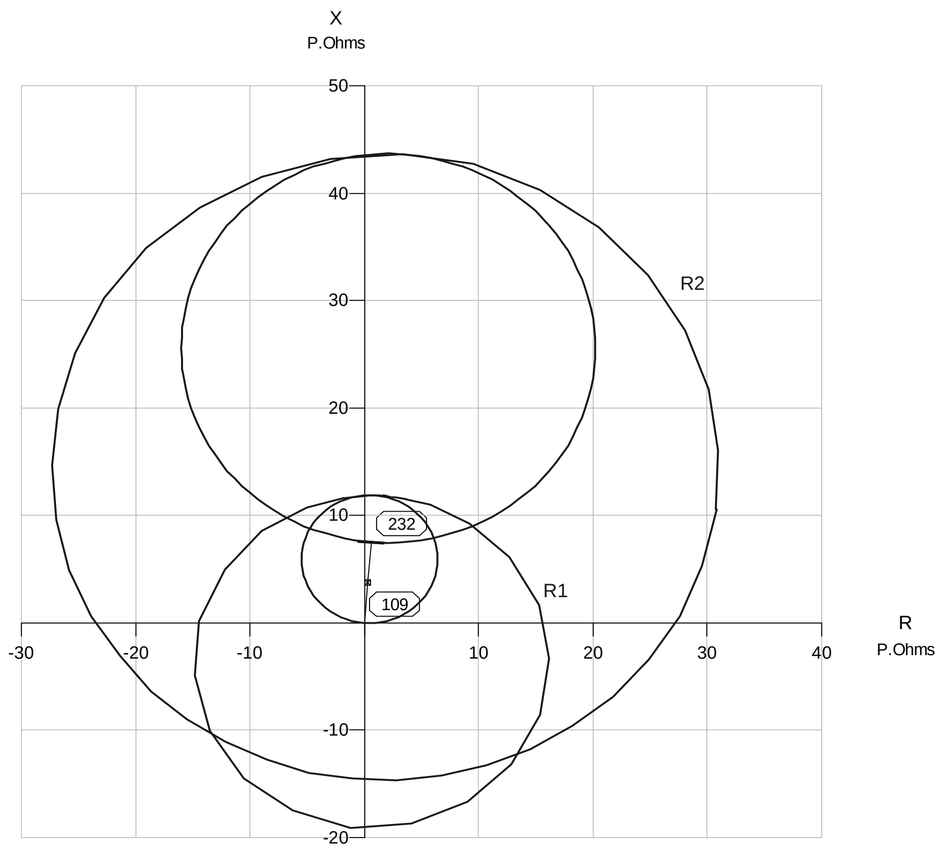


Figure 7 – Forward pilot zone at Red Hills (109) and reverse pilot zone at Sturgis (232) with dynamic expansion for single-line-ground faults at bus 232.

R1: expanded forward pilot zone
R2: expanded reverse pilot zone

In this relay [7], memory polarization expands the phase and ground MHO characteristics. The expanded circles in Figure 7 plot the phase A apparent impedance at the operating limits, both for the forward pilot ground zone and for the reverse pilot ground zone. The points are computed by applying faults with varying arc impedance at a fixed fault location (bus 232 here). At each angle in turn (0 to 360 degrees), the algorithm iterates the impedance magnitude to find the operating limit, modeling the actual relay comparator. These limits depend on the particular relay type and on the equivalent source impedance at the relay. Hence they also vary with fault location along the line in a fixed direction. The relay operates when the apparent impedance lies in the expanded circle.

4.2 Sensitivity to Ground-Fault Resistance

A plot of the largest detectable fault resistance against fault location is a convenient measure of ground element sensitivity [12]. The technique involves fixing the fault type, opening chosen breakers, and varying the fault location and resistance to plot the operating limit, again using the actual relay comparator equations.

Examples are as follows:

(a) Apply sliding faults on the protected line and compute the largest fault resistance that will trip zone 1 at each point. Also check that zone 1 reaches no more than 80 percent along the line.

(b) Using sliding faults on the protected line, compute the largest fault resistance that will operate the forward pilot zone, and hence the largest fault resistance that allows the overlapping zones from all terminals to protect the line [12]. Larger resistances will produce an unprotected region where the permissive scheme will fail; such faults must be cleared with the time-delayed backup tripping logic.

Figure 8 plots the maximum fault resistance that the distance and overcurrent elements can detect for single-line-ground (1Ph) faults in circuit #1, accounting for the fault detectors and directional supervision.

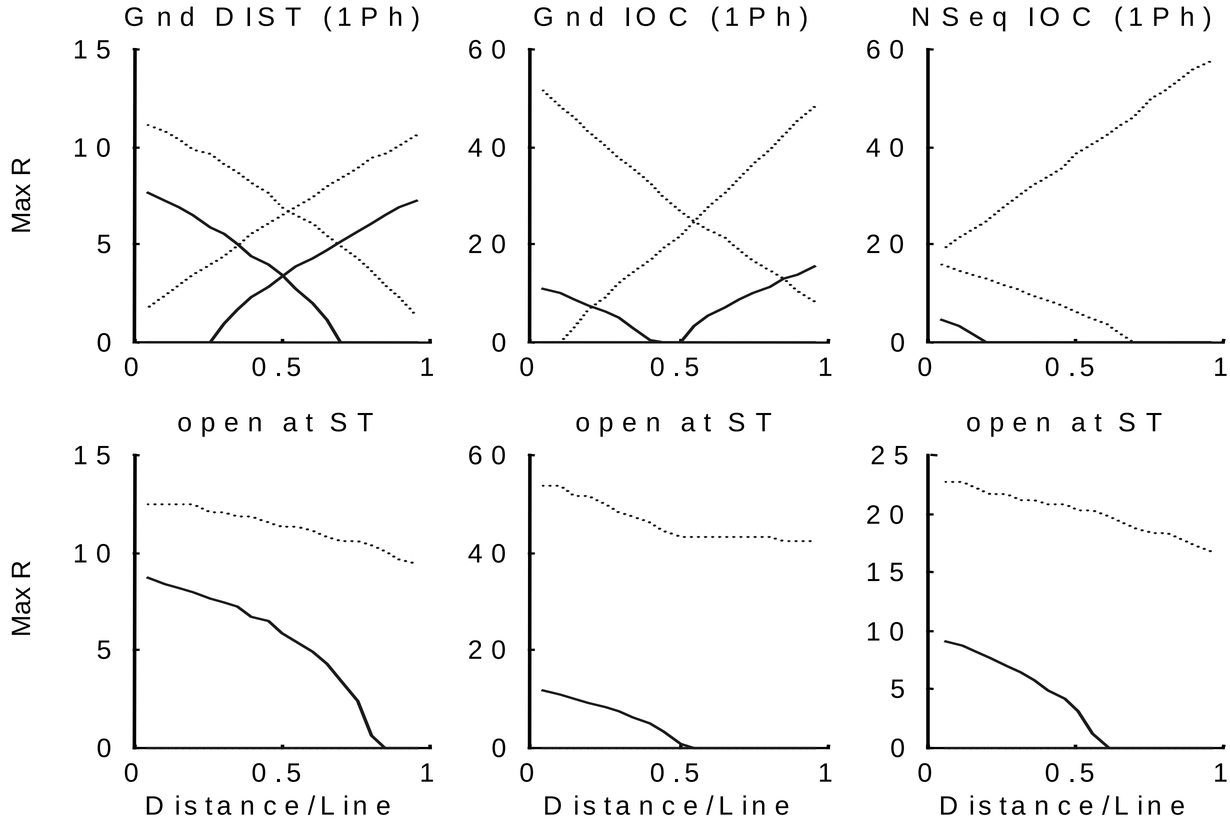


Figure 8 – Threshold fault resistance (primary ohms) for zone 1 (solid lower curves) and zone 2 (dashed upper).

Red Hills (RH) substation is at the left (Distance/Line = 0) and Sturgis (ST) is at the right. The largest resistance seen by zones 1 and 2 at Red Hills decreases with increasing distance along the line. Zone 2 is more sensitive than zone 1 and detects higher fault resistances. The “Gnd IOC” elements are set to be more sensitive than the “NSeq IOC” elements, using the results of the fault studies; hence the zone 1 “NSeq IOC” element at Sturgis does not operate for 1Ph faults.

The region below the zone 1 curves shows the faults in zone 1 that trip directly; the region under both zone 2 curves shows faults that the pilot scheme will detect. A 15-ohm close-in fault at Sturgis is not seen from Red Hills because of neutral infeed from the two tapped autotransformers at Ackerman. Such faults will be cleared with zone-2 time delay (20 cycles), by the TOC element, or sequentially if the current rises enough after the breaker opens at Sturgis. The lower plots in Figure 8 ("open at ST") show the increased coverage in this case. The "Gnd IOC" curve flattens out for faults beyond the transformers; this is a result of the neutral infeed, which does not affect the "NSeq IOC" element.

The plotting algorithm is valid for any relay model. For each curve, the user chooses a group of elements at one end of the line, all of which must operate together. For example, the "Gnd DIST" zone 1 curve includes both the zone 1 ground distance and the forward negative-sequence directional element. It is also possible to customize the algorithm to use specific elements. Figure 8 was obtained by combining six cases with a graphics software package. These cases involved over 6000 fault calculations (under 15 minutes on a 450 Mhz PC).

(c) Make sure that the overreach of the forward pilot distance or directional overcurrent element is fully protected by the reverse pilot element of the relay at the opposite end of the line, for echo signal suppression.

Figure 9 shows the forward pilot reaches for line-line faults and Figure 10 shows similar reaches for single-line-ground faults around two loops, as follows:

Red Hills (at 0) to Sturgis (at 1) on circuit 1, and Sturgis to Red Hills (at 2) on circuit 2

Sturgis (at 0) to Red Hills (at 1) on circuit 1, and Red Hills to Sturgis (at 2) on circuit 2

The forward pilot zone (solid line) covers the protected line (from position 0 to 1) and part of the second half of the loop, from position 1 to 2. The reverse pilot zone (dashed line) sees faults only in the second half of the loop.

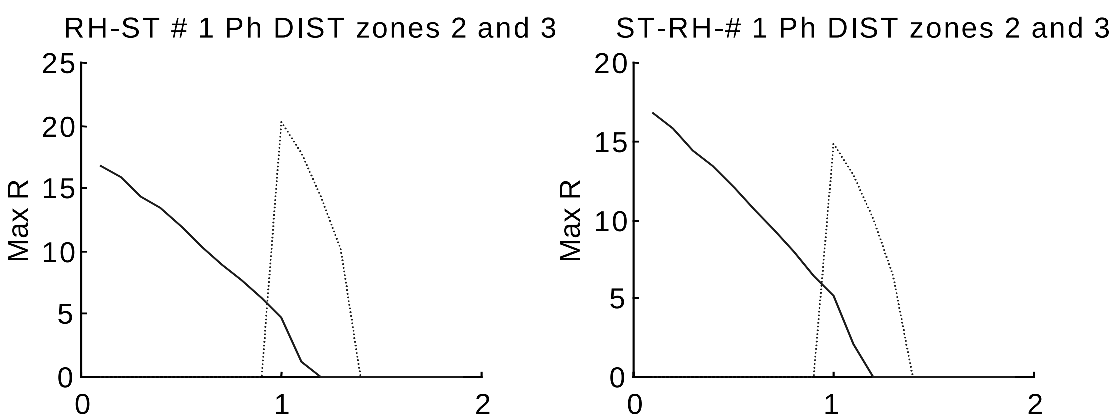


Figure 9 – Zone-2 forward reach and zone-3 reverse reach around loop for line-line faults.

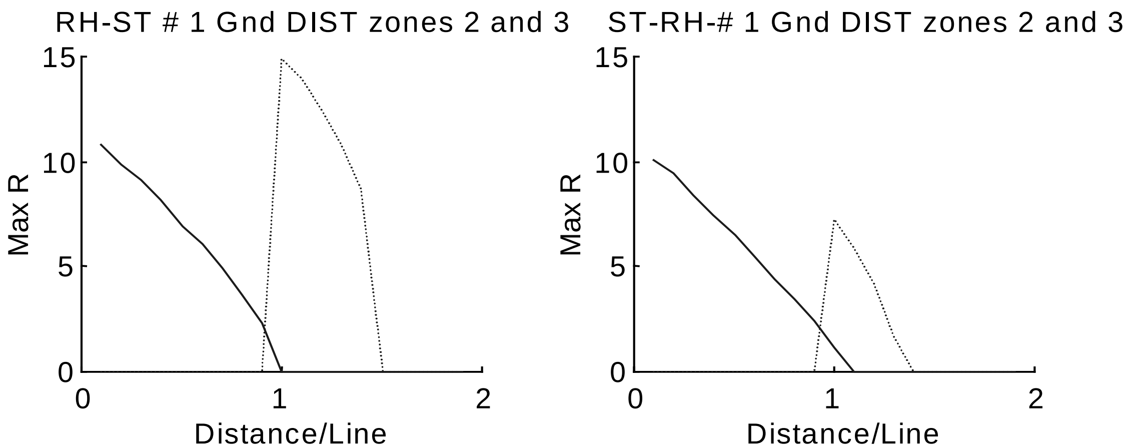


Figure 10 – Zone-2 forward reach and zone-3 reverse reach around loop for single-line-ground faults.

Table 2 summarizes the extra checking rules. If these tests produce warnings, the user must use judgment in finding a compromise setting.

Table 2

Summary of Extra Checking Rules

Distance zone 1	Reach margin < 0.8 for line-end solid faults on the protected line or on a coupled line.
Forward pilot zone and time-delayed distance zone 2	Reach margin > 1.2 for line-end solid faults. Reach margin < 0.8 for faults at downstream zone 1 limits with infeed branches outaged.
Time-delayed forward distance zone 3	Reach margin > 1.2 for solid faults at a depth of 2 buses.
Reverse distance pilot zone	Cover the overreach region of the forward pilot zone at the opposite end of the line. Plot the dynamic distance characteristics in the line-impedance plane.
Distance and overcurrent zones 1 and 2	Plot the largest detectable fault resistance for sliding faults on the protected line.
Directional overcurrent	Confirm that internal faults on the protected line are measured as forward at both ends, with coupled branches outaged or grounded. Confirm that external faults on coupled lines are measured as reverse at one or both ends of the protected line.

5. System Simulation

After setting the relay, the engineer can test its operation in the network. The stepped event simulation uses detailed phasor models of the relays, including the TOC curves and distance-element comparators, and accounts for the logic of multiple relays in the scheme. It verifies that the primary protection can successfully clear faults on the protected line, and that other relays will not operate unintentionally.

Figure 1 shows a close-in solid single-line fault at Sturgis for which the zone 2 ground distance element at Red Hills does not operate. The 67N2 pilot element at Red Hills trips on receiving the permissive signal. The following events are reproduced:

Event	Cycles from start	
Close-in fault at Sturgis	0.0	
Zones 1 and 2 assert at Sturgis	1.0	
161 kV breaker starts to open at Sturgis	1.0	
Transmission to Red Hills	1.0	
Signal received at Red Hills	1.2	
67N2 asserts at Red Hills	1.2	(includes 0.2 cycles for torque control element)
161 kV breaker starts to open at Red Hills	1.2	
Breaker opens at Sturgis	4.0	
Breaker opens at Red Hills	4.2	

The total time has about 0.5 cycle of random error, since the prefault voltage angle at the instant of the fault is unknown in a phasor model.

Figure 11 simulates a single-line fault with fault resistance of 6 ohms.

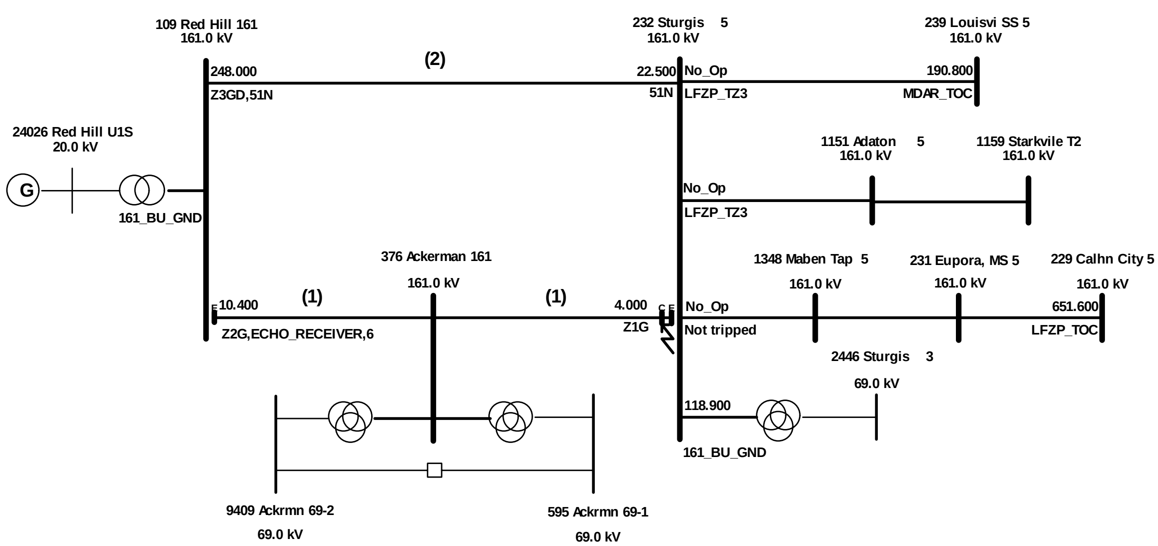


Figure 11 – Delayed tripping at Red Hills for 6-ohm ground fault. This fault is outside the reach of zone 2 at Red Hills until the breaker opens at Sturgis.

It has already been shown (Figure 8) that the zone 2 mho and IOC elements may both underreach in this case, so the pilot zone at Red Hills sees the fault only after the breaker has opened at Sturgis. The following events are reproduced:

Event	Cycles from start
Close-in fault at Sturgis	0.0
Zone 1 tripping at Sturgis	1.0
161 kV breaker opens at Sturgis	4.0
Zone 2 sequential tripping at Red Hills	5.0
Transmission to Sturgis	5.0
Signal received at Sturgis	5.2
Echo transmission to Red Hills	7.2
Echo received at Red Hills	7.4
161 kV breaker opens at Red Hills	10.4

In a systematic search for miscoordinations, the engineer can run many different faults [2]. A typical series of stepped-event simulations varies the fault resistance for close-in and midline single-line-ground faults on the protected line:

Protected line: local branch 232 376 circuit 1 to remote bus 109

Fault type	Location
Single-line-ground (SLG)	Close-in at 232
Single-line-ground	Close-in at 109
Single-line-ground	0.5 from 232 376 1 to 109
SLG - 2 Ohms	Close-in at 232
SLG - 2 Ohms	Close-in at 109
SLG - 2 Ohms	0.5 from 232 376 1 to 109
SLG - 6 Ohms	Close-in at 232
SLG - 6 Ohms	Close-in at 109
SLG - 6 Ohms	0.5 from 232 376 1 to 109
SLG - 10 Ohms	Close-in at 232
SLG - 10 Ohms	Close-in at 109
SLG - 10 Ohms	0.5 from 232 376 1 to 109
SLG - 20 Ohms	Close-in at 232
SLG - 20 Ohms	Close-in at 109
SLG - 20 Ohms	0.5 from 232 376 1 to 109
SLG - 40 Ohms	Close-in at 232
SLG - 40 Ohms	Close-in at 109
SLG - 40 Ohms	0.5 from 232 376 1 to 109

The simulation evaluates the time delay between the fastest primary and fastest backup local zones of protection, reports any miscoordinations or time intervals below the chosen minimum, and continues with the next fault. In this instance, all the faults can be cleared sequentially by the POTT scheme in 12 cycles. Without the pilot signals, tripping would occur after the zone 2 time delay or with the time-overcurrent elements.

6. Summary

Algorithms presented for a Permissive Overreach Transfer Trip scheme allow an engineer to set the overcurrent and distance elements and find the margins of secure operation automatically in a complex relay. The algorithms improve engineering productivity by checking and reporting a large number of cases systematically. A simulation verifies the overall protection scheme in the full network. Settings can be saved in the system database, which includes a library of relays with actual tap names and ranges. Approved settings can then be transferred to the relay electronically.

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