7SG18 Solkor N

Numeric Differential Protection

Document Release History

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Pre release

2010/02	Document reformat due to rebrand

Software Revision History

Contents

1 Introduction 4
2 General Information 5
2.1 Relay External Connections 5
2.2 Current Differential - Fixed or Optional Variable Settings 5
3 Current Transformer Requirements 5
3.1 Current Transformer Ratio Selection 5
3.2 Current Transformer Class/Rating 6
3.3 CT Formulae 7
4 Determining Current Transformer Requirements 9
4.1.1 Step 1 - Determine the Bias Break Point Setting 9
4.1.2 Step 2 - Determine the Fault Level and X/R Ratio of a Through Fault 9
4.1.3 Step 3 – Estimate of Total Resistance of the CT Secondary Circuit 10
4.1.4 Example CT Requirement - Solidly Earthed 10km 132kV Feeder 10
4.1.5 Fault Level and X/R for a Phase Through Fault 13
5 Fibre Optic Losses 14
6 Relay Functions & Settings 16
6.1 Current Differential Protection 16
6.2 Backup Over current and Earth Fault 18
6.3 Differential Guard Elements 18
6.4 Protection Signalling 18
6.5 Intertripping 18
6.6 Circuit Breaker Fail (CBF) Protection 19
6.7 User Defined Alarms 20
6.8 Trip Circuit Supervision 20
6.9 CT Supervision 20
6.10 Waveform, Fault and Event Records 20
6.11 Relay Settings Groups 21
6.12 Trip and Intertrip Tests 21
7 Differential Protection Settings For Feeder Circuits 21
7.1 Capacitive Charging Current – Cable and Hybrid Feeders 22
7.2 Plain Poly Phase Cable Feeders 24
7.3 Phase Segregated Single Phase Cable Feeders 24
7.4 Overhead Line Feeder 24
7.5 Earth Fault Sensitivity 24
7.5.1 Solid or Effective Neutral Earthing 25
7.5.2 High Impedance and Resistance Earthed Neutrals 25
7.5.3 Isolated (unearthed) and Reactance Earthing 31

Figures

Figure 1 – Relay Amplitude for CT Saturation for an external Phase Fault. 8
Figure 2 – Fault Level and X/R reducing with feeder length. 13
Figure 3 – Relay Magnitude and Phase Angle Comparators (Revision 4 and above) 17
Figure 4 – Earth Fault with load bias for Resistance Earthed System 26
Figure 5 – Setting of P/F Diff. Setting for Load Bias 27

Figure 6 – Setting of Bias Slope for Load Bias 27
Figure 7 – Settings for correct Load Bias 27
Figure 8 – Setting of Bias Break Point for Load Bias 28
Figure 9– 10% P/F Differential and Bias Break Point of 0.5, 1.0, 1.5 and 2.0. 29
Figure 10 – 15% Differential and Bias Break Point of 0.5, 1.0, 1.5 and 2.0. 29
Figure 11 – 20% Differential and Bias Break Point of 0.5, 1.0, 1.5 and 2.0. 30

REFERENCE MATERIAL

[1] – REYDISP EVOLUTION: is a PC based relay support package which allows local or remote access to relays for uploading and downloading settings, down loading waveform, event and fault records, reading real time instruments and plant control. This software is a MS Windows™ based package, and is compatible with Solkor N, Argus and Modular II Reyrolle numerical relays. This package is very useful tool for commissioning and setting relays, as it saves time. The use of Reydisp Evolution is covered in the communications section of this manual.

[2] – INFORMATIVE COMMUNICATIONS INTERFACE: is a report detailing all aspects of the IEC 870-5-103 communications protocol used by the Solkor N, Argus and Modular II products available from Siemens Protection Devices Limited. This manual is very useful when interfacing the relay protocol to the control system protocol for remote access and control.

[3] – REYROLLE COMMUNICATIONS MANUAL: is a report detailing the methods of how relays supplied by Siemens Protection Devices Ltd can be connected together to realise communications access to the relays. This report covers the configuration, type and interface equipment required for remote and local access.

1 Introduction

This relay is a numerical current differential relay providing unit protection of a cable or over head line feeder. It has all of the usual features of such a device such as remote communications, waveform and event recording.

It uses two concurrent phase and amplitude comparators on each of the three phases to detect internal faults. It can employ several common types of direct protection communications link.

- Several types of Direct Fibre Optic to 70km
- Multiplexed
- RS485 Four Wire Cable to 1.5km
- Screened Twisted Pair Pilotwire to 10km

The relays can be applied to the following circuit types:

- ➢ Two Terminal Cable Feeders.
- ➢ Two Terminal Overhead Line Feeders.
- ➢ Two Terminal Hybrid or Mixed Cable/Overhead line Feeders

The speed of operation is 30 to 40ms for normal feeder faults such as lightening strikes and cable sealing end flashovers. The operate time will suit applications for sub-transmission and distribution feeder protection. When the relay is set to 38.4K baud

The relay provides the following functions:

- ➢ Current Differential using independent phase angle and magnitude comparison for each phase current.
- ➢ IDMTL and DTL Backup Over Current and Earth Fault
- ➢ Differential Guard elements
- ➢ Protection Signal Channel Supervision
- ➢ External and Internal initiated Inter-tripping/Protection Signalling
- ➢ Trip Circuit Supervision
- ➢ CT Ratio Correction
- ➢ Circuit Breaker Fail
- ➢ CT Supervision
- ➢ User definable Alarms
- ➢ Communications for Remote Access of Relay Data via IEC-60870-5-103 or Modbus Protocols
- ➢ Waveform, Event and Maximum Demand Recording.

The typical end to end protection signalling length limitations, for direct connection between relays are indicated in the Performance Specification, for each type of the direct protection communication channel. A fibre optic loss budget calculation should be considered for any prospective application. An example is shown in this manual section.

One of the above types of communication medium must be specified at the time of order.

The Fibre Optic or RS485 type signal may also be multiplexed using a high speed MUX device.

The specification of the fibre optic and RS485 cable can be found in Section 4 – Communications Interface of this manual.
The communications output type may be changed easily, as the send and receive module can be removed from the case and changed.

The maximum length of the Cable Feeder that can be protected with a pilot wire type output is primarily dependant upon the pilot wire resistance and inter-core capacitance. A larger diameter pilot wire will allow greater feeder lengths to be covered. The Twisted pilots must have an earthed screen to limit any induced interference. The drop out pilot wire resistance and capacitance product is approximately 340,000 nano-Farad ohms. The limits for the communications range, as set out in the Section 4 Communications of this Technical Manual are based on approximately 250,000 nano-Farad ohms to allow for a safety margin for tolerances. An absolute limit on the length of pilot wire that may be used with the pilotwire modem is 300,000 nano-farad ohms.

The relay requires two pairs of screened conductors when used over pilotwires. Where conventional circulating protection using two or three wire connection is used, such as with Solkor A, B, R or Rf, the inter-tripping pilots may be utilised, this relay has a two internal, supervised, inter-trip channels.

2 General Information

2.1 Relay External Connections

The relay should be connected to a three-phase set of CT's at either end of the protected zone. Typical connections are shown in Figures 6 (Fibre Optic), Figure 7 (RS485 Cable) and Figure 8 (Screened Twisted Pair Metallic Pilotwire). These connections provide the facility to provide backup over current and earth fault protection, as well as current differential. Figure 8 details the CT connections for the relays at either end of the feeder. The Protection Signalling connection diagram for fibre optics, RS485 cable and Pilotwire interface can be found at the end of Section 4 – Communication Interface.

The auxiliary DC supply voltage of the relay must be specified at time of order. The user may choose from two power supplies. One is rated from 18 to 60V DC and is suitable for 24V, 30V, or 50 V systems. The other is rated from 88V to 280V DC, and is suitable for 110V or 220V systems. If ac voltage is used to power the relays, the instantaneous peak voltage must not exceed the maximum DC voltage, i.e. 60V for the first power supply and 280V for the other.

The rating of status inputs can be either 30V, 50V, 110V or 220V. Refer to Sections 2 – Performance Specification of this manual, for their range of operating voltage.

The relay is supplied with seven output contacts and either one or nine status inputs. The status inputs can be programmed to any of the relay elements. The output relays consist of 4 normally open and 3 change over contacts.

2.2 Current Differential - Fixed or Optional Variable Settings

The relay can be ordered in two variants, it can have fixed or variable differential settings.

If relays are ordered for the protection of plain feeder circuit current differential on medium voltage distribution networks, or where personnel are inexperienced in setting numerical differential protection, a fixed setting relay may be the most appropriate choice.

Generally the Variable Settings version affords more flexibility when applying the relay to a variety circuits. The circuits may vary in terms of length or type (overhead line, cable or hybrid). Where there is a mis-match of CT ratios or rating, the variable setting relay is also recommended. Eight settings groups are included in the variable setting relay. Relays can be converted from fixed to variable differential type if setting problems occur by software upgrade.

Refer to Section 3 - Relay Settings for the range of settings available. The variable setting version of the relay is supplied with the default settings as set out in Section 3.

3 Current Transformer Requirements

The two primary criteria to be met when specifying current transformers (C.T.) for use with the relay are C.T. ratio and kneepoint voltage. The CT connections and polarity are shown at the end of this section.

3.1 Current Transformer Ratio Selection

The first criterion is to select a CT ratio to step the primary rated current of the protected circuit down to approximately a relay nominal current of 1A or 5A. Ratios should be chosen to provide the relay with about rated current at full feeder rating. As a general comment, 1A secondary rated CT's are superior to 5A, for all types of protection relays, as they are less prone to saturation. Where possible 1A rated CT's are recommended, however the relay does have 1A and 5A rated CT terminals.

The relay settings can then be chosen to allow the use of sensitive settings. The relay can be connected with 1A rated CT's at one end and 5A rated CT's at the other end. CT ratio correction is provided in the range of 0.5 to 1.0 to cater for retrofit applications whereby the c.t. ratio at one end may have a different ratio to that at the other. This setting operates on the secondary level of current from the line CT's. The setting range of the CT ratio correction factor of 0.5 to 1.0 must be taken into account when considering protection of a circuit with different CT ratio's.

Example of Applying CT Ratio Correction

A feeder circuit rated at 600A and maximum anticipated load of 600A has a line CT ratio of 600/1 at one end and 800/5 at the other end. The ratio correction would be set to 600/800 = 0.75 on the relay connected to the 600/1 CT, and 800/800 = 1.0 on the other relay. Each relay has 1A and 5A inputs for connection to the C.T.'s, allowing for example 600/1A at one end of the feeder circuit and 800/5A at the other.

3.2 Current Transformer Class/Rating

The second criterion is the specification of the c.t. class/rating. The relay is a relatively sensitive biased current differential relay and therefore, to ensure stability for high values of through fault current (ie high multiples of the rated current) a class PX c.t. to IEC 60044 is recommended.

A class PX ensures a guaranteed turns ratio, maximum excitation current, minimum knee-point (or saturation) voltage and maximum secondary wiring resistance. With an appropriate design specification for ratio and class PX, the relay can be set sensitively without concern for false operation for a through fault.

The following formula for establishing a class PX knee-point voltage design is based on the relay settings for the fixed setting variant, (or the defaults of the variable setting models) and the settings are listed below. This c.t. specification is also suitable for any settings which are less sensitive than those listed.

The CT requirements may be altered by selection of any one of three relay Bias Break Point settings. A lower Bias Break Point setting will lower the CT requirements.

The following page contains formulae that may be used to select appropriate CT kneepoint voltages. The CT e.m.f. is chosen to allow the protection to be stable for the worst case through fault.

3.3 CT Formulae

The minimum kneepoint voltage of the CT's is dependant on the settings used:

With Bias Slope 2 = 150% and Bias Break Point = 2 x I_N

$$Vk = \left(0.6 + 0.05\frac{X}{R}\right) \times IFm \times Rs \quad for \quad \frac{X}{R} \leq 18$$

$$Vk = \left(1.5 + 0.3\left(\frac{X}{R} - 18\right)\right) \times IFm \times Rs \quad for \quad 18 < \frac{X}{R} \leq 25$$

$$Vk = \left(3.6 + 0.08\left(\frac{X}{R} - 25\right)\right) \times IFm \times Rs \quad for \quad \frac{X}{R} > 25$$

With Bias Slope 2 = 150% and Bias Break Point = 1 x I_N

$$Vk = 1 \times IFm \times Rs \quad for \quad \frac{X}{R} \leq 15$$

$$Vk = \left(1.0 + 0.13\left(\frac{X}{R} - 15\right)\right) \times IFm \times Rs \quad for \quad 15 < \frac{X}{R} \leq 30$$

$$Vk = \left(2.95 + 0.033\left(\frac{X}{R} - 30\right)\right) \times IFm \times Rs \quad for \quad \frac{X}{R} > 30$$

With Bias Slope 2 = 150% and Bias Break Point = 0.5 x I_N

$$Vk = 1 \times IFm \times Rs \quad for \quad \frac{X}{R} \leq 20$$

$$Vk = \left(1.0 + 0.135\left(\frac{X}{R} - 20\right)\right) \times IFm \times Rs \quad for \quad 20 < \frac{X}{R} \leq 30$$

$$Vk = \left(2.35 + 0.029\left(\frac{X}{R} - 30\right)\right) \times IFm \times Rs \quad for \quad \frac{X}{R} > 30$$

where,

V_k - is the knee point voltage of the CT defined as the point where a 10% increase in excitation voltage produces a 50% increase in magnetising or excitation current.
X/R - is the system reactance to resistance ratio for a three phase **through** fault on the protected feeder.
I_{FM} - is the **f**eeder **m**aximum primary three phase **through** fault current referred to the secondary side.
R_S - is the total resistive burden of the **s**econdary circuit, including CT secondary winding, relay phase input and lead loop resistance.

The above formulae include a minimum safety margin in excess of 120%. This may be utilised if the CT's calculated above are loo large to fit in the Circuit Breaker chamber. Therefore a 120% reduction may be made to the above minimum kneepoint requirements. This margin is present, as the above expressions were based on tests using the saturation e.m.f (Esat) level of the CT. As the kneepoint voltage (Vk) of the CT is a measurable constant, this was instead of Esat in the expression above. Esat is always at between 120% and 160% of the kneepoint voltage Vk and therefore reducing the Vk calculated above by up to 20% is valid.

The above expressions are derived from system conjunctive tests and power system simulations. The lower the Bias Break Point setting becomes the greater the level of saturation that may be tolerated as is shown in the following figure. This must be offset against fault sensitivity for load bias that may continue during an internal earth fault on resistance earthed power systems.

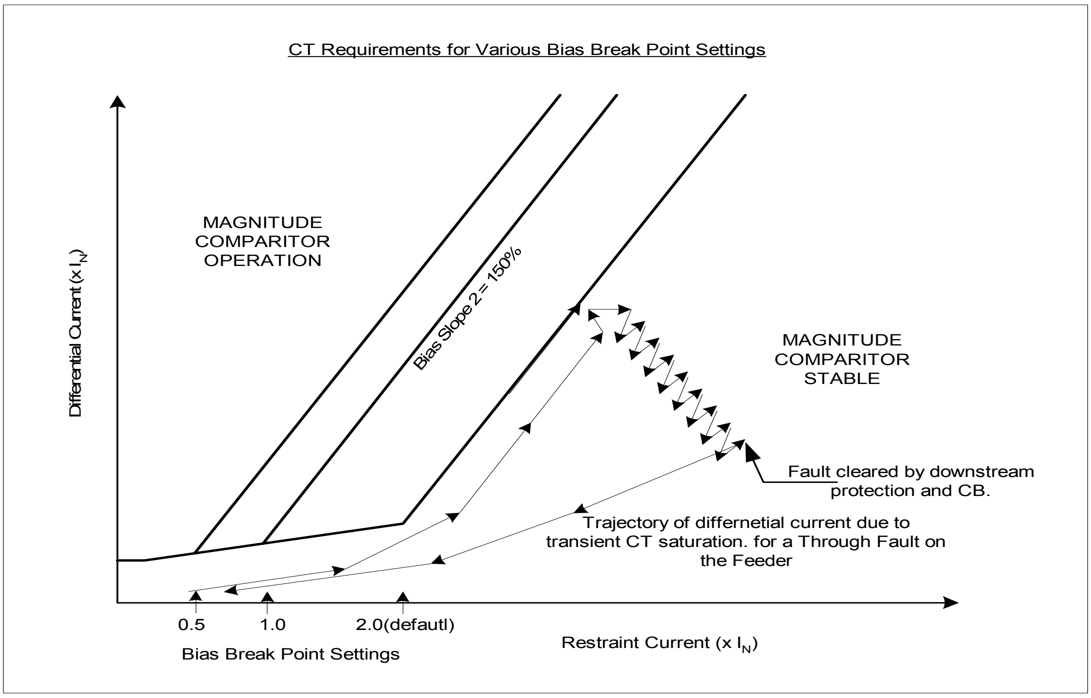


Figure 1 – Relay Amplitude for CT Saturation for an external Phase Fault.

The above demonstrates that decreasing the Bias Break Point (B_2) setting has the affect of lowering the Minimum CT requirements. The reduction in Bias Break Point setting must be balanced against making sure the relay will operate for load bias due to arc resistance and non-effectively earth systems for single end fed internal faults.

For example if the system was resistance earthed and an earth fault occurred on a cable at a very high load a Bias Break Point of 0.5 may not be suitable. A typical example for setting the relay with a resistance earthed power system is given later.

4 Determining Current Transformer Requirements

There are four parameters that must be established before the minimum CT kneepoint voltage can be specified for a particular circuit. This assumes the Bias Slope 2 setting is set to its default of 150%. For all applications of the relay this setting should be set to 150%.

- Bias Breakpoint Setting.
- Maximum Three Phase Fault Through Fault Level.
- X/R of the through Fault.
- Estimation of the total secondary resistance

The process of specifying the CT kneepoint voltage required is done in three steps:

4.1.1 Step 1 - Determine the Bias Break Point Setting

As discussed above the Bias Breakpoint setting is established by examining the earth fault sensitivity required to detect the minimum internal earth fault. The relay settings are selected so that the relay measures this fault to be in the operate region. This setting should be set as low as possible to lower CT requirements and add stability for through faults.

As a general guideline, cable feeders used on power systems with solidly earthed neutrals allow for lower Bias Breakpoint Setting of 0.5 to 1 x In to be selected. Cable and all overhead line feeders that are resistively earthed may require a setting of 1.0 to 2.0 xIn, in order to detect the minimum earth fault, as some load bias will also be measured during the fault. The Bias Break Point setting should therefore be set as low as possible, but should be set to attempt to allow tripping of the minimum earth fault on the feeder. This compromise between lowered CT requirements for through phase faults and detection of low level internal earth faults with load bias dictate the best setting to adopt.

4.1.2 Step 2 - Determine the Fault Level and X/R Ratio of a Through Fault

This maximum level for a three phase **through fault** can be calculated if the source and feeder primary resistance (R) and reactance (X) values are known. Sometimes only the source fault level at the busbars will be known. The system primary time constant can also be used to calculate the source X /R ratio, as the time constant (X/R) = 2π x f x L / R.

The maximum through fault and maximum X/R ratio cannot occur simultaneously as one counter acts the other. Therefore it is not technically sound to use both the circuit breaker breaking capacity and maximum system X/R simultaneously when calculating the CT requirements. If the source X/R is at a maximum the external fault level will tend towards a minimum.

System Voltage (kV)	Source - Transient Current Multiple(TCM) X/R x Fault Level (kA)
33 and Below	500
66	600
132	700
275	900
400	1000

The above TCM limits are the extremes taken from the system data contained in international power system standards. The above figures can be used for all circuits, except for circuits where the feeder protected by the relays is fed from a busbar source with several directly connected (i.e. no step up transformer) generators, such as at 11kV. In this case the source TCM may exceed the above limits, and such circuit will need careful consideration for the CT’s requirements.

For example at the 132kV busbar, the source X/R is considered to be 50 and the circuit breaker has a fault current breaking capacity of 40kA, this produces a TCM of 2000. This value is not practical for a through fault on any power system, so the practical maximum limit of 700 is imposed.

The maximum source fault level and X/R can then be calculated. The two cases are studied separately. The first considers the maximum source X/R and the second the maximum fault level.

Example

Case1 – Maximum Source X/R

The source fault level to use in the CT calculations = 700 / 50 = 14kA.

Therefore a check of each feeder should be done with an X/R of 50 and a fault level of 14kA.

Case 2 – Maximum Fault Level

The source X/R to use with the maximum source fault level = 700 / 40 = 17.5

The second case should be done with an X/R of 17.5 and a fault level of 40kA

For the above example the three phase fault level may be quoted in MVA instead of kA. In this case, the fault current can be calculated by using:

3Phase Fault MVA / (Rated Voltage Line Voltage x root 3)

System positive sequence impedance information is required in order to accurately estimate both values. Otherwise the Appendix 2 include in this Technical Manual can be used to estimate the values required. The calculation process needs to evaluate the following:

X/R used in CT equation = $(X_S + X_F) / (R_S + R_F)$

The source reactance (X_S) and resistance (R_S) will be fixed, but the feeder reactance (X_F) and resistance (R_F) will increase with the length of the circuit. This means the line impedance dominating the over all X/R for the external fault as the circuit length increases.

Several sources feeding the busbar will have the affect of magnifying the feeder impedance. For example four transformers feeding the busbar in parallel will have affect of keeping the source X/R (=X/4 / R/4) at around 40 to 50, but means the effect of the feeder impedance is magnified by a factor of 4, in dominating the overall X/R of the feeder external phase fault.

4.1.3 Step 3 – Estimate of Total Resistance of the CT Secondary Circuit

The lead loop resistance may be estimated by examining the cable run. For 2.5mm square multi-cores used with a one ampere secondary nominal rating, the resistance is approximately 7.4 ohms per km. For 4mm square multi-core the resistance is about 4.6 ohms per km. The CT secondary winding resistance and relay phase input burden should be added to this.

The relay burden is 0.05 ohms when using one ampere rated CT's and relay inputs.

The relay burden is 0.01 ohms when using one ampere rated CT's and relay inputs.

$\mathbf{R_S}$ = CT Secondary Winding Resistance + Relay Phase Input + Lead Loop Resistance

$\mathbf{R_S} = (R_{CT} + R_{PH} + R_{LL})$

4.1.4 Example CT Requirement - Solidly Earthed 10km 132kV Feeder

The cable feeder is 10 km in length and uses single core 630mm square cables. The 132kV power system is solidly earthed and has a minimum internal earth fault level of 15000 amperes and the cable circuit has a rating of 840 amperes. The CT ratio is chosen to be 1000/1A. Cables rated at 132kV have earthed sheaths and are cross bonded. All internal feeder faults will therefore be earth faults.

As shown later the P/F Differential setting should be chosen so that the minimum internal earth fault level is detected. Where the power system is non-effectively earthed such as resistance or reactance type earthing, the load current will continue during the fault. The load current will have an effective of biasing the relay towards stability. Setting the differential protection for non-effectively earthed systems is covered in 5.5.2.

In this case, as the system is solidly earthed, and the cables are cross bonded to earth at each substation and cable joint all internal earth faults will be large. The fault current will almost exclusively return to the source via the cable sheathed, which will cancel most of the induction effect of the fault current.

The minimum earth fault level is estimated to be not less than 15,000 amperes, are the minimum setting of 0.5 x I_N can be chosen. This level of earth fault will always produce a large differential current and a fast and definite relay operation. If the circuit were resistance or reactance earthed a higher setting would be required.

Differential Current = 15000/1000A = 15 x I_N, Bias Current = (15 + 0) / 2 = 7.5 x I_N. This fault would appear in the operate region of the bias characteristic at a percentage slope of approximately 200%.

If we assume the total secondary resistance is 5 ohms, then the Vk requirement can be established.

The cable feeder is fed from a busbar with a three phase fault level of 40kA and a maximum X/R of 50. As explained earlier these two extremes cannot occur together as they would compromise the circuit breaker breaking capacity. The above Transient Current Multiples are used to limit the parameters used to practical maximum values. The maximum TCM of 700 is applied to 132kV systems. The parameters to use for each of the two cases were calculated previously to be:

Case 1 – CT required with a maximum X/R of 50 and a fault level of 14kA.

Case 2 – CT required with a maximum fault level of 40kA and an X/R of 17.5.

The CT's are 1000/1A and have a secondary winding resistance of 4 ohms. The lead loop resistance (R_{LL}), CT secondary winding resistance and relay phase input resistance of 0.05 oms, must be added together to find the total circuit resistance of the secondary circuit (R_S).

The cable has a characteristic impedance of X = -j 0.1277 ohms per km, and R = 0.039 ohms per km. The charging current for this type of cable is 8 amperes per km.

Example calculation

Case 1: Source X/R=50 FL=14kA | **Case 2: Source X/R=17.5 FL=40kA**

I_F = 14kA, X/R=50	**I_F=40kA, X/R=17.5**
Z_S = 132,000 / (√3 x 14,000) = 5.443 ohms.	Z_S = 132,000 / (√3 x 40,000) = 1.905 ohms.

As the busbar X/R is known for both cases the X and R components of the source impedance may be found.

X_S=Cos(Tan^{-1}(1/X/R))xZ_S=-j5.442 ohms	X_S=Cos(Tan^{-1}(1/X/R))xZ_S=-j1.9046 ohms
R_S=Sin(Tan^{-1}(1/X/R))xZ_S=0.109 ohms	R_S=Sin(Tan^{-1}(1/X/R))xZ_S = 0.0381 ohms
Cable Impedance = 0.39 – j1.277 ohms	Cable Impedance = 0.39 – j1.277 ohms
Total Impedance = 0.499 – j6.719ohms	Total Impedance = 0.4281 – j3.1816 ohms
The X/R for external fault = 13.46	The X/R for external fault = 8.91
Z_T = √(0.499^2 + 6.719^2) = 6.737ohms	Z_T = √(0.4281^2 + 3.1816^2) = 3.210 ohms
External Fault Level = 132kV / (root 3 x Z_T) = 11,312 A	External Fault Level = 132kV / (root 3 x Z_T) = 23,741 A

Both Cases should be considered when arriving at the CT minimum e.m.f. requirements

The X/R= ranges from 8.91 to 13.46. The through fault level ranges from 11.312 to 23.741A.

As the bias break point is being set to 0.5 xIN the following CT formula is applicable:

$$Vk = 1 \times IFm \times Rs \qquad for \quad \frac{X}{R} \leq 20$$

CT Requirements:

Case 1: Source X/R=50 FL=14kA	**Case 2: Source X/R=17.5 FL=40kA**
Vk ≥ 1 x 11312/1000 x (R_{LL} + R_{PH} + R_{CT})	Vk ≥ 1 x 23741/1000 x (R_{LL} + R_{PH} + R_{CT})

From the above, Case 2 requirements are more onerous and should be use to calculate the Vk minimum required.

CT's for Substation A:	**CT's for Substation B:**
Vk ≥ 1 x 23741/1000 x (1.95+0.05+5)	Vk ≥ 1 x 23741/1000 x (3.5+0.05+5)
Vk ≥ 167 volts	Vk ≥ 203 volts

The above figures are recommended for the relay, however the safety margin of 20% may be used if CT core size makes fitting the CT into the switchgear chamber difficult. In the above example the absolute lower limits would be:

Vk ≥ 167 / 1.2 = 140 volts | Vk ≥ 203 / 1.2 = 170 volts

This 20% reduction is attributable to the fact the CT formulae were based on the saturation emf (e_{sat}). The e_{sat} of a CT is always ≥ 120 % of the CT kneepoint voltage. The relay would still remain stable for these CT kneepoint voltages as there are other safety margins built into the formulae.

These additional safety margins are:

- The CT requirements was based on three phase fault levels, therefore only the single core run between the relay and CT needed to be considered as the lead burden. The formulae used included the full lead loop resistance.

- The CT core was induced with a one Tesla of remnant flux prior to the fault being applied.
- The fault inception point was set at zero degrees, which produces the largest dc offset in the primary fault current and the highest dc transient flux requirement in the CT core. Most short circuit faults occur at between fourty-five and ninety degrees.

On solidly earthed systems the earth fault level can exceed the phase fault level by up to a factor of 1.2. However the X/R of the earth fault will always be less than the three phase fault as the return path via the earth/sheath is mainly resistive. This will reduce any dc offsets in the primary fault current for an earth fault. It is therefore it is sufficient to consider three phase faults only.

The above figures demonstrate the feeder impedance reduces the CT minimum requirements as the feeder length increases. The Feeder reactance and resistance will become more dominant as the feeder length increases. This is shown graphically for the 132kV cable feeder used in the example.

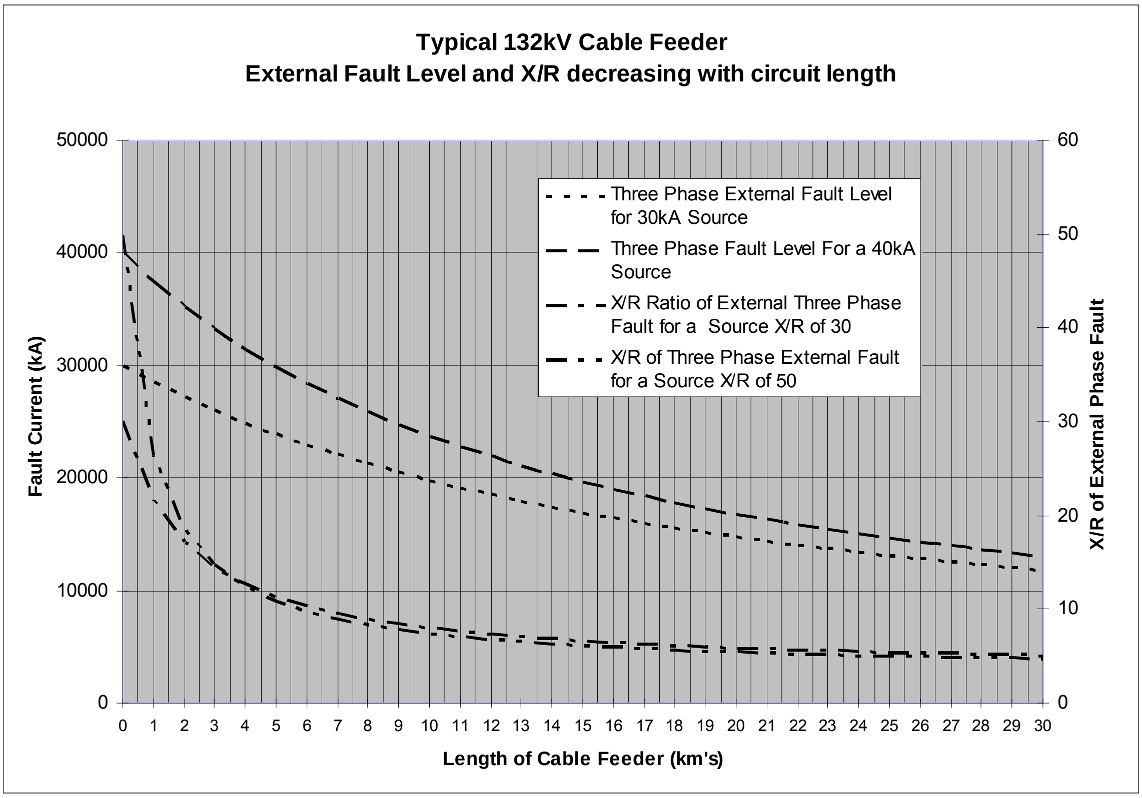


Figure 2 – Fault Level and X/R reducing with feeder length.

The above shows the X/R ratio of feeder through fault current is less than half the source X/R when the cable exceeds only 3km's in length. The fault level also reduces with increasing length and may allow the use of an instantaneous high set over current element for longer feeders. This may be set to provide fast tripping for close up faults, if say a flexible earth clamp was inadvertently left connected when the circuit is energised.

4.1.5 Fault Level and X/R for a Phase Through Fault

Combinations of X/R and Fault level will rarely exceed a maximum of 1000 on any power system. This is because a high X/R will tend to reduce the fault level. System X/R and fault level therefore have an inverse relationship. In the above example the source reactance (Xs) and resistance (Rs) are calculated and additional feeder reactance (X_F) and resistance (R_F) are added as the feeder length increases, to arrive at the profile shown above.

Therefore using the Maximum Breaking capacity of the CB and maximum system X/R together is not technically valid as the both of these values cannot occur at the same time. If one of these parameters is at a maximum the other tends towards its minimum value. This is why a limit is imposed on the product of these two parameters. These limits are the maximum practical case possible.

The circuit type also affects the CT requirements. Cables have much lower X/R ratios than over head lines and therefore tend to dominate as feeder length increases.

Cables in particular will reduce the through fault X/R ratio, as they have small X/R ratios in the 5 to 0.3 range. Higher voltage single phase cables tending towards the higher figure and lower voltage trifoil cable tend towards the lower end of this range. If the cable feeder is longer than a few miles then it is fairly safe to use the X/R of the cable. Using more then one cable per phase will of course reduce this affect and increase charging current. In all cases it is better to calculate the X/R and fault level of the through fault if the data is available. Where multiple sources are present to feed the fault this has a magnifying affect in reducing the overall X/R of the external fault as the feeder circuit impedance will dominate.

A spreadsheet is available to allow easy calculation of the CT kneepoint voltage required for a particular application of the relay.

5 Fibre Optic Losses

The main factors limiting transmission distances with fibre-optics are:

- Transmitter launch power
- Attenuation, based on light frequency, fibre material and fibre diameter
- Number of intermediate connectors and splices
- Receiver sensitivity

The light power at the receiver must be above the sensitivity of the receiver in order that effective communication can occur.

The sensitivity of the fibre optic receiver is -30dB.

The launch power of the fibre optic transmitter is as follows:

Relay Type	Fibre Type	Launch Power
Long Range device	Single-mode fibre	-10dB
Long Range device	Multi-mode fibre	-7dB
Short Range device	Multi-mode fibre	-10dB

Typical attenuation for 1300nm:

Fibre Type	Loss (dB/km)
9μm Single mode Glass	0.3
62.5μm Multi-mode Glass	1.2

Consult fibre manufacturers data for actual values

Fibre cables are supplied on reels of finite length which may necessitate additional jointing. Jointing losses should be allowed for to suit this limitation, for example one additional splice every 4km.

Typical losses at connectors are 0.5-1.0dB each. This allows for normal age related deterioration. Consult manufacturers data for actual values

Typical Splice losses are <0.3dB.

A 3dB safety margin is usually allowed after the budget calculation is performed.

Individual applications should be assessed using actual manufacturers data.

Following installation the actual losses should be measured for each fibre using a calibrated light source and meter and the measured values compared to the calculated estimate before the relay is applied.

The following table can be used to record budget calculations:

A Launch power

dB

B Fibre Type

C Loss (dB/km)

dB/km

D	Length	km
E	Total fibre loss (CxD)	dB
F	No. of Splices	
G	Loss at each splice	dB
H	Total loss at splices (FxG)	dB
I	No. of connectors	
J	Loss per connector	dB
K	Total loss at connectors (IxJ)	dB
L	Total losses (E+H+K)	dB
M	Receive power budget (A-L)	dB
N	Safety Margin	dB
O	Device Receive Sensitivity	dB

6 Relay Functions & Settings

6.1 Current Differential Protection

The current differential elements have separate phase angle and current magnitude comparators. The current differential magnitude comparator has four settings; P/F differential (I_S), Bias Slope 1 (S_1), Bias Break Point (B_2) and Bias Slope 2 (S_2). The relay operates by comparing the magnitude and phase of the local and remote relay currents. The characteristics and equations are shown in Figure 3. The differential algorithm is phase segregated and will produce a trip for the operation of any of the three phase differential elements.

It is imperative that the relay differential settings and software revisions are identical for each pair of relays protecting a feeder at all times. The Software Revision can be checked by pressing and holding the [TEST/RESET] and [CANCEL] pushbutton simultaneously, when the relay displaying its identifier at the top of the menu structure. The Software Revision number installed is scrolled across the LCD.

Advice on setting the differential elements for various types of circuits and earthing methods are covered later. But a summary of the technical aspects to consider is listed.

P/F Differential - this setting defines the minimum sensitivity of the internal fault that the protection can detect. This setting also defines the bias current that the phase angle comparator becomes active. The phase angle comparator is active when the bias current measured by a pair of relay is greater than half of this setting. A lower setting can normally be used on. The feeder charging current must be assessed when defining the lowest setting that could be applied to a feeder.

Bias Slope 1- this is used to allow the relay to detect lower level internal earth faults. It will generally be selected to 20% for resistance earthed power systems and 30% for solidly earthed power systems.

Bias Slope 2 – this setting is used to accommodate some saturation of the CT's caused by through phase faults on the feeder. This setting should always be selected to 150%.

Bias Break Point – this setting as a multiple of rated current, defines where Slope 1 ends and Slope 2 begins. This setting is critical as it defines the CT formula to use and the ability of the relay to detect earth faults on resistance earthed networks. A lower setting makes the relay more stable for through faults but may compromise earth fault detection. Non-effectively earthed power systems will tend to require a higher setting than solidly earthed power systems, as some load will tend to continue to flow during the earthed. This will provide extra bias to the relays and shift the fault point towards a more stable position.

The following page illustrates the relay differential characteristics and settings.

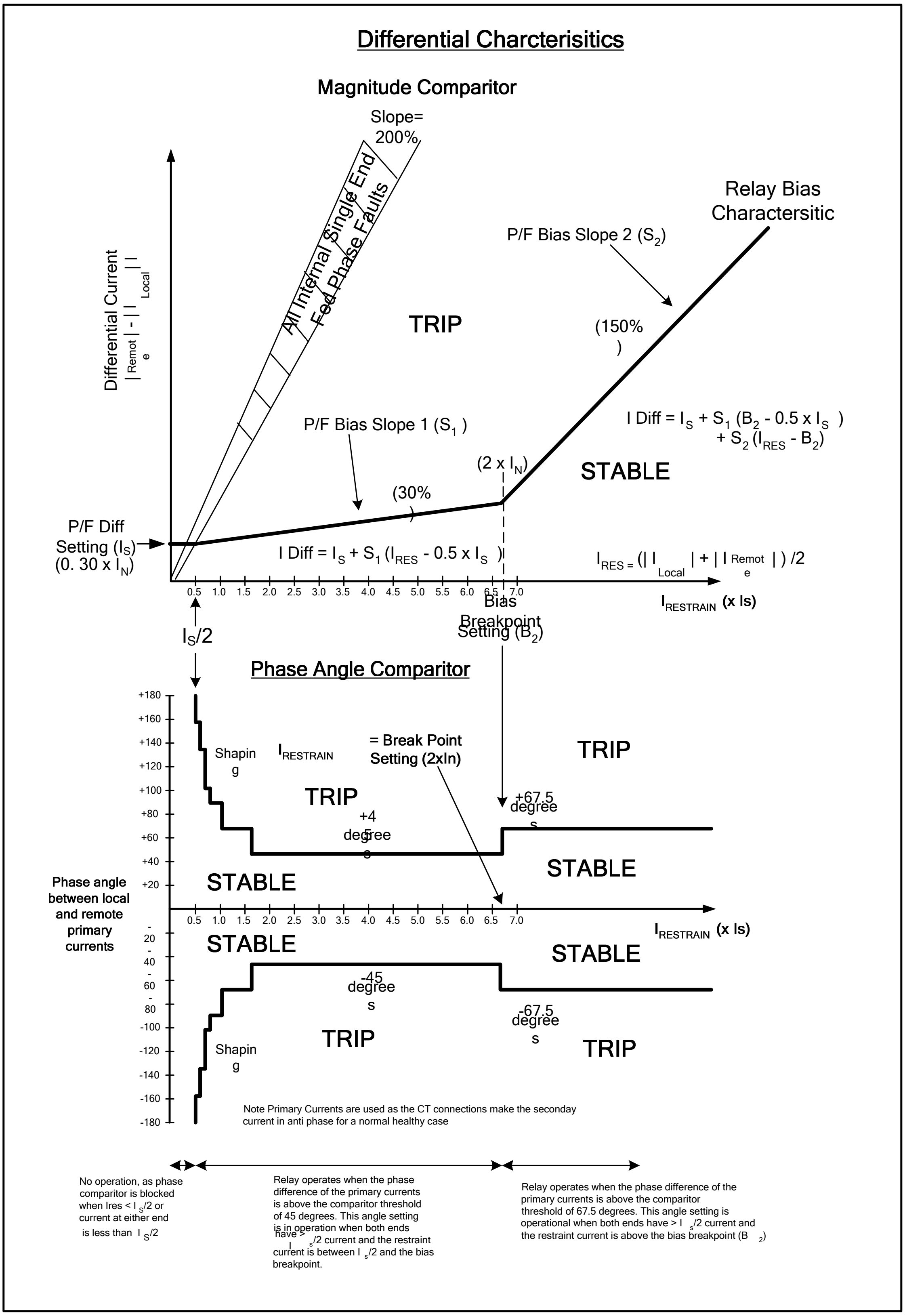


Figure 3 – Relay Magnitude and Phase Angle Comparators (Revision 4 and above)

6.2 Backup Over current and Earth Fault

The relay provides one IDMTL (inverse definite minimum time lag) inverse curve and three instantaneous or DTL (definite time lag) elements, for both phase and earth faults. The DTL elements are named Highset 1, Highset 2 and Lowset in the relay OC PROTECTION menu. The P/F or E/F Characteristic settings can be selected to Normal inverse, long-time inverse, extremely inverse and very inverse IDMTL curves or to DTL.

Any of these elements can be set to be in service permanently, or only when the end to end protection signal becomes corrupted, i.e. when differential protection is no longer possible. To use any of the elements in this way, scroll down to the Status Input menu and select the element required to be inhibited by the signal healthy. The elements can be inhibited by any of the status inputs, plus the virtual input of the state of signal healthy (SIG) seen on the relay display screen at the end of the binary string. Setting the SIG input to ‘1’ means the element is inhibited by a healthy signal.

These elements can be set and used as guard relays for the differential protection, ie the differential protection will only operate and trip when the local relay current exceeds the guard element setting(s).

The IDMTL/DTL elements can be set to grade with relays or fuses up and down-stream of the protected feeder. In most applications, the selection of relay IDMTL characteristics will be dictated by the type of curve used on the over current and earth fault protection relays on the source and load side of this relay. Usually normal inverse curves are selected for grading between relays. Extremely Inverse curves type C to IEC 255 are often used on H.V. transformer circuits, since this type of curve grades with L.V. fuses or moulded case circuit breakers. The setting applied to the earth fault elements must consider residual current caused by charging current under normal load and under fault conditions.

6.3 Differential Guard Elements

When overcurrent and earth fault elements are allocated as a “guard” to the differential elements, the feeder current must exceed the guard level(s) before a differential trip is allowed. Other relay functions such as inter-trip, status inputs, circuit breaker fail may be used as differential guard relays. The guard elements are allocated in the O/P RELAY CONFIG menu. Setting the virtual relay output GPF (guard phase fault differential) to 1 in the output setting string enables the guard feature.

The differential elements are automatically blocked if a protection signaling disturbance occurs; i.e. a discrete guard element does not have to be set to ensure stability.

6.4 Protection Signalling

The relay provides two separate external signalling channels. These can be used for externally initiated inter-tripping or for signalling from another protection, such as a permissive or blocking signal required by distance protection schemes. The use of this differential protection with a distance relay is a cost-effective method of protecting a circuit. It provides dual main protections (operating on different principles and hardware), inter-tripping, signalling and backup over current protection.

The protection/intertrip signal is initiated by a contact on the external device, wired to energise one or more of the status inputs. The operating time is approximately 50ms from energising the local relay status input to closing the output contact of the remote relay. The reset time is approximately 45ms.

6.5 Intertripping

Provision for both Internally and Externally initiated intertripping is included in the relay. The relay is provided with an intertrip LED to signal the operation of this function. The intertrip LED on the receive relay, is always illuminated, for both external and internal type intertrips. The relay at the send end, only illuminates its own intertrip LED flag, if the intertrip is initiated from its own protection elements, i.e. it is an internal intertrip. This assists in determining where the external intertrip was originated. The internal and external intertripping can be enabled or disabled in the DIFF. PROTECTION MENU. Either type of inter-tripping can be selected to ON or OFF in this menu.

a) Externally Initiated Intertipping

The external inter-tripping can be initiated by energising a relay Status Input. The status input(s) used for this purpose, must be assigned as External Intertrips (iTrip1&2) in the STATUS CONFIG setting menu. The output relay(s) assigned to trip the circuit breaker, of the remote end relay must be allocated in the [Remote Ext. itrip1&2]

of the O/P RELAY CONFIG menu. The operate time of the external intertrip, from energising the status input to closure of the remote output contact, is 50ms, ie if no pickup delay is applied to the status input. As mentioned previously, **the external intertrip must be selected to ON** in the DIFF. PROTECTION relay menu.

b) Internally Initiated Intertripping
The Internal inter-tripping may be used when over current and earth fault elements are used as guard relays and fault current can only be fed from one end of the feeder. The differential element of the relay at the end of the feeder with no fault infeed will not trip, as the guard element(s) will prevent operation. The relay sensing fault current will trip on differential, as the guard levels will be exceeded. This relay can send an internal inter-trip signal to the other relay and force a trip of the other relay.

The internal inter-trip must be set to ON in the DIFF. PROTECTION relay menu, and trip outputs allocated.

6.6 Circuit Breaker Fail (CBF) Protection

This type of protection function is designed to ensure a fault current is cleared even if the local circuit breaker fails to trip and remove the fault. For this reason it is also called local backup protection.

The CBF function may use either internal protection elements or external relay outputs to initiate the circuit breaker fail logic.

Internally Initiated CBF

The relay incorporates an internal two-stage circuit breaker fail feature. The sequence of the internal CBF logic is as follows.

An internal protection element picks up and operates its output contact(s) to trip the circuit breaker. If the circuit breaker fails to open, the protection algorithm pickup and the output contact closure will both continue for as long as the fault current continues to flow. The output relay(s) closure and pickup of the protection algorithm are both monitored. The output contacts used to trigger the internal CBF logic **MUST** be allocated as Fault Triggers in the DATA STORAGE menu. This is necessary to differentiate the use of output contacts used for alarms and trips.

Additionally the relay has over current and earth fault CBF level detectors that may be used to give additional security to the CBF scheme. If the level detectors are required both must be set. If one or both the CB Fail detectors are set to OFF the additional level detector check is not implemented.

The level detectors are triggered by three conditions:

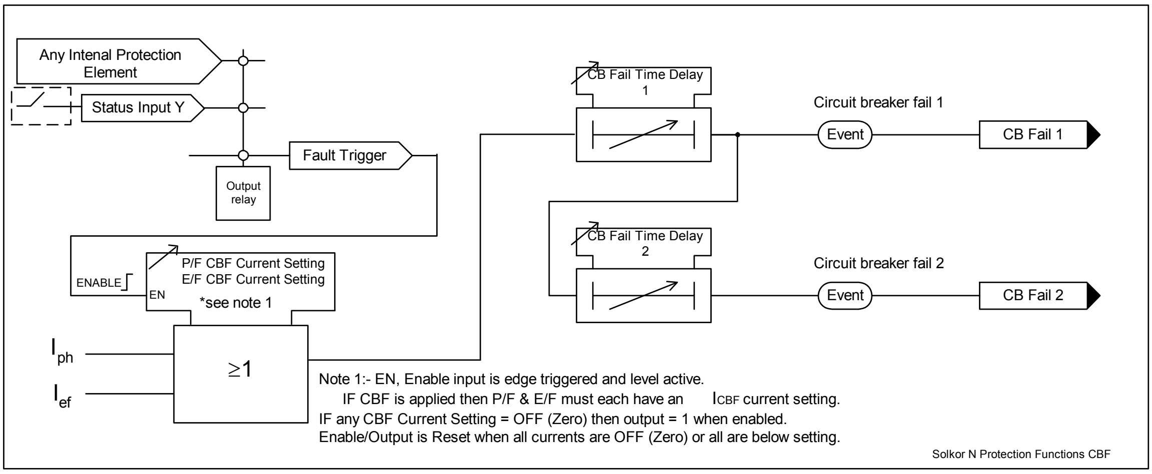
Protection element timing out
An output allocated as a Fault Trigger has operated
The pick up level of one the CBF level detectors is exceeded.

This combination of a relay algorithm that has not reset following an output contact closure and optionally the level detector being exceeded will start the definite time lag feature designated “CB Fail 1”. This function can be programmed to energise an output relay when the CB Fail 1 time delay has elapsed.

The contacts of CB Fail 1 element can be employed to energise a second trip coil on the feeder circuit breaker or to trip another circuit breaker - typically an incoming breaker. The timing out of the CB Fail 1 timer starts a second time lag feature designated “CB Fail 2”. If the trip outputs already initiated do not stop the current flow through the relay, another output relay can be programmed in the output matrix to trip a further breaker e.g. a bus section circuit breaker. The timers should be set to operate in 50ms plus the longest C.B. tripping time. The 50ms time allows for operating and reset times of the internal relay elements. The circuit breaker fail feature can also be used to implement multi-stage tripping.

Externally Initiated CBF
A conventional circuit breaker fail relay is usually initiated by main protection trip relay(s). CB Fail current detectors monitor if fault current is removed and allow the CBF timer(s) to run. When these timer(s) have expired the scheme will initiate repeat and/or back tripping. This relay can be employed to provide the c.b. fail function in this manner by employing a status input, initiated by an external trip output. This status input is mapped to operate an output relay. This output relay must also be allocated as a “Fault Trigger”.

Two stage timing via dedicated output contacts can then be employed for repeat or back tripping as required. The CB Fail logic is shown in the diagram below.



6.7 User Defined Alarms

These alarms allow flagging of the operation of external protection on the relay LCD display. The waveform recording of the relay can also be triggered.
For example, operation of a cable low oil pressure detector could be wired to a status input of the relay. This could be used to display “Low Cable Oil Pressure” alarm on the relay lcd display.

This is programmed into the relay by assigning a relay Status Input as Alarm 1, in the STATUS CONFIG menu and naming Set Alarm 1 as “Low Cable Oil Pressure”, in the SYSTEM CONFIG menu.

If the external device is initiated by a fault and trips the feeder (eg Bucholz protection on an in-zone power transformer), the status input can also be programmed to initiate the waveform storage to assess if fault current was flowing.

6.8 Trip Circuit Supervision

The relay provides trip circuit supervision for up to nine trip circuits. The trip circuit supervision scheme is implemented using the relay status inputs. The status input is held energised and monitors the continuity of current through the input. The supervision is in service with the circuit breaker in the open and closed positions. Figure 5 at the back of this Section shows how the scheme is connected. The relay displays ‘Trip Cct Fail’ on it’s LCD when a trip circuit becomes unhealthy.

To be compliant with the ESI48-4 ESI1 Trip Circuit Supervision standard a 30 or 48V rated input must be used with an external dropper resistor.

6.9 CT Supervision

The relay provides supervision of the CT’s connected to the relay. It is used to produce an alarm if the connection between relay and one or more CT’s is broken. The function does not block operation of the differential protection. If the load level is above the relay P/F Differential Setting, when the CT wiring becomes open circuit, then the relay will still trip.

The feeder circuit must be loaded for the CT supervision element to operate. The CT Supervision element must have a time delay applied to allow external faults to be cleared before the CT supervision times out. A typical setting would be 0.1 x I_N and 5 to 10 seconds time delay.

The function will give an alarm after the set time delay if the current measured on one or two phases falls below the setting whilst at least one other phase remains above the setting, and remains so for the set time delay. This function may be disabled by applying a setting of OFF.

Where single pole reclosing is applied either the function must be set to OFF or the time delay set longer than the longest dead time plus a margin.

6.10 Waveform, Fault and Event Records

The relay has three types of information provided to help investigate relay operation. The waveform recorder is an oscillograph of a.c. current waveforms, r.m.s. values of local and remote currents, state of differential elements and state of status input and output relays. The waveform recorder displays both local and remote currents to determine differential operation.

The sine waves shown by the Waveform Records are instantaneous samples, i.e. the peak level of current. The relay uses the r.m.s. value of current to determine operation. The r.m.s. value of current, may be estimated from the peak value by dividing the peak value on a sine wave by √2. The waveform recorder, can be configured to be automatically triggered by operation of starter elements, differential, over current and earth fault, inter-trip, and signal unhealthy (ST+DF+OC+iTp+SIG) in the DATA STORAGE - Waveform Trigger menu. The waveform can be set with a pre-trigger, to capture the fault currents before the relay trip occurred.

The waveform recorder can be triggered from a relay status input or from Reydisp Evolution. This can be used to trigger a hard copy of the commissioning tests carried out. The waveforms can be printed out and used to form part of the Commissioning Test Report.

The Fault Recorder is used to display operation of any of the relay elements on the front of the relay via the LCD. The fault record is scrolled across the LCD, and displays the pickup value and the elements that have operated. To trigger the fault recorder the Fault Trigger output relays must be set and the Waveform Trigger must be set. For example, if an over current element is meant to trigger the Fault Recorder and is allocated to use output relay 2 (RL2), the Waveform Trigger Menu must include OC and the relay 2 must be allocated as a Fault Trigger in the DATA storage menu.

The Event Records is a list of time stamped pick-up, drop-off and operation status of the relay algorithms. This is particularly useful, in determining the sequence of events that led to a relay operation, and the cause of the trip. It does not have to be set as it continuously records any events. Five hundred events are recorded with a time stamped accuracy of 1ms.

6.11 Relay Settings Groups

The variable settings version of the relay has eight Settings Groups. The fixed setting relay does not have settings groups.

The active Settings Group can be changed manually via the front pushbuttons, Reydisp Evolution, or remotely via the relay communications. It can also be changed automatically by energising a relay status input. Care must be taken to ensure the differential elements are stable if settings at either end are different. Advice can be provided on request, if an application requires this feature to be used.

6.12 Trip and Intertrip Tests

The settings in the CB maintenance menu can be used to do trip and intertrip tests.

The trip test allows the local circuit breaker to be tested and the intertrip test allows the remote CB to be tested. The settings to do these tests are found in the CB maintenance menu. The trip test has a ten second delay before closure of the selected trip contacts to allow personnel to vacate the vicinity of the circuit breaker.

7 Differential Protection Settings For Feeder Circuits

The relay was developed to provide protection for two ended sub-transmission and distribution feeders. The relay combines current differential feeder protection with back-up over current and earth fault protection suitable for these feeders. The fibre optic, RS485 and twisted pair pilotwire connections to the relay are shown in figures 6, 7 and 8. The relay is only suitable for two ended feeders.

There are various primary circuit types each requiring specific considerations.

These include:

- Plain poly-phase Tri-foil cable Feeders.
- Phase segregated, single phase cables Feeders.
- Overhead line feeders.
- A Feeder with a mixture of the above.

Each of these configurations is discussed below.

Special consideration is also given to earth fault protection provided by the relay for different network designs with respect to the method of grounding. The feeder charging current will have the most impact on the minimum differential setting that may be chosen.

7.1 Capacitive Charging Current – Cable and Hybrid Feeders

Significant Charging currents are to be expected on cable or hybrid (a mix of cable and over head line) feeder circuits. Pure overhead line feeders will not have significant charging currents and will not generally affect the lowest differential setting that may be chosen. The cable charging current will increase linearly with circuit length. The capacitive charging current is at leading power factor to the feeder load current and has the affect of causing a phase and magnitude difference to arise between the current measured at each end of the feeder. This normal steady state difference in currents will have an impact on the minimum differential settings that may be used.

The relay must be set with a P/F Differential setting that must be minimum multiple of the steady state charging current. The steady state charging current may be calculated from the cable data and the circuit length. This multiple of charging current is necessary to accommodate transient charging current, steady state charging current and rises in phase to neutral voltages during system faults. As the relay design was developed an effort was made to improve the relay sensitivity to allow resistive earth faults to be detected. Later releases of code allowed lower differential settings to be used.

The phase angle comparator was altered in Release 4 of the relay code. This was done to allow the relay differential protection to be set to improve sensitivity by allowing the relay to be set to a lower multiple of steady state charging current. This enhancement also improves relay stability for lightly loaded circuits.

The minimum initial setting that can be selected on the relay depends upon the revision of software installed on the relay. Revision 3 or earlier requires the following minimum sensitivities to be selected:

The recommended figures are in terms of a multiple of the steady state feeder charging current (Ic).

Minimum P/F Differential Setting recommended for Relays with Revision 1 to 3 code(prior to July 2004):

Feeder Type and System Earth Method	Pure Cable Feeder	Hybrid Feeder (OHL+Cable)	Pure OHL Feeder
Solidly Earthed	8 x Ic	14 x Ic	14 x Ic
Resistance Earthed	14 x Ic	14 x Ic	14 x Ic
Reactance Earthed	14 x Ic	14 x Ic	14 x Ic
Isolated	14 x Ic	14 x Ic	14 x Ic

Revision code 4 or later allows the relay to be set more sensitively as the comparison of the tables above and below demonstrate.

Minimum P/F Differential Setting recommended for Revision 4 (released July 2004) code with or later are:

Feeder Type and System Earth Method	Pure Cable Feeder	Hybrid Feeder (OHL+Cable)	Pure OHL Feeder
Solidly Earthed	2.5 x Ic	4 x Ic	4 x Ic
Resistance Earthed	4 x Ic	4 x Ic	4 x Ic
Reactance Earthed	5 x Ic	5 x Ic	5 x Ic
Isolated	5 x Ic	5 x Ic	5 x Ic

A significant transient charging current will flow a cable feeder is first energised. The relay digital filtering is designed to remove almost all of this transient current. The frequency of this current tends to be a high multiple of power system frequency. Therefore the steady state charging current only need to be considered when selecting the differential setting.

The revision of the relay software installed, may be found moving to the top of the menu structure to display the relay identifier and holding the [Cancel] and [Test/Reset] pushbuttons depressed or by selecting [Relay] [Information][Get System Information] in Reydisp Evolution. If the setting file for the relay is saved, open the .set file in Reydisp Evolution, clicking on the Info (***i)*** tab at the top right hand corner of the “Settings Editor” window. The Software Revision should now be displayed in the “Settings Source Information” window.

If relays with installed code of Revision 1 to 3 do not provide enough sensitivity, the latest revision may be downloaded. Note a pair of relays must have identical software installed and differential settings selected at all times.

These above figures include provision for transient increases in healthy phase charging current during external earth faults on non-effectively earthed power systems.

Some typical Examples of Cable Charging Currents are given in the Table below:

Voltage	Charging current per km
3.3	0.2 to 0.7
6.6	0.5 to 1.6
11	0.7 to 2.4
22	1.1 to 3.2
33	1.3 to 3.5
66	4 to 7.5
132	5 to 11
220	10 to 20
400	15 to 30

The above figures are for single cables only. Where two cables per phase are used the feeder charging current will double. The highest charging current figure at the top end of the range are for the largest cross-sectional area single core cables and for small diameter three core cables at the bottom of the table. If the charging current is not known the top figure in the range may be used with confidence, as it will tend to over estimate the feeder charging current and set the relay to a more stable differential setting.

The above table should only been used as a worst case estimate. For optimum relay settings the differential setting to select, should be based a multiple on the true charging current or susceptance of the cable.

7.2 Plain Poly Phase Cable Feeders

This type of cable is usually used at 33kV and below. The reactance of these cables tends to be low as the phase currents tend to cancel in each cable. The X/R of the external fault to use in the CT formula will tends towards the cable X/R if the cable exceeds 2 to 3 km. This assists in reducing the CT requirements.

7.3 Phase Segregated Single Phase Cable Feeders

The major difference between this type of circuit and poly-phase cable circuits, is that the transient and steady state charging current will be higher. The charging current will rise with rated voltage and the length of the circuit. The variable setting relay is recommended for this type of circuit, as it offers the flexibility to cope with a variable level of charging current. The P/F differential setting must be set above the charging current on the feeder. The waveform recorder in the relay can be used to assess the magnitude of charging current. The method is covered in part 4.4 of this section of the manual. Several Cables per phase may be used and this may increase overall charging current by a multiple of a single cable.

The P/F Differential should be set as per the recommendations in 5.1.

The cable X/R will reduce the external fault X/R to a significant extent is the cable is more than a few kilometres in length.

7.4 Overhead Line Feeder

The relay is suitable for protecting circuits of this type. The settings can be set more sensitively than for cable feeders as charging current is much lower. The P/F differential setting may need to be set towards the lower settings of 10% to 20% to cover arc resistance and/or resistively earthed neutral. The Slope 1 Setting should also be set to 20% and the Bias Break Point may need to be set to 1.0, 1.5 or 2.0 to allow for load current flow during the internal earth fault. The Bias Break Point will usually have to be set higher for overhead lines, than for cable circuits, to allow for load bias during a high resistance earth fault on the feeder.

Where twisted pair pilotwire connection is used for protection signalling, and the circuit is an overhead line, the consideration of the induced voltage onto the pilotwires becomes important. Please contact Customer Services for applications advice.

7.5 Earth Fault Sensitivity

The method adopted for earthing the power system network will determine the amount of fault current available to operate the differential elements. As mentioned above care must be taken when assessing the best combination of settings to use.

Network feeder circuits of the type that this relay is likely to be applied on, eg 3kV to 150kV, may operate with their neutral points either solidly earthed (typical for the 150 kV end of the range), unearthed (often employed in the middle range of distribution voltage ratings) and impedance earthed at the lower end.

This must be considered when selecting and applying the relay, as outlined below:

7.5.1 Solid or Effective Neutral Earthing

Solid earthing will normally result in earth fault levels of a similar magnitude or just above the three phase faults. Low impedance earthed generators are normally designed to allow fault current of the order of magnitude of the source incoming circuit rating, typical values being in the range of 100-1600 amps.

In either case, solid or low impedance, the standard basic relay, with fixed or variable settings should provide adequate sensitivity for earth faults. Both the differential and the back-up non-unit protection will provide sensitive protection.

For low impedance earthed networks it is only necessary to ensure that the current transformer primary rating and ratio is compatible with the earth fault current, or is of a lower value.

Example: maximum fault current – 800 amp
c.t ratio ≤ 800/1 (or 5)

For low impedance earthed networks it is recommended that the differential sensitivity be no more than 80% of the minimum earth fault current. The relay with variable differential settings should allow this to be met.

7.5.2 High Impedance and Resistance Earthed Neutrals

This method is often employed in medium voltage power system, where the fault current in each source neutral is limited to a low value, for reasons of safety and to limit fault damage.

The fault current may be of the order of 100 to 1000 amps.

In this type of network, with feeders typically rated 400-800 amps and c.t ratios chosen appropriately, eg 800/400/1 or 5 amp, the earth fault current may not be sufficient to operate relay models from the basic range. The minimum relay setting is 10% of nominal current rating for both the differential (ie variable setting models) and back-up protection.

The relay set at it’s minimum setting of 10% would be satisfactory provided that the primary equivalent fault current is at least 4 x the relay operating current. This is based on the recommendation of a maximum operating current of 25% given above. This allows for factors such as fault limitation by arcing earths, c.t. error and the relay’s bias characteristic.

For transformer feeders, an earth fault part way into the transformer winding would result in a much lower proportion of maximum fault current. For Delta windings this is usually acceptable, whereas for star connected windings a separate more sensitive restricted earth fault protection is normally provided.

For plain feeders, acceptable settings to apply to the relay are as follows:

Example: Maximum earth fault from one source = 40 amps
C.t. ratio ≤ 100/1 (or 5 amp)

Relay settings	P/F Differential (I_S)	= 0.10 x I_N
	Bias slope 1 (S_1) = 20%	
	Bias slope 2 (S_2) = 150%	
	Bias Break Point (B2)	= 2.0 x I_N

<u>Example - 33kV Earth Fault on Resistance Earthed Cable Feeder</u>

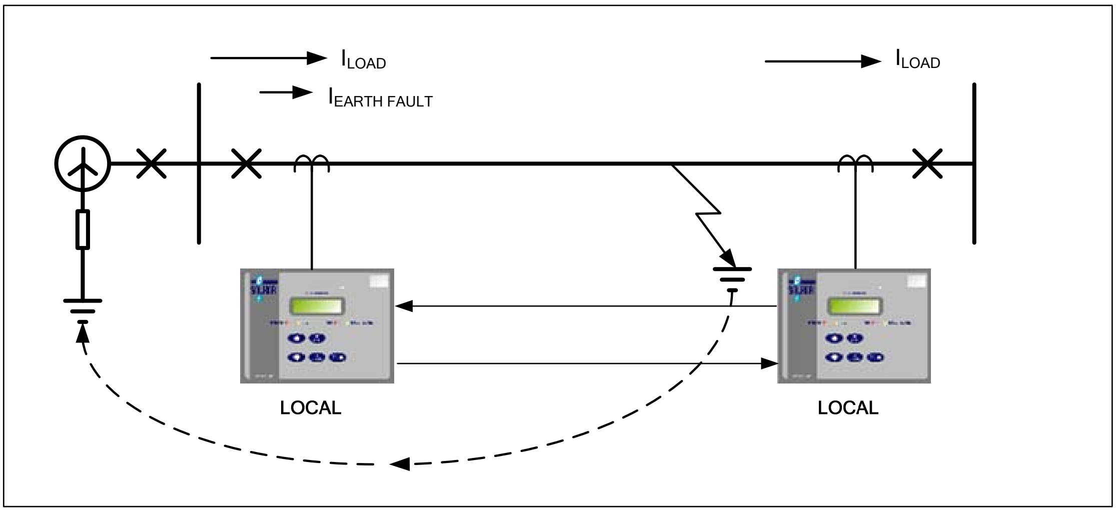


Figure 4 – Earth Fault with load bias for Resistance Earthed System

Circuit Parameters:

33kV Cable Length = 7km
Load prior to Fault inception = 700A.
Load during Earth Fault ≈ 600A
Circuit Rating = 800A
CT Ratio = 1000/1A
Maximum Feeder Earth Fault level = 800A (two transformers)
Minimum Feeder Earth Fault Level = 400A (one transformer)
Charging Current per cable = 4.5A per km

At the fault point the phase to neutral voltage may not fall significantly and therefore load current will continue to flow through the radial cable to the load during the earth fault. The load will usually reduce, but the full circuit rating is used to calculate the fault position on the relay bias characteristic, as this will test the relay setting for the worst case. At one end of the feeder only the load current will be measured. At the other end the load and the superimposed fault current will flow.

As the system is radial the phase comparator will generally not operate as the fault current and load is often of a very similar power factor. Therefore it is essential the relay is set to ensure this minimum earth fault level is detected by the magnitude comparator.

Secondary Currents under Fault conditions:

For a minimum earth fault of 400 amps, the currents measured by the relays at either end of the feeder will be:

Local End = 600 amps + 400 amps = 1000 amps / 1200 = 0.833 amps

Remote End = 600 amps / 1200= 0.500 amps

Restraint or Bias Current = (0.833 + 0.500) / 2 = 0.666A

Differential Current = 0.833 - 0.500 = 0.333A

The measured relay point is therefore 0.333A differential current at bias current 0.666A.

This can be compared graphically with the relay default P/F Diff. Setting of 0.3xIn and 30% Slope.

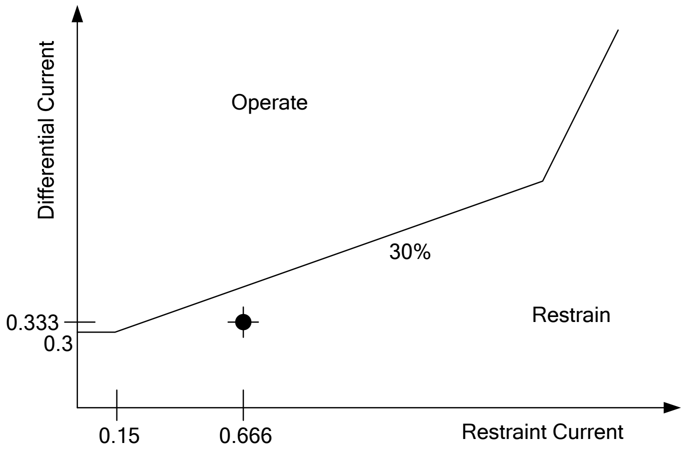


Figure 5 – Setting of P/F Diff. Setting for Load Bias

It is clear that the relay will not operate for this fault. To detect this level of fault the relay P/F Differential and/or Slope 1 setting must be reduced.
This setting must be set in excess of the multiple of steady state charging current required by the relay to ensure stable operation. For relays with shaped phase angle comparators (Revision 4 and above) the required minimum limit is 4 x Ic, where Ic is the steady state cable charging current of the feeder.

Cable Charging Current:

The P/F Differential Setting > 4 x charging current [Resistance Earthed System]

The secondary charging current can be estimated to be: 7km x 4.5A x 1/1200 = 0.0263 A

P/F Differential Setting > 4 x 0.0263A / rated current = 0.106 x I_N

The relay should be set to the next highest Differential Setting of 0.15 x I_N

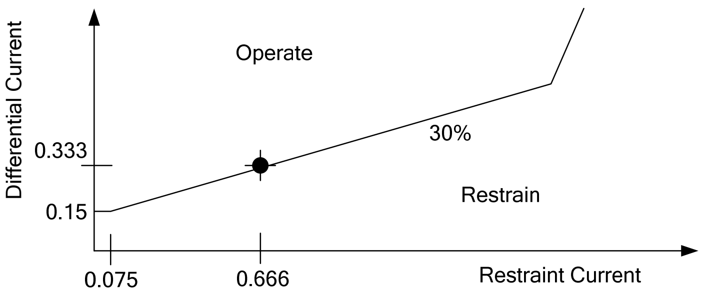


Figure 6 – Setting of Bias Slope for Load Bias

Shown graphically it is clear that it would be advantageous to reduce the bias slope. The next setting below 30% is the minimum of 20%.

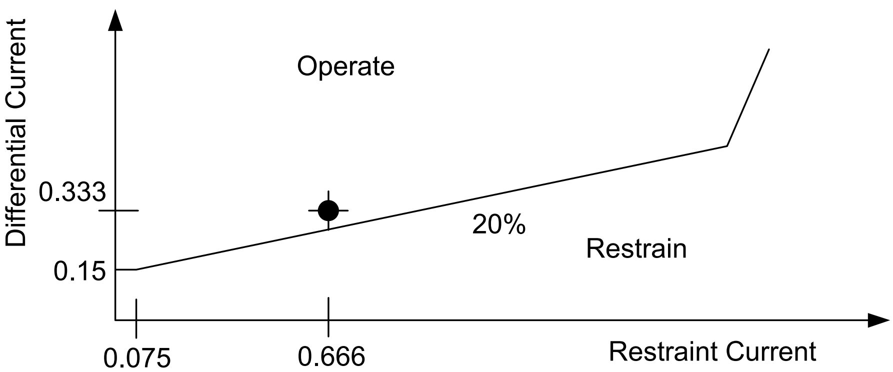


Figure 7 – Settings for correct Load Bias

To allow operation of the relay for this minimum earth fault the Bias Break Point must be set to 1.0 x I_N or above. A setting of 1 x I_N, rather than 1.5 x I_N, would be selected as this help lower the CT requirements. The Figure below shows the effect of settings applied for detecting earth faults on resistance earthed systems. It also shows the fault point for the above example:

Where the relay is used on interconnected systems and the fault current is fed from both ends of the feeder (double end fed) the phase comparator will generally operate.

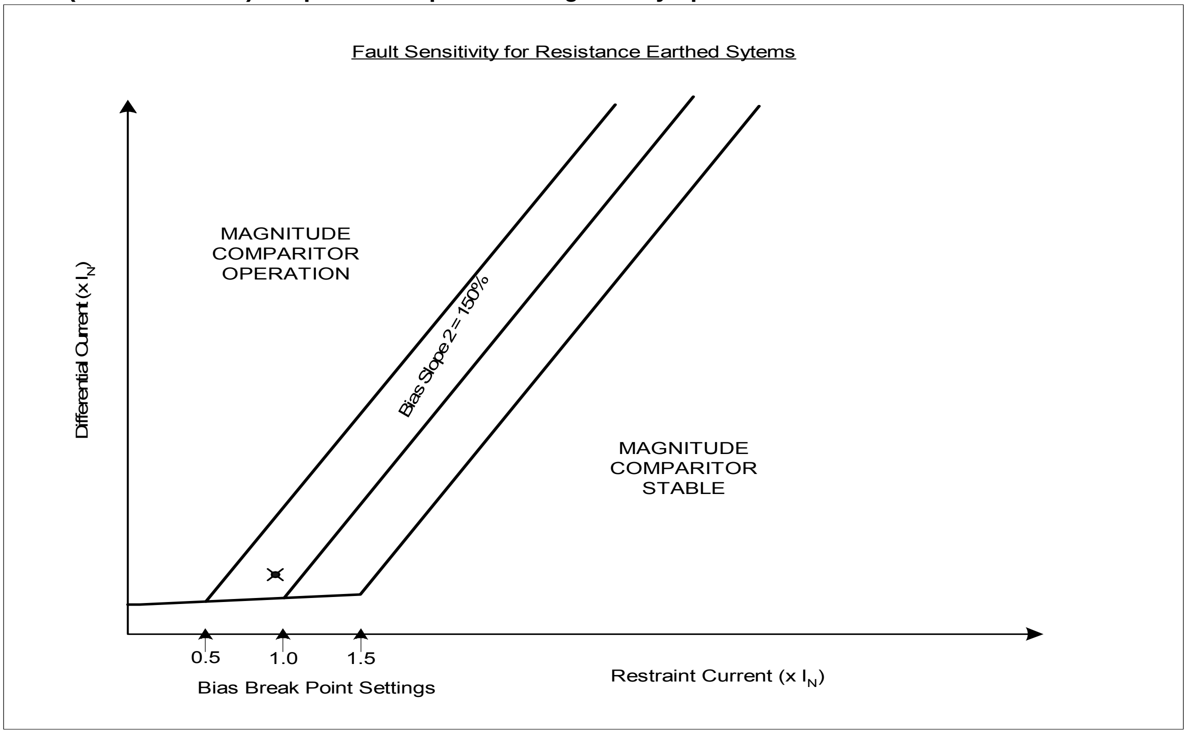


Figure 8 – Setting of Bias Break Point for Load Bias

Figure 9 to 11 shows typical values chosen for the P/F Differential, Bias Slope 1 and Bias Break Point settings to allow an earth fault with some load biasing to be detected. Three typical relay settings used for resistance earthed systems are shown graphically, to assist with selecting appropriate settings.

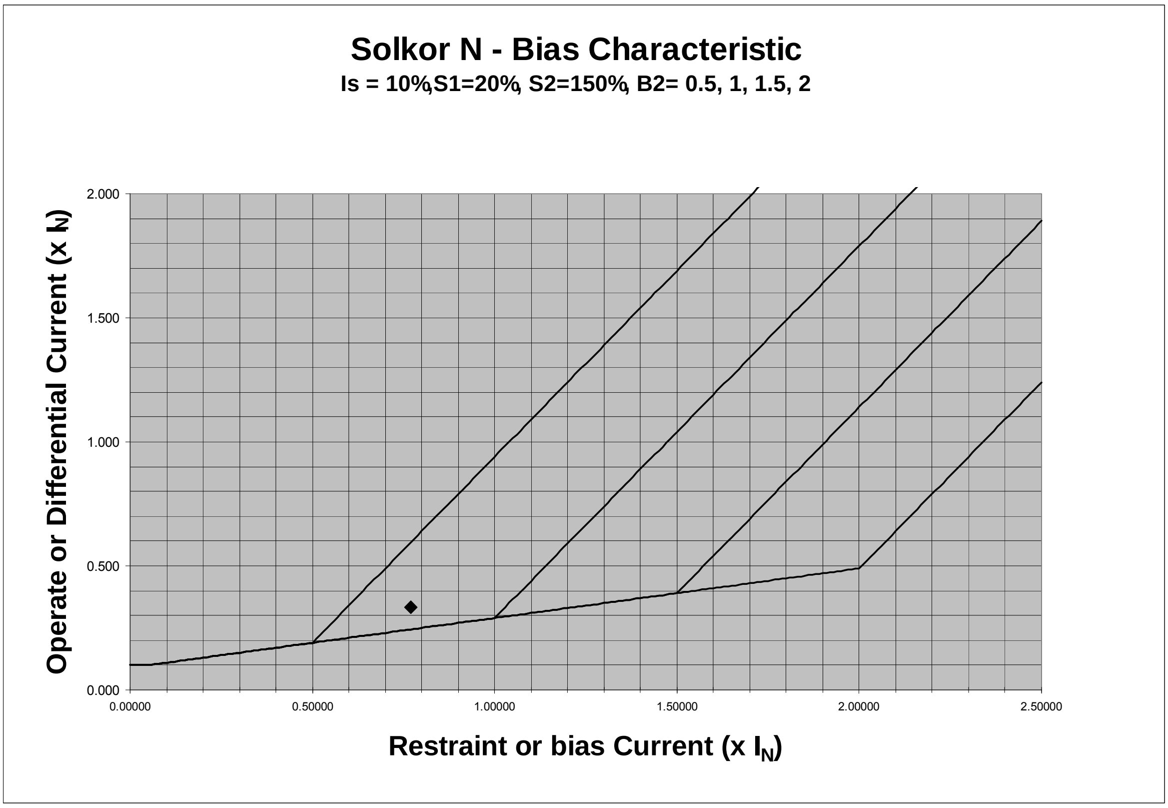


Figure 9– 10% P/F Differential and Bias Break Point of 0.5, 1.0, 1.5 and 2.0.

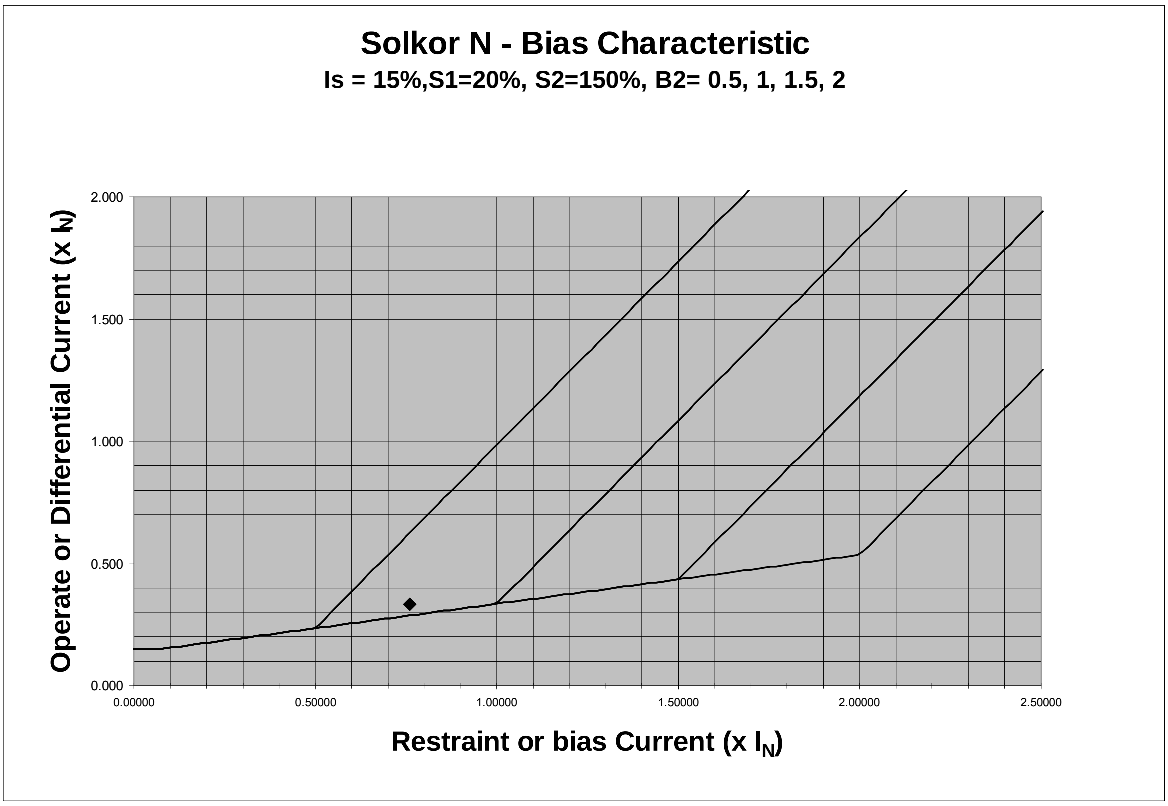


Figure 10 – 15% Differential and Bias Break Point of 0.5, 1.0, 1.5 and 2.0.

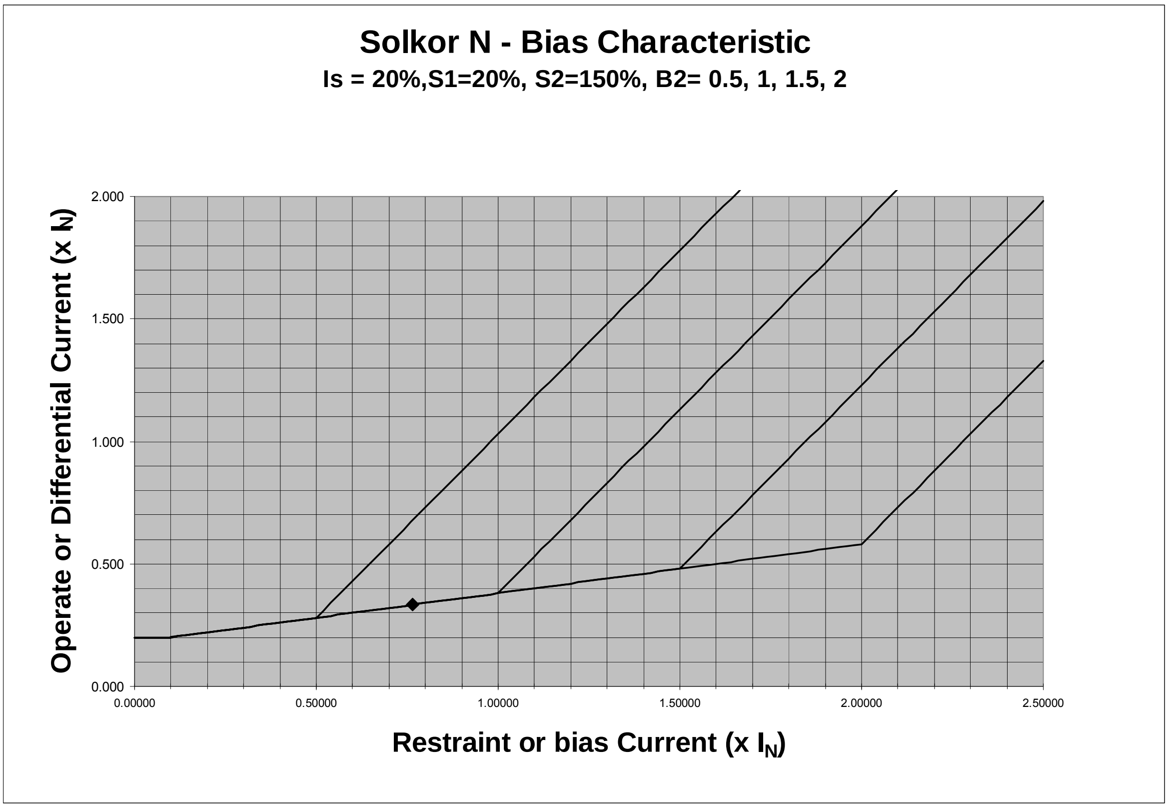


Figure 11 – 20% Differential and Bias Break Point of 0.5, 1.0, 1.5 and 2.0.

7.5.3 Isolated (unearthed) and Reactance Earthing

For these networks, the intention is to ensure that an earthed live conductor does not result in any significant fault current and minimise interruptions to supply. Utility networks of this type do not normally include discriminating protection as a first level, e.g. whilst the network is earthed via a Peterson Coil (reactance earthing).

Often the earth fault position is found by applying a short to the neutral reactance after a time delay. If the fault is within the protected zone of the relay then the device would then trip. Often systems with this type of earthing will have “pecking” type faults that may lead to problems in grading different types of over current and earth fault relays. XLPE cable circuits typically have pecking faults where the arc is extinguished and the fault re-seals.

The reset of the relays may become out of step as the pulses of fault current usually are not long enough to allow relays to time out, and eventually this will often lead to loss of grading. Where circuits have pilot wires often this grading problem may be over come by the use of this relay type.

For industrial networks, employing the isolated network neutral philosophy, it is usually intended that discriminating protection be employed if possible. This type of protection employs the detection of zero sequence fault current resulting from network cable capacitance, employing a core balance c.t., and zero sequence voltage from a neutral displacement voltage transformer winding, in combination, to establish the position of a fault.

During the period where the system is earthed via a variable neutral reactance, the fault current pulse is usually long enough for this relay type to provide satisfactory earth fault protection on such a network. After the neural control time delay has expired and the reactance earthed system becomes solidly earthed, the relay will operate and trip the faulted circuit.

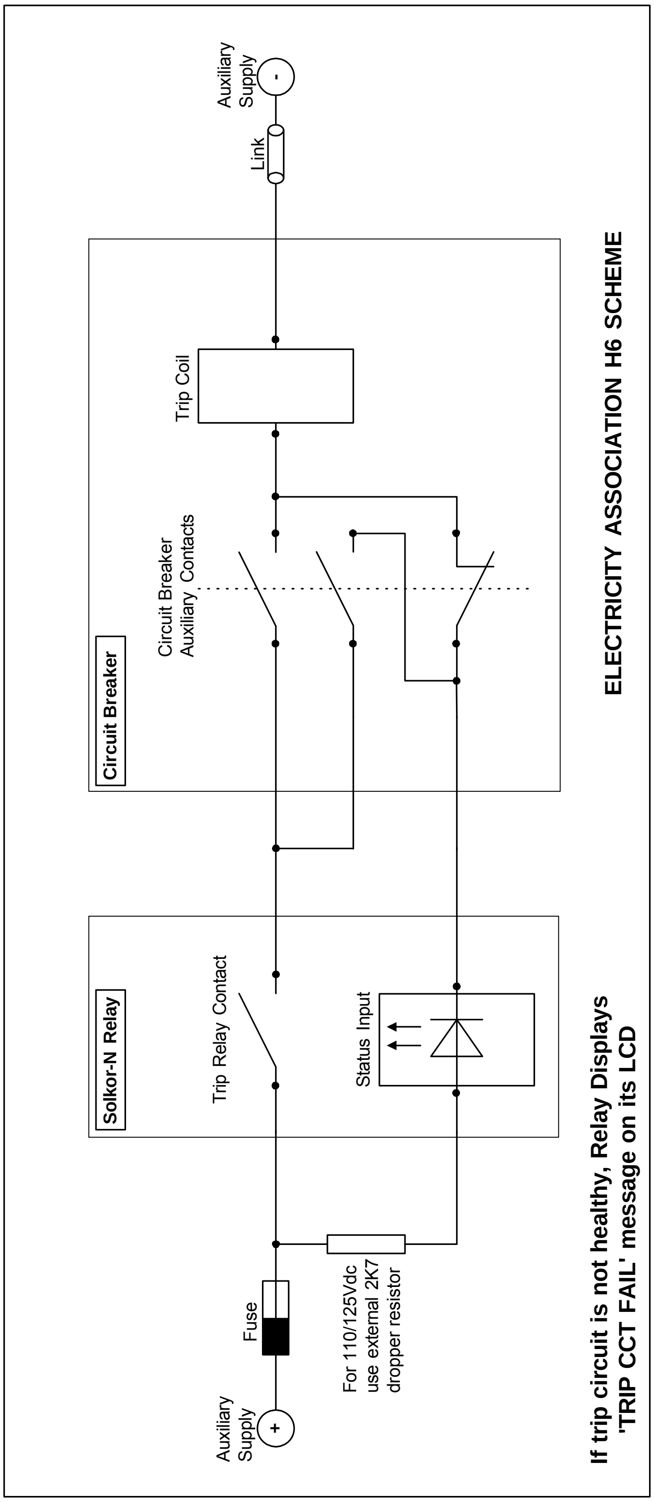


Figure 12 – Trip Circuit Supervision Connections

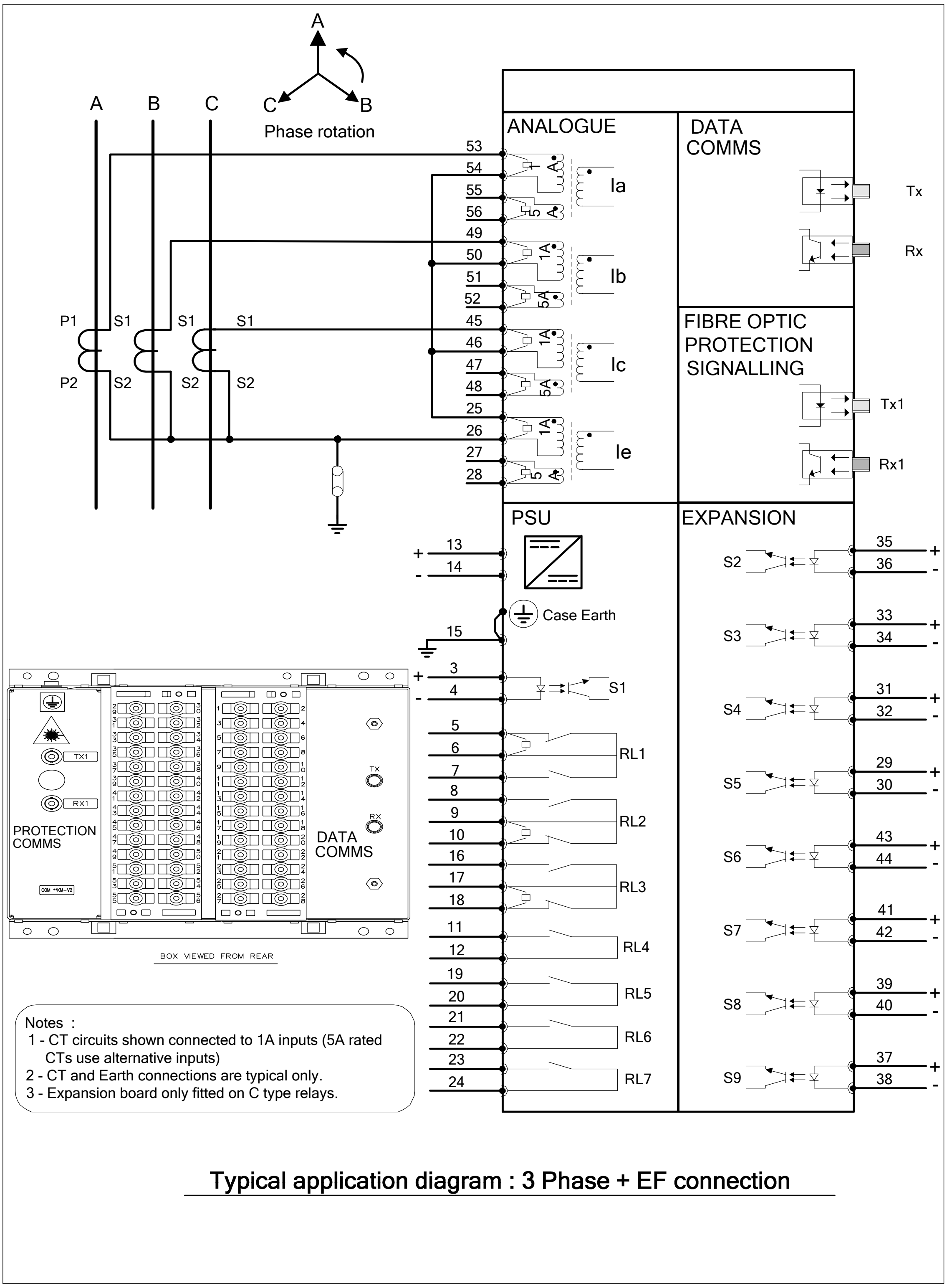


Figure 13 – Relay Connections for Fibre Optic

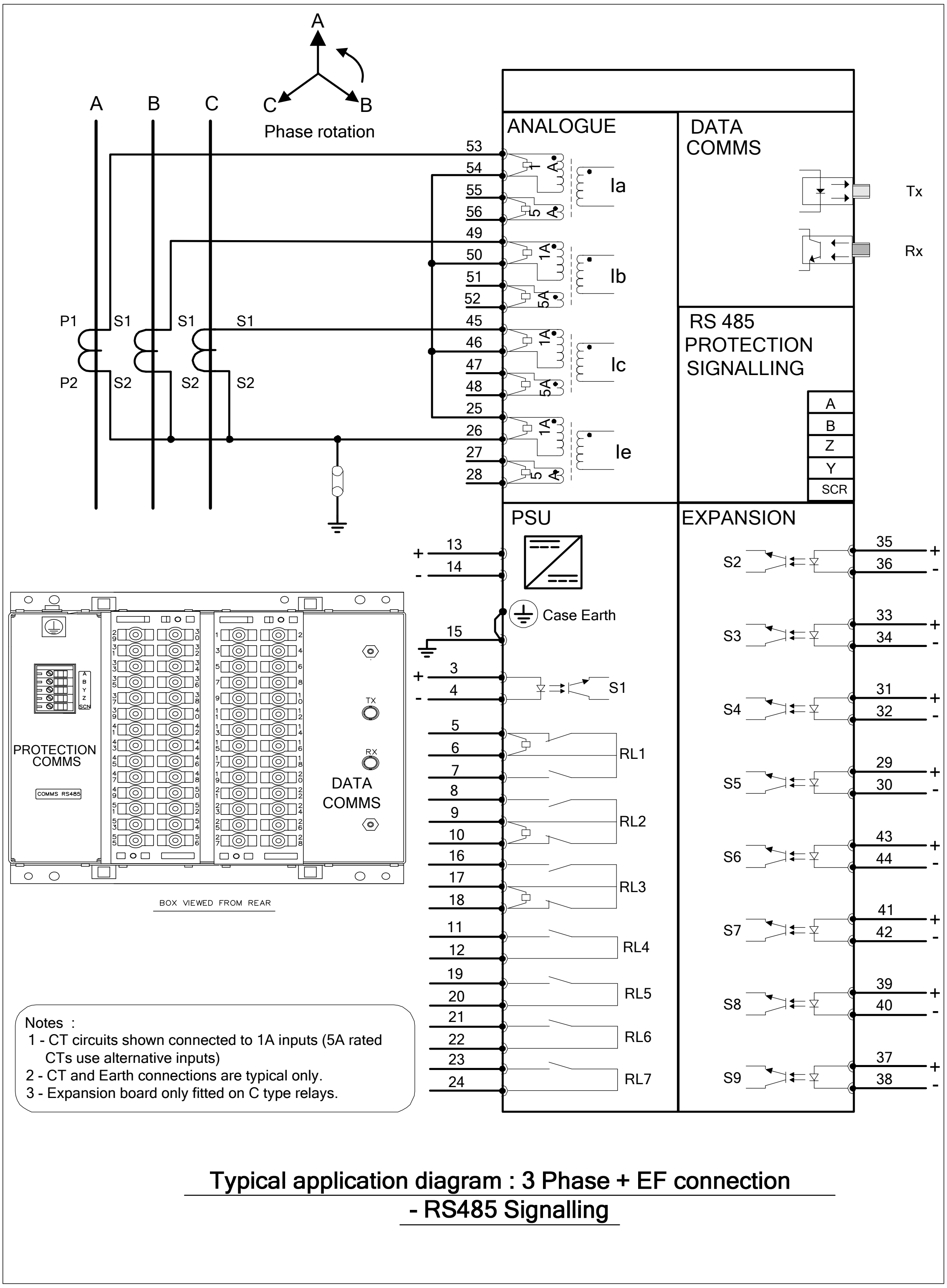


Figure 14 – Relay connections for RS485 Cable

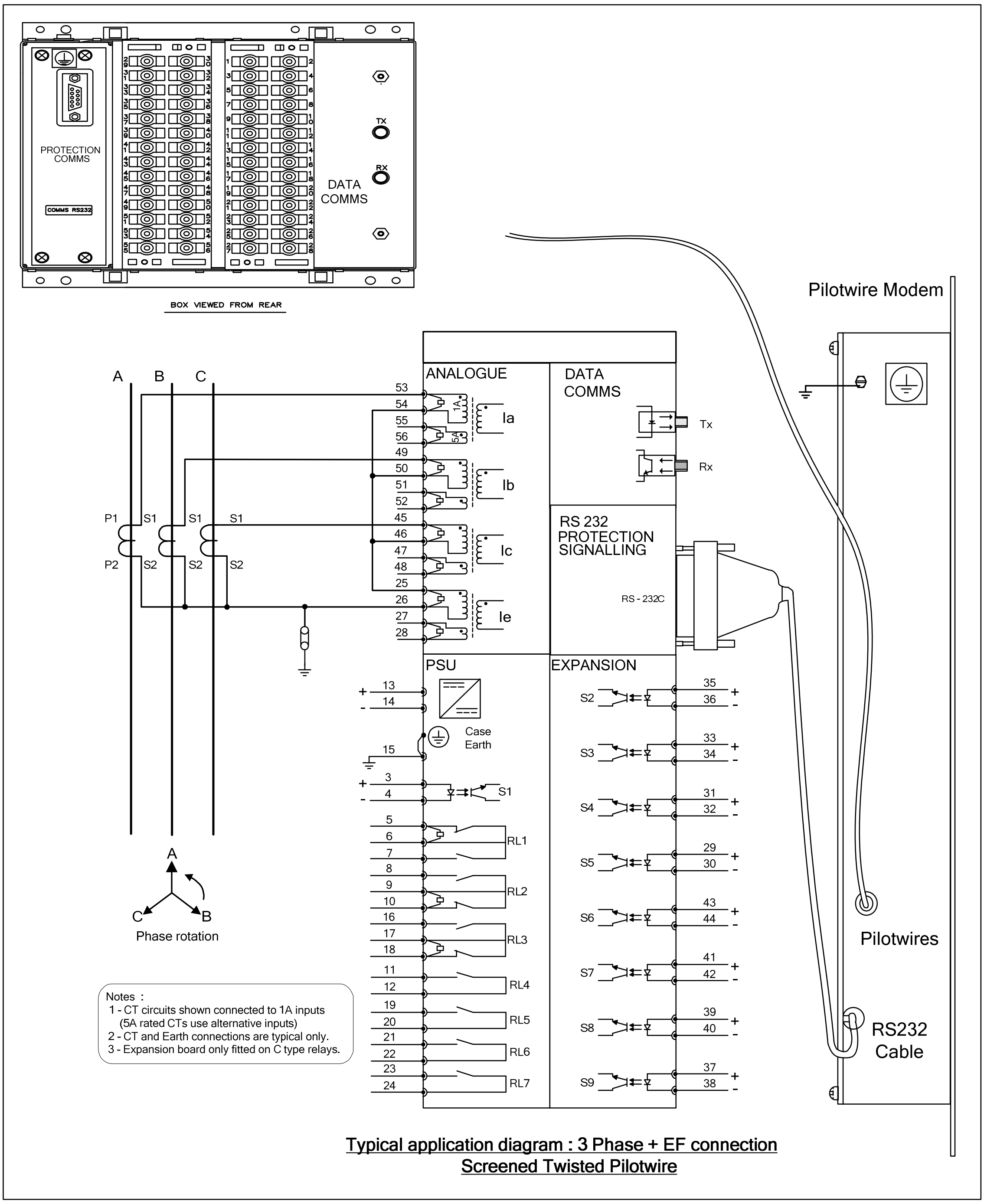


Figure 15 – Relay Connections for Screened Twisted Pair Metallic Pilotwires

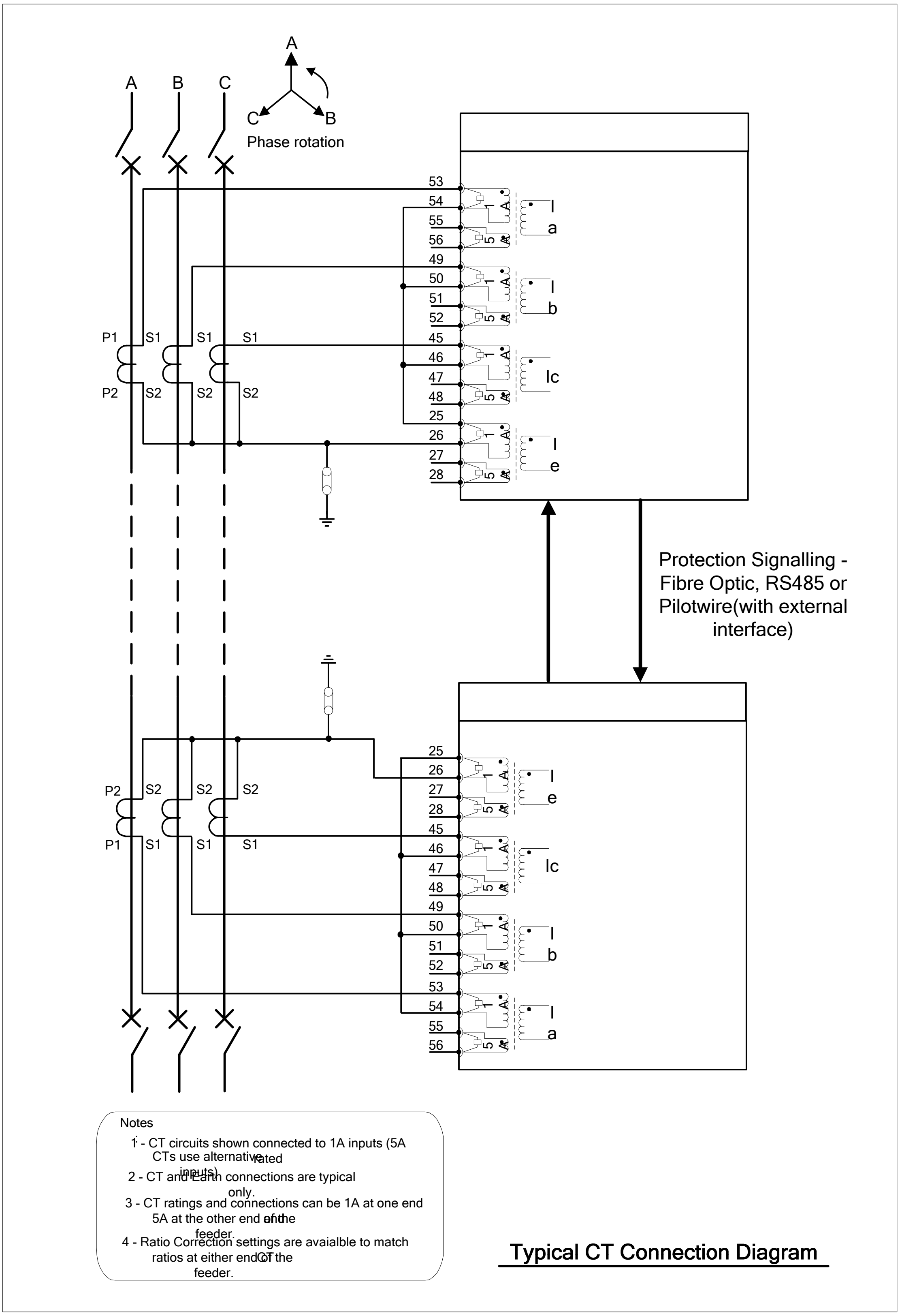


Figure 16 - Typical CT Connection Diagram