Unit Protection of Feeders

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Unit Protection of Feeders

Introduction

The graded overcurrent protection design, though quite simple, do not meet all the protection demands of an electrical power system. Application issues are experienced for two reasons: firstly, acceptable grading cannot be accomplished for a complex electrical system, and secondly, the protection adjustments may lead to maximum operating times that are excessive and cannot stop faults.

These issues directed to the unit protection concept. This concept means that parts of the electrical system are separately protected without reference to other parts of the electrical system. One unit protection concept is widely known as 'Differential Protection'. Foundation of this principle is to detect the difference in currents between the incoming and outgoing terminals of the protected element. Other unit protection concepts can be based on directional comparison, distance tele-protection arrangements or phase comparison unit protection.

The design of the electrical system may lend itself to unit protection concept. For example, a simple ground fault protection relay used at the source end of a transformer-feeder can be treated as unit protection given that the transformer winding associated with the protected feeder is not grounded. In this example the protection area is limited to the feeder and power transformer winding because the transformer cannot transfer zero sequence current to an out-of-zone fault.

However, in most situations a unit protection arrangement requires the measurement of short circuit currents (and sometimes voltages) at each protection zone, and the data transfer between the elements at zone boundaries. It should be kept in mind that stand-alone distance protection relay, even though nominally reacting only to short circuits within their setting zone, does not meet the conditions for a unit arrangement because the zone is not clearly specified. The zone is specified only within the accuracy boundaries of the measurement. Besides, the setting of a stand-alone distance protection relay may also extend outside of the protected zone to cater for specific conditions.

Fundamental differential arrangements have established the foundation of many sophisticated protection arrangements for feeders and other system elements. In certain protection schemes, an auxiliary ‘pilot’ circuit interconnects similar current transformers at each end of the protected zone, as presented in Figure 1. Current running through the zone causes secondary current to circulate round the pilot circuit without generating any current in the protection relay. For a short circuit within the protected zone the CT secondary currents will not balance, in comparison with the through-fault condition. The difference between the currents will flow in the protection relay. An optional scheme is presented in Figure 2. In this arrangement, the CT secondary windings are opposed for through-fault conditions so that no current runs in the series connected relays. The first protection arrangement is known as a ‘Circulating Current’ system. The second protection arrangement is known as a ‘Balanced Voltage’ system. The majority of unit protection systems work through the determination of the relative direction of the fault current. Fault current direction can only be presented on a comparative basis, and such a comparative measurement is the typical factor of many protection systems, including directional comparison protection and distance tele-protection protection schemes with directional impedance measurement.

One of the most important factors of unit protection is the communication method between the protection relays.

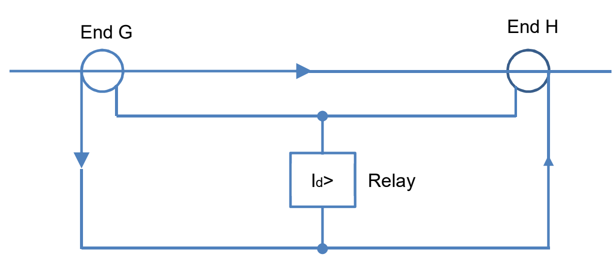


Figure 1. Circulating current unit protection system

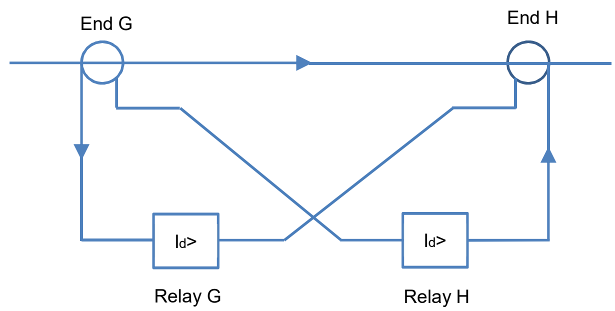


Figure 2. Balanced voltage unit protection system

Direction Convention

It is useful to adopt a direction convention of current flow. In order to accomplish this, the direction measured from a busbar outwards along a feeder is regarded as positive. The notation of current flow is presented in Figure 3. The portion GH transfers a through current which is considered positive at G but negative at H. The infeeds to the faulted portion HJ are both positive.

Neglecting this rule typically leads to anomalous equipment arrangements or problems in describing the action of a complex system. When used, the described rule will typically lead to the application of identical equipment at the zone boundaries. This rule is equally appropriate for extension to multi-ended systems. It also adjusts to network analysis standard methods.

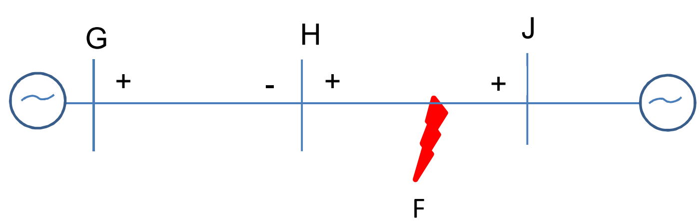


Figure 3. Current direction convention

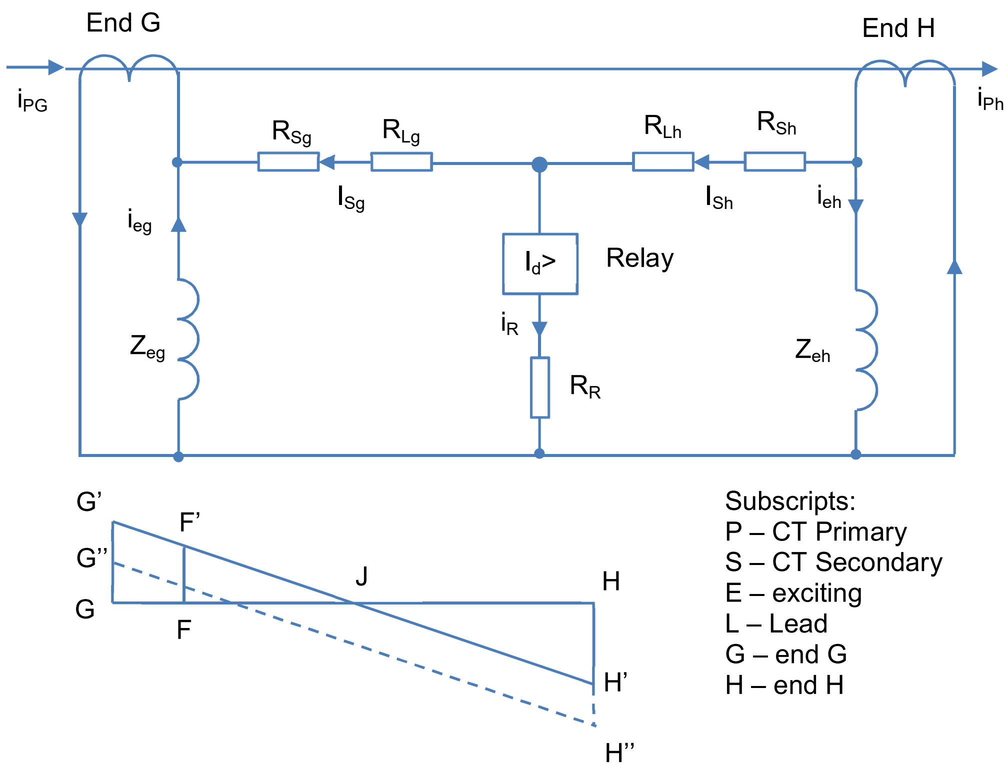
Conditions for Direction Comparison

The circulating current and balanced voltage protection systems presented in Figure 1 and Figure 2 complete full vectorial comparison of the zone boundary currents. Such protection arrangements can be treated as analogues of the protected zone of the power system. In them CT secondary quantities represent primary currents and the relay tripping current corresponds to an in-zone short circuit current. These arrangements are simple in concept. However, they are applicable to zones having any number of boundary connections and for any pattern of terminal currents.

Defining a current requires that both magnitude and phase are presented, however it is not always easy to transfer all this information over available pilot channels.

Circulating Current System

The principle of this arrangement is presented in outline in Figure 1. In the case current transformers are ideal, the system operation is straightforward. However, the transformers will have errors developing from both Wattmetric and magnetizing current losses. They will cause deviation from the ideal, and the interconnections between them may have different impedances. This can increase a ‘spill’ current through the protection relay even without an existing fault, therefore limiting the potential sensitivity. An equivalent circuit of the circulating current protection arrangement is presented in Figure 4. If a high impedance protection relay is applied, and unless the protection relay is installed at point J, a current will run through the protection relay even with identical currents I_{Pg} and I_{Ph}. If a low impedance protection relay is applied, voltage FF’ will be insignificant, but the CT exciting currents will be different due to the different burdens and relay current I_R will still be non-zero.



GG’, HH’ Electro-motive forces with high impedance protection relay
GG’’, HH’’ Electro-motive forces with low impedance protection relay

Figure 4. Equivalent circuit and potential diagram for circulating current protection arrangement

Transient Instability

An asymmetrical current applied to a current transformer will generate a flux that is higher than the peak flux corresponding to the current steady state alternating component. It may bring the CT into saturation, decrease dynamic exciting impedance and highly increase the exciting current.

When the unit protection balancing current transformers differ in excitation features, or have different burdens, the transient flux build-ups will be different and an increased 'spill' current will occur. There is a subsequent risk of protection relay operation on a healthy line under transient conditions, which cannot be accepted. Potential solution includes installation of a stabilising resistance in series with the protection relay.

Stabilising resistor calculation procedure is usually included in the instruction manuals of all protection relays. When a stabilising resistor is installed, the protection relay current setting can be decreased to any practical value. The protection relay is now being a voltage-measuring instrument. Apparently, there is a lower limit, below which the protection relay element does not have the sensitivity to pick up.

Bias

The 'spill' current in the protection relay generated from different sources of error depends on the magnitude of the through current. It is negligible at through-fault current low values but occasionally reaches a disproportionately large value for serious faults. Defining the protection operating threshold above the maximum level of spill current creates poor sensitivity. By making the differential setting roughly proportional to the short circuit current, the low-level fault sensitivity is highly improved. Figure 5 presents a common bias characteristic for a modern protection relay that solves the problem. At low currents, the bias is insignificant, thus allowing protection relay to be sensitive. At higher fault currents that are experienced during inrush or through fault conditions, the used bias is higher. Therefore, the spill current needed to start operation is higher. It can be concluded that the protection relay is more tolerant of spill current at higher short circuit currents and therefore less likely to maloperate. It is still sensitive at lower short circuit current levels.

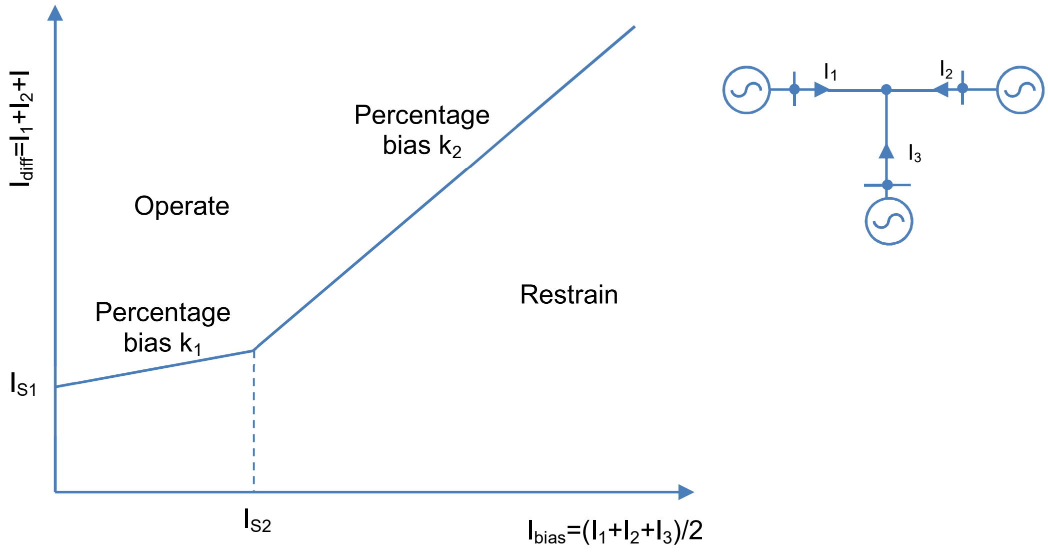


Figure 5. Common bias protection relay characteristic

Balanced Voltage System

This paragraph is presented for historical reasons, since the number of such protection arrangements are still found in service. Circulating current schemes are almost exclusively used for new installations.

With primary through current, the secondary e.m.f.s of the current transformers are opposed, and do not generate current in the interconnecting pilot leads or the series connected protection relays. An in-zone short circuit leads to a circulating current condition in the CT secondaries and therefore to relay operation.

Consequence of the protection arrangement is that the current transformers are in effect open-circuited, since secondary current does not flow for any primary through-current conditions. To avoid excessive core saturation and secondary waveform distortion, the core is supplied with nonmagnetic gaps. They are sufficient to absorb the complete primary m.m.f. at the maximum current level and the flux density will remain within the linear range. Therefore, the secondary winding generates an e.m.f. and can be regarded as a voltage source. The transformer shunt reactance is rather low, so the device acts as a transformer loaded with a reactive shunt. This device is known as transactor. System equivalent circuit is presented in Figure 6.

The series connected protection relays have relatively high impedance. Due to this CT secondary winding resistances are not of great importance and the pilot resistance can be fairly large without significantly affecting the system operation. This is why the protection arrangement was developed for feeder protection.

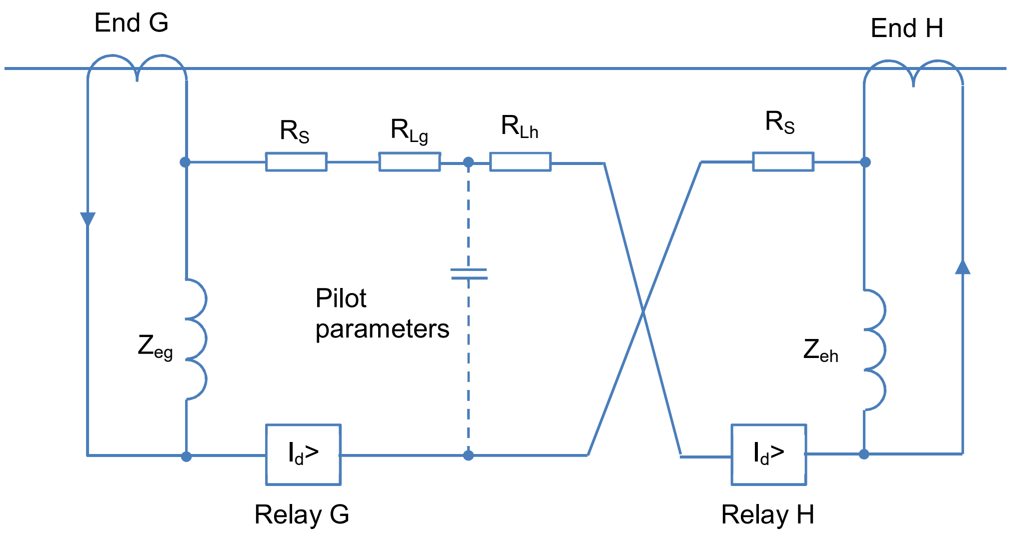


Figure 6. Equivalent circuit for balanced voltage system

Voltage Balance System Stability Limit

Unlike typical current transformers, transactors are not prone to errors generated by the progressive build-up of exciting current, because the total primary current is expended as exciting current. Effectively, the secondary e.m.f. is a precise measure of the primary current within the transformer linear range. Considering that the transformers are made to be linear up to the maximum value of fault current, balance is limited only by the inherent limit of transformer accuracy, and as a result of capacitance between the pilot cores. A broken line in the equivalent circuit presented in Figure 6 shows such capacitance. Under through-fault conditions the pilots are energised to a proportionate voltage and the charging current runs through the protection relays. The stability ratio that can be reached with this system is rather moderate and a bias technique is applied to solve the problem.

Summation Arrangements

Protection arrangements have so far been discussed as though they are applied to single-phase systems. A polyphase system could be supplied with independent protection for each phase. Modern digital or numerical protection relays communicating via fibre-optic links function on this principle, since the amount of information to be communicated is not a major constraint. For older protection relays, application of pilot wires technique may be practical for relatively short distances that are usually encountered in industrial and urban power distribution systems. Obviously, each phase needs a separate set of pilot wires if the protection is applied on a per phase basis. The cost of supplying separate pilot-pairs and also separate protection relay elements per phase is typically high. Summation methods can be used to combine the separate phase currents into a unique relaying quantity for comparison over a single pair of pilot wires.

Transformer Summation Principle

A winding, either within a measuring relay, or an auxiliary current transformer, is arranged as shown in in Figure 7. The interphase sections of this winding, A-B, and B-C, usually have a similar number of turns while the neutral end of the winding (C-N) typically has a higher number of turns.

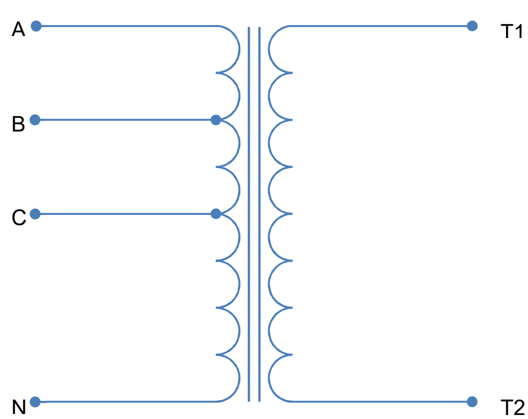


Figure 7. Typical summation winding

This winding has a number of special features that are described in the next section.

Sensitivity Using Summation Transformers

This paragraph presents the performance of the summation transformer in a common MBCI ‘Translay’ arrangement. In the MBCI protection relay, the number of turns on the input side of the summation CT is in the ratio:

- A-B 1.25
- B-C 1
- C-N 3 (or 6)

Increasing the turns ratio to 6 for the neutral end of the winding serves to improve the ground fault sensitivity of the protection arrangement, as is presented in the performance below. Unbalanced fault currents will energise different numbers of turns, according to which phase(s) is/are faulted. This leads to protection relay settings which are in inverse ratio to the number of turns involved. If the protection relay has a setting of 100% for a B-C short circuit, the following proportionate trip thresholds will be used:

A-B	80%
B-C	80%
C-A	44%
A-B-C	50%
A-N	19% (or 12% for N=6)
B-N	25% (or 14% for N=6)
C-N	33% (or 17% for N=6)

Electromechanical and Static Unit Protection Arrangement Examples

As presented above, the basic protection balanced voltage principle developed to biased protection systems. Several of these have been made, some of which seem to be quite different from others. However, these dissimilarities are trivial. A number of these arrangements that are still in common use are presented below.

‘Translay’ Balanced Voltage Electromechanical System

A common biased, electromechanical balanced voltage system, which is usually known as ‘Translay’, is presented in Figure 8.

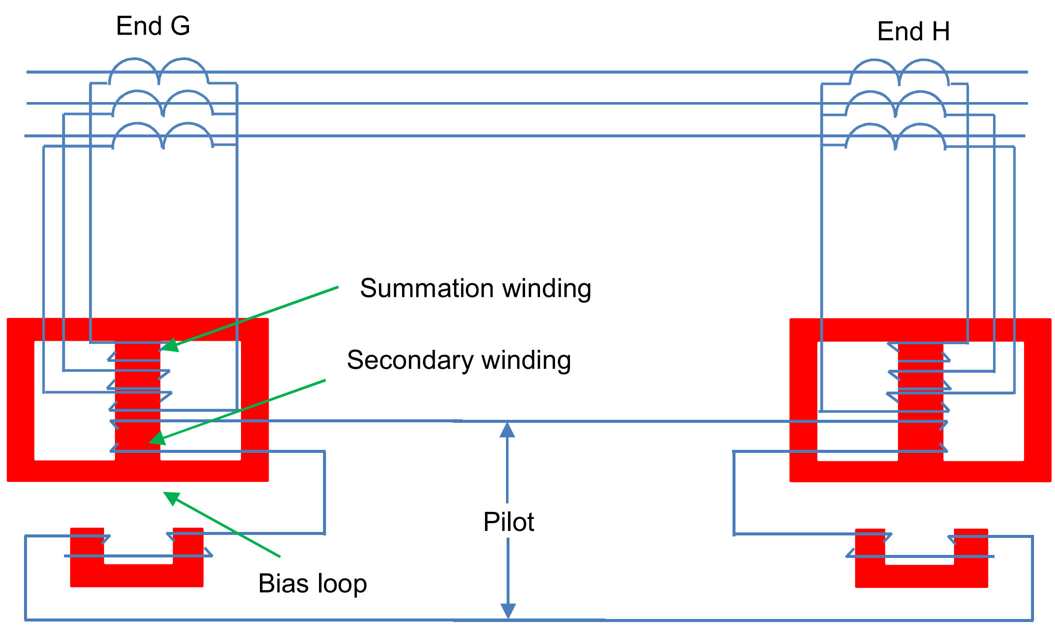


Figure 8. “Translay” biased electromechanical differential protection arrangement

The electromechanical design gets its balancing voltages from the transactor installed in the measuring relay at each line end. Measurement relays are based on the induction-type meter electromagnet as presented in Figure 8. The upper magnet contains a summation winding to get the output of the current transformers, and a secondary winding which delivers the reference e.m.f. The secondary windings of the coupled relays are interconnected as a balanced voltage system over the pilot channel. The lower electromagnets of both relays are included in this circuit. Through current in the power circuit generates a state of balance in the pilot circuit and zero current in the lower electromagnet coils. In this situation, operating torque is not generated.

An in-zone fault making an inflow of current from each end of the line generates circulating current in the pilot circuit and the energisation of the lower electromagnets. These electromagnets co-operate with the flux of the upper electromagnets to generate an operating torque in the discs of both relays. An infeed from only one end will result in relay service at the feeding end, but no operation at the other, because of the absence of upper magnet flux. Bias is generated by a copper shading loop installed in the pole of the upper magnet.

Common settings that can be accomplished with such relays are:

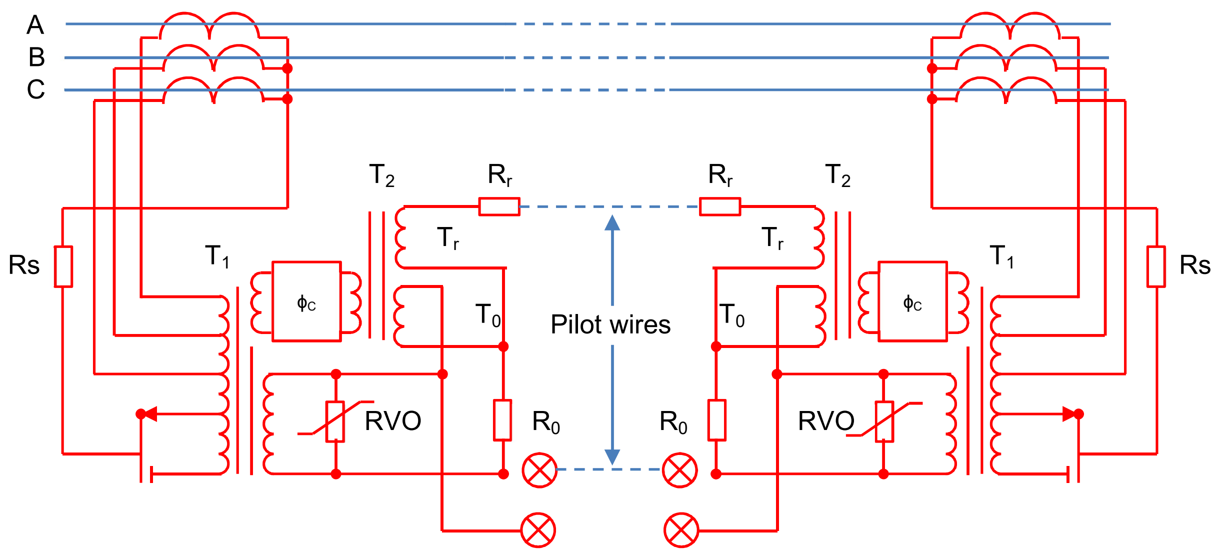
- Least sensitive ground fault - 40% of rating

- Least sensitive phase-phase fault - 90% of rating

- Three-phase fault - 52% of rating

Static Circulating Current Unit Protection System - 'MBCI Translay'

A common static modular pilot wire unit protection arrangement, working on the circulating current principle is presented in Figure 9. It uses summation transformers with a neutral section that is tapped, to give optional ground fault sensitivities. Phase comparators tuned to the power frequency are used for measurement and a restraint circuit provides a high stability level for through faults and transient charging currents. High-speed tripping is achieved with moderately sized current transformers and where space for current transformers is limited. In situations when the lowest possible operating time is not crucial, smaller current transformers may be applied. This is achievable by a special adjustment (Kt) by which the operating time of the differential protection can be selectively increased. This enables the application of current transformers that have a correspondingly decreased knee-point voltage, whilst ensuring that through fault stability is kept greater than 50 times the rated current. Internal faults cause simultaneous relay tripping at both ends of the line, providing quick fault clearance irrespective of whether the fault current is fed from both line ends or from only one line end.



T1-Summation transformer
T2-Auxiliary transformer
RVO-Non-linear resistor
T_o-Operating winding
T_r-Restraining winding
R_0-Linear resistor
P_r-Pilots padding resistor
ϕC-Phase comparator

Figure 9. Common static circulating current feeder unit protection arrangement

Digital/Numerical Current Differential Protection Arrangements

A digital or numerical unit protection relay may provide phase-segregated current differential protection. This means that the comparison of the currents at each protection relay is done on a per phase basis. For digital data exchange between protection relays, it is common that a direct optical connection is installed (for short distances) or a multiplexed communication link. Link speeds of 64kbit/s (56kbit/s in N. America) are typical, and up to 2 Mbit/s in certain situations. Through current bias is commonly used to provide through fault stability in the case of CT saturation. A dual slope bias arrangement (presented in Figure 5) is used to improve stability for through faults. A common trip criterion is as follows:

$$|I_{bias}| < I_{S2}$$

For

$$|I_{diff}| > k1|I_{bias}| + I_{S1}$$

$$|I_{bias}| > I_{S2}$$

For

$$|I_{diff}| > k2|I_{bias}| - (k2 - k1)I_{S2} + I_{S1}$$

Once the protection relay at one end of the protected section has determined that a trip condition exists, an intertrip signal is transferred to the protection relay at the other end. Protection relays that are provided with information on line currents at all ends of the line may not need to use intertripping facilities. Nevertheless, it is common to provide intertripping in any case to ensure the protection functions in the case of any of the relays discovering a fault.

A facility for vector/ratio compensation of the measured currents increases versatility, so that transformer feeders can be incorporated in the unit protection arrangement without the application of interposing CTs. Required interposing CTs are incorporated in software. Maloperation on transformer inrush is avoided by second harmonic detection. Attention has to be paid if the transformer has a wide-ratio on-load tap changer because this ends in the current ratio deviating from nominal and may cause maloperation, depending on the relay sensitivity. The initial bias slope should be defined taking this into account.

Measurement of power frequency currents gives a high level of stability with capacitance inrush currents during line energisation. The normal steady-state capacitive charging current can be allowed for if a voltage signal can be provided and the susceptance of the protected zone is known.

Also, if the grounded transformer winding or earthing transformer is included within the protection zone, some form of zero sequence current filtering is needed. This happens because there will be an in-zone source of zero sequence current for an external ground fault. The differential protection will see zero sequence differential current for an external fault. Therefore it could incorrectly operate. In older protection arrangements, the problem was fixed by CT secondary windings delta connection. For a digital or numerical protection relay selectable software zero sequence filter is normally used.

The minimum setting that can be reached with such techniques while ensuring proper stability is 20% of CT primary current.

The problem of compensating for the time difference between the current measurements made at the ends of the feeder remains. Small differences can upset arrangement stability, even when using fast direct fibre-optic links. The problem is resolved by either time synchronisation of the relay measurements or calculation of the propagation delay of the link.

Relay Time Synchronisation

Fibre-optic media allow direct signal transfer between protection relays for distances of up to several km without the need for repeaters. For longer distances repeaters will be needed. In situations when a dedicated fibre pair is not installed, multiplexing techniques can be applied. As phase comparison methods are applied on a per phase basis, measurement time synchronization is critically important. This demands knowledge of the transmission delay between the protection relays. Four methods are possible for this:

- Predict a value
- Measurement only during commissioning
- Permanent online measurement
- GPS time signal

The first method is not used since the error between the assumed and the real value will be too high.

The second method gives reliable data if direct communication between protection relays is applied. As signal propagation delays may change over a period of years, repeat measurements may be needed at intervals. In that case relays should be accordingly re-programmed.

There is a certain risk of maloperation due to variations in signal propagation time which can cause incorrect time synchronization between measurement intervals. The method is less suitable if rented fibre-optic pilots are used, since the owner may complete circuit re-routing for operational reasons without prior warning, resulting in the propagation delay being outside of limits and leading to protection system maloperation. Where re-routing is limited to several routes, it may be feasible to measure the delay on all routes and accordingly pre-program the protection relays. Relay digital inputs and ladder logic is used to discover route variations and chose the appropriate delay.

The third method, permanent online measurement of the signal propagation delay, also known as 'ping-pong', is a complex technique. One method of accomplishing this is presented in Figure 10.

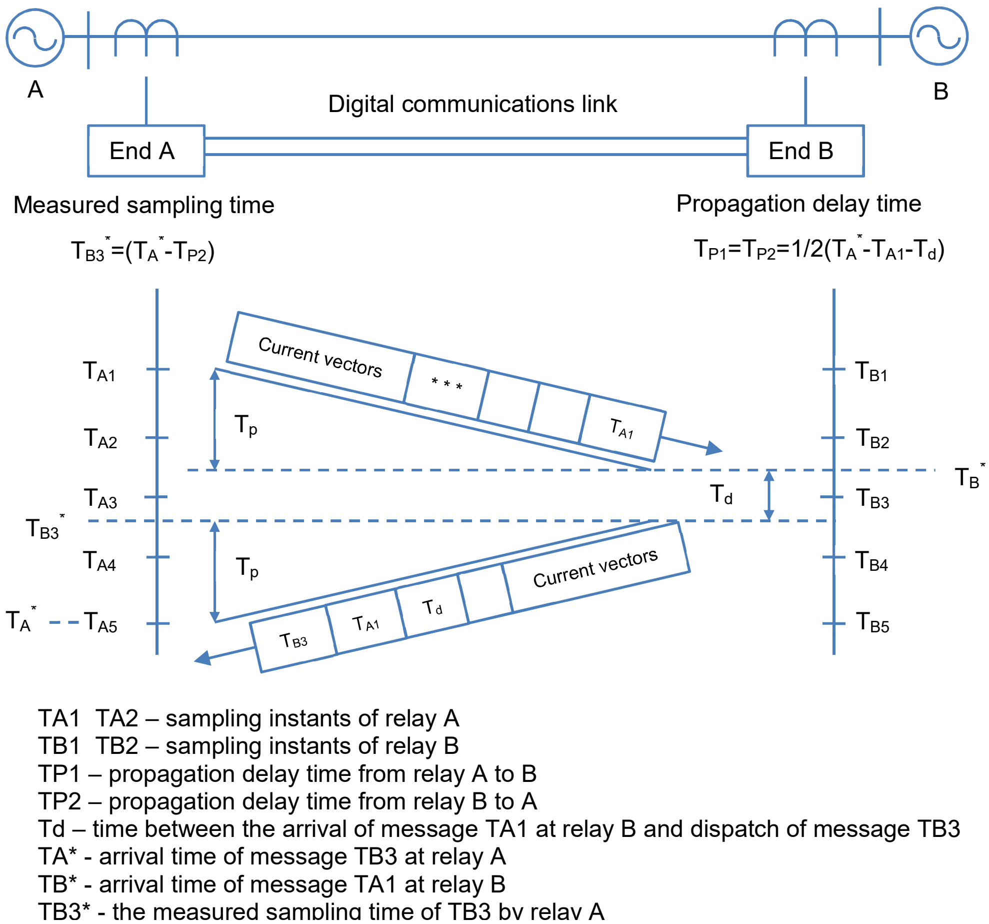


Figure 10. Signal propagation delay measurement

Protection relays at ends A and B sample signals at time TA1, TA2 … and TB1, TB2 … respectively. The times will not be simultaneous, even if they start coincidentally, due to little differences in sampling frequencies. At time TA1 relay A transfers its information to relay B, containing a time tag and other information. Relay B gets it at time TA1+Tp1 where Tp1 is the propagation time from protection relay A to relay B. Protection relay B enters this time as time TB*. Relay B also sends messages of identical format to relay A. It transfers such a message at time TB3, obtained by relay A at time TB3+Tp2 (say time TA*), where Tp2 is the propagation time from protection relay B to relay A. The message from protection relay B to relay A contains the time TB3, the last received time tag from relay A (TA1) and the delay time between the arrival time of the message from

A (TB*) and TB3. This can be called the delay time Td. Therefore, the total elapsed time is:

$$(T_{A^*} - T_{A1}) = (T_d + T_{p1} + T_{p2})$$

In the case it is assumed that Tp1 = Tp2, then the value of Tp1 and Tp2 can be computed, and hence also TB3. The protection relay B measured data as received at relay A can then be used to allow data comparison. Relay B completes similar computations using the data received from relay A (which also contains similar time data). Hence, continuous propagation delay measurement is completed. This reduces the possibility of maloperation. Comparison is completed out on a per-phase basis, so signal transfer and the computation are needed for each phase. A variation of this method is also available. It can cope with unequal propagation delays in the two communication channels under well-defined conditions. The method can also be used with all types of pilots, subject to provision of appropriate interfacing devices.

The fourth method is also a complex technique. It requires that both relays are capable of receiving a time signal from a GPS clock source. The propagation delay on each communication channel is no longer needed since both relays are synchronised to a common time signal. GPS signal must be reliable and clear for the protection scheme to meet the required performance in respect of availability and maloperation. Also, extra satellite signal equipment needs to be installed at both ends of the line, which introduces extra cost.

In applications where SONET (synchronous digital hierarchy) communication links are installed, it cannot be assumed that TP1 is same to TP2, as split path routings which differ from A to B, and B to A are possible. In this case, the forth method is highly suggested, since it can calculate the independent propagation delays in each direction. The minimum setting that can be accomplished with such methods while maintaining good stability is 20% of CT primary current.

Application to Mesh Corner and 1 1/2 Breaker Switched Substations

These substation schemes are quite frequent. Breaker and a half switched substation arrangement is presented in Figure 11. Problems happens when protecting the feeders due to the position of the line CTs, as either Bus 1, Bus 2 or both can supply the feeder. Two options are used to solve the problem, and they are presented in the Figure 11. The first is to common the line CT inputs (as shown for Feeder A) and the alternative is to apply a second set of CT inputs to the protection relay (as shown for Feeder B).

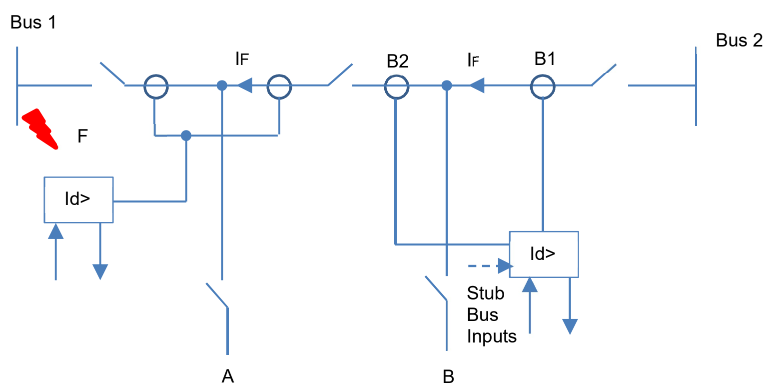


Figure 11. Breaker and a half switched substation arrangement

In the case of a through fault, the protection relay connected to Feeder A theoretically does not see unbalance current, and hence will be stable. Nevertheless, with the line disconnect switch open, no bias is generated in the relay, so CTs need to be properly matched and equally loaded if maloperation is to be prevented. For Feeder B, the protection relay theoretically does not see differential current. However, it will see a large bias current even with the line disconnect switch open. This generates a high degree of stability, in the case of transient asymmetric CT saturation. Hence, this method is preferred. Discovering the state of the line isolator through auxiliary contacts allows that current values are transmitted and received from remote relays. It also allows that current values are set to zero when the isolator is open. Therefore, stub-bus protection for the energised part of the bus is then possible. Any fault will result in tripping of the relevant CB.

Carrier Unit Protection Arrangements

In previous paragraphs, the pilot links between protection relays have been considered as an auxiliary wire circuit that interconnects relays at the protected zone boundaries. In many situations, such as the protection of longer line sections or where the route involves installation difficulties, it is too expensive to install an auxiliary cable circuit. Power system frequencies cannot be directly transferred on the communication medium in all situations. Instead a relaying quantity may be applied to vary the higher frequency related with each medium. This process is typically known to as modulation of a carrier wave. Demodulation or detection of the change at a remote receiver allows the relaying quantity to be reconstituted for use in conjunction with the relaying quantities locally derived. It makes the foundation for all unit protection carrier systems. Carrier systems are typically not sensitive to induced power system currents since the systems are made to function at much higher frequencies. However, each medium may be subjected to noise at the carrier frequencies that may interfere with its correct service. Differences in signal levels, restrictions of the available bandwidth for relaying and other features unique to each medium, impact the selection of the most appropriate arrangement.

Current Differential Arrangement – Analogue Techniques

The carrier channel is used in this arrangement to convey both the phase and magnitude of the current at one relaying point to another. This is done for comparison with the phase and magnitude of the current at the receiving point. Transmission methods may use either voice frequency channels with FM modulation or A/D converters and digital transmission. Signal propagation delays still need to be considered by introducing a deliberate delay in the locally derived signal before a comparison with the remote signal is completed.

An additional problem that may happen concerns the dynamic range of the protection arrangement. Since the fault current may be up to 30 times the rated current, a protection arrangement with linear characteristics demands a wide dynamic range, which implies a wide signal transmission bandwidth. In reality, bandwidth is limited, so either a nonlinear modulation feature has to be used or discovering fault currents close to the setpoint will be challenging.

Phase Comparison Arrangement

The carrier channel is used to convey the phase angle of the current at one relaying point to another for comparison with the phase angle of the current at that point. The basics of phase comparison are presented in Figure 12. The carrier channel transmits logic or 'on/off' signal that switches at the zero crossing points of the power frequency waveform. Comparison of a local logic signal with the corresponding signal from the remote end gives the basis for the measurement of phase shift between power system currents at the two ends. Therefore it provides discrimination between internal and through faults. Load or through fault currents at the two ends of a protected feeder are in anti-phase, whilst during an internal fault the currents tend towards the in-phase condition. Therefore, if the phase relationship of through fault currents is taken as a reference condition, internal faults create a phase shift of roughly 180° with respect to the reference condition. Phase comparison arrangements react to any phase shift from the reference conditions. However, tripping is normally allowed when the phase shift exceeds an angle of typically 30 to 90°. This angle is calculated by the time delay setting of the measurement circuit, and this angle is known as the Stability Angle. Figure 13 is a polar diagram that presents the discrimination feature that results from the measurement techniques used in phase comparison arrangements.

Blocking or permissive trip operation modes are possible. Nevertheless, Figure 12 presents the more usual blocking mode, since the comparator gives an output when neither squarer is at logic '1'. A permissive trip arrangement can be accomplished if the comparator is designed to give an output when both squarers are at logic '1'. Arrangement performance during failure or disturbance of the carrier channel and its ability to clear single-end-fed faults depends on the operation mode, the type and function of fault detectors or starting units, and the use of extra signals or codes for channel monitoring and transfer tripping.

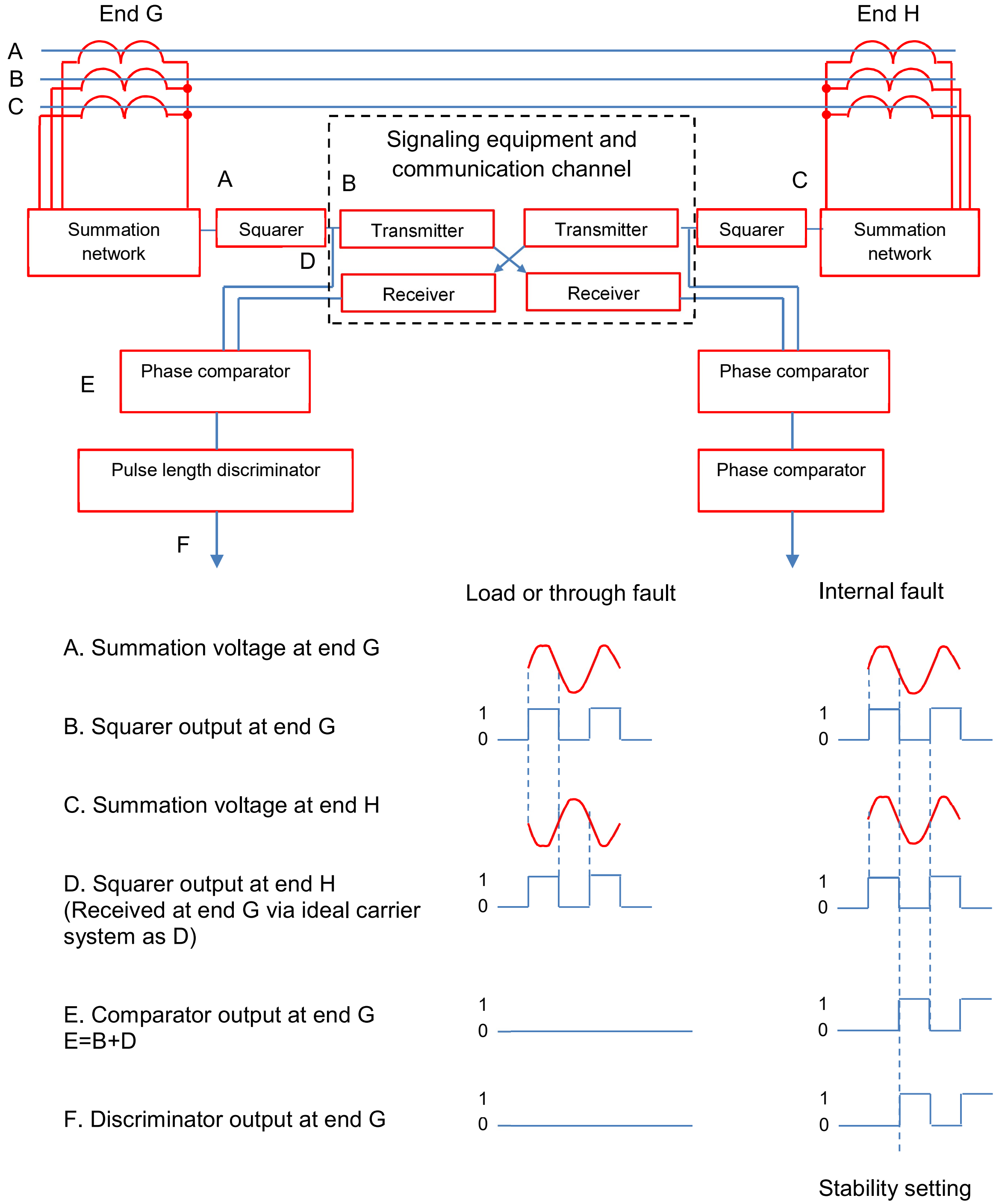


Figure 12. Principles of phase comparison protection

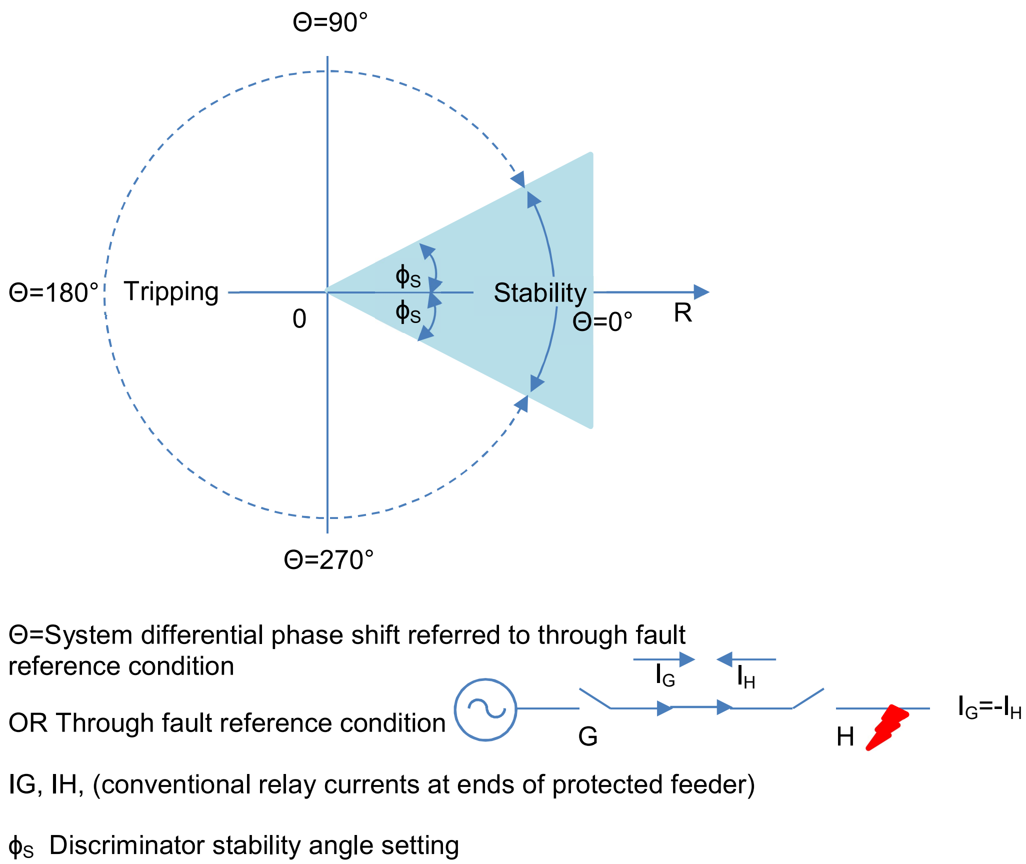


Figure 13. Polar diagram for phase comparison arrangement

Signal transmission is typically completed by voice frequency channels using frequency shift keying (FSK) or PLC techniques.

Voice frequency FSK channels use two discrete frequencies. This scheme is less sensitive to delay differences or frequency response than if the full bandwidth is used. Blocking or permissive trip operation modes may be used. In addition to the two frequencies used for transferring the squarer data, a third tone is frequently used, either for channel monitoring or transfer tripping. For a sensitive phase comparison arrangement, precise compensation for channel delay is needed. Nevertheless, since both the local and remote signals are logic pulses, simple time delay circuits can be applied, in contrast to the analogue delay circuitry typically needed for current differential arrangements.

The basics of the Power Line Carrier channel method are presented in Figure 14. The arrangement works in the blocking mode. The 'squarer' logic is directly used to turn a transmitter 'on' or 'off' at one end. The resultant burst (or block) of carrier is coupled to and spreads along the transmission line which is being protected to a receiver at the other end. Carrier signals above a threshold are discovered by the receiver, and therefore generate a logic signal corresponding to the block of carrier. In contrast to Figure 12, the signalling system is a 2-wire rather than 4-wire scheme, in which the local transmission is directly supplied to the local receiver along with any received signal. The transmitter frequencies at both ends are typically equal, so the receiver equally responds to blocks of carrier from either end. Through-fault current results in transmission of carrier blocks from both ends. Each lasts for half a cycle, and with a phase displacement of half a cycle, composite signal is permanently above the threshold level and the detector output logic is permanently '1'. Any phase shift relative to the through fault condition creates a gap in the composite carrier signal. Therefore, a corresponding '0' logic level from the detector is created. The duration of the logic '0' gives the basis for discrimination between internal and external faults, tripping being allowed only when a time delay setting is surpassed. This delay is typically showed in terms of the corresponding phase shift at system frequency φ_s, as shown in Figure 13.

The benefits typically related with the use of the power line as the communication medium include provision of robust, reliable, and low-loss interconnection between the relaying points. Also, dedicated 'on/off' signalling is especially suited for application in phase comparison blocking mode arrangements since signal attenuation is not an issue. This is in contrast to permissive or direct tripping arrangements, where high power output or boosting is needed to overcome the extra attenuation due to the fault.

The noise immunity is also great, making the arrangement very reliable. Signal propagation delay is easily allowed for in the stability angle setting, making the arrangement also very sensitive.

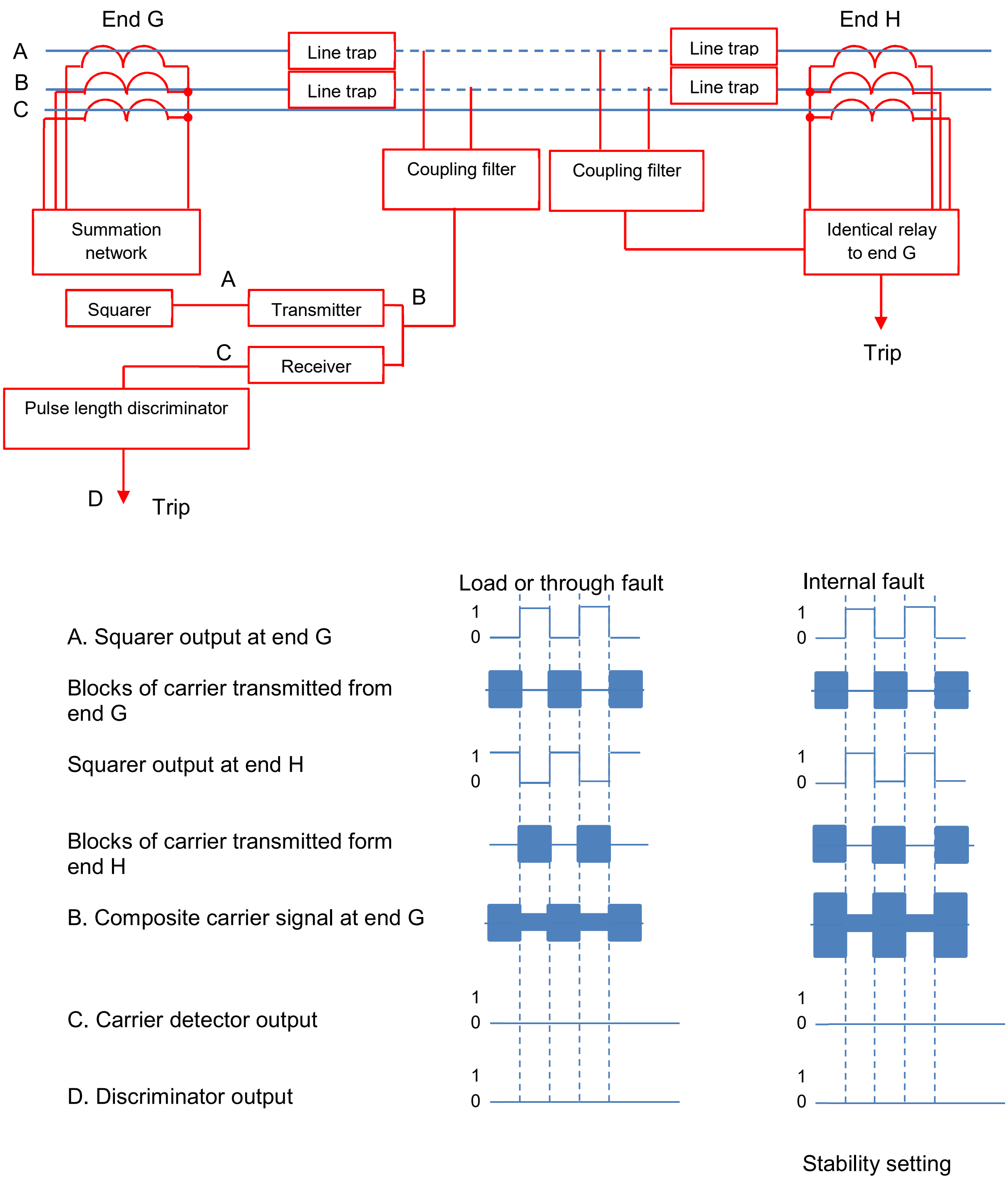


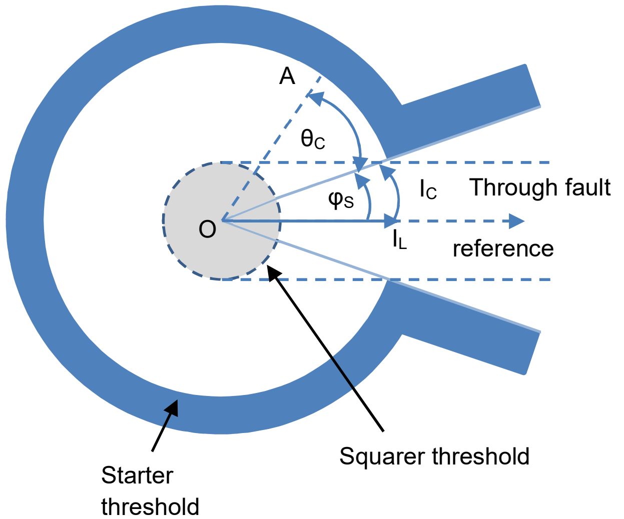
Figure 14. Basics of power line carrier phase comparison

Considerations of Phase Comparison Protection Arrangement

One type of unit protection that uses carrier methods for communication between protection relays is phase comparison protection. Communication between protection relays typically uses PLCC or frequency modulated carrier modem techniques. There are different considerations that apply only to phase comparison protection arrangements. These are discussed in next paragraphs.

Power Lines with Shunt Capacitance

A problem can happen with the shunt capacitance current that runs from an energising source. Since this current is in addition to the load current that runs out of the line, and commonly leads it by more than 90°, substantial differential phase shifts between the currents at the ends of the line can happen, especially when load current is low. The system differential phase shift may encroach into the tripping region of the simple discriminator characteristic, no matter of how large the stability angle setting may be. Figure 15 presents the effect and shows methods that are normally applied to ensure stability.



Limits of differential phase shift due to capacitive current Ic

Encroachment into tripping region for discriminator with stability angle setting φ_s

'Keyhole' characteristic
Minimum starter threshold = capacitive current / sinφ_S
where $\varphi_S=\tan^{-1}(I_C/I_L)$

Characteristic of system with amplitude dependent compensation φS=angular compensation for current of magnitude OA

($2\sin^{-1}(I_C/OA)$ for squarer threshold I_C)

I_L = load current

Figure 15. Capacitive current in phase comparison arrangements and methods used to avoid instability

Operation of the discriminator can be only allowed when current is above some threshold, so that measurement of the high differential phase shifts which happen near the origin of the polar diagram is averted. By selection of a suitable threshold and stability angle, a 'keyhole' characteristic can be provided so the capacitive current characteristic falls within the resultant stability region. Quick resetting of the fault detector is needed to assure stability following the clearance of a through fault. At that moment the currents tend to fall towards the origin of the polar diagram.

The mark-space ratio of the squarer (or modulating) waveform can be made dependent on the current magnitude. Any reduction in the mark-space ratio will allow a corresponding differential phase shift to happen between the currents before any output is provided from the comparator for measurement in the discriminator. A squarer circuit with an offset or bias can give a falling mark-space ratio at low currents. With an appropriate threshold level the extra phase shift θ_C which is permitted can be arranged to equal or exceed the phase shift due to capacitive current. At high current levels the capacitive current compensation decreases towards zero and the resultant stability region on the polar diagram is typically smaller than on the keyhole characteristic. This gives sensitivity improvements in and/or dependability of the arrangement. Since the stability region covers all through-fault currents, the resetting speed of any fault detectors or starter (which may still be needed for other needs, such as the control of a commonly quiescent scheme) is far less crucial than with the keyhole characteristic.

System Tripping Angles

For the protection arrangement to properly operate on internal faults the change in differential phase shift, θ_0, from the through fault condition taken as reference, must surpass the effective stability angle of the arrangement. Therefore:

$$\theta_0 \geq \emptyset_s + \theta_c$$

Where

$\emptyset_s$ – Stability angle setting

θ_c – Capacitive current compensation (when appropriate)
The currents at the ends of a power line I_G and I_H may be presented in terms of magnitude and phase shift θ with respect a common system voltage.

$$I_G = |I_G|\angle\theta_G$$

$$I_H = |I_H|\angle\theta_H$$

Using the relay convention presented in previous paragraphs, the reference through-fault situation is

$$I_G = -I_H$$

$$\therefore I_G \angle \theta_G = -I_H \angle \theta_H = I_H \angle \theta_H \pm 180°$$

$$\therefore |\theta_G - \theta_H| = 180°$$

During internal faults, the system tripping angle θ_0 is the differential phase shift relative to the reference condition.

$$\therefore \theta_0 = 180 - |\theta_G - \theta_H|$$

Substituting θ_0 in $\theta_0 \geq \emptyset_s + \theta_c$, the conditions for tripping are:

$$\theta_0 = 180 - |\theta_G - \theta_H| \geq \emptyset_S + \theta_C$$

$$\therefore |\theta_G - \theta_H| \leq 180 - (\emptyset_S + \theta_C)$$

The term ($\emptyset_S$ + θ_C) is the effective stability angle setting of the arrangement. Putting a common value of 60° in the last equation, gives the tripping condition as

$$|\theta_G - \theta_H| \leq 120°$$

In the absence of pre-fault load current, the voltages at the two ends of a line are in phase. Internal faults are supplied from both line ends with fault contributions whose magnitudes and angles are determined by the fault and the system source impedances positions. Even though the amplitudes may be markedly different, the angles (line plus source) are similar and rarely differ by more than about 20°.

Therefore, $|\theta_G - \theta_H| \leq 20^{\circ}$ and the requirements presented in $|\theta_G - \theta_H| \leq 120°$ are easily accomplished. The addition of arc or fault resistance makes no difference, so the arrangement is capable of clearing such faults.

Load Current Effect

When a line is heavily loaded before the fault the e.m.f.s of the sources which cause the fault current transfer may be displaced by up to about 50°, that is, the power system stability limit. To this the differential line and source angles of up to 20° presented above need to be taken into account. So $|\theta_G - \theta_H| \leq 70^{\circ}$ and the requirements of $|\theta_G - \theta_H| \leq 120°$ are still easily accomplished.

For three phase faults, or solid ground faults on phase-by-phase comparison arrangements, through load current decreases to zero during the fault and it does not have to be considered. For all other faults, load current keeps flowing in the healthy phases. Hence, it tends to increase $|\theta_G - \theta_H|$ towards the through fault reference value. For low resistance faults the fault current typically surpasses the load current and so has little effect. High resistance faults or the presence of a weak source at one end seems more challenging, but high performance can be accomplished if the modulating quantity is selected with care and/or fault detectors are installed.

Modulating Quantity

Phase-by-phase comparison arrangements typically use phase current for carrier modulation. Load and fault currents are in anti-phase at an end with a weak source. Right performance is achievable only when fault current surpasses load current, or

$$for\ I_F < I_L, |\theta_G - \theta_H| \approx 180°$$

$$for\ I_F > I_L, |\theta_G - \theta_H| \approx 0°$$

where

I_F = fault current infeed from weak source

I_L = load current running towards weak source

To prevent any risk of failure to trip, fault detectors with a setting higher than the maximum load current may be used, but they may limit arrangement the sensitivity. When the fault detector is not operated at one end, fault clearance invariably demands sequent tripping of the circuit breakers. Majority of the phase comparison arrangements use summation methods to generate a single modulating quantity, responsive to faults on any of the three phases. Phase sequence components are typically used and a common modulating quantity is

$$I_m = MI_2 + NI_1$$

Where

I_1 - Positive phase sequence component

I_2 - Negative phase sequence component

M, N - constants (N commonly negative)

With the exception of three phase faults all internal faults increase negative phase sequence (NPS) currents, I_2, which are roughly in phase at the line ends. Therefore, they could make an ideal modulating quantity. To generate a modulating signal during three phase faults, which increase positive phase sequence (PPS) currents, I_1, a practical modulating quantity has to consider some response to I_1 in addition to I_2.

Common values of the ratio M:N exceed 5:1, so that the modulating quantity is weighted heavily in favour of NPS, and any PPS related to load current tends to be swamped out on all but the highest resistance faults. For a high resistance phase-ground fault, the system stays well balanced so that load current I_L is completely positive sequence. The fault contribution I_F gives equal parts of positive, negative and zero sequence components $I_F/3$.

Assuming the short circuit is on 'A' phase and the load is resistive, all sequence components are in phase at the end G infeed.

$$\therefore \mathrm{I_{mG}} = \mathrm{NI_L} + \frac{\mathrm{MI_{FG}}}{3} + \frac{\mathrm{NI_{FG}}}{3} \therefore \theta_G \approx 0$$

At the outfeed, end load current is negative,

$$\therefore \mathrm{I_{mH}} = -\mathrm{NI_L} + \frac{\mathrm{MI_{FH}}}{3} + \frac{\mathrm{NI_{FH}}}{3}$$

For

$$\mathrm{I_{mH}} > 0, \theta_\mathrm{H} \approx 0 \;\therefore\; |\theta_\mathrm{G} - \theta_\mathrm{H}| = 0°$$

For

$$\mathrm{I_{mH}} < 0, \theta_\mathrm{H} \approx 180° \;\therefore\; |\theta_\mathrm{G} - \theta_\mathrm{H}| = 180°$$

Therefore, for correct operation $\mathrm{I_{mH}} \geq 0$

Let $\mathrm{I_{mH}} = 0$

Then $\mathrm{I_{FH}} = \frac{3\mathrm{I_L}}{\left(\frac{\mathrm{M}}{\mathrm{N}}+1\right)} = \mathrm{I_E}$

The fault current in above equation is the effective earth fault sensitivity I_E of the protection arrangement. For the common values of

$$M = 6 \; and \; N = -1, \frac{M}{N} = -6$$

$$\therefore I_E = -\frac{3}{5} I_L$$

Comparing this with

$$for \; I_F < I_L, |\theta_G - \theta_H| \approx 180°$$

$$for \; I_F > I_L, |\theta_G - \theta_H| \approx 0°$$

a scheme using summation is possibly 1.667 times more sensitive than one using phase current for modulation. Although, the use of a negative value of M provides a lower value of I_E than if it were positive, it is commonly preferred since the limiting condition of I_m = 0 then applies at the load infeed end. Load and fault components are additive at the outfeed end so that a correct modulating quantity happens there, even with the lowest fault levels. For scheme operation it is enough that the fault current contribution from the load infeed end surpasses the effective setting. For faults on B or C phases, the NPS components are displaced by 120° or 240° with respect to the PPS components. Simple cancellation cannot happen, but instead a phase displacement is introduced. For tripping to happen

$$\theta_0 = 180 - |\theta_G - \theta_H| \geq \emptyset_S + \theta_C$$

$$\therefore |\theta_G - \theta_H| \leq 180 - (\emptyset_S + \theta_C)$$

above equation must be satisfied, and to reach high dependability under these marginal conditions, a small effective stability angle is crucial. Very sensitive protection arrangements may be used by using high values of M/N but the arrangement then becomes more sensitive to differential errors in NPS currents. These include unbalanced components of capacitive current or spill from partially saturated CTs.

Methods such as capacitive current compensation and reduction of M/N at high fault levels may be needed to ensure arrangement stability.

Fault Starting and Detection

For a protection arrangement using a carrier system that continuously transfers the modulating quantity, protecting an ideal line (capacitive current = 0), measurement of current magnitude might not be needed. In reality, fault detector or starting elements are invariably given and the arrangement then becomes a permissive tripping scheme in which both the fault detector and the discriminator must operate to provide a trip output. Fault detector may limit the scheme sensitivity. Requirements for the fault detectors differ according to the type of used carrier channel, operation mode used in the phase angle measurement, that is, blocking or permissive, and the features used to give tolerance to capacitive current.

Typically Quiescent Power Line Carrier (Blocking Mode)

To ensure stability of through faults, it is crucial that carrier transmission starts before any measurement of the gap width is permitted. To allow for equipment tolerances and the magnitude difference of the two currents due to capacitive current, two starting elements are applied. There are typically referred to as 'Low Set' and 'High Set' respectively. Low Set controls the start-up of transmission whilst High Set, having a setting normally 1.5 to 2 times that of the Low Set element, allows the phase angle measurement to proceed. The use of impulse starters that respond to the current level change enables sensitivities of less than rated current. Resetting of the starters happens normally after a swell time or at the fault clearance. Dwell times and resetting characteristics must ensure that during through faults, a High Set is never operated when a Low Set has reset and potential race conditions are typically avoided by the transmitting of demodulated carrier for a short time following the reset of low set. This feature is often referred to as 'Marginal Guard.'

Arrangements without Capacitive Current Compensation

The 'keyhole' discrimination characteristic depends on the inclusion of a fault detector. It has to ensure that no measurements of phase angle can happen at low current levels, when the capacitive current might cause large phase shifts. Resetting needs to be very fast to ensure stability following the shedding of through load.

Arrangements with Capacitive Current Compensation (Blocking Mode)

When the magnitude of the modulating quantity is less than the threshold of the squarer, transmission if it happened, would be a continuous blocking signal. This might happen at an end with a weak source, remote from a fault close to a strong source. A fault detector is needed to allow transmission only when the current surpasses the modulator threshold by some multiple (normally about 2 times) so that the effective stability angle is not excessive. For PLCC arrangements, the low set element is normally used for this purpose. If the fault current is not sufficient to trip the fault detector, circuit breaker tripping will typically happen sequentially.

Fault Detector Operating Quantities

Most faults cause an increase in the corresponding phase current(s) so measurement of current increase could form the basis for fault detection. Nevertheless, when a line is heavily loaded and has a low fault level at the outfeed end, some faults can be accompanied by a fall in current. This leads to failure of such fault detection, resulting in sequential tripping (for blocking mode arrangements) or no tripping (for permissive arrangements). Even though fault detectors can be made to respond to any disturbance (increase or decrease of current), it is more common to use phase sequence components. All unbalanced faults generate a rise in the NPS components from the zero level related with balanced load current. Balanced faults generate an increase in the PPS components from the load level so that the use of NPS and PPS fault detectors make the arrangement sensitive to all faults. For arrangements using summation of NPS and PPS components for the modulating quantity, the use of NPS and PPS fault detectors is appropriate since, in addition to any hardware reductions, the arrangement may be characterised entirely in terms of sequence components. Fault sensitivities I_F for PPS and NPS impulse starter settings I_{1s} and I_{2s} respectively are as shown:

Three phase fault $I_F=I_{1S}$

Phase – phase fault $I_F = \sqrt{3}I_{2S}$

Phase – earth fault $I_F = 3I_{2S}$