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Fundamentals of Protection Practice

Network Protection & Automation Guide

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Chapter A1

Fundamentals of Protection Practice

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1. Introduction

The purpose of an electrical power system is to generate and supply electrical energy to consumers. The system should be designed and managed to deliver this energy to the utilisation points with both reliability and economy. Severe disruption to the normal routine of modern society is likely if power outages are frequent or prolonged, placing an increasing emphasis on reliability and security of supply. As the requirements of reliability and economy are largely opposed, power system design is inevitably a compromise.

A power system comprises many diverse items of equipment. Figure A1.2 shows a hypothetical power system; this and Figure A1.1 illustrates the diversity of equipment that is found.

Figure A1.1:
Power station

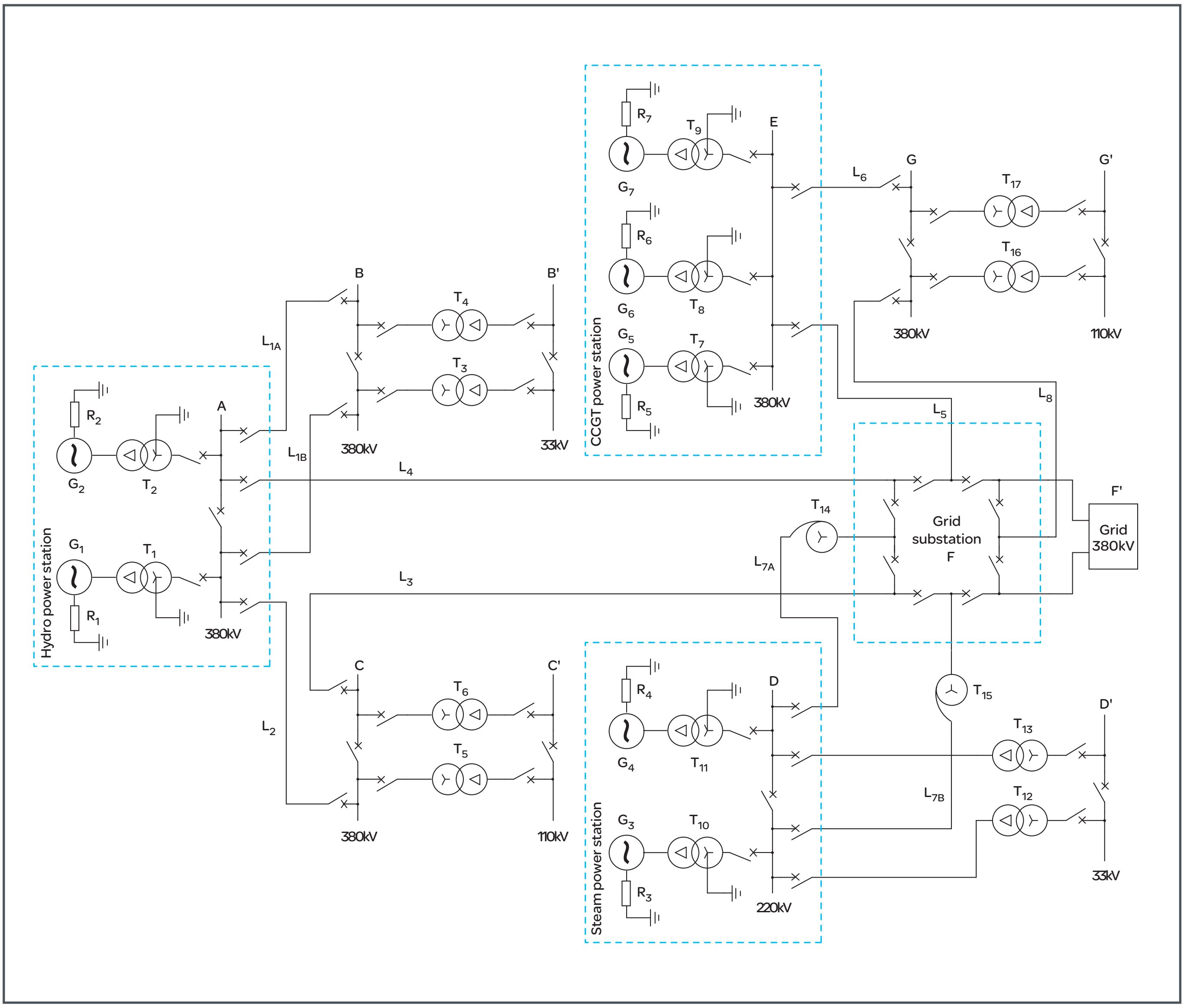

Figure A1.2:
Example power system

1. Introduction

Many items of equipment are very expensive, and so the complete power system represents a very large capital investment. To maximise the return on this outlay, the system must be utilised as much as possible within the applicable constraints of security and reliability of supply. More fundamental, however, is that the power system should operate in a safe manner at all times. No matter how well designed, faults will always occur on a power system, and these faults may represent a risk to life and/or property. Figure A1.3 shows the onset of a fault on an overhead line. The destructive power of a fault arc carrying a high current is very great; it can burn through copper conductors or weld together core laminations in a transformer or machine in a very short time – some tens or hundreds of milliseconds. Even away from the fault arc itself, heavy fault currents can cause damage to plant if they continue for more than a few seconds.

The provision of adequate protection to detect and disconnect elements of the power system in the event of fault is therefore an integral part of power system design. Only by so doing can the objectives of the power system be met and the investment protected. Figure A1.4 provides an illustration of the consequences of failure to provide appropriate protection.

This is the measure of the importance of protection systems as applied in power system practice and of the responsibility vested in the Protection Engineer.

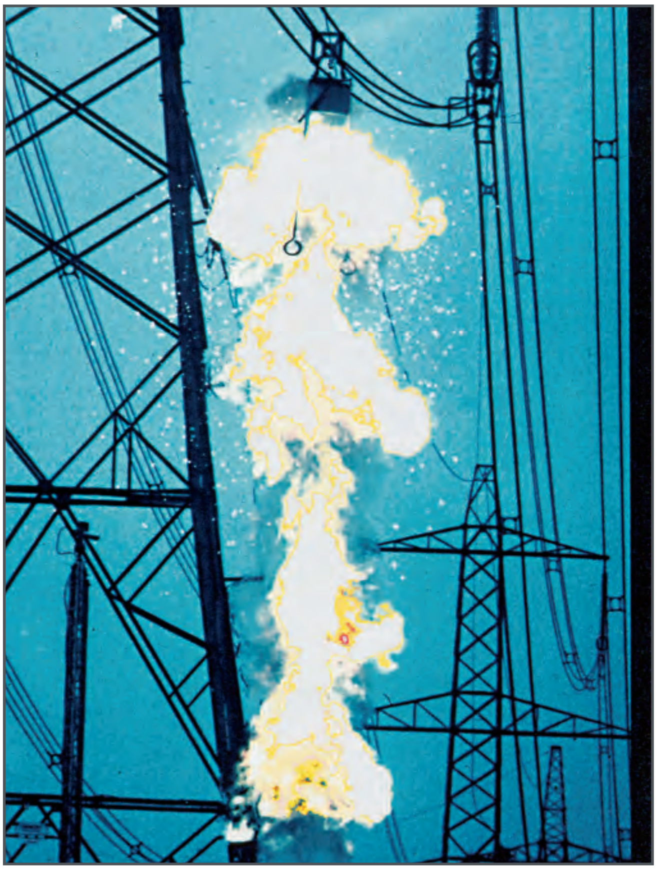

Figure A1.3:
Onset of an overhead line fault

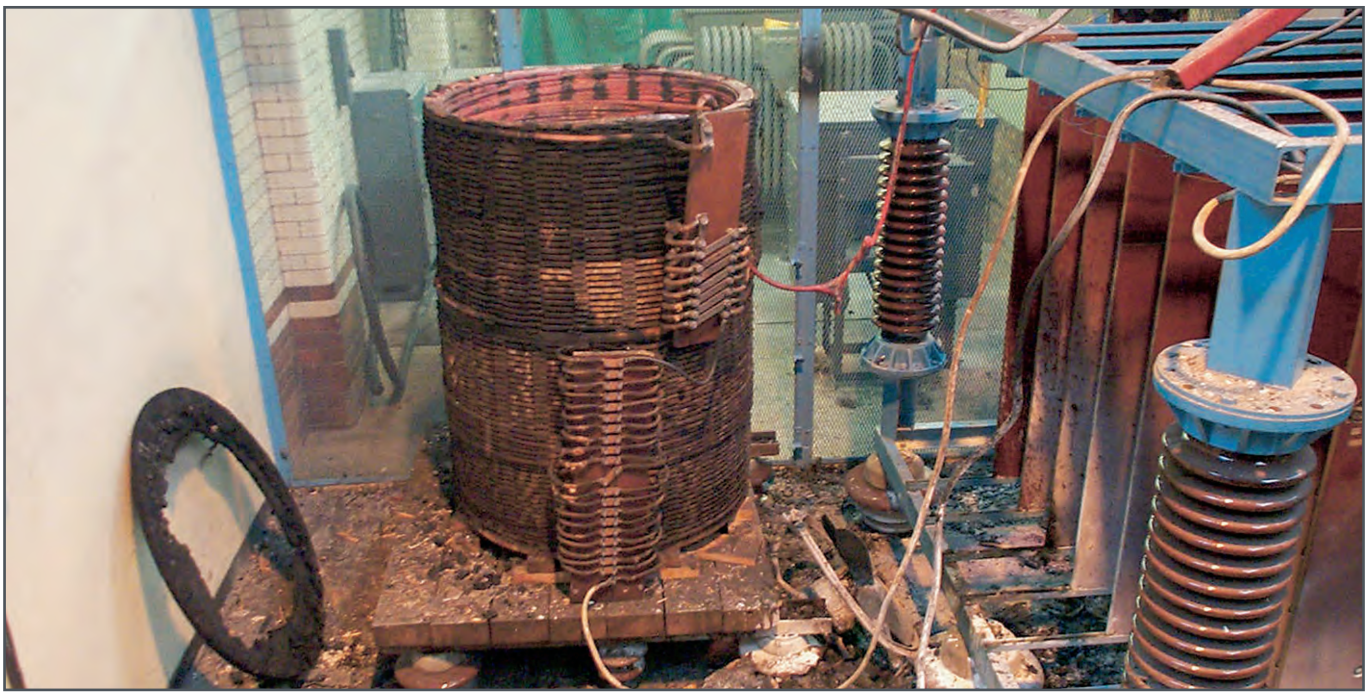

Figure A1.4:
Possible consequence of inadequate protection

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2. Protection equipment

The definitions that follow are generally used in relation to power system protection:

a. Protection System: a complete arrangement of protection equipment and other devices required to achieve a specified function based on a protection principal (IEC 60255-20)

b. Protection Equipment: a collection of protection devices (relays, fuses, etc.). Excluded are devices such as Current Transformers (CT's),Circuit Breakers (CB's), Contactors, etc.

c. Protection Scheme: a collection of protection equipment providing a defined function and including all equipment required to make the scheme work (i.e. relays, CT's, CB's, batteries, etc.)

In order to fulfill the requirements of protection with the optimum speed for the many different configurations, operating conditions and construction features of power systems, it has been necessary to develop many types of relay that respond to various functions of the power system quantities. For example, observation simply of the magnitude of the fault current suffices in some cases but measurement of power or impedance may be necessary in others. Relays frequently measure complex functions of the system quantities, which are only readily expressible by mathematical or graphical means.

Relays may be classified according to the technology used:

a. static

b. digital

c. numerical

The different types have somewhat different capabilities, due to the limitations of the technology used. They are described in more detail in Chapter [B1: Relay Technology].

In many cases, it is not feasible to protect against all hazards with a relay that responds to a single power system quantity. An arrangement using several quantities may be required. In this case, either several relays, each responding to a single quantity, or, more commonly, a single relay containing several elements, each responding independently to a different quantity may be used.

The terminology used in describing protection systems and relays is given in Appendix [AX1: Terminology]. Different symbols for describing relay functions in diagrams of protection schemes are used.The two most common methods (IEC and IEEE/ANSI) are provided in Appendix [AX2: ANSI & IEC Function References]. In addition these are cross referred to equivalent Logical Nodes from the IEC 61850 standard.

3. Zones of protection

To limit the extent of the power system that is disconnected when a fault occurs, protection is arranged in zones. The principle is shown in Figure A1.5. Ideally, the zones of protection should overlap, so that no part of the power system is left unprotected. This is shown in Figure A1.6(a), the circuit breaker being included in both zones.

For practical physical and economic reasons, this ideal is not always achieved, accommodation for current transformers being in some cases available only on one side of the circuit breakers, as in Figure A1.6(b). This leaves a section between the current transformers and the circuit breaker A that is not completely protected against faults. In Figure A1.6(b) a fault at F would cause the busbar protection to operate and open the circuit breaker but the fault may continue to be fed through the feeder. The feeder protection, if of the unit type (see section 5.2), would not operate, since the fault is outside its zone. This problem is dealt with by intertripping or some form of zone extension, to ensure that the remote end of the feeder is tripped also.

The point of connection of the protection with the power system usually defines the zone and corresponds to the location of the current transformers. Unit type protection will result in the boundary being a clearly defined closed loop. Figure A1.7 illustrates a typical arrangement of overlapping zones.

Alternatively, the zone may be unrestricted; the start will be defined but the extent (or 'reach') will depend on measurement of the system quantities and will therefore be subject to variation, owing to changes in system conditions and measurement errors.

3. Zones of protection

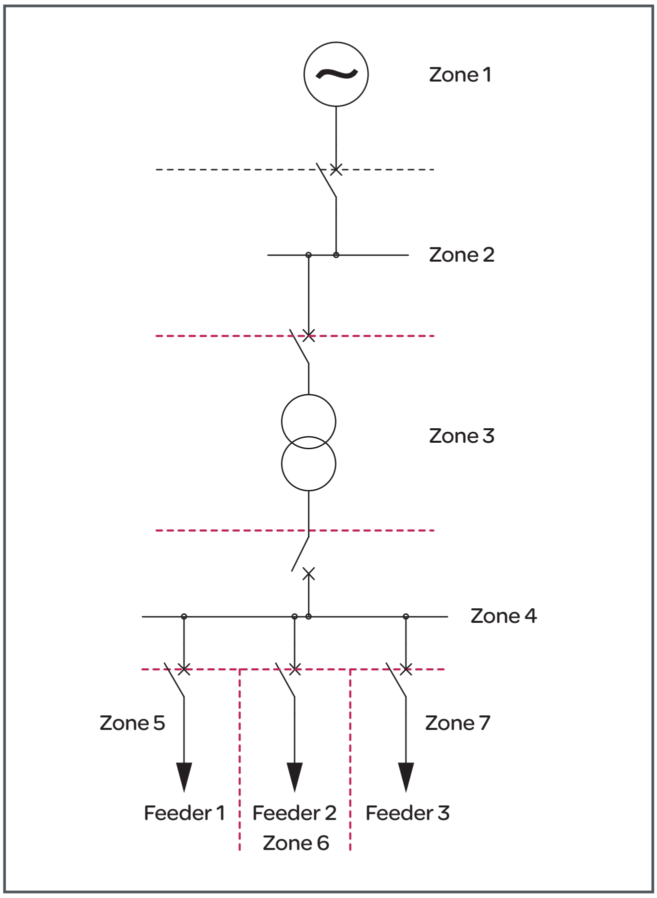

Figure A1.5:
Division of power system into protection zones

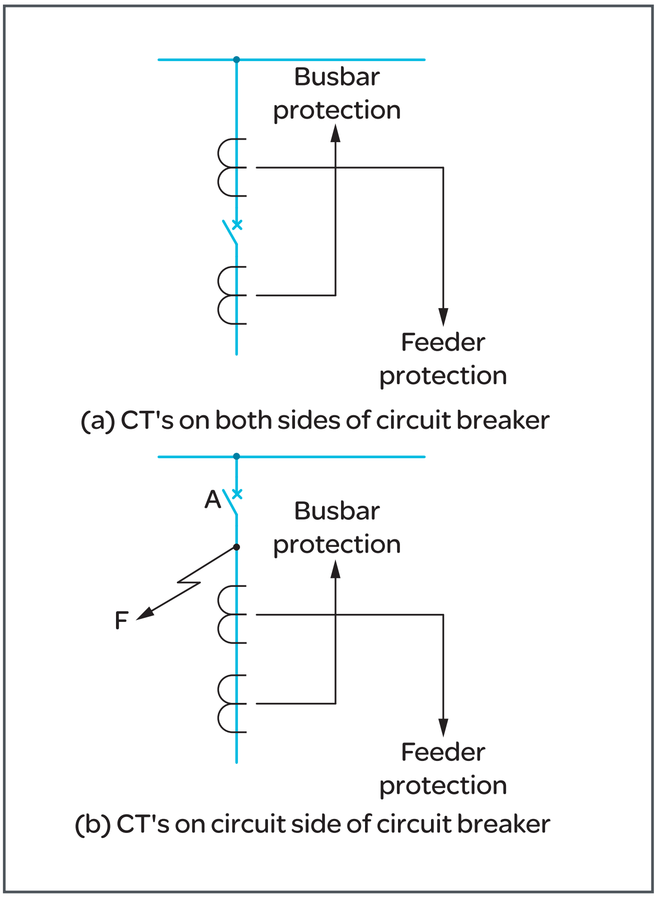

Figure A1.6:
CT locations

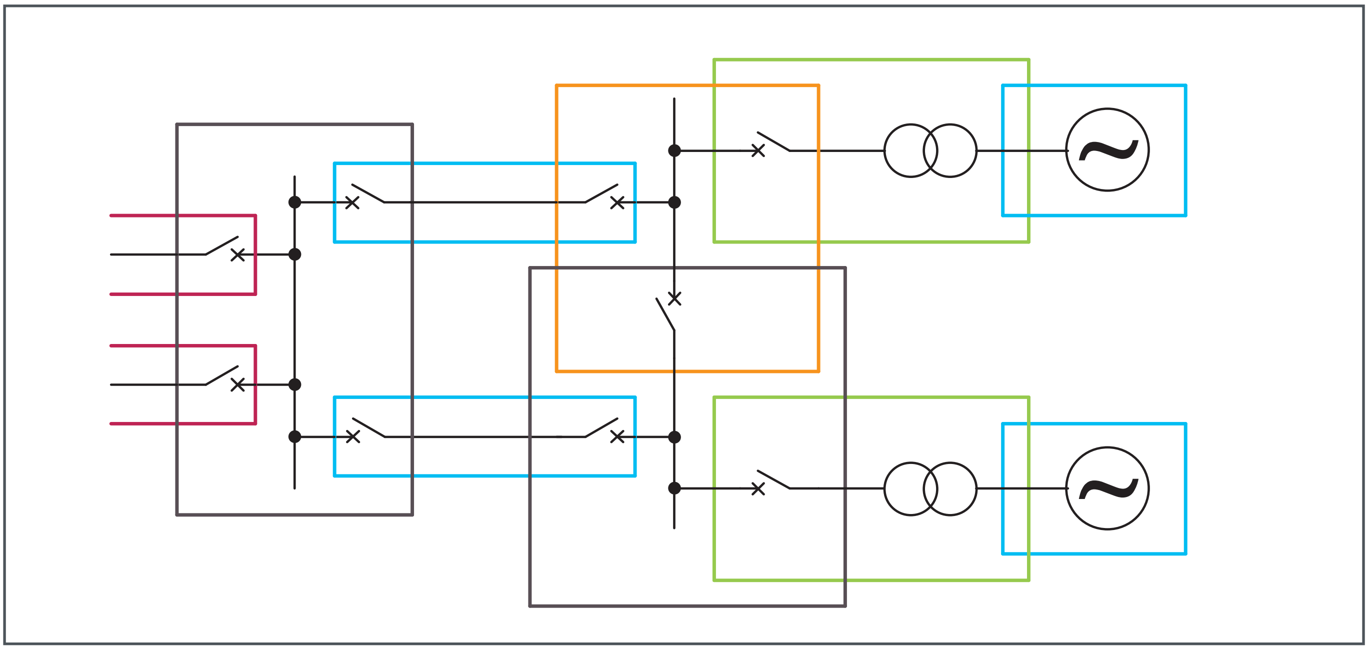

Figure A1.7:
Overlapping zones of protection systems

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4. Reliability

The need for a high degree of reliability is discussed in Section 1. Incorrect operation can be attributed to one of the following classifications:

a. incorrect design/settings

b. incorrect installation/testing

c. deterioration in service

4.1 Design

The design of a protection scheme is of paramount importance. This is to ensure that the system will operate under all required conditions, and (equally important) refrain from operating when so required (including, where appropriate, being restrained from operating for faults external to the zone being protected). Due consideration must be given to the nature, frequency and duration of faults likely to be experienced, all relevant parameters of the power system (including the characteristics of the supply source, and methods of operation) and the type of protection equipment used. Of course, no amount of effort at this stage can make up for the use of protection equipment that has not itself been subject to proper design.

4.2 Settings

It is essential to ensure that settings are chosen for protection relays and systems which take into account the parameters of the primary system, including fault and load levels, and dynamic performance requirements etc. The characteristics of power systems change with time, due to changes in loads, location, type and amount of generation, etc. Therefore, setting values of relays may need to be checked at suitable intervals to ensure that they are still appropriate. Otherwise, unwanted operation or failure to operate when required may occur.

4.3 Installation

The need for correct installation of protection systems is obvious, but the complexity of the interconnections of many systems and their relationship to the remainder of the installation may make checking difficult. Site testing is therefore necessary; since it will be difficult to reproduce all fault conditions correctly, these tests must be directed to proving the installation. The tests should be limited to such simple and direct tests as will prove the correctness of the connections, relay settings, and freedom from damage of the equipment. No attempt should be made to 'type test' the equipment or to establish complex aspects of its technical performance.

4.4 Testing

Comprehensive testing is just as important, and this testing should cover all aspects of the protection scheme, as well as reproducing operational and environmental conditions as closely as possible. Type testing of protection equipment to recognised standards fulfils many of these requirements, but it may still be necessary to test the complete protection scheme (relays, current transformers and other ancillary items) and the tests must simulate fault conditions realistically.

4.5 Deterioration in service

Subsequent to installation in perfect condition, deterioration of equipment will take place and may eventually interfere with correct functioning. For example, contacts may become rough or burnt owing to frequent operation, or tarnished owing to atmospheric contamination; coils and other circuits may become open-circuited, electronic components and auxiliary devices may fail, and mechanical parts may seize up.

The time between operations of protection relays may be years rather than days. During this period defects may have developed unnoticed until revealed by the failure of the protection to respond to a power system fault. For this reason, relays should be regularly tested in order to check for correct functioning.

Testing should preferably be carried out without disturbing permanent connections. This can be achieved by the provision of test blocks or switches.

The quality of testing personnel is an essential feature when assessing reliability and considering means for improvement. Staff must be technically competent and adequately trained, as well as self-disciplined to proceed in a systematic manner to achieve final acceptance.

Important circuits that are especially vulnerable can be provided with continuous electrical supervision; such arrangements are commonly applied to circuit breaker trip circuits and to pilot circuits. Digital and numerical relays usually incorporate self-testing/ diagnostic facilities to assist in the detection of failures. With these types of relay, it may be possible to arrange for such failures to be automatically reported by communications link to a remote operations centre, so that appropriate action may be taken to ensure continued safe operation of that part of the power system and arrangements put in hand for investigation and correction of the fault.

4.6 Protection performance

Protection system performance is frequently assessed statistically. For this purpose each system fault is classed as an incident and only those that are cleared by the tripping of the correct circuit breakers are classed as 'correct'. The percentage of correct clearances can then be determined.

This principle of assessment gives an accurate evaluation of the protection of the system as a whole, but it is severe in its judgement of relay performance. Many relays are called into operation for each system fault, and all must behave correctly for a correct clearance to be recorded.

Complete reliability is unlikely ever to be achieved by further improvements in construction. If the level of reliability achieved by a single device is not acceptable, improvement can be achieved through redundancy, e.g. duplication of equipment. Two complete, independent, main protection systems are provided, and arranged so that either by itself can carry out the required function. If the probability of each equipment failing is x/unit, the resultant probability of both equipments

4. Reliability

failing simultaneously, allowing for redundancy, is x2. Where x is small the resultant risk (x2) may be negligible.

Where multiple protection systems are used, the tripping signal can be provided in a number of different ways. The two most common methods are:

a. all protection systems must operate for a tripping operation to occur (e.g. 'two-out-of-two' arrangement)

b. only one protection system need operate to cause a trip (e.g.'one-out-of two' arrangement)

The former method guards against maloperation while the latter guards against failure to operate due to an unrevealed fault in a protection system. Rarely, three main protection systems are provided, configured in a 'two-out-of three' tripping arrangement, to provide both reliability of tripping, and security against unwanted tripping.

It has long been the practice to apply duplicate protection systems to busbars, both being required to operate to complete a tripping operation. Loss of a busbar may cause widespread loss of supply, which is clearly undesirable. In other cases, important circuits are provided with duplicate main protection systems, either being able to trip independently. On critical circuits, use may also be made of a fault simulator to model the relevant section of the power system and check the performance of the relays used.

5. Selectivity

When a fault occurs, the protection scheme is required to trip only those circuit breakers whose operation is required to isolate the fault. This property of selective tripping is also called 'discrimination' and is achieved by two general methods.

5.1 Time grading

Protection systems in successive zones are arranged to operate in times that are graded through the sequence of equipments so that upon the occurrence of a fault, although a number of protection equipments respond, only those relevant to the faulty zone complete the tripping function. The others make incomplete operations and then reset. The speed of response will often depend on the severity of the fault, and will generally be slower than for a unit system.

5.2 Unit systems

It is possible to design protection systems that respond only to fault conditions occurring within a clearly defined zone. This type of protection system is known as 'unit protection'. Certain types of unit protection are known by specific names, e.g. restricted earth fault and differential protection. Unit protection can be applied throughout a power system and, since it does not involve time grading, is relatively fast in operation. The speed of response is substantially independent of fault severity.

Unit protection usually involves comparison of quantities at the boundaries of the protected zone as defined by the locations of the current transformers. This comparison may be achieved by direct hard-wired connections or may be achieved via a communications link. However certain protection systems derive their 'restricted' property from the configuration of the power system and may be classed as unit protection, e.g. earth fault protection applied to the high voltage delta winding of a power transformer. Whichever method is used, it must be kept in mind that selectivity is not merely a matter of relay design. It also depends on the correct co- ordination of current transformers and relays with a suitable choice of relay settings, taking into account the possible range of such variables as fault currents, maximum load current, system impedances and other related factors, where appropriate.

6. Stability

The term 'stability' is usually associated with unit protection schemes and refers to the ability of the protection system to remain unaffected by conditions external to the protected zone, for example through load current and external fault conditions.

7. Speed

The function of protection systems is to isolate faults on the power system as rapidly as possible. The main objective is to safeguard continuity of supply by removing each disturbance before it leads to widespread loss of synchronism and consequent collapse of the power system.

As the loading on a power system increases, the phase shift between voltages at different busbars on the system also increases, and therefore so does the probability that synchronism will be lost when the system is disturbed by a fault. The shorter the time a fault is allowed to remain in the system, the greater can be the loading of the system. Figure A1.8 shows typical relations between system loading and fault clearance times for various types of fault. It will be noted that phase faults have a more marked effect on the stability of the system than a simple earth fault and therefore require faster clearance.

System stability is not, however, the only consideration. Rapid operation of protection ensures that fault damage is minimised, as energy liberated during a fault is proportional to the square of the fault current times the duration of the fault. Protection must thus operate as quickly as possible but speed of operation must be weighed against economy. Distribution circuits, which do not normally require a fast fault clearance, are usually protected by time-graded systems. Generating plant and EHV systems require protection gear of the highest attainable speed; the only limiting factor will be the necessity for correct operation, and therefore unit systems are normal practice.

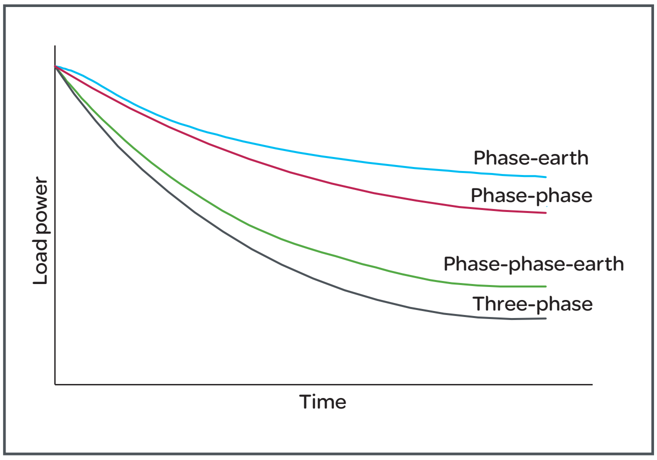

Figure A1.8:
Typical power/time relationship for various fault types

8. Sensitivity

Sensitivity is a term frequently used when referring to the minimum operating level (current, voltage, power etc.) of relays or complete protection schemes. The relay or scheme is said to be sensitive if the primary operating parameter(s) is low.

With older electromechanical relays, sensitivity was considered in terms of the sensitivity of the measuring movement and was measured in terms of its volt-ampere consumption to cause operation. With digital and numerical relays the achievable sensitivity is seldom limited by the device design but by its application and CT/VT parameters.

9. Primary and back-up protection

The reliability of a power system has been discussed earlier, including the use of more than one primary (or 'main') protection system operating in parallel. In the event of failure or non- availability of the primary protection some other means of ensuring that the fault is isolated must be provided. These secondary systems are referred to as 'back-up protection'.

Back-up protection may be considered as either being 'local' or 'remote'. Local back-up protection is achieved by protection which detects an un-cleared primary system fault at its own location and which then trips its own circuit breakers, e.g. time graded overcurrent relays. Remote back-up protection is provided by protection that detects an un-cleared primary system fault at a remote location and then issues a local trip command, e.g. the second or third zones of a distance relay. In both cases the main and back-up protection systems detect a fault simultaneously, operation of the back-up protection being delayed to ensure that the primary protection clears the fault if possible. Normally being unit protection, operation of the primary protection will be fast and will result in the minimum amount of the power system being disconnected. Operation of the back-up protection will be, of necessity, slower and will result in a greater proportion of the primary system being lost.

The extent and type of back-up protection applied will naturally be related to the failure risks and relative economic importance of the system. For distribution systems where fault clearance times are not critical, time delayed remote back-up protection may be adequate. For EHV systems, where system stability is at risk unless a fault is cleared quickly, multiple primary protection systems, operating in parallel and possibly of different types (e.g. distance and unit protection), will be used to ensure fast and reliable tripping. Back-up overcurrent protection may then optionally be applied to ensure that two separate protection systems are available during maintenance of one of the primary protection systems.

Back-up protection systems should, ideally, be completely separate from the primary systems. For example a circuit protected by a current differential relay may also have time graded overcurrent and earth fault relays added to provide circuit breaker tripping in the event of failure of the main primary unit protection. To maintain complete separation and thus integrity, current transformers, voltage transformers, relays, circuit breaker trip coils and d.c. supplies would be duplicated. This ideal is rarely attained in practice.

The following compromises are typical:

a. separate current transformers (cores and secondary windings only) are provided. This involves little extra cost or accommodation compared with the use of common current transformers that would have to be larger because of the combined burden. This practice is becoming less common when digital or numerical relays are used, because of the extremely low input burden of these relay types

b. voltage transformers are not duplicated because of cost and space considerations. Each protection relay supply is separately protected (fuse or MCB) and continuously supervised to ensure security of the VT output. An alarm is given on failure of the supply and, where appropriate, prevent an unwanted operation of the protection

c. trip supplies to the two protections should be separately protected (fuse or MCB). Duplication of tripping batteries and of circuit breaker tripping coils may be provided. Trip circuits should be continuously supervised

d. it is desirable that the main and back-up protections (or duplicate main protections) should operate on different principles, so that unusual events that may cause failure of the one will be less likely to affect the other

Digital and numerical relays may incorporate suitable back-up protection functions (e.g. a distance relay may also incorporate time-delayed overcurrent protection elements as well). A reduction in the hardware required to provide back-up protection is obtained, but at the risk that a common relay element failure (e.g. the power supply) will result in simultaneous loss of both main and back-up protection. The acceptability of this situation must be evaluated on a case-by-case basis.

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10. Output devices

In order to perform their intended function, relays must be fitted with some means of providing the various output signals required. Contacts of various types usually fulfill this function.

10.1 Contact systems

Relays may be fitted with a variety of contact systems for providing electrical outputs for tripping and remote indication purposes. The most common types encountered are as follows:

a. Self-reset
The contacts remain in the operated condition only while the controlling quantity is applied, returning to their original condition when it is removed

b. Hand or electrical reset
These contacts remain in the operated condition after the controlling quantity is removed. They can be reset either by hand or by an auxiliary electromagnetic element

The majority of protection relay elements have self-reset contact systems, which, if so desired, can be modified to provide hand reset output contacts by the use of auxiliary elements. Hand or electrically reset relays are used when it is necessary to maintain a signal or lockout condition. Contacts are shown on diagrams in the position corresponding to the un-operated or de-energised condition, regardless of the continuous service condition of the equipment. For example, an undervoltage relay, which is continually energised in normal circumstances, would still be shown in the de-energised condition.

A 'make' contact is one that closes when the relay picks up, whereas a 'break' contact is one that is closed when the relay is de-energised and opens when the relay picks up. Examples of these conventions and variations are shown in Figure A1.9.

A protection relay is usually required to trip a circuit breaker, the tripping mechanism of which may be a solenoid with a plunger acting directly on the mechanism latch or an electrically operated valve. The power required by the trip coil of the circuit breaker may range from up to 50 watts for a small 'distribution' circuit breaker, to 3000 watts for a large, extra-high-voltage circuit breaker.

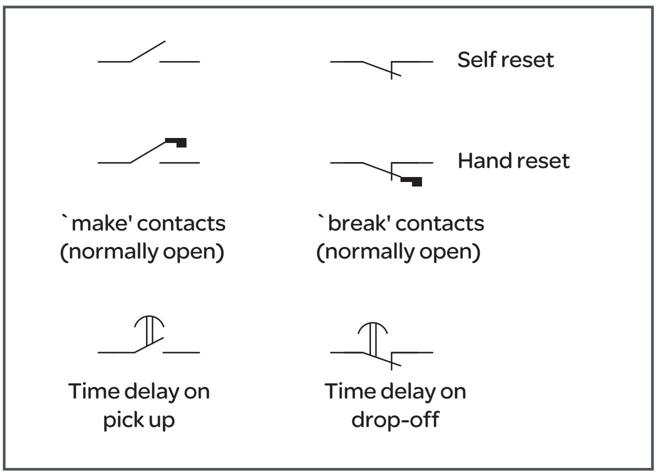


Figure A1.9: Contact types

The relay may therefore energise the tripping coil directly, or, according to the coil rating and the number of circuits to be energised, may do so through the agency of another multi-contact auxiliary relay.

The basic trip circuit is simple, being made up of a hand-trip control switch and the contacts of the protection relays in parallel to energise the trip coil from a battery, through a normally open auxiliary switch operated by the circuit breaker. This auxiliary switch is needed to open the trip circuit when the circuit breaker opens since the protection relay contacts will usually be quite incapable of performing the interrupting duty.

The auxiliary switch will be adjusted to close as early as possible in the closing stroke, to make the protection effective in case the breaker is being closed onto a fault.

Where multiple output contacts, or contacts with appreciable current-carrying capacity are required, interposing, contactor type elements will normally be used.

In general, static and microprocessor relays have discrete measuring and tripping circuits, or modules. The functioning of the measuring modules is independent of operation of the tripping modules. Such a relay is equivalent to a sensitive electromechanical relay with a tripping contactor, so that the number or rating of outputs has no more significance than the fact that they have been provided.

For larger switchgear installations the tripping power requirement of each circuit breaker is considerable, and further, two or more breakers may have to be tripped by one protection system. There may also be remote signalling requirements, interlocking with other functions (for example auto-reclosing arrangements), and other control functions to be performed. These various operations may then be carried out by multi-contact tripping relays, which are energised by the protection relays and provide the necessary number of adequately rated output contacts.

10.2 Operation indicators

Electrical indicators may be simple attracted armature elements, where operation of the armature releases a shutter to expose an indicator as above, or indicator lights (usually light emitting diodes). For the latter, some kind of memory circuit is provided to ensure that the indicator remains lit after the initiating event has passed.

With the advent of digital and numerical relays, the operation indicator has almost become redundant. Relays will be provided with one or two simple indicators that indicate that the relay is powered up and whether an operation has occurred. The remainder of the information previously presented via indicators is available by interrogating the relay locally via a 'Human Machine Interface' (e.g. a keypad and liquid crystal display screen), or remotely via a communication system.

11. Tripping circuits

There are three main circuits in use for circuit breaker tripping:

a. series sealing

b. shunt reinforcing

c. shunt reinforcement with sealing

These are illustrated in Figure A1.10.

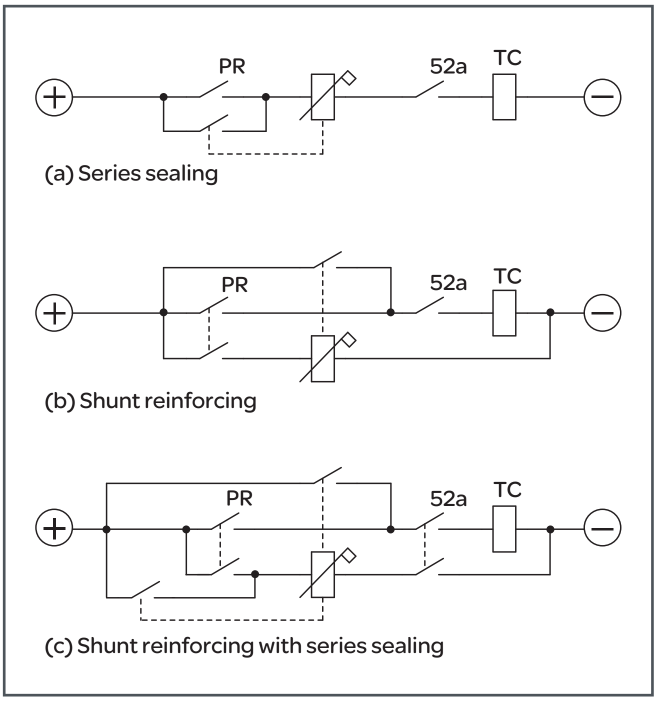


Figure A1.10:
Typical relay tripping circuits

For electromechanical relays, electrically operated indicators, actuated after the main contacts have closed, avoid imposing an additional friction load on the measuring element, which would be a serious handicap for certain types. Care must be taken with directly operated indicators to line up their operation with the closure of the main contacts. The indicator must have operated by the time the contacts make, but must not have done so more than marginally earlier. This is to stop indication occurring when the tripping operation has not been completed. With protection relays, the use of various alternative methods of providing trip circuit functions is largely obsolete. Auxiliary miniature contactors are provided within the relay to provide output contact functions and the operation of these contactors is independent of the measuring system, as mentioned previously. The making current of the relay output contacts and the need to avoid these contacts breaking the trip coil current largely dictates circuit breaker trip coil arrangements. Comments on the various means of providing tripping arrangements are, however, included below as a historical reference applicable to earlier electromechanical relay designs.

11.1 Series sealing

The coil of the series contactor carries the trip current initiated by the protection relay, and the contactor closes a contact in parallel with the protection relay contact. This closure relieves the protection relay contact of further duty and keeps the tripping circuit securely closed, even if chatter occurs at the main contact. The total tripping time is not affected, and the indicator does not operate until current is actually flowing through the trip coil.

The main disadvantage of this method is that such series elements must have their coils matched with the trip circuit with which they are associated.

The coil of these contacts must be of low impedance, with about 5% of the trip supply voltage being dropped across them.

When used in association with high-speed trip relays, which usually interrupt their own coil current, the auxiliary elements must be fast enough to operate and release the flag before their coil current is cut off. This may pose a problem in design if a variable number of auxiliary elements (for different phases and so on) may be required to operate in parallel to energise a common tripping relay.

11.2 Shunt reinforcing

Here the sensitive contacts are arranged to trip the circuit breaker and simultaneously to energise the auxiliary unit, which then reinforces the contact that is energising the trip coil.

Two contacts are required on the protection relay, since it is not permissible to energise the trip coil and the reinforcing contactor in parallel. If this were done, and more than one protection relay were connected to trip the same circuit breaker, all the auxiliary relays would be energised in parallel for each relay operation and the indication would be confused.

The duplicate main contacts are frequently provided as a three-point arrangement to reduce the number of contact fingers.

11.3 Shunt reinforcement with sealing

This is a development of the shunt reinforcing circuit to make it applicable to situations where there is a possibility of contact bounce for any reason.

Using the shunt reinforcing system under these circumstances would result in chattering on the auxiliary unit, and the possible burning out of the contacts, not only of the sensitive element but also of the auxiliary unit. The chattering would end only when the circuit breaker had finally tripped. The effect of contact bounce is countered by means of a further contact on the auxiliary unit connected as a retaining contact.

This means that provision must be made for releasing the sealing circuit when tripping is complete; this is a disadvantage, because it is sometimes inconvenient to find a suitable contact to use for this purpose.

12. Trip circuit supervision

The trip circuit includes the protection relay and other components, such as fuses, links, relay contacts, auxiliary switch contacts, etc., and in some cases through a considerable amount of circuit wiring with intermediate terminal boards. These interconnections coupled with the importance of the circuit, result in a requirement in many cases to monitor the integrity of the circuit. This is known as trip circuit supervision. The simplest arrangement contains a healthy trip lamp, as shown in Figure A1.11(a).

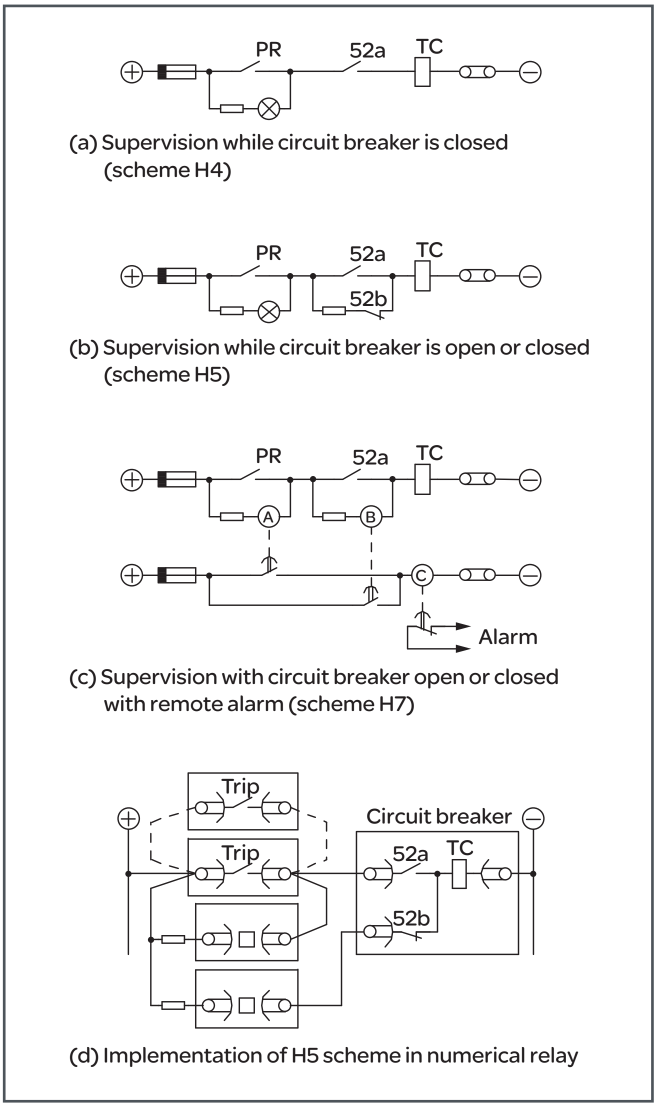


Figure A1.11:
Typical relay tripping circuits

The resistance in series with the lamp prevents the breaker being tripped by an internal short circuit caused by failure of the lamp. This provides supervision while the circuit breaker is closed; a simple extension gives pre-closing supervision.

Figure A1.11(b) shows how, the addition of a normally closed auxiliary switch and a resistance unit can provide supervision while the breaker is both open and closed.

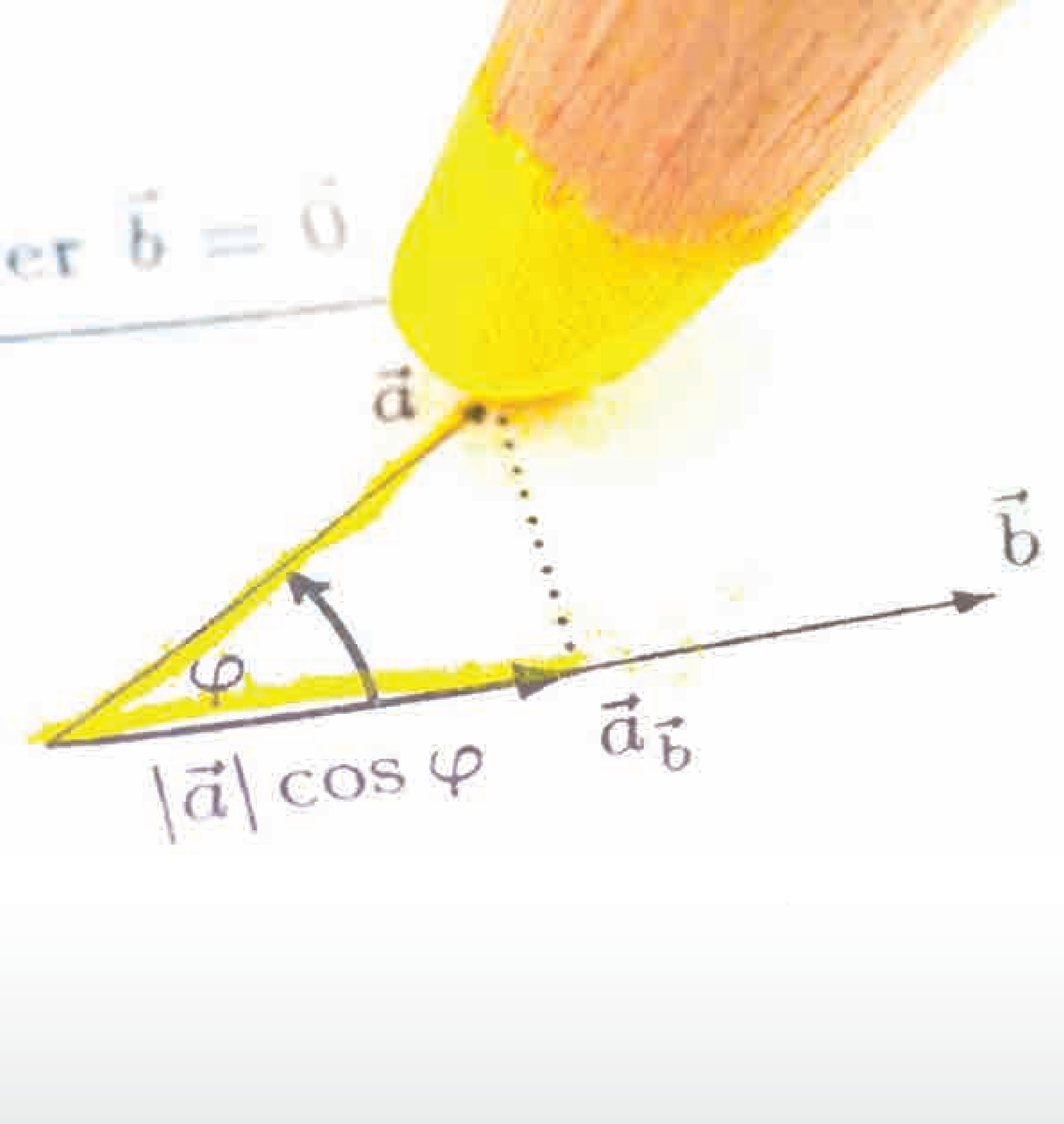
In either case, the addition of a normally open push-button contact in series with the lamp will make the supervision indication available only when required.

Schemes using a lamp to indicate continuity are suitable for locally controlled installations, but when control is exercised from a distance it is necessary to use a relay system. Figure A1.11(c) illustrates such a scheme, which is applicable wherever a remote signal is required.

With the circuit healthy, either or both of relays A and B are operated and energise relay C. Both A and B must reset to allow C to drop- off. Relays A, B and C are time delayed to prevent spurious alarms during tripping or closing operations. The resistors are mounted separately from the relays and their values are chosen such that if any one component is inadvertently short-circuited, tripping will not take place.

The alarm supply should be independent of the tripping supply so that indication will be obtained in case of failure of the tripping supply.

The above schemes are commonly known as the H4, H5 and H7 schemes, arising from the diagram references of the utility specification in which they originally appeared. Figure A1.11(d) shows implementation of scheme H5 using the facilities of a modern numerical relay. Remote indication is achieved through use of programmable logic and additional auxiliary outputs available in the protection relay.



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Fundamental Theory

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Chapter A2

Fundamental Theory

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1. Introduction

The Protection Engineer is concerned with limiting the effects of disturbances in a power system. These disturbances, if allowed to persist, may damage plant and interrupt the supply of electric energy. They are described as faults (short and open circuits) or power swings, and result from natural hazards (for instance lightning), plant failure or human error.

To facilitate rapid removal of a disturbance from a power system, the system is divided into 'protection zones'. Relays monitor the system quantities (current, voltage) appearing in these zones; if a fault occurs inside a zone, the relays operate to isolate the zone from the remainder of the power system.

The operating characteristic of a relay depends on the energising quantities fed to it such as current or voltage, or various combinations of these two quantities, and on the manner in which the relay is designed to respond to this information. For example, a directional relay characteristic would be obtained by designing the relay to compare the phase angle between voltage and current at the relaying point. An impedance-measuring characteristic, on the other hand, would be obtained by designing the relay to divide voltage by current. Many other more complex relay characteristics may be obtained by supplying various combinations of current and voltage to the relay. Relays may also be designed to respond to other system quantities such as frequency, power, etc.

In order to apply protection relays, it is usually necessary to know the limiting values of current and voltage, and their relative phase displacement at the relay location, for various types of short circuit and their position in the system. This normally requires some system analysis for faults occurring at various points in the system.

The main components that make up a power system are generating sources, transmission and distribution networks, and loads. Many transmission and distribution circuits radiate from key points in the system and these circuits are controlled by circuit breakers. For the purpose of analysis, the power system is treated as a network of circuit elements contained in branches radiating from nodes to form closed loops or meshes. The system variables are current and voltage, and in steady state analysis, they are regarded as time varying quantities at a single and constant frequency. The network parameters are impedance and admittance; these are assumed to be linear, bilateral (independent of current direction) and constant for a constant frequency.

2. Vector algebra

A vector represents a quantity in both magnitude and direction. In Figure A2.1 the vector OP has a magnitude $|Z|$ at an angle θ with the reference axis OX.

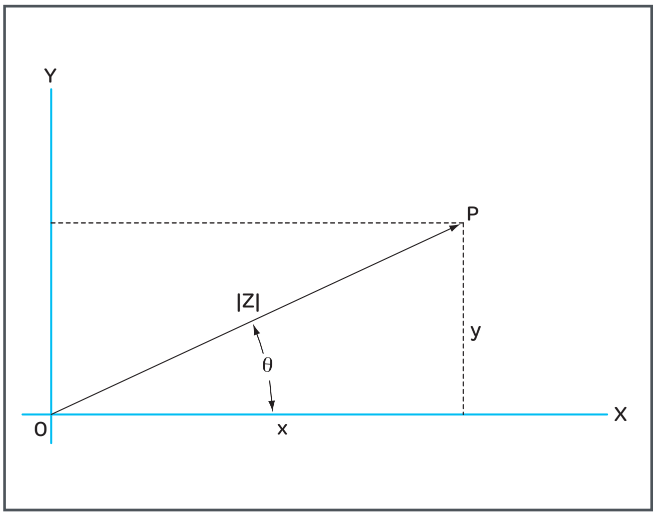

Figure A2.1: Vector OP

It may be resolved into two components at right angles to each other, in this case x and y. The magnitude or scalar value of vector Z is known as the modulus $|Z|$, and the angle θ is the argument, and is written as arg $\overline{Z}$.

The conventional method of expressing a vector $\overline{Z}$ is to write simply $|Z| \angle \theta$.

This form completely specifies a vector for graphical representation or conversion into other forms.

For vectors to be useful, they must be expressed algebraically. In Figure A2.1, the vector $\overline{Z}$ is the resultant of vectorially adding its components x and y; algebraically this vector may be written as:

$$\overline{Z} = x + jy \quad \text{...Equation A2.1}$$

where the operator j indicates that the component y is perpendicular to component x. In electrical nomenclature, the axis OC is the 'real' or 'in-phase' axis, and the vertical axis OY is called the 'imaginary' or 'quadrature' axis. The operator j rotates a vector anti-clockwise through 90°. If a vector is made to rotate anti-clockwise through 180°, then the operator j has performed its function twice, and since the vector has reversed its sense, then:

2. Vector algebra

$j \times j$ or $j^2 = -1$

whence $j = \sqrt{-1}$

The representation of a vector quantity algebraically in terms of its rectangular co-ordinates is called a 'complex quantity'. Therefore, $x + jy$ is a complex quantity and is the rectangular form of the vector $|Z| \angle \theta$ where:

$$\left.\begin{aligned} |Z| &= \sqrt{(x^2 + y^2)} \\ \theta &= \tan^{-1} y/x \\ x &= |Z| \cos\theta \\ y &= |Z| \sin\theta \end{aligned}\right\} \quad \text{...Equation A2.2}$$

From Equations A2.1 and A2.2:

$$\bar{Z} = |Z| (\cos\theta + j\sin\theta) \quad \text{...Equation A2.3}$$

and since cos θ and sin θ may be expressed in exponential form by the identities:

$$\sin\theta = \frac{e^{j\theta} - e^{-j\theta}}{2j}$$

$$\cos\theta = \frac{e^{j\theta} + e^{-j\theta}}{2}$$

it follows that $\bar{Z}$ may also be written as:

$$\bar{Z} = |Z|\, e^{j\theta} \quad \text{...Equation A2.4}$$

Therefore, a vector quantity may also be represented trigonometrically and exponentially.

3. Manipulation of complex quantities

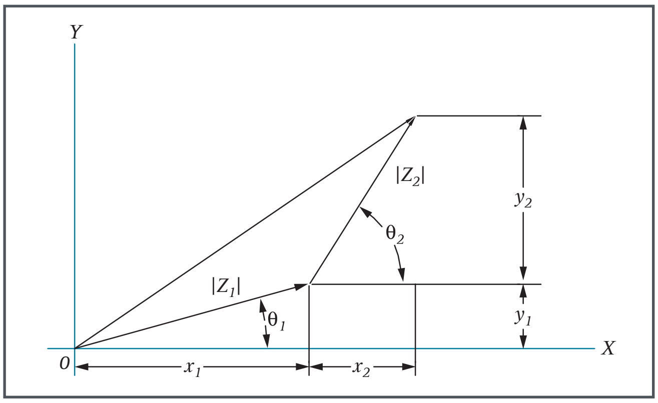

Figure A2.2: Addition of vectors

Complex quantities may be represented in any of the four co-ordinate systems given below:

a. Polar $|Z| \angle \theta$

b. Rectangular $x + jy$

c. Trigonometric $|Z| (\cos\theta + j\sin\theta)$

d. Exponential $|Z|\, e^{j\theta}$

The modulus $|Z|$ and the argument θ are together known as 'polar co-ordinates', and x and y are described as 'cartesian co-ordinates'. Conversion between co-ordinate systems is easily achieved. As the operator j obeys the ordinary laws of algebra, complex quantities in rectangular form can be manipulated algebraically, as can be seen by the following:

$$\bar{Z}_1 + \bar{Z}_2 = (x_1 + x_2) + j(y_1 + y_2) \quad \text{...Equation A2.5}$$

$$\bar{Z}_1 - \bar{Z}_2 = (x_1 - x_2) + j(y_1 - y_2) \quad \text{...Equation A2.6 (see Figure A2.2)}$$

$$\left.\begin{aligned} \bar{Z}_1 \bar{Z}_2 &= |Z_1||Z_2| \angle \theta_1 + \theta_2 \\ \frac{\bar{Z}_1}{\bar{Z}_2} &= \frac{|Z_1|}{|Z_2|} \angle \theta_1 - \theta_2 \end{aligned}\right\} \quad \text{...Equation A2.7}$$

3.1 Complex variables

Some complex quantities are variable with, for example, time; when manipulating such variables in differential equations it is expedient to write the complex quantity in exponential form.

When dealing with such functions it is important to appreciate that the quantity contains real and imaginary components. If it is required to investigate only one component of the complex variable, separation into components must be carried out after the mathematical operation has taken place.

Example:

Determine the rate of change of the real component of a vector $|Z| \angle \omega t$ with time.

$$|Z| \angle \omega t = |Z| (\cos\omega t + j\sin\omega t) = |Z| e^{j\omega t}$$

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3. Manipulation of complex quantities

The real component of the vector is $|Z| cos\omega t$. Differentiating $|Z| e^{j\omega t}$with respect to time:

$$\frac{d}{dt}|Z|\, e^{j\omega t} = j\omega\, |Z|\, e^{j\omega t}$$

Separating into real and imaginary components:

$$\frac{d}{dt}\left(|Z|\, e^{j\omega t}\right) = |Z|\ (-\omega sin\omega t\ +\ j\omega cos\omega t)$$

Thus, the rate of change of the real component of a vector $|Z|\angle\omega t$ is:

$$-|Z|\omega sin\omega t$$

3.2 Complex numbers

A complex number may be defined as a constant that represents the real and imaginary components of a physical quantity. The impedance parameter of an electric circuit is a complex number having real and imaginary components, which are described as resistance and reactance respectively.

Confusion often arises between vectors and complex numbers. A vector, as previously defined, may be a complex number. In this context, it is simply a physical quantity of constant magnitude acting in a constant direction. A complex number, which, being a physical quantity relating stimulus and response in a given operation, is known as a 'complex operator'. In this context, it is distinguished from a vector by the fact that it has no direction of its own.

Because complex numbers assume a passive role in any calculation, the form taken by the variables in the problem determines the method of representing them.

3.3 Mathematical operators

Mathematical operators are complex numbers that are used to move a vector through a given angle without changing the magnitude or character of the vector. An operator is not a physical quantity; it is dimensionless.

The symbol j, which has been compounded with quadrature components of complex quantities, is an operator that rotates a quantity anti-clockwise through 90°. Another useful operator is one which moves a vector anti-clockwise through 120°, commonly represented by the symbol a.

Operators are distinguished by one further feature; they are the roots of unity. Using De Moivre's theorem, the nth root of unity is given by solving the expression:

$$1^{1/n} = (cos\ 2\pi m + j sin\ 2\pi m)^{1/n}$$

where m is any integer. Hence:

$$1^{1/n} = cos\frac{2\pi m}{n} + j sin\frac{2\pi m}{n}$$

where m has values $1,\ 2,\ 3,\ldots\ (n-1)$

From the above expression j is found to be the 4th root and a the 3rd root of unity, as they have four and three distinct values respectively. Table A2.1 gives some useful functions of the a operator.

$$a = -\frac{1}{2} + j\frac{\sqrt{3}}{2} = e^{j\frac{2P}{3}}$$

$$a^2 = -\frac{1}{2} - j\frac{\sqrt{3}}{2} = e^{j\frac{4P}{3}}$$

$1 = 1 + j0 = e^{j0}$	$1 - a^2 = -j\sqrt{3a}$
$1 + a + a^2 = 0$	$a - a^2 = j\sqrt{3}$
$1 - a = j\sqrt{3a^2}$	$j = \frac{a - a^2}{\sqrt{3}}$

Table A2.1:
Properties of the a operator

4. Circuit quantities and conventions

Circuit analysis may be described as the study of the response of a circuit to an imposed condition, for example a short circuit. The circuit variables are current and voltage. Conventionally, current flow results from the application of a driving voltage, but there is complete duality between the variables and either may be regarded as the cause of the other.

When a circuit exists, there is an interchange of energy; a circuit may be described as being made up of 'sources' and 'sinks' for energy. The parts of a circuit are described as elements; a 'source' may be regarded as an 'active' element and a 'sink' as a 'passive' element. Some circuit elements are dissipative, that is, they are continuous sinks for energy, for example resistance. Other circuit elements may be alternately sources and sinks, for example capacitance and inductance. The elements of a circuit are connected together to form a network having nodes (terminals or junctions) and branches (series groups of elements) that form closed loops (meshes).

In steady state a.c. circuit theory, the ability of a circuit to accept a current flow resulting from a given driving voltage is called the impedance of the circuit. Since current and voltage are duals the impedance parameter must also have a dual, called admittance.

4.1 Circuit variables

As current and voltage are sinusoidal functions of time, varying at a single and constant frequency, they are regarded as rotating vectors and can be drawn as plan vectors (that is, vectors defined by two co-ordinates) on a vector diagram.

For example, the instantaneous value e, of a voltage varying sinusoidally with time is:

$$e = E_m \sin(\omega t + \delta)$$ ...Equation A2.8

where:

E_m is the maximum amplitude of the waveform

$\omega = 2\pi f$ is the angular velocity

δ is the argument defining the amplitude of the voltage at a time $t = 0$

At $t = 0$, the actual value of the voltage is $E_m \sin\delta$. So if E_m is regarded as the modulus of a vector, whose argument is δ, then $E_m \sin\delta$ is the imaginary component of the vector $|E_m|\angle\delta$.

Figure A2.3 illustrates this quantity as a vector and as a sinusoidal function of time.

The current resulting from applying a voltage to a circuit depends upon the circuit impedance. If the voltage is a sinusoidal function at a given frequency and the impedance is constant the current will also vary harmonically at the same frequency, so it can be shown on the same vector diagram as the voltage vector, and is given by the equation:

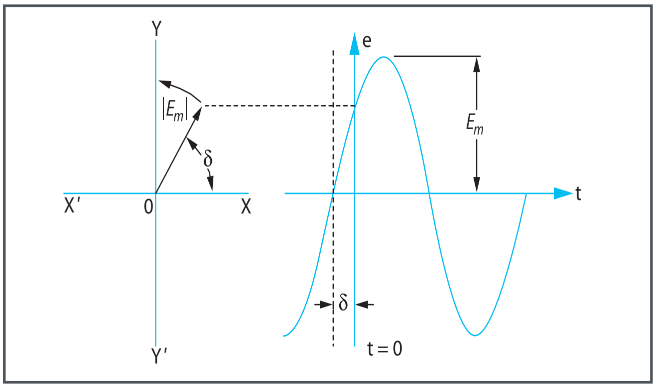

Figure A2.3: Representation of a sinusoidal function

$$i = \frac{|E_m|}{|Z|} \sin(\omega t + \delta - \phi)$$ ...Equation A2.9

where:

$$\left.\begin{aligned} |Z| &= \sqrt{R^2 + X^2} \\ X &= \left(\omega L - \frac{1}{\omega C}\right) \\ \phi &= \tan^{-1} X/R \end{aligned}\right\}$$ ...Equation A2.10

From Equations A2.9 and A2.10 it can be seen that the angular displacement ϕ between the current and voltage vectors and the current magnitude $|I_m| = |E_m|/|Z|$ is dependent upon the impedance $\bar{Z}$. In complex form the impedance may be written $\bar{Z} = R + jX$. The 'real component', R, is the circuit resistance, and the 'imaginary component', X, is the circuit reactance. When the circuit reactance is inductive (that is, $\omega L > 1/\omega C$), the current 'lags' the voltage by an angle ϕ, and when it is capacitive (that is, $1/\omega C > \omega L$) it 'leads' the voltage by an angle ϕ.

When drawing vector diagrams, one vector is chosen as the 'reference vector' and all other vectors are drawn relative to the reference vector in terms of magnitude and angle. The circuit impedance $|Z|$ is a complex operator and is distinguished from a vector only by the fact that it has no direction of its own. A further convention is that sinusoidally varying quantities are described by their 'effective' or 'root mean square' (r.m.s.) values; these are usually written using the relevant symbol without a suffix.

Thus:

$$\left.\begin{aligned} |I| &= |I_m|/\sqrt{2} \\ |E| &= |E_m|/\sqrt{2} \end{aligned}\right\}$$ ...Equation A2.11

The 'root mean square' value is that value which has the same heating effect as a direct current quantity of that value in the same circuit, and this definition applies to non-sinusoidal as well as sinusoidal quantities.

4. Circuit quantities and conventions

4.2 Sign conventions

In describing the electrical state of a circuit, it is often necessary to refer to the 'potential difference' existing between two points in the circuit. Since wherever such a potential difference exists, current will flow and energy will either be transferred or absorbed, it is obviously necessary to define a potential difference in more exact terms. For this reason, the terms voltage rise and voltage drop are used to define more accurately the nature of the potential difference.

Voltage rise is a rise in potential measured in the direction of current flow between two points in a circuit. Voltage drop is the converse. A circuit element with a voltage rise across it acts as a source of energy. A circuit element with a voltage drop across it acts as a sink of energy. Voltage sources are usually active circuit elements, while sinks are usually passive circuit elements. The positive direction of energy flow is from sources to sinks.

Kirchhoff's first law states that the sum of the driving voltages must equal the sum of the passive voltages in a closed loop. This is illustrated by the fundamental equation of an electric circuit:

$$iR + \frac{Ldi}{dt} + \frac{1}{C}\int idt = e$$ ...Equation A2.12

where the terms on the left hand side of the equation are voltage drops across the circuit elements. Expressed in steady state terms Equation A2.12 may be written:

$$\sum \overline{E} = \sum \overline{I}\,\overline{Z}$$ ...Equation A2.13

and this is known as the equated-voltage equation [Ref A2.1: Power System Analysis].

It is the equation most usually adopted in electrical network calculations, since it equates the driving voltages, which are known, to the passive voltages, which are functions of the currents to be calculated.

In describing circuits and drawing vector diagrams, for formal analysis or calculations, it is necessary to adopt a notation which defines the positive direction of assumed current flow, and establishes the direction in which positive voltage drops and voltage rises act. Two methods are available: one, the double suffix method, is used for symbolic analysis; the other, the single suffix or diagrammatic method, is used for numerical calculations.

In the double suffix method the positive direction of current flow is assumed to be from node a to node b and the current is designated Iab. With the diagrammatic method, an arrow indicates the direction of current flow.

The voltage rises are positive when acting in the direction of current flow. It can be seen from Figure A2.4 that $\overline{E}_1$ and $\overline{E}_{an}$ are positive voltage rises and $\overline{E}_2$ and $\overline{E}_{bn}$ are negative voltage rises. In the diagrammatic method their direction of action is simply indicated by an arrow, whereas in the double suffix method, $\overline{E}_{an}$ and $\overline{E}_{bn}$ indicate that there is a potential rise in directions na and nb.

Voltage drops are also positive when acting in the direction of current flow. From Figure A2.4(a) it can be seen that $(\overline{Z}_1 + \overline{Z}_2 + \overline{Z}_3)\overline{I}$ is the total voltage drop in the loop in the direction of current flow, and must equate to the total voltage rise $\overline{E}_1 - \overline{E}_2$.

In Figure A2.4(b), the voltage drop between nodes a and b designated $\overline{V}_{ab}$ indicates that point b is at a lower potential than a, and is positive when current flows from a to b. Conversely $\overline{V}_{ba}$ is a negative voltage drop.

Symbolically:

$$\left.\begin{aligned}\overline{V}_{ab} &= \overline{V}_{an} - \overline{V}_{bn}\\ \overline{V}_{ba} &= \overline{V}_{bn} - \overline{V}_{an}\end{aligned}\right\}$$ ...Equation A2.14

where n is a common reference point.

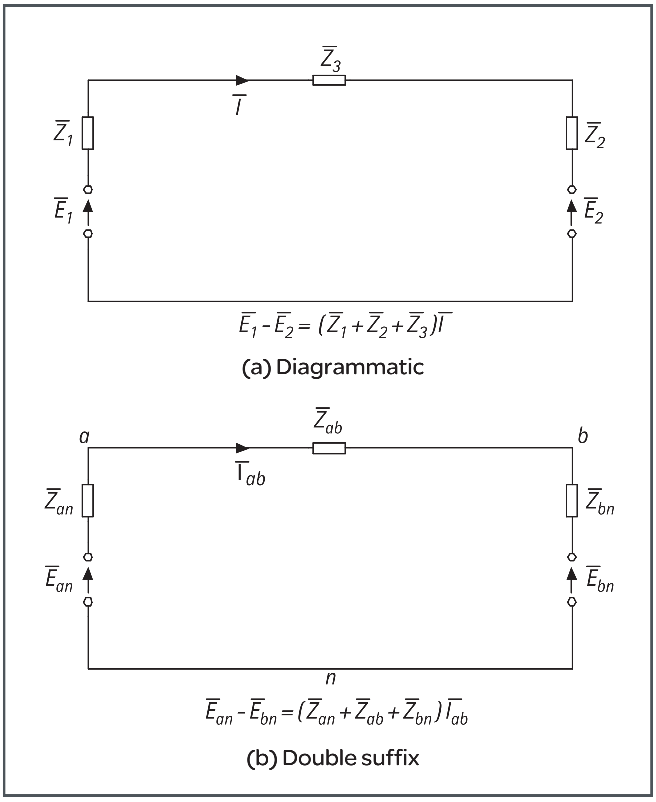

Figure A2.4:
Methods of representing a circuit

4.3 Power

The product of the potential difference across and the current through a branch of a circuit is a measure of the rate at which energy is exchanged between that branch and the remainder of the circuit. If the potential difference is a positive voltage drop, the branch is passive and absorbs energy. Conversely, if the potential difference is a positive voltage rise, the branch is active and supplies energy.

4. Circuit quantities and conventions

The rate at which energy is exchanged is known as power, and by convention, the power is positive when energy is being absorbed and negative when being supplied. With a.c. circuits the power alternates, so, to obtain a rate at which energy is supplied or absorbed, it is necessary to take the average power over one whole cycle.

If $e = E_m \sin(\omega t+\delta)$ and $i = I_m \sin(\omega t+\delta-\phi)$ then the power equation is:

$$p = ei = P[1-\cos 2(\omega t+\delta)]+Q\sin 2(\omega t+\delta) \quad \textit{...Equation A2.15}$$

where:

$P = |E||I|\cos\phi$ and

$Q = |E||I|\sin\phi$

From Equation A2.15 it can be seen that the quantity P varies from 0 to $2P$ and quantity Q varies from $-Q$ to $+Q$ in one cycle, and that the waveform is of twice the periodic frequency of the current voltage waveform.

The average value of the power exchanged in one cycle is a constant, equal to quantity P, and as this quantity is the product of the voltage and the component of current which is 'in phase' with the voltage it is known as the 'real' or 'active' power.

The average value of quantity Q is zero when taken over a cycle, suggesting that energy is stored in one half-cycle and returned to the circuit in the remaining half-cycle.

Q is the product of voltage and the quadrature component of current, and is known as 'reactive power'. As P and Q are constants which specify the power exchange in a given circuit, and are products of the current and voltage vectors, then if $\bar{S}$ is the vector product $\bar{E}\bar{I}$ it follows that with $\bar{E}$ as the reference vector and ϕ as the angle between $\bar{E}$ and $\bar{I}$.

$$\bar{S} = P + jQ \quad \textit{...Equation A2.16}$$

The quantity $\bar{S}$ is described as the 'apparent power', and is the term used in establishing the rating of a circuit. $\bar{S}$ has units of VA.

4.4 Single-phase and polyphase systems

A system is single or polyphase depending upon whether the sources feeding it are single or polyphase. A source is single or polyphase according to whether there are one or several driving voltages associated with it. For example, a three-phase source is a source containing three alternating driving voltages that are assumed to reach a maximum in phase order, A, B, C. Each phase driving voltage is associated with a phase branch of the system network as shown in Figure A2.5(a).

If a polyphase system has balanced voltages, that is, equal in magnitude and reaching a maximum at equally displaced time intervals, and the phase branch impedances are identical, it is called a 'balanced' system. It will become 'unbalanced' if any of the above conditions are not satisfied. Calculations using a balanced polyphase system are simplified, as it is only necessary to solve for a single phase, the solution for the remaining phases being obtained by symmetry.

The power system is normally operated as a three-phase, balanced, system. For this reason the phase voltages are equal in magnitude and can be represented by three vectors spaced 120° or $2\pi/3$ radians apart, as shown in Figure A2.5(b).

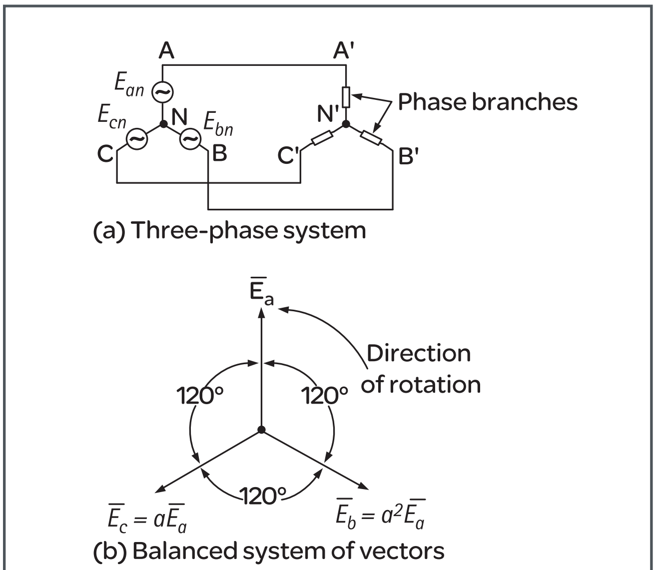

Figure A2.5: Methods of representing a circuit

Since the voltages are symmetrical, they may be expressed in terms of one, that is:

$$\bar{E}_a = \bar{E}_a$$
$$\bar{E}_b = a^2\bar{E}_a$$
$$\bar{E}_c = a\bar{E}_a \quad \textit{...Equation A2.17}$$

where a is the vector operator $e^{j2p/3}$. Further, if the phase branch impedances are identical in a balanced system, it follows that the resulting currents are also balanced.

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5. Impedance notation

It can be seen by inspection of any power system diagram that:

a. several voltage levels exist in a system

b. it is common practice to refer to plant MVA in terms of per unit or percentage values

c. transmission line and cable constants are given in ohms/km

Before any system calculations can take place, the system parameters must be referred to 'base quantities' and represented as a unified system of impedances in either ohmic, percentage, or per unit values.

The base quantities are power and voltage. Normally, they are given in terms of the three-phase power in MVA and the line voltage in kV. The base impedance resulting from the above base quantities is:

$$Z_b = \frac{(kV)^2}{MVA}\ \Omega$$

...Equation A2.18

and, provided the system is balanced, the base impedance may be calculated using either single-phase or three-phase quantities.

The per unit or percentage value of any impedance in the system is the ratio of actual to base impedance values.

Hence:

$$\left.\begin{aligned} Z(p.u.) &= Z(\Omega) \times \frac{MVA_b}{(kV_b)^2} \\ Z(\%) &= Z(p.u.) \times 100 \end{aligned}\right\}$$

...Equation A2.19

Where: $MVA_b = base\ MVA$

$kV_b = base\ kV$

Simple transposition of the above formulae will refer the ohmic value of impedance to the per unit or percentage values and base quantities.

Having chosen base quantities of suitable magnitude all system impedances may be converted to those base quantities by using the equations given below:

$$\left.\begin{aligned} Z_{b2} &= Z_{b1} \times \frac{MVA_{b2}}{MVA_{b1}} \\ Z_{b2} &= Z_{b1} \times \left(\frac{kV_{b1}}{kV_{b2}}\right)^2 \end{aligned}\right\}$$

...Equation A2.20

where

suffix $b1$ denotes the value to the original base and $b2$ denotes the value to new base.

The choice of impedance notation depends upon the complexity of the system, plant impedance notation and the nature of the system calculations envisaged.

If the system is relatively simple and contains mainly transmission line data, given in ohms, then the ohmic method can be adopted with advantage. However, the per unit method of impedance notation is the most common for general system studies since:

a. impedances are the same referred to either side of a transformer if the ratio of base voltages on the two sides of a transformer is equal to the transformer turns ratio

b. confusion caused by the introduction of powers of 100 in percentage calculations is avoided

c. by a suitable choice of bases, the magnitudes of the data and results are kept within a predictable range, and hence errors in data and computations are easier to spot

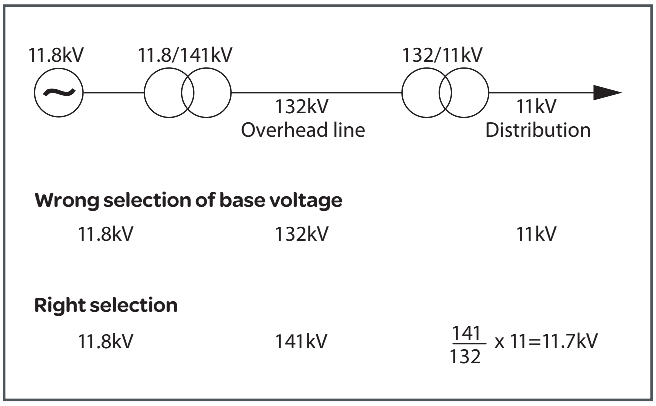

Figure A2.6:
Selection of base voltages

Most power system studies are carried out using software in per unit quantities. Irrespective of the method of calculation, the choice of base voltage, and unifying system impedances to this base, should be approached with caution, as shown in Figure A2.6.

From Figure A2.6 it can be seen that the base voltages in the three circuits are related by the turns ratios of the intervening transformers. Care is required as the nominal transformation ratios e.g. a 110/33kV (nominal) transformer may have a turns ratio of 110/34.5kV. Therefore, the rule for hand calculations is: 'to refer an impedance in ohms from one circuit to another multiply the given impedance by the square of the turns ratio (open circuit voltage ratio) of the intervening transformer'.

Where power system simulation software is used, the software normally has calculation routines built in to adjust transformer parameters to take account of differences between the nominal primary and secondary voltages and turns ratios. In this case, the choice of base voltages may be more conveniently made as the nominal voltages of each section of the power system. This approach avoids confusion when per unit or percent values are used in calculations in translating the final results into volts, amps, etc.

5. Impedance notation

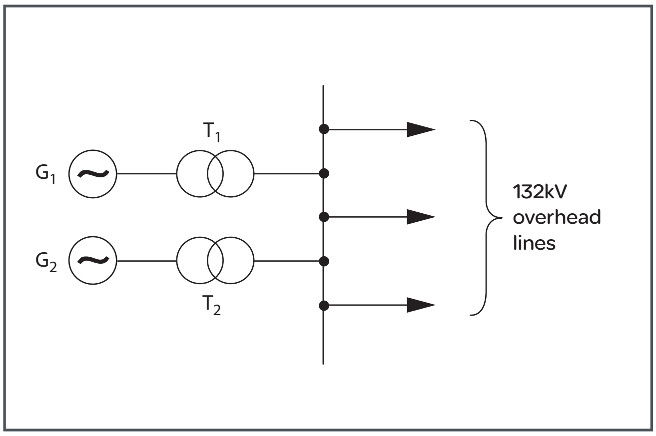

Figure A2.7:
Section of a power system

For example, in Figure A2.7, generators G_1 and G_2 have a sub-transient reactance of 26% on 66.6MVA rating at 11kV, and transformers T_1 and T_2 a voltage ratio of 11/145kV and an impedance of 12.5% on 75MVA. Choosing 100MVA as base MVA and 132kV as base voltage, find the percentage impedances to new base quantities.

a. Generator reactances to new bases are:

$$26 \times \frac{100}{66.6} \times \frac{(11)^2}{(132)^2} = 0.27\%$$

b. Transformer reactances to new bases are:

$$12.5 \times \frac{100}{75} \times \frac{(145)^2}{(132)^2} = 20.1\%$$

NOTE: *The base voltages of the generator and circuits are 11kV and 145kV respectively, that is, the turns ratio of the transformer. The corresponding per unit values can be found by dividing by 100, and the ohmic value can be found by using Equation A2.19.*

6. Basic circuit laws, theorems and network reduction

Most practical power system problems are solved by using steady state analytical methods. The assumptions made are that the circuit parameters are linear and bilateral and constant for constant frequency circuit variables. In some problems, described as initial value problems, it is necessary to study the behaviour of a circuit in the transient state. Such problems can be solved using operational methods. Again, in other problems, which fortunately are few in number, the assumption of linear, bilateral circuit parameters is no longer valid. These problems are solved using advanced mathematical techniques that are beyond the scope of this book.

6.1 Circuit laws

In linear, bilateral circuits, three basic network laws apply, regardless of the state of the circuit, at any particular instant of time. These laws are the branch, junction and mesh laws, due to Ohm and Kirchhoff, and are stated below, using steady state a.c. nomenclature.

Branch law

The current $\overline{I}$ in a given branch of impedance $\overline{Z}$ is proportional to the potential difference $\overline{V}$ appearing across the branch, that is, $\overline{V} = \overline{I}\,\overline{Z}$.

Junction law

The algebraic sum of all currents entering any junction (or node) in a network is zero, that is:

$$\sum \overline{I} = 0$$

Mesh law

The algebraic sum of all the driving voltages in any closed path (or mesh) in a network is equal to the algebraic sum of all the passive voltages (products of the impedances and the currents) in the components branches, that is:

$$\sum \overline{E} = \sum \overline{Z}\,\overline{I}$$

Alternatively, the total change in potential around a closed loop is zero.

6.2 Circuit theorems

From the above network laws, many theorems have been derived for the rationalisation of networks, either to reach a quick, simple, solution to a problem or to represent a complicated circuit by an equivalent. These theorems are divided into two classes: those concerned with the general properties of networks and those concerned with network reduction.

6. Basic circuit laws, theorems and network reduction

Of the many theorems that exist, the three most important are given. These are: the Superposition Theorem, Thévenin's Theorem and Kennelly's Star/Delta Theorem.

Superposition theorem (general network theorem)

The resultant current that flows in any branch of a network due to the simultaneous action of several driving voltages is equal to the algebraic sum of the component currents due to each driving voltage acting alone with the remainder short-circuited.

Thévenin's theorem (active network reduction theorem)

Any active network that may be viewed from two terminals can be replaced by a single driving voltage acting in series with a single impedance. The driving voltage is the open-circuit voltage between the two terminals and the impedance is the impedance of the network viewed from the terminals with all sources short-circuited.

Kennelly's star/delta theorem (passive network reduction theorem)

Any three-terminal network can be replaced by a delta or star impedance equivalent without disturbing the external network. The formulae relating the replacement of a delta network by the equivalent star network is as follows (Figure A2.8):

$$\overline{Z}_{co} = \overline{Z}_{13} + \overline{Z}_{23} \Big/ \left(\overline{Z}_{12} + \overline{Z}_{13} + \overline{Z}_{23} \right)$$

and so on.

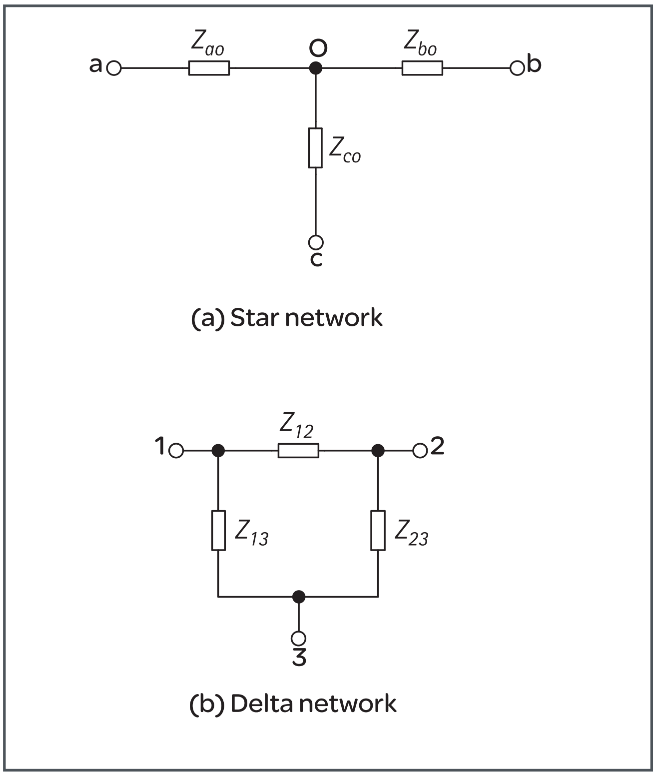

Figure A2.8 :
Star-delta network transformation

The impedance of a delta network corresponding to and replacing any star network is:

$$\overline{Z}_{12} = \overline{Z}_{ao} + \overline{Z}_{bo} + \frac{\overline{Z}_{ao}\,\overline{Z}_{bo}}{\overline{Z}_{co}}$$

and so on.

6.3 Network reduction

The aim of network reduction is to reduce a system to a simple equivalent while retaining the identity of that part of the system to be studied.

For example, consider the system shown in Figure A2.9. The network has two sources E' and E'', a line AOB shunted by an impedance, which may be regarded as the reduction of a further network connected between A and B, and a load connected between O and N. The object of the reduction is to study the effect of opening a breaker at A or B during normal system operations, or of a fault at A or B. Thus the identity of nodes A and B must be retained together with the sources, but the branch ON can be eliminated, simplifying the study. Proceeding, A, B, N, forms a star branch and can therefore be converted to an equivalent delta.

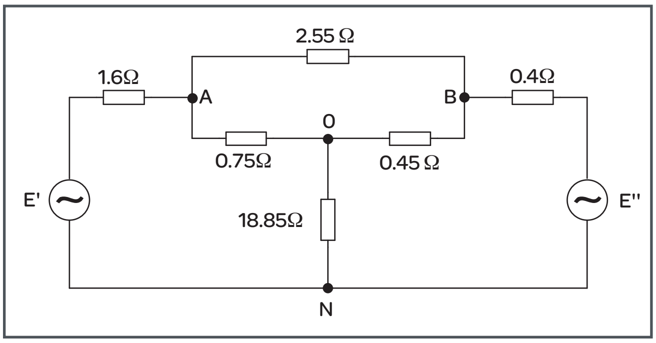

Figure A2.9:
Typical power system network

$$Z_{AN} = Z_{AO} + Z_{NO} + \frac{Z_{AO}\,Z_{NO}}{Z_{BO}} = 0.75 + 18.85 + \frac{0.75 \times 18.85}{0.45}$$
$$= 51\ \Omega$$

$$Z_{BN} = Z_{BO} + Z_{NO} + \frac{Z_{BO}\,Z_{NO}}{Z_{AO}} = 0.45 + 18.85 + \frac{0.45 \times 18.85}{0.75}$$
$$= 30.6\ \Omega$$

$$Z_{AB} = Z_{AO} + Z_{BO} + \frac{Z_{AO}\,Z_{BO}}{Z_{NO}} = 1.2\ \Omega\ (since\ Z_{NO} >>> Z_{AO} Z_{BO})$$

The network is now reduced as shown in Figure A2.10.

By applying Thévenin's theorem to the active loops, these can be replaced by a single driving voltage in series with an impedance as shown in Figure A2.11.

6. Basic circuit laws, theorems and network reduction

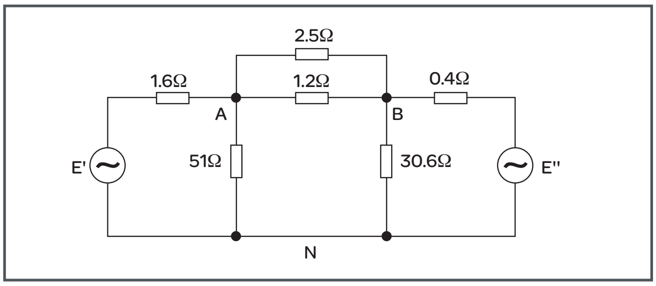

Figure A2.10:
Reduction using star/delta transformation

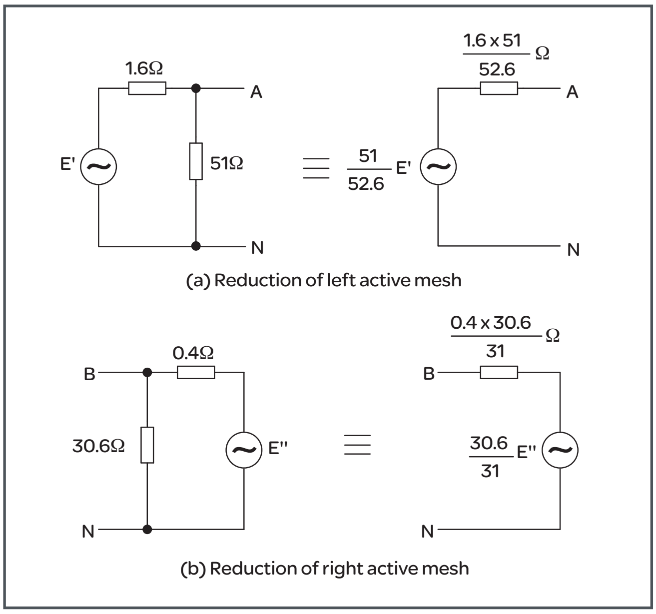

Figure A2.11:
Reduction of active meshes, Thévenin's Theorem

The network shown in Figure A2.9 is now reduced to that shown in Figure A2.12 with the nodes A and B retaining their identity. Further, the load impedance has been completely eliminated.

The network shown in Figure A2.12 may now be used to study system disturbances, for example power swings with and without faults.

Most reduction problems follow the same pattern as the example above. The rules to apply in practical network reduction are:

a. decide on the nature of the disturbance or disturbances to be studied

b. decide on the information required, for example the branch currents in the network for a fault at a particular location

c. reduce all passive sections of the network not directly involved with the section under examination

d. reduce all active meshes to a simple equivalent, that is, to a simple source in series with a single impedance

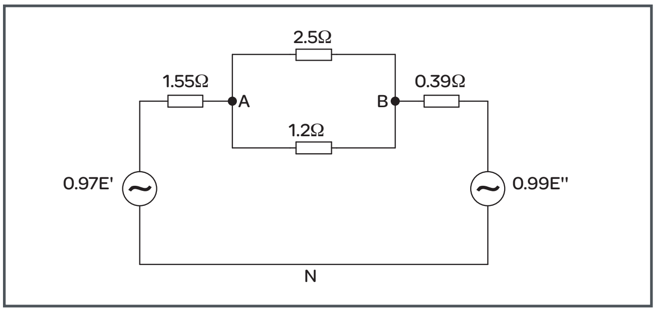

Figure A2.12:
Reduction of typical power system network

With the widespread availability of computer-based power system simulation software, it is now usual to use such software on a routine basis for network calculations without significant network reduction taking place. However, the network reduction techniques given above are still valid, as there will be occasions where such software is not immediately available and a hand calculation must be carried out.

In certain circuits, for example parallel lines on the same towers, there is mutual coupling between branches. Correct circuit reduction must take account of this coupling.

Three cases are of interest. These are:

a. two branches connected together at their nodes

b. two branches connected together at one node only

c. two branches that remain unconnected

Considering each case in turn:

a. consider the circuit shown in Figure A2.13(a). The application of a voltage V between the terminals P and Q gives:

$$V = I_a Z_{aa} + I_b Z_{ab}$$
$$V = I_a Z_{ab} + I_b Z_{bb}$$

where Ia and Ib are the currents in branches a and b, respectively and $I = I_a + I_b$, the total current entering at terminal P and leaving at terminal Q.

Solving for I_a and I_b:

$$I_b = \frac{(Z_{aa} - Z_{ab})V}{Z_{aa}Z_{bb} - Z_{ab}^2}$$

from which

$$I_a = \frac{(Z_{bb} - Z_{ab})V}{Z_{aa}Z_{bb} - Z_{ab}^2}$$

and

$$I = I_a + I_b = \frac{V(Z_{aa} + Z_{bb} - 2Z_{ab})}{Z_{aa}Z_{bb} - Z_{ab}^2}$$

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6. Basic circuit laws, theorems and network reduction

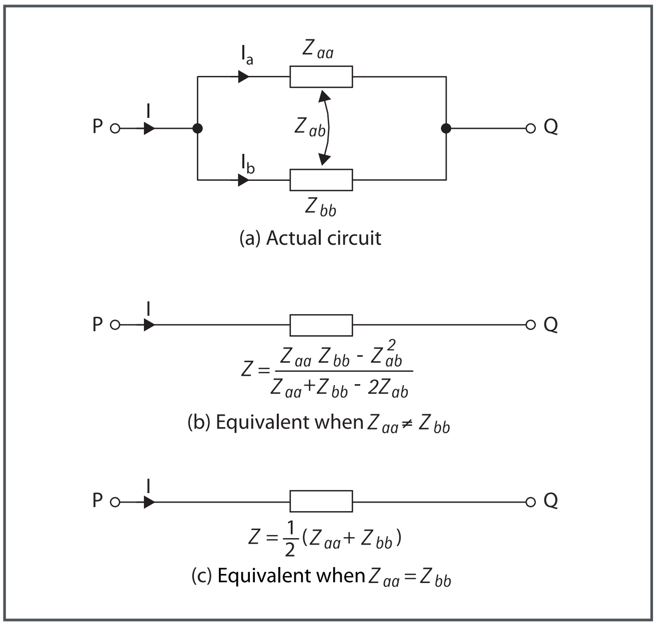

Figure A2.13:
Reduction of two branches with mutual coupling

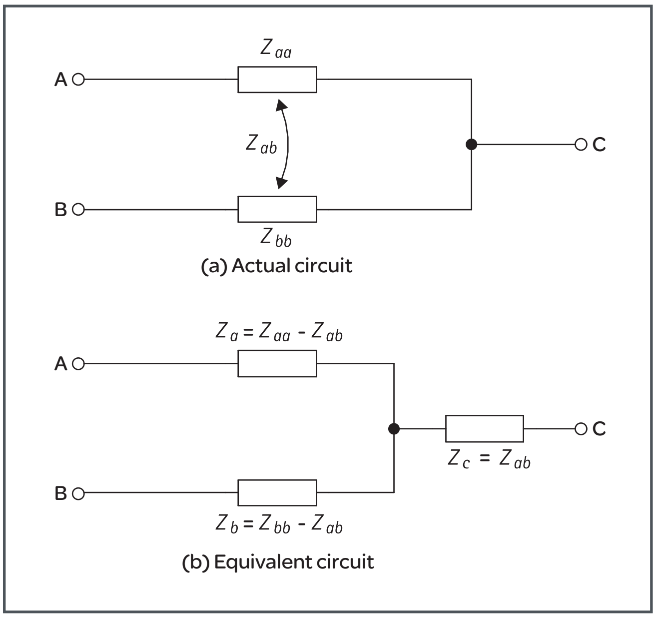

Figure A2.14:
Reduction of mutually-coupled branches with a common terminal

so that the equivalent impedance of the original circuit is:

$$Z = \frac{V}{I} = \frac{Z_{aa}Z_{bb} - Z_{ab}^2}{Z_{aa} + Z_{bb} - 2Z_{ab}} \quad \text{...Equation A2.21}$$

(Figure A2.13(b)), and, if the branch impedances are equal, the usual case, then:

$$Z = \frac{1}{2}\left(Z_{aa} + Z_{ab}\right) \quad \text{...Equation A2.22 (Figure A2.13(c))}$$

b. consider the circuit in Figure A2.14(a).

The assumption is made that an equivalent star network can replace the network shown. From inspection with one terminal isolated in turn and a voltage *v* impressed across the remaining terminals it can be seen that:

$$Z_a + Z_c = Z_{aa}$$
$$Z_b + Z_c = Z_{bb}$$
$$Z_a + Z_b = Z_{aa} + Z_{bb} + 2Z_{ab}$$

Solving these equations gives:

$$\left.\begin{aligned} Z_a &= Z_{aa} + Z_{ab} \\ Z_b &= Z_{bb} + Z_{ab} \\ Z_a &= -Z_{ab} \end{aligned}\right\} \quad \text{...Equation A2.23 (see Figure A2.14(b))}$$

c. consider the four-terminal network given in Figure A2.15(a), in which the branches 11' and 22' are electrically separate except for a mutual link. The equations defining the network are:

$$V_1 = Z_{11}I_1 + Z_{12}I_2$$
$$V_2 = Z_{21}I_1 + Z_{22}I_2$$
$$I_1 = Y_{11}V_1 + Y_{12}V_2$$
$$I_2 = Y_{21}V_1 + Y_{22}V_2$$

where $Z_{12}=Z_{21}$ and $Y_{12}=Y_{21}$, if the network is assumed to be reciprocal. Further, by solving the above equations it can be shown that:

$$\left.\begin{aligned} Y_{11} &= Z_{22}/\Delta \\ Y_{22} &= Z_{11}/\Delta \\ Y_{12} &= Z_{12}/\Delta \\ \Delta &= Z_{11}Z_{22} - Z_{12}^2 \end{aligned}\right\} \quad \text{...Equation A2.24}$$

There are three independent coefficients, namely Z_{12}, Z_{11}, Z_{22}, so the original circuit may be replaced by an equivalent mesh containing four external terminals, each terminal being connected to the other three by branch impedances as shown in Figure A2.15(b).

6. Basic circuit laws, theorems and network reduction

In order to evaluate the branches of the equivalent mesh let all points of entry of the actual circuit be commoned except node 1 of circuit 1, as shown in Figure A2.15(c). Then all impressed voltages except V_1 will be zero and:

$$I_1 = Y_{11} V_1$$
$$I_2 = Y_{12} V_1$$

If the same conditions are applied to the equivalent mesh, then:

$$I_1 = V_1 Z_{11}$$
$$I_2 = -V_1/Z_{12} = -V_1/Z_{12}$$

These relations follow from the fact that the branch connecting nodes 1 and 1' carries current I_1 and the branches connecting nodes 1 and 2' and 1 and 2 carry current I_2. This must be true since branches between pairs of commoned nodes can carry no current.

By considering each node in turn with the remainder commoned, the following relationships are found:

$$Z_{11'} = 1/Y_{11}$$
$$Z_{22'} = 1/Y_{22}$$
$$Z_{12'} = -1/Y_{12}$$
$$Z_{12} = Z_{1'2'} = -Z_{21'} = -Z_{12'}$$

Hence:

$$\left.\begin{aligned} Z_{11'} &= \frac{Z_{11} Z_{22} - Z_{12}^2}{Z_{22}} \\ Z_{22'} &= \frac{Z_{11} Z_{22} - Z_{12}^2}{Z_{11}} \\ Z_{12'} &= \frac{Z_{11} Z_{22} - Z_{12}^2}{Z_{12}} \end{aligned}\right\} \quad \text{...Equation A2.25}$$

A similar but equally rigorous equivalent circuit is shown in Figure A2.15(d). This circuit [Ref A2.2: Equivalent Circuits I.] follows the fact that the self - impedance of any circuit is independent of all other circuits. Therefore, it need not appear in any of the mutual branches if it is lumped as a radial branch at the terminals. So putting Z_{11} and Z_{22} equal to zero in Equation A2.25, defining the equivalent mesh in Figure A2.15(b), and inserting radial branches having impedances equal to Z_{11} and Z_{22} in terminals 1 and 2, results in Figure A2.15(d).

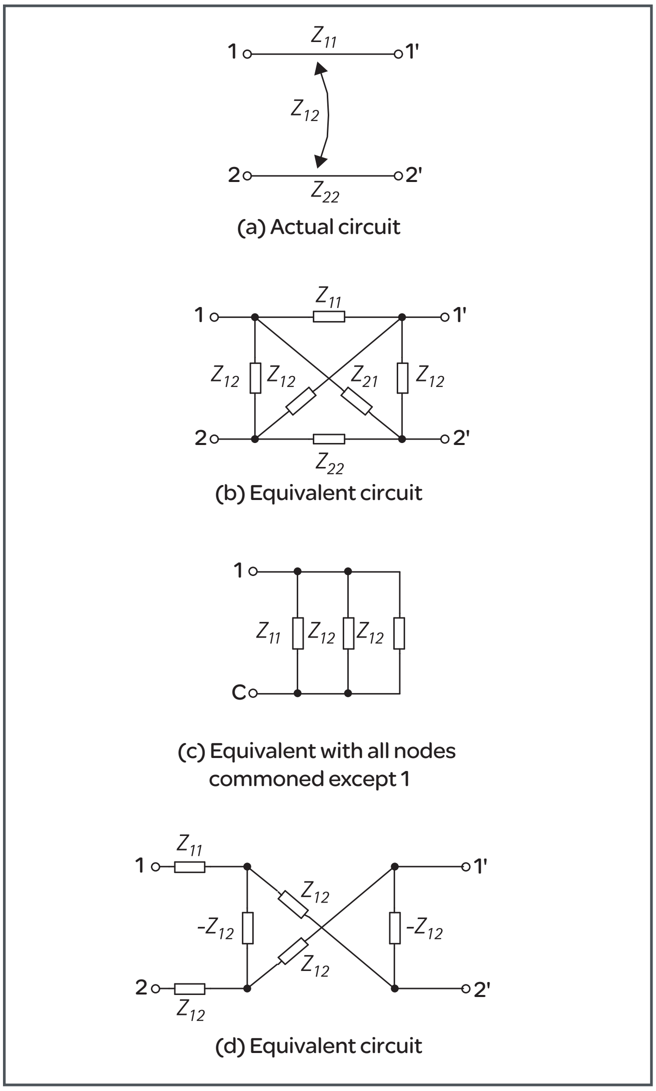

Figure A2.15 :
Equivalent circuits for four terminal network with mutual coupling

7. References

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[A2.2] Equivalent Circuits I.
Frank M. Starr,
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A3

Fault Calculations

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Chapter A3

Fault Calculations

A3

1. Introduction

A power system is normally treated as a balanced symmetrical three-phase network. When a fault occurs, the symmetry is normally upset, resulting in unbalanced currents and voltages appearing in the network. The only exception is the three-phase fault, which, because it involves all three phases equally at the same location, is described as a symmetrical fault. By using symmetrical component analysis and replacing the normal system sources by a source at the fault location, it is possible to analyse these fault conditions.

For the correct application of protection equipment, it is essential to know the fault current distribution throughout the system and the voltages in different parts of the system due to the fault. Further, boundary values of current at any relaying point must be known if the fault is to be cleared with discrimination.

The information normally required for each kind of fault at each relaying point is:

a. maximum fault current

b. minimum fault current

c. maximum through fault current

To obtain the above information, the limits of stable generation and possible operating conditions, including the method of system earthing, must be known. Faults are always assumed to be through zero fault impedance.

2. Three-phase fault calculations

Three-phase faults are unique in that they are balanced, that is, symmetrical in the three phases, and can be calculated from the single-phase impedance diagram and the operating conditions existing prior to the fault.

A fault condition is a sudden abnormal alteration to the normal circuit arrangement. The circuit quantities (current and voltage) will alter, and the circuit will pass through a transient state to a steady state. In the transient state, the initial magnitude of the fault current will depend upon the point on the voltage wave at which the fault occurs. The decay of the transient condition, until it merges into steady state, is a function of the parameters of the circuit elements. The transient current may be regarded as a d.c. exponential current superimposed on the symmetrical steady state fault current. In a.c. machines, owing to armature reaction, the machine reactances pass through 'sub transient' and 'transient' stages before reaching their steady state synchronous values. For this reason, the resultant fault current during the transient period, from fault inception to steady state also depends on the location of the fault in the network relative to that of the rotating plant.

In a system containing many voltage sources, or having a complex network arrangement, it is tedious to use the normal system voltage sources to evaluate the fault current in the faulty branch or to calculate the fault current distribution in the system. A more practical method [Ref A3.1: Circuit Analysis of A.C. Power Systems] is to replace the system voltages by a single driving voltage at the fault point. This driving voltage is the voltage existing at the fault point before the fault occurs.

Consider the circuit given in Figure A3.1 where the driving voltages are E' and $\overline{E}''$, the impedances on either side of fault

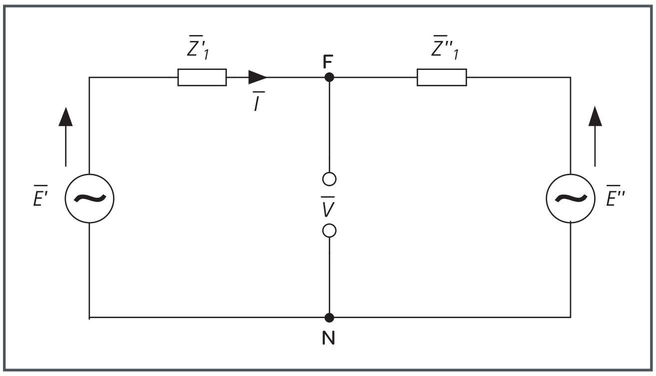

Figure A3.1: Network with fault at F

point F are $\overline{Z}'_1$ and $\overline{Z}''_1$, and the current through point F before the fault occurs is $\overline{I}$.

The voltage V at F before fault inception is:

$$\overline{V} = \overline{E}' - \overline{I}\,\overline{Z}' = \overline{E}'' + \overline{I}\,\overline{Z}''$$

After the fault the voltage $\overline{V}$ is zero. Hence, the change in voltage is $-\overline{V}$. Because of the fault, the change in the current flowing into the network from F is:

$$\Delta\overline{I} = -\frac{\overline{V}}{\overline{Z}_1} = -\overline{V}\,\frac{\left(\overline{Z}'_1 + \overline{Z}''_1\right)}{\overline{Z}'_1\overline{Z}''_1}$$

and, since no current was flowing into the network from F prior to the fault, the fault current flowing from the network into the fault is:

2. Three-phase fault calculations

$$\bar{I}_f = -\Delta\bar{I} = \bar{V}\frac{\left(\bar{Z}'_1 + \bar{Z}''_1\right)}{\bar{Z}'_1\bar{Z}''_1}$$

By applying the Principle of Superposition, the load currents circulating in the system prior to the fault may be added to the currents circulating in the system due to the fault, to give the total current in any branch of the system at the time of fault inception. However, in most problems, the load current is small in comparison to the fault current and is usually ignored.

In a practical power system, the system regulation is such that the load voltage at any point in the system is within 10% of the declared open-circuit voltage at that point. For this reason, it is usual to regard the pre-fault voltage at the fault as being the open-circuit voltage, and this assumption is also made in a number of the standards dealing with fault level calculations.

For an example of practical three-phase fault calculations, consider a fault at A in Figure A2.9. With the network reduced as shown in Figure A3.2, the load voltage at A before the fault occurs is:

$$\bar{V} = 0.97\bar{E}' + 1.55\bar{I}$$

$$\bar{V} = 0.99\bar{E}'' + \left(\frac{1.2 \times 2.5}{2.5 + 1.2} + 0.39\right)\bar{I}$$

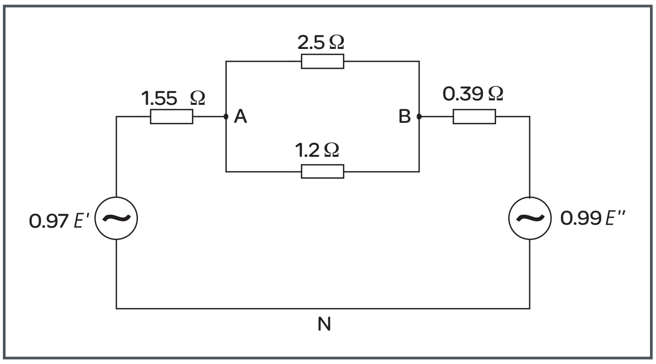

Figure A3.2:
Reduction of typical power system network

For practical working conditions, $\bar{E}' >>> 1.55\bar{I}$ and $\bar{E}'' >>> 1.207\bar{I}$. Hence $\bar{E}' \cong \bar{E}'' \cong \bar{V}$.

Replacing the driving voltages $\bar{E}'$ and $\bar{E}''$ by the load voltage $\bar{V}$ between A and N modifies the circuit as shown in Figure A3.3(a).

The node A is the junction of three branches. In practice, the node would be a busbar, and the branches are feeders radiating from the bus via circuit breakers, as shown in Figure A3.3(b). There are two possible locations for a fault at A; the busbar side of the breakers or the line side of the breakers. In this example, it is assumed that the fault is at X, and it is required to calculate the current flowing from the bus to X.

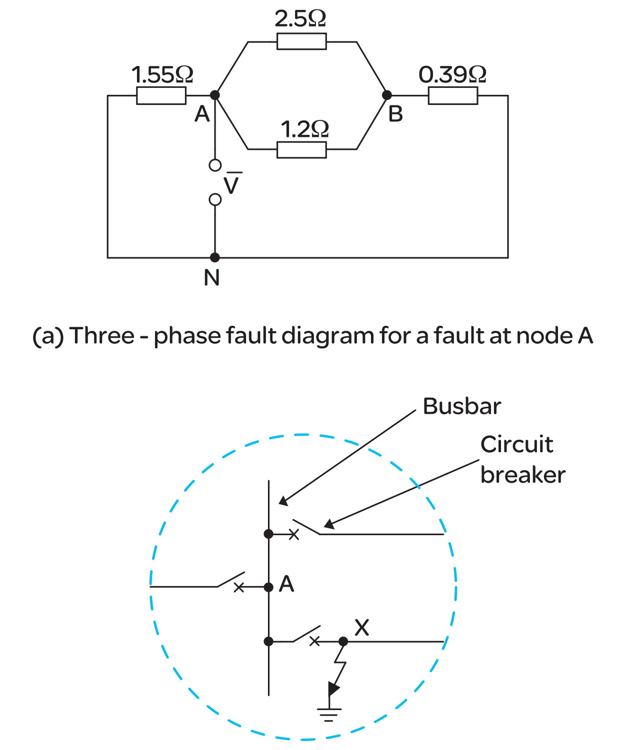

Figure A3.3:
Network with fault at node A

The network viewed from AN has a driving point impedance $|Z_1| = 0.68\ \Omega$.

The current in the fault is $\left|\frac{V}{Z_1}\right|$.

Let this current be 1.0 per unit. It is now necessary to find the fault current distribution in the various branches of the network and in particular the current flowing from A to X on the assumption that a relay at X is to detect the fault condition. The equivalent impedances viewed from either side of the fault are shown in Figure A3.4(a).

The currents from Figure A3.4(a) are as follows:

From the right: $\frac{1.55}{2.76} = 0.563\ p.u.$

From the left: $\frac{1.21}{2.76} = 0.437\ p.u.$

There is a parallel branch to the right of A

Therefore, current in 2.5 ohm branch

$$= \frac{1.2 \times 0.563}{3.7} = 0.183\ p.u.$$

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2. Three-phase fault calculations

and the current in 1.2 ohm branch

$$= \frac{2.5 \times 0.563}{3.7} = 0.38\ p.u.$$

Total current entering X from the left, that is, from A to X, is 0.437 + 0.183 = 0.62 $p.u.$ and from B to X is 0.38 $p.u.$ The equivalent network as viewed from the relay is as shown in Figure A3.4(b).

The impedances on either side are:

0.68/0.62 = 1.1 Ω

and 0.68/0.38 = 1.79 Ω

The circuit of Figure A3.4(b) has been included because the Protection Engineer is interested in these equivalent parameters when applying certain types of protection relay.

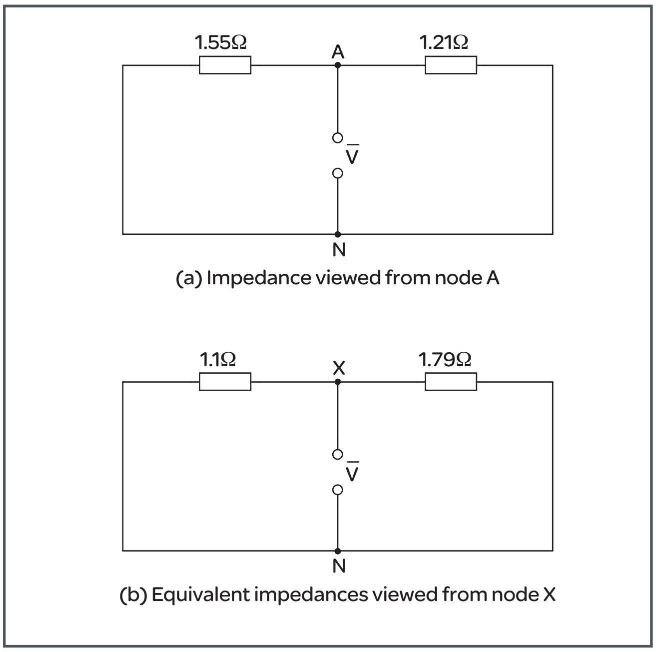

Figure A3.4:
Impedances viewed from fault

3. Symmetrical component analysis of a three-phase network

The Protection Engineer is interested in a wider variety of faults than just a three-phase fault. The most common fault is a single- phase to earth fault, which, in LV systems, can produce a higher fault current than a three-phase fault. Similarly, because protection is expected to operate correctly for all types of fault, it may be necessary to consider the fault currents due to many different types of fault. Since the three-phase fault is unique in being a balanced fault, a method of analysis that is applicable to unbalanced faults is required. It can be shown [Ref A3.2: Method of Symmetrical Co-ordinates Applied to the Solution of Polyphase Networks] that, by applying the 'Principle of Superposition', any general three-phase system of vectors may be replaced by three sets of balanced (symmetrical) vectors; two sets are three-phase but having opposite phase rotation and one set is co-phasal. These vector sets are described as the positive, negative and zero sequence sets respectively.

The equations between phase and sequence voltages are given below:

$$\left.\begin{aligned} \bar{E}_a &= \bar{E}_1 + \bar{E}_2 + \bar{E}_0 \\ \bar{E}_b &= a^2\bar{E}_1 + a\bar{E}_2 + \bar{E}_0 \\ \bar{E}_c &= a\bar{E}_1 + a^2\bar{E}_2 + \bar{E}_0 \end{aligned}\right\} \quad \text{...Equation A3.1}$$

$$\left.\begin{aligned} \bar{E}_1 &= \frac{1}{3}\left(\bar{E}_a + a\bar{E}_b + a^2\bar{E}_c\right) \\ \bar{E}_2 &= \frac{1}{3}\left(\bar{E}_a + a^2\bar{E}_b + a\bar{E}_c\right) \\ \bar{E}_0 &= \frac{1}{3}\left(\bar{E}_a + \bar{E}_b + \bar{E}_c\right) \end{aligned}\right\} \quad \text{...Equation A3.2}$$

where all quantities are referred to the reference phase A. A similar set of equations can be written for phase and sequence currents.

Figure A3.5 illustrates the resolution of a system of unbalanced vectors.

When a fault occurs in a power system, the phase impedances are no longer identical (except in the case of three-phase faults) and the resulting currents and voltages are unbalanced, the point of greatest unbalance being at the fault point. It has been shown in Chapter [A1: Fundamentals of Protection Practice] that the fault may be studied by short-circuiting all normal driving voltages in the system and replacing the fault connection by a source whose driving voltage is equal to the pre-fault

3. Symmetrical component analysis of a three-phase network

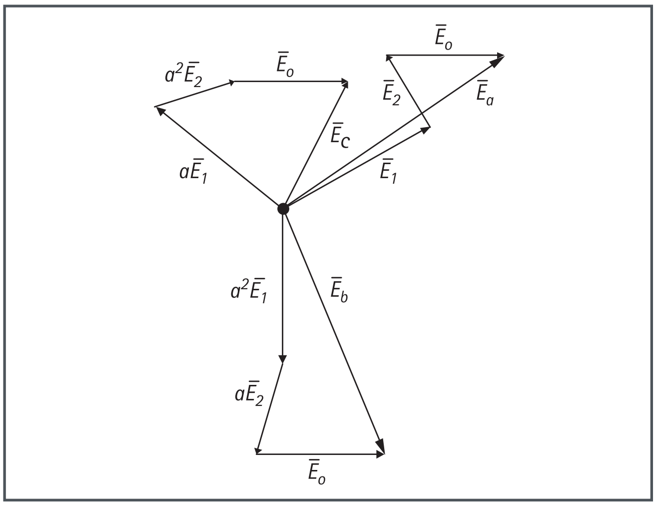

Figure A3.5:
Resolution of a system of unbalanced vectors

voltage at the fault point. Hence, the system impedances remain symmetrical, viewed from the fault, and the fault point may now be regarded as the point of injection of unbalanced voltages and currents into the system.

This is a most important approach in defining the fault conditions since it allows the system to be represented by sequence networks [Ref A3.3: Power System Analysis] using the method of symmetrical components.

3.1 Positive sequence network

During normal balanced system conditions, only positive sequence currents and voltages can exist in the system, and therefore the normal system impedance network is a positive sequence network.

When a fault occurs in a power system, the current in the fault branch changes from 0 to $\bar{I}$ and the positive sequence voltage across the branch changes from $\bar{V}$ to $\bar{V}_1$; replacing the fault branch by a source equal to the change in voltage and short-circuiting all normal driving voltages in the system results in a current $\Delta\bar{I}$ flowing into the system, and:

$$\Delta\bar{I} = -\frac{\left(\bar{V} - \bar{V}_1\right)}{\bar{Z}_1}$$ *...Equation A3.3*

where $\bar{Z}_1$ is the positive sequence impedance of the system viewed from the fault. As before the fault no current was flowing from the fault into the system, it follows that $\bar{I}_1$, the fault current flowing from the system into the fault must equal $-\Delta\bar{I}$.

Therefore:

$$\bar{V}_1 = \bar{V} - \bar{I}_1\bar{Z}_1$$ *...Equation A3.4*

is the relationship between positive sequence currents and voltages in the fault branch during a fault.

In Figure A3.6, which represents a simple system, the voltage drops $\bar{I}_1'\bar{Z}_1'$ and $\bar{I}_1'\bar{Z}_1''$ are equal to $(\bar{V} - \bar{V}_1)$ where the currents $\bar{I}_1'$ and $\bar{I}_1''$ enter the fault from the left and right respectively and impedances $\bar{Z}_1'$ and $\bar{Z}_1''$ are the total system impedances viewed from either side of the fault branch. The voltage $\bar{V}$ is equal to the open-circuit voltage in the system, and it has been shown that $\bar{E}' \cong \bar{E}'' \cong \bar{V}$ (see Section 2). So the positive sequence voltages in the system due to the fault are greatest at the source, as shown in the gradient diagram, Figure A3.6(b).

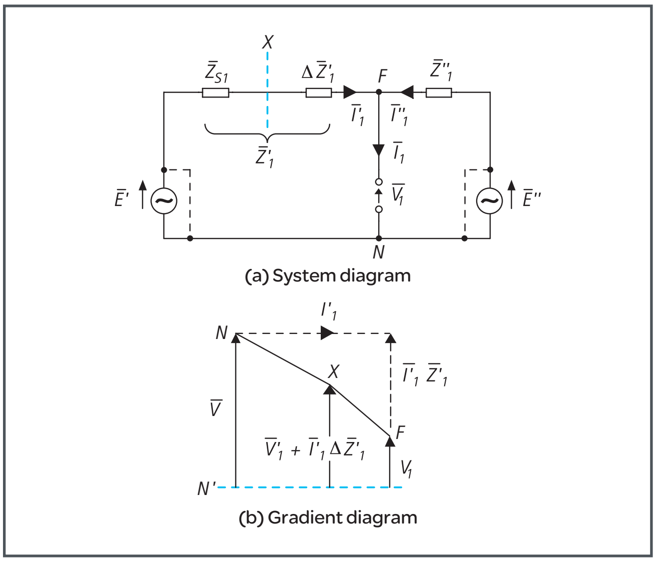

Figure A3.6:
Fault at F, Positive sequence diagrams

3.2 Negative sequence network

If only positive sequence quantities appear in a power system under normal conditions, then negative sequence quantities can only exist during an unbalanced fault.

If no negative sequence quantities are present in the fault branch prior to the fault, then, when a fault occurs, the change in voltage is $\bar{V}_2$, and the resulting current $\bar{I}_2$ flowing from the network into the fault is:

$$\bar{I}_2 = \frac{-\bar{V}_2}{\bar{Z}_2}$$ *...Equation A3.5*

The impedances in the negative sequence network are generally the same as those in the positive sequence network. In machines $\bar{Z}_1 \neq \bar{Z}_2$, but the difference is generally ignored, particularly in large networks.

The negative sequence diagrams, shown in Figure A3.7, are similar to the positive sequence diagrams, with two important differences; no driving voltages exist before the fault and the negative sequence voltage $\bar{V}_2$ is greatest at the fault point.

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3. Symmetrical component analysis of a three-phase network

3.3 Zero sequence network

The zero sequence current and voltage relationships during a fault condition are the same as those in the negative sequence network.

Hence:

$$\bar{V}_0 = -\bar{I}_0 \bar{Z}_0 \qquad \text{...Equation A3.6}$$

Also, the zero sequence diagram is that of Figure A3.7, substituting $\bar{I}_0$ for $\bar{I}_2$, and so on.

The currents and voltages in the zero sequence network are co-phasal, that is, all the same phase. For zero sequence currents to flow in a system there must be a return connection through either a neutral conductor or the general mass of earth. Note must be taken of this fact when determining zero sequence equivalent circuits. Further, in general $\bar{Z}_1 \neq \bar{Z}_0$ and the value of $\bar{Z}_0$ varies according to the type of plant, the winding arrangement and the method of earthing.

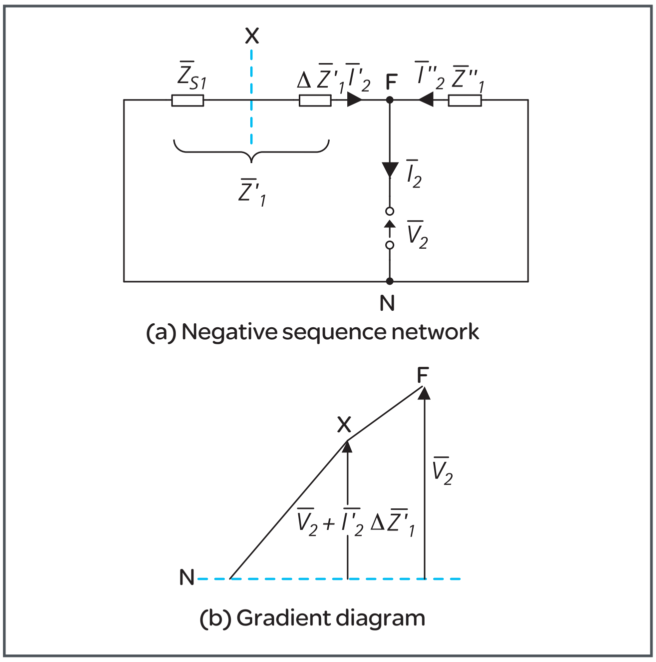


Figure A3.7:
Fault at F, positive sequence diagrams

4. Equations and network connections for various types of faults

The most important types of faults are as follows:

a. single-phase to earth

b. phase to phase

c. phase-phase-earth

d. three-phase (with or without earth)

The above faults are described as single shunt faults because they occur at one location and involve a connection between one phase and another or to earth.

In addition, the Protection Engineer often studies two other types of fault:

e. single-phase open circuit

f. cross-country fault

By determining the currents and voltages at the fault point, it is possible to define the fault and connect the sequence networks to represent the fault condition. From the initial equations and the network diagram, the nature of the fault currents and voltages in different branches of the system can be determined.

For shunt faults of zero impedance, and neglecting load current, the equations defining each fault (using phase-neutral values) can be written down as follows:

a. Single-phase-earth (A-E)

$$\left.\begin{aligned} \bar{I}_b &= 0 \\ \bar{I}_c &= 0 \\ \bar{V}_a &= 0 \end{aligned}\right\} \qquad \text{...Equation A3.7}$$

b. Phase-phase (B-C)

$$\left.\begin{aligned} \bar{I}_a &= 0 \\ \bar{I}_b &= -\bar{I}_c \\ \bar{V}_b &= \bar{V}_c \end{aligned}\right\} \qquad \text{...Equation A3.8}$$

c. Phase-phase-earth (B-C-E)

$$\left.\begin{aligned} \bar{I}_a &= 0 \\ \bar{V}_b &= 0 \\ \bar{V}_c &= 0 \end{aligned}\right\} \qquad \text{...Equation A3.9}$$

4. Equations and network connections for various types of faults

d. Three-phase (A-B-C or A-B-C-E)

$$\left.\begin{aligned} \bar{I}_a + \bar{I}_b + \bar{I}_c &= 0 \\ \bar{V}_a &= \bar{V}_b \\ \bar{V}_b &= \bar{V}_c \end{aligned}\right\} \quad \text{...Equation A3.10}$$

It should be noted from the above that for any type of fault there are three equations that define the fault conditions.

When there is a fault impedance, this must be taken into account when writing down the equations. For example, with a single phase-earth fault through fault impedance $\bar{Z}_f$, Equations A3.7 are re-written:

$$\left.\begin{aligned} \bar{I}_b &= 0 \\ \bar{I}_c &= 0 \\ \bar{V}_a &= \bar{I}_a \bar{Z}_f \end{aligned}\right\} \quad \text{...Equation A3.11}$$

4.1 Single-phase-earth fault (A-E)

Consider a fault defined by Equations A3.7 and by Figure A3.8(a). Converting Equations A3.7 into sequence quantities by using Equations A3.1 and A3.2, then:

$$\bar{I}_1 = \bar{I}_2 = \bar{I}_0 = \frac{1}{3}\bar{I}_a \quad \text{...Equation A3.12}$$

$$\bar{V}_1 = -(\bar{V}_2 + \bar{V}_0) \quad \text{...Equation A3.13}$$

Substituting for $\bar{V}_1$, $\bar{V}_2$ and $\bar{V}_0$ in Equation A3.13 from Equations A3.4, A3.5 and A3.6:

$$\bar{V} - \bar{I}_1\bar{Z}_1 = \bar{I}_2\bar{Z}_2 + \bar{I}_0\bar{Z}_0$$

but, from Equation A3.12, $\bar{I}_1 = \bar{I}_2 = \bar{I}_0$, therefore:

$$\bar{V} = \bar{I}_1(\bar{Z}_1 + \bar{Z}_2 + \bar{Z}_3) \quad \text{...Equation A3.14}$$

The constraints imposed by Equations A3.12 and A3.14 indicate that the equivalent circuit for the fault is obtained by connecting the sequence networks in series, as shown in Figure A3.8(b).

4.2 Phase-phase fault (B-C)

From Equation A3.8 and using Equations A3.1 and A3.2:

$$\bar{I}_1 = \bar{I}_2$$

$$\bar{I}_1 = 0 \quad \text{... Equation A3.15}$$

$$\bar{V}_1 = \bar{V}_2 \quad \text{... Equation A3.16}$$

From network Equations A3.4 and A3.5, Equation A3.16 can be re-written:

$$\bar{V} - \bar{I}_1\bar{Z}_1 = \bar{I}_2\bar{Z}_2 + \bar{I}_0\bar{Z}_0$$

$$\bar{V} - \bar{I}_1\bar{Z}_1 = \bar{I}_2\bar{Z}_2$$

and substituting for $\bar{I}_2$ from Equation A3.15:

$$\bar{V} = \bar{I}_1(\bar{Z}_1 + \bar{Z}_2) \quad \text{... Equation A3.17}$$

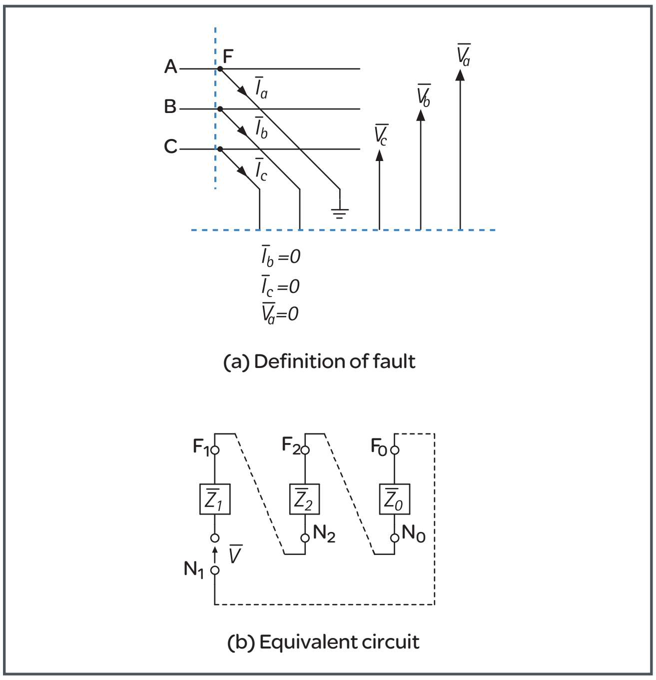


Figure A3.8:
Single-phase-earth fault at F

The constraints imposed by Equations A3.15 and A3.17 indicate that there is no zero sequence network connection in the equivalent circuit and that the positive and negative sequence networks are connected in parallel. Figure A3.9 shows the defining and equivalent circuits satisfying the above equations.

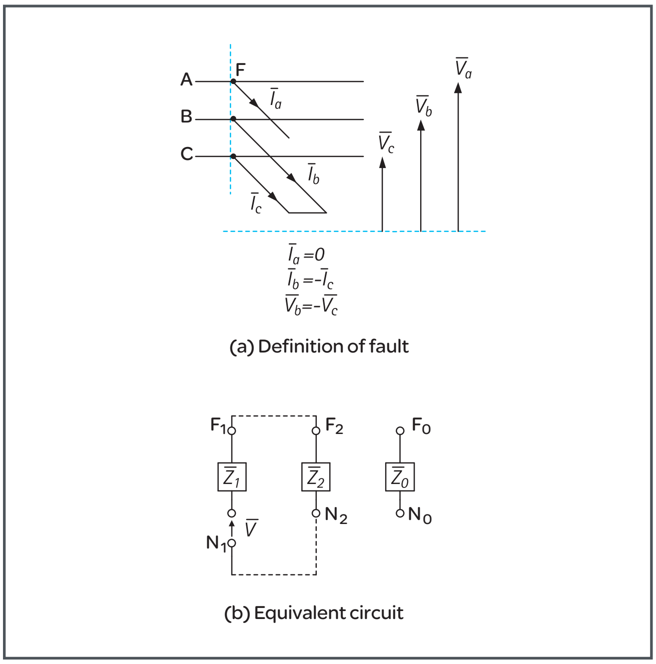


Figure A3.9:
Phase-phase fault at F

4. Equations and network connections for various types of faults

4.3 Phase-phase-earth fault (B-C-E)

Again, from Equation A3.9 and Equations A3.1 and A3.2:

$\bar{I}_1 = -(\bar{I}_2 + \bar{I}_0)$ ...*Equation A3.18*

and

$\bar{V}_1 = \bar{V}_2 = \bar{V}_0$ ...*Equation A3.19*

Substituting for $\bar{V}_2$ and $\bar{V}_0$ using network Equations A3.5 and A3.6:

$\bar{I}_2\,\bar{Z}_2 = \bar{I}_0\,\bar{Z}_0$

thus, using Equation A3.18:

$$\bar{I}_0 = -\frac{\bar{Z}_2\bar{I}_1}{\bar{Z}_0 + \bar{Z}_2}$$ ...*Equation A3.20*

$$\bar{I}_2 = -\frac{\bar{Z}_0\bar{I}_1}{\bar{Z}_0 + \bar{Z}_2}$$ ...*Equation A3.21*

Now equating $\bar{V}_1$ and $\bar{V}_2$ and using Equation A3.4 gives:

$\bar{V} - \bar{I}_1\bar{Z}_1 = \bar{I}_2\,\bar{Z}_2$

or

$\bar{V} = \bar{I}_1\bar{Z}_1 - \bar{I}_2\,\bar{Z}_2$

Substituting for $\bar{I}_2$ from Equation A3.21:

$$\bar{V} = \left[\bar{Z}_1 + \frac{\bar{Z}_0\bar{Z}_2}{\bar{Z}_0 + \bar{Z}_2}\right]\bar{I}_1$$

or

$$\bar{I}_1 = \bar{V}\frac{\left(\bar{Z}_0 + \bar{Z}_2\right)}{\bar{Z}_1\bar{Z}_0 + \bar{Z}_1\bar{Z}_2 + \bar{Z}_0\bar{Z}_2}$$ ...*Equation A3.22*

From the above equations it follows that connecting the three sequence networks in parallel as shown in Figure A3.10(b) may represent a phase-phase-earth fault.

4.4 Three-phase fault (A-B-C or A-B-C-E)

Assuming that the fault includes earth, then, from Equations A3.10 and A3.1, A3.2, it follows that:

$$\left.\begin{aligned}\bar{V}_0 &= \bar{V}_a\\ \bar{V}_1 &= \bar{V}_2 = 0\end{aligned}\right\}$$ ...*Equation A3.23*

and

$\bar{I}_0 = 0$ ...*Equation A3.24*

Substituting $\bar{V}_2 = 0$ in Equation A3.5 gives:

$\bar{I}_2 = 0$ ...*Equation A3.25*

and substituting $\bar{V}_1 = 0$ in Equation A3.4:

$0 = \bar{V}_1 - \bar{I}_1\bar{Z}_1$

or

$\bar{V}_1 = \bar{I}_1\bar{Z}_1$ ...*Equation A3.26*

Further, since from Equation A3.24 $\bar{I}_0 = 0$ it follows from Equation A3.6 that $\bar{V}_0$ is zero when $\bar{Z}_0$ is finite. The equivalent sequence connections for a three-phase fault are shown in Figure A3.11.

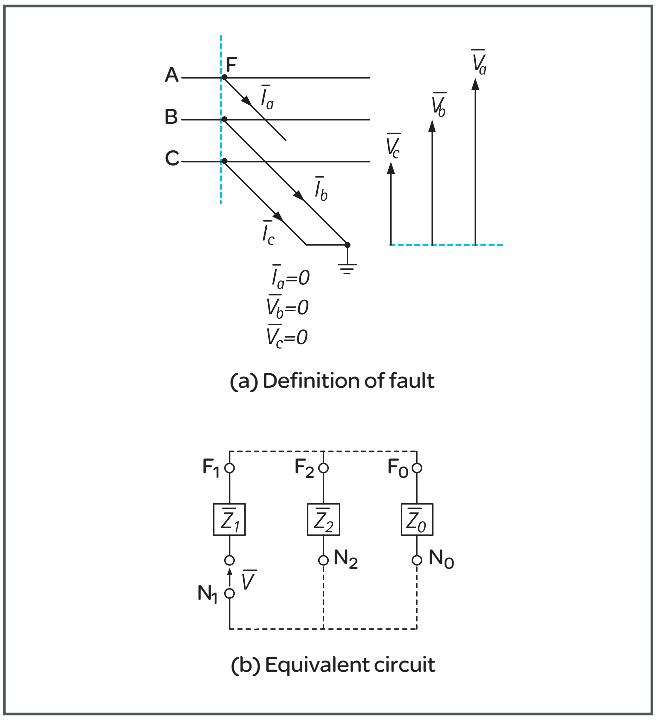


Figure A3.10: Phase-phase-earth fault at F

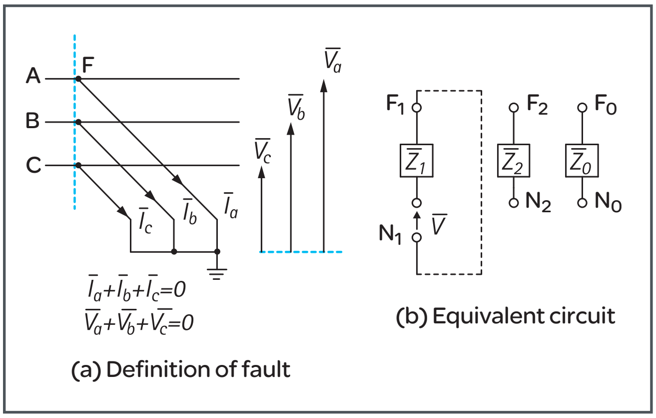


Figure A3.11: Three-phase-earth fault at F

4. Equations and network connections for various types of faults

4.5 Single-phase open circuit fault

The single-phase open circuit fault is shown diagrammatically in Figure A3.12(a). At the fault point, the boundary conditions are:

$$\left.\begin{aligned} I_a &= 0 \\ V_b &= V_c = 0 \end{aligned}\right\} \quad \text{...Equation A3.27}$$

Hence, from Equations A3.2,

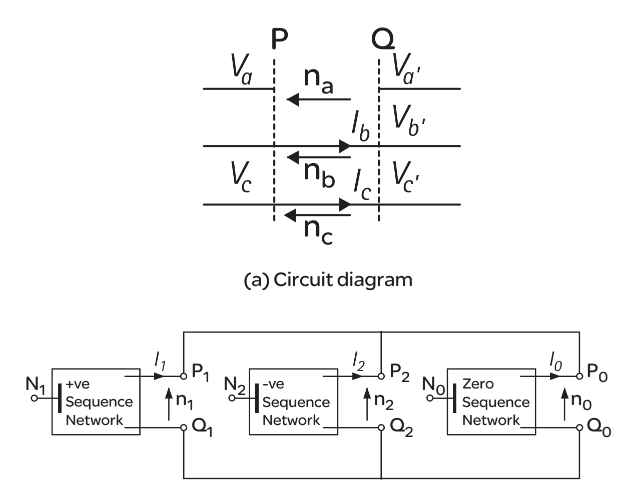
$$V_0 = 1/3\ Va$$

$$V_1 = 1/3\ Va$$

and therefore:

$$\left.\begin{aligned} V_1 &= V_2 = V_0 = 1/3\,V_a \\ I_a &= I_1 + I_2 + I_0 = 0 \end{aligned}\right\} \quad \text{...Equation A3.28}$$

From Equations A3.28, it can be concluded that the sequence networks are connected in parallel, as shown in Figure A3.12(b).



(a) Circuit diagram

(b) Equivalent circuit

Figure A3.12:
Open circuit on phase A

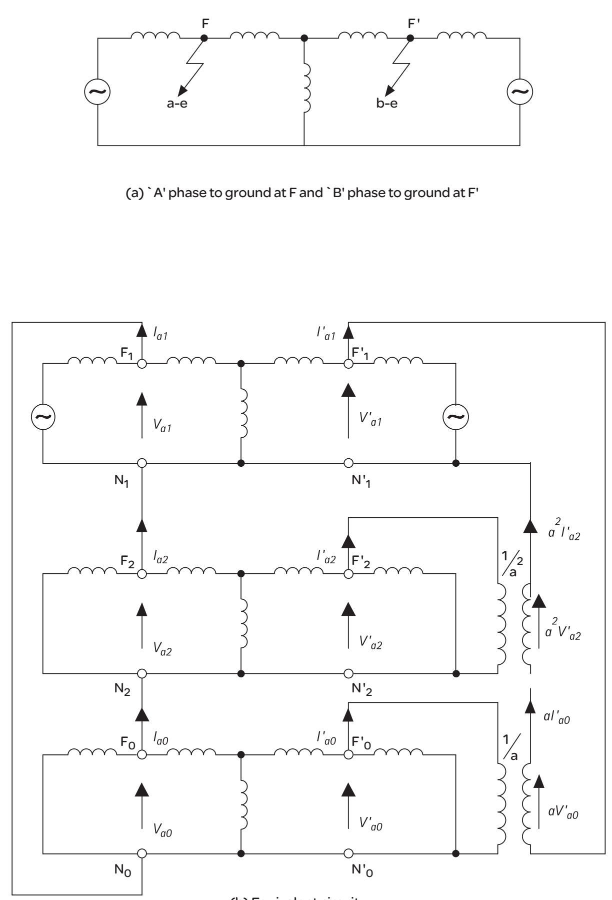
4.6 Cross-country faults

A cross-country fault is one where there are two faults affecting the same circuit, but in different locations and possibly involving different phases. Figure A3.13(a) illustrates this.

The constraints expressed in terms of sequence quantities are as follows:

a) At point F

$$\left.\begin{aligned} I_b + I_c &= 0 \\ V_a &= 0 \end{aligned}\right\}$$



(a) `A' phase to ground at F and `B' phase to ground at F'

(b) Equivalent circuit

Figure A3.13:
Cross-country fault-phase A to phase B

Therefore:

$$\left.\begin{aligned} I_{a1} &= I_{a2} = I_{a0} \\ V_{a1} + V_{a2} + V_{a0} &= 0 \end{aligned}\right\} \quad \text{...Equation A3.29}$$

b) At point F'

$$\left.\begin{aligned} I'_a &= I'_c = 0 \\ V'_b &= 0 \end{aligned}\right\} \quad \text{...Equation A3.31}$$

and therefore:

$$I'_{b1} = I'_{b2} = I'_{b0} \quad \text{...Equation A3.32}$$

A3

4. Equations and network connections for various types of faults

To solve, it is necessary to convert the currents and voltages at point F' to the sequence currents in the same phase as those at point F. From Equation A3.32,

$$a^2 I'_{a1} = a I'_{a2} = I'_{a0}$$

or

$$I'_{a1} = a^2 I'_{a2} = a I'_{a0} \quad \text{... Equation A3.33}$$

and, for the voltages

$$V'_{b1} + V'_{b2} = V'_{b0} = 0$$

Converting:

$$a^2 V'_{a1} + a V'_{a2} + V'_{a0} = 0$$

or

$$V'_{a1} + a^2 V'_{a2} + a V'_{a0} = 0 \quad \text{...Equation A3.34}$$

The fault constraints involve phase shifted sequence quantities. To construct the appropriate sequence networks, it is necessary to introduce phase-shifting transformers to couple the sequence networks. This is shown in Figure A3.13(b).

5. Current and voltage distribution in a system due to a fault

Practical fault calculations involve the examination of the effect of a fault in branches of network other than the faulted branch, so that protection can be applied correctly to isolate the section of the system directly involved in the fault. It is therefore not enough to calculate the fault current in the fault itself; the fault current distribution must also be established. Further, abnormal voltage stresses may appear in a system because of a fault, and these may affect the operation of the protection. Knowledge of current and voltage distribution in a network due to a fault is essential for the application of protection.

The approach to network fault studies for assessing the application of protection equipment may be summarised as follows:

a. from the network diagram and accompanying data, assess the limits of stable generation and possible operating conditions for the system

NOTE: *When full information is not available assumptions may have to be made*

b. with faults assumed to occur at each relaying point in turn, maximum and minimum fault currents are calculated for each type of fault

NOTE: *The fault is assumed to be through zero impedance*

c. by calculating the current distribution in the network for faults applied at different points in the network (from (b) above) the maximum through fault currents at each relaying point are established for each type of fault

d. at this stage more or less definite ideas on the type of protection to be applied are formed.

Further calculations for establishing voltage variation at the relaying point, or the stability limit of the system with a fault on it, are now carried out in order to determine the class of protection necessary, such as high or low speed, unit or non-unit, etc.

5.1 Current distribution

The phase current in any branch of a network is determined from the sequence current distribution in the equivalent circuit of the fault. The sequence currents are expressed in per unit terms of the sequence current in the fault branch.

In power system calculations, the positive and negative sequence impedances are normally equal. Thus, the division of sequence currents in the two networks will also be identical.

The impedance values and configuration of the zero sequence network are usually different from those of the positive and negative sequence networks, so the zero sequence current distribution is calculated separately.

If C_0 and C_1 are described as the zero and positive sequence distribution factors then the actual current in a sequence branch is given by multiplying the actual current in the sequence fault branch by the appropriate distribution factor.

For this reason, if $\bar{I}_1$, $\bar{I}_2$ and $\bar{I}_0$ are sequence currents in an arbitrary branch of a network due to a fault at some point in the network, then the phase currents in that branch may be expressed in terms of the distribution constants and the sequence currents in the fault.

These are shown for the various common shunt faults, using Equation A3.1 and the appropriate fault equations:

5. Current and voltage distribution in a system due to a fault

a. single-phase-earth (A-E)

$$\left.\begin{aligned} \bar{I}'_a &= (2C_1 + C_0)\bar{I}_0 \\ \bar{I}'_b &= -(C_1 - C_0)\bar{I}_0 \\ \bar{I}'_c &= -(C_1 - C_0)\bar{I}_0 \end{aligned}\right\}$$

...Equation A3.35

b. phase-phase (B-C)

$$\left.\begin{aligned} \bar{I}'_a &= 0 \\ \bar{I}'_b &= (a^2 - a)\ C_1\bar{I}_1 \\ \bar{I}'_c &= (a - a^2)\ C_1\bar{I}_1 \end{aligned}\right\}$$

...Equation A3.36

c. phase-phase-earth (B-C-E)

$$\left.\begin{aligned} \bar{I}'_a &= -(C_1 - C_0)\bar{I}_0 \\ \bar{I}'_b &= \left[(a - a^2)C_1\frac{\bar{Z}_0}{\bar{Z}_1} - a^2C_1 - C_0\right]\bar{I}_0 \\ \bar{I}'_c &= \left[(a^2 - a)C_1\frac{\bar{Z}_0}{\bar{Z}_1} - aC_1 + C_0\right]\bar{I}_0 \end{aligned}\right\}$$

...Equation A3.37

d. three-phase (A-B-C or A-B-C-E)

$$\left.\begin{aligned} \bar{I}'_a &= C_1\bar{I}_1 \\ \bar{I}'_b &= a^2C_1\bar{I}_1 \\ \bar{I}'_c &= aC_1\bar{I}_1 \end{aligned}\right\}$$

...Equation A3.38

As an example of current distribution technique, consider the system in Figure A3.14(a). The equivalent sequence networks are given in Figures A3.14(b) and (c), together with typical values of impedances. A fault is assumed at A and it is desired to find the currents in branch OB due to the fault. In each network, the distribution factors are given for each branch, with the current in the fault branch taken as 1.0 $p.u.$ From the diagram, the zero sequence distribution factor C_0 in branch OB is 0.112 and the positive sequence factor C_1 is 0.373. For an earth fault at A the phase currents in branch OB from Equation A3.35 are:

$$\bar{I}_a = (0.746+0.112)\,\bar{I}_0 = 0.858\,\bar{I}_0$$

and

$$\bar{I}'_b = \bar{I}'_c = -(0.373+0.112)\bar{I}_0 = 0.261\,\bar{I}_0$$

By using network reduction methods and assuming that all impedances are reactive, it can be shown that

$$\bar{Z}_1 = \bar{Z}_0 = j0.68\ \Omega$$

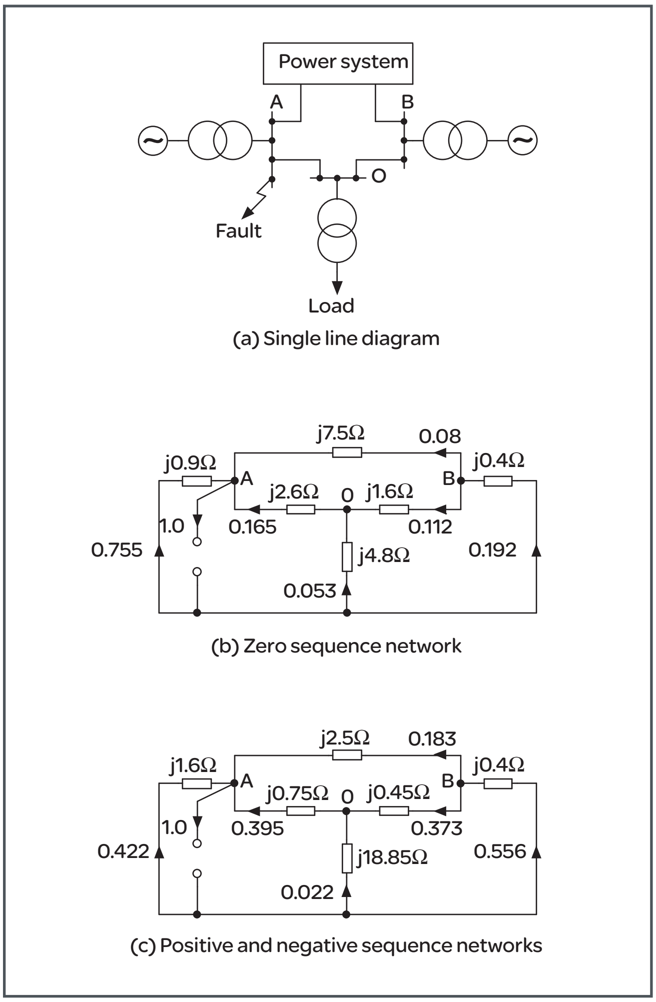


Figure A3.14:
Typical power system

Therefore, from Equation A3.14, the current in fault branch

$$|I_a| = \frac{|V|}{0.68}$$

Assuming that $|V| = 63.5\ volts$, then:

$$|I_0| = \tfrac{1}{3}|I_a| = \frac{63.5}{3 \times 0.68} = 31.2\,A$$

If $\bar{V}$ is taken as the reference vector, then:

$$\bar{I}'_a = 26.8 <\!-90°\ A$$

$$\bar{I}'_b = \bar{I}'_c = 8.15 <\!-90°\ A$$

The vector diagram for the above fault condition is shown in Figure A3.15.

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5. Current and voltage distribution in a system due to a fault

5.2 Voltage distribution

The voltage distribution in any branch of a network is determined from the sequence voltage distribution. As shown by Equations A3.4, A3.5 and A3.6 and the gradient diagrams, Figures A3.6(b) and A3.7(b), the positive sequence voltage is a minimum at the fault, whereas the zero and negative sequence voltages are a maximum. Thus, the sequence voltages in any part of the system may be given generally as:

$$\left.\begin{aligned} \bar{V}_1' &= \bar{V} - \bar{I}_1\left[\bar{Z}_1 - \sum_1^n C_{1n}\Delta\bar{Z}_{1n}\right] \\ \bar{V}_2' &= -\bar{I}_2\left[\bar{Z}_1 - \sum_1^n C_{1n}\Delta\bar{Z}_{1n}\right] \\ \bar{V}_0' &= -\bar{I}_0\left[\bar{Z}_0 - \sum_1^n C_{0n}\Delta\bar{Z}_{0n}\right] \end{aligned}\right\}$$

...Equation A3.39

Using the above equation, the fault voltages at bus B in the previous example (Figure A3.14) can be found.

From the positive sequence distribution diagram Figure A3.8(c):

$$\bar{V}'_1 = \bar{V} - \bar{I}_1\left[\bar{Z}_1 - j\{(0.395\times 0.75)+(0.373\times 0.45)\}\right]$$

$$\bar{V}'_2 = \bar{V} - \bar{I}_1\left[\bar{Z}_1 - j0.464\right]$$

From the zero sequence distribution diagram Figure A3.8(b):

$$\bar{V}'_0 = \bar{I}_0\left[\bar{Z}_0 - j\{(0.165\times 2.6)+(0.112\times 1.6)\}\right]$$

$$= \bar{I}_0\left[\bar{Z}_0 - j0.608\right]$$

For earth faults, at the fault

$$\bar{I}_1 = \bar{I}_2 = \bar{I}_0 = j31.2A$$

when $|\bar{V}|$ = 63.5 volts and is taken as the reference vector.

Further, $\bar{Z}_1 = \bar{Z}_2 = j0.68\ \Omega$.

Hence:

$$\bar{V}'_1 = 63.5 - (0.216 \times 31.2) = 56.76\angle 0°\ \text{volts}$$

$$\bar{V}'_2 = 6.74\angle 180°\ \text{volts}$$

$$\bar{V}'_0 = 2.25\angle 180°\ \text{volts}$$

and, using Equations A3.1:

$$\bar{V}_a = \bar{V}_1 + \bar{V}_2 + \bar{V}_0 = 56.76 - (6.74 + 2.25)$$

$$\bar{V}'_a = 47.8\angle 0°$$

$$\bar{V}'_b = a^2\bar{V}'_1 + a\bar{V}'_2 + \bar{V}'_0 = 56.76a^2 - (6.74a + 2.25)$$

$$\bar{V}'_b = 61.5\angle -116.4°\ \text{volts}$$

$$\bar{V}'_c = a\bar{V}'_1 + a^2\bar{V}'_2 + \bar{V}'_0 = 56.76a - (6.74a^2 + 2.25)$$

$$\bar{V}'_c = 61.5\angle 116.4°\ \text{volts}$$

These voltages are shown on the vector diagram, Figure A3.15.

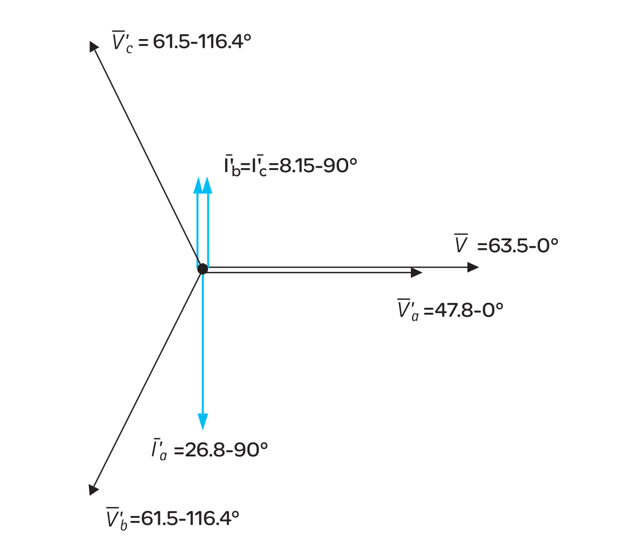

Figure A3.15:
Vector diagram-fault currents and voltages in branch OB due to P-E fault at bus A

6. Effect of system earthing on zero sequence quantities

It has been shown previously that zero sequence currents flow in the earth path during earth faults, and it follows that the nature of these currents will be influenced by the method of earthing. Because these quantities are unique in their association with earth faults they can be utilised in protection, provided their measurement and character are understood for all practical system conditions.

6.1 Residual current and voltage

Residual currents and voltages depend for their existence on two factors:

a. a system connection to earth at two or more points

b. a potential difference between the earthed points resulting in a current flow in the earth paths

Under normal system operation there is a capacitance between the phases and between phase and earth; these capacitances may be regarded as being symmetrical and distributed uniformly through the system. So even when (a) above is satisfied, if the driving voltages are symmetrical the vector sum of the currents will equate to zero and no current will flow between any two earth points in the system. When a fault to earth occurs in a system an unbalance results in condition (b) being satisfied. From the definitions given above it follows that residual currents and voltages are the vector sum of phase currents and phase voltages respectively.

Hence:

$$\left.\begin{aligned}\bar{I}_R &= \bar{I}_a + \bar{I}_b + \bar{I}_c \\ &\text{and} \\ \bar{V}_R &= \bar{V}_{ae} + \bar{V}_{be} + \bar{V}_{ce}\end{aligned}\right\} \quad \text{...Equation A3.40}$$

Also, from Equations A3.2:

$$\left.\begin{aligned}\bar{I}_R &= 3\bar{I}_0 \\ \bar{V}_R &= 3\bar{V}_0\end{aligned}\right\} \quad \text{...Equation A3.41}$$

It should be further noted that:

$$\left.\begin{aligned}\bar{V}_{ae} &= \bar{V}_{an} + \bar{V}_{ne} \\ \bar{V}_{be} &= \bar{V}_{bn} + \bar{V}_{ne} \\ \bar{V}_{ce} &= \bar{V}_{cn} + \bar{V}_{ne}\end{aligned}\right\} \quad \text{...Equation A3.42}$$

and since $\bar{V}_{bn} = a^2\bar{V}_{an}, \bar{V}_{cn} = a\bar{V}_{an}$ then:

$$\bar{V}_R = 3\bar{V}_{ne} \quad \text{...Equation A3.43}$$

where $\bar{V}_{ne}$ is the neutral displacement voltage.

Measurements of residual quantities are made using current and voltage transformer connections as shown in Figure A3.16. If relays are connected into the circuits in place of the ammeter and voltmeter, it follows that earth faults in the system can be detected.

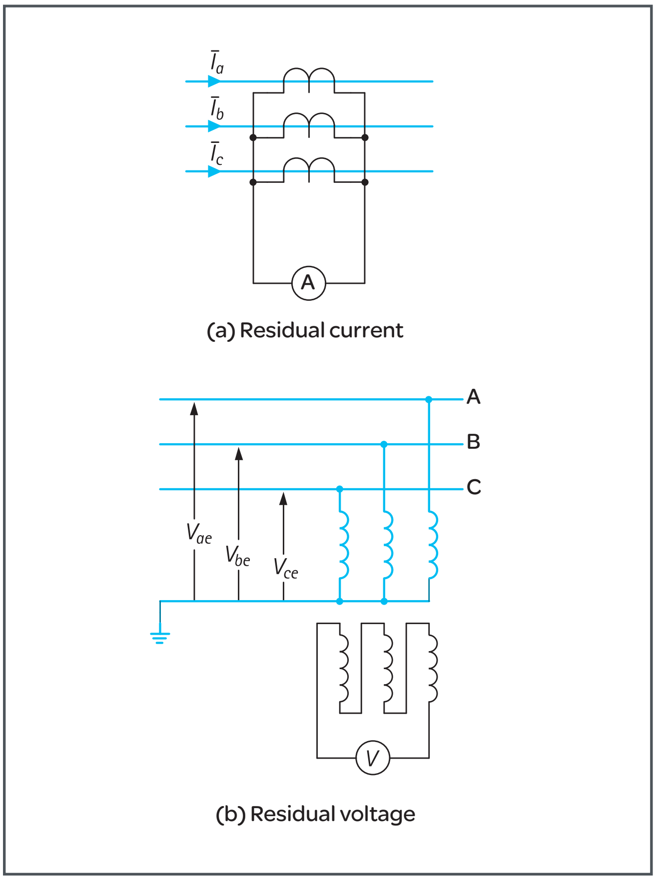

Figure A3.16:
Measurement of residual quantities

6.2 System $\bar{Z}_0/\bar{Z}_1$ ratio

The system $\bar{Z}_0/\bar{Z}_1$ ratio is defined as the ratio of zero sequence and positive sequence impedances viewed from the fault; it is a variable ratio, dependent upon the method of earthing, fault position and system operating arrangement.

When assessing the distribution of residual quantities through a system, it is convenient to use the fault point as the reference as it is the point of injection of unbalanced quantities into the system. The residual voltage is measured in relation to the normal phase-neutral system voltage and the residual current is compared with the three-phase fault current at the fault point. It can be shown [Ref A3.4: Neutral Groundings] [Ref A3.5: Fault Calculations] that the character of these quantities can be expressed in terms of the system $\bar{Z}_0/\bar{Z}_1$ ratio.

The positive sequence impedance of a system is mainly reactive, whereas the zero sequence impedance being affected by the method of earthing may contain both resistive and reactive components of comparable magnitude. Thus the express of the $\bar{Z}_0/\bar{Z}_1$ ratio approximates to:

$$\frac{\bar{Z}_0}{\bar{Z}_1} = \frac{\bar{X}_0}{\bar{X}_1} - j\frac{\bar{R}_0}{\bar{X}_1} \quad \text{...Equation A3.44}$$

6. Effect of system earthing on zero sequence quantities

Expressing the residual current in terms of the three-phase current and $\bar{Z}_0/\bar{Z}_1$ ratio:

a. Single-phase-earth (A-E)

$$\bar{I}_R = \frac{3\bar{V}}{2\bar{Z}_1 + \bar{Z}_0} = \frac{3}{\left(2 + \bar{K}\right)}\frac{\bar{V}}{\bar{Z}_1} \quad \text{where } K=\bar{Z}_0/\bar{Z}_1$$

$$\bar{I}_{3\phi} = \frac{\bar{V}}{\bar{Z}_1}$$

Thus:

$$\frac{\bar{I}_R}{\bar{I}_{3\phi}} = \frac{3}{\left(2 + \bar{K}\right)} \qquad \text{...Equation A3.45}$$

b. Phase-phase-earth (B-C-E)

$$\bar{I}_R = 3\bar{I}_0 = -\frac{3\bar{Z}_1}{\bar{Z}_1 + \bar{Z}_0}\bar{I}_1 \qquad \bar{I}_1 = \frac{\bar{V}\left(\bar{Z}_1 + \bar{Z}_0\right)}{2\bar{Z}_1\bar{Z}_0 + \bar{Z}_1^2}$$

Hence:

$$\bar{I}_R = -\frac{3\bar{V}\,\bar{Z}_1}{2\bar{Z}_1\bar{Z}_0 + \bar{Z}_1^2} = -\frac{3}{\left(2\bar{K} + 1\right)}\frac{\bar{V}}{\bar{Z}_1}$$

Therefore:

$$\frac{\bar{I}_R}{\bar{I}_{3\phi}} = -\frac{3}{\left(2\bar{K} + 1\right)} \qquad \text{...Equation A3.46}$$

Similarly, the residual voltages are found by multiplying Equations A3.45 and A3.46 by $-\bar{K}\bar{V}$.

a. Single-phase-each (A-E)

$$\bar{V}_R = -\frac{3\bar{K}}{\left(2 + \bar{K}\right)}\bar{V} \qquad \text{...Equation A3.47}$$

b. Phase-phase-earth (B-C-E)

$$\bar{V}_R = \frac{3\bar{K}}{\left(2\bar{K} + 1\right)}\bar{V} \qquad \text{...Equation A3.48}$$

The curves in Figure A3.17 illustrate the variation of the above residual quantities with the $\bar{Z}_0/\bar{Z}_1$ ratio. The residual current in any part of the system can be obtained by multiplying the current from the curve by the appropriate zero sequence distribution factor. Similarly, the residual voltage is calculated by subtracting from the voltage curve three times the zero sequence voltage drop between the measuring point in the system and the fault.

6.3 Variation of residual quantities

The variation of residual quantities in a system due to different earth arrangements can be most readily understood by using vector diagrams. Three examples have been chosen, namely solid fault-isolated neutral, solid fault-resistance neutral, and resistance fault-solid neutral. These are illustrated in Figures A3.18, A3.19 and A3.20 respectively.

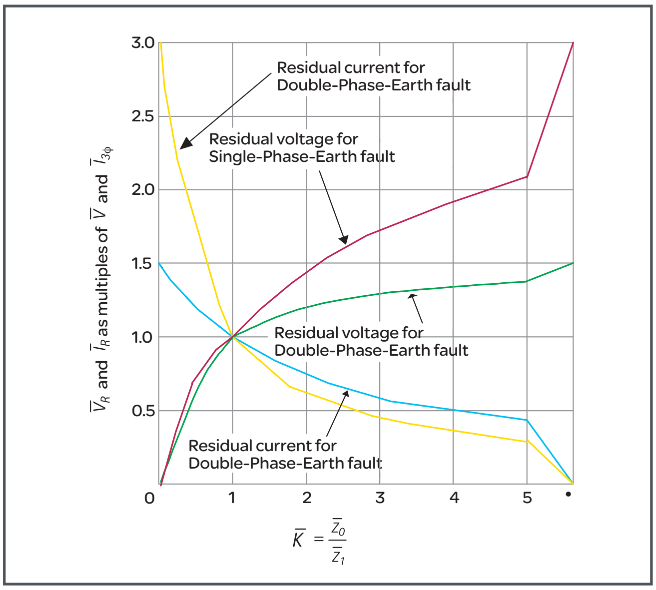

Figure A3.17: Variation of residual quantities at fault point

6.3.1 Solid fault-isolated neutral

From Figure A3.18 it can be seen that the capacitance to earth of the faulted phase is short circuited by the fault and the resulting unbalance causes capacitance currents to flow into the fault, returning via sound phases through sound phase capacitances to earth.

At the fault point:

$$\bar{V}_{aF} = 0$$

and

$$\bar{V}_R = \bar{V}_{bF} + \bar{V}_{cF} = -3\bar{E}_{an}$$

At source:

$$\bar{V}_R = 3\bar{V}_{ne} = -3\bar{E}_{an}$$

since

$$\bar{E}_{an} + \bar{E}_{bn} + \bar{E}_{cn} = 0$$

Thus, with an isolated neutral system, the residual voltage is three times the normal phase-neutral voltage of the faulted phase and there is no variation between $\bar{V}_R$ at source and $\bar{V}_R$ at fault.

In practice, there is some leakage impedance between neutral and earth and a small residual current would be detected at X if a very sensitive relay were employed.

6. Effect of system earthing on zero sequence quantities

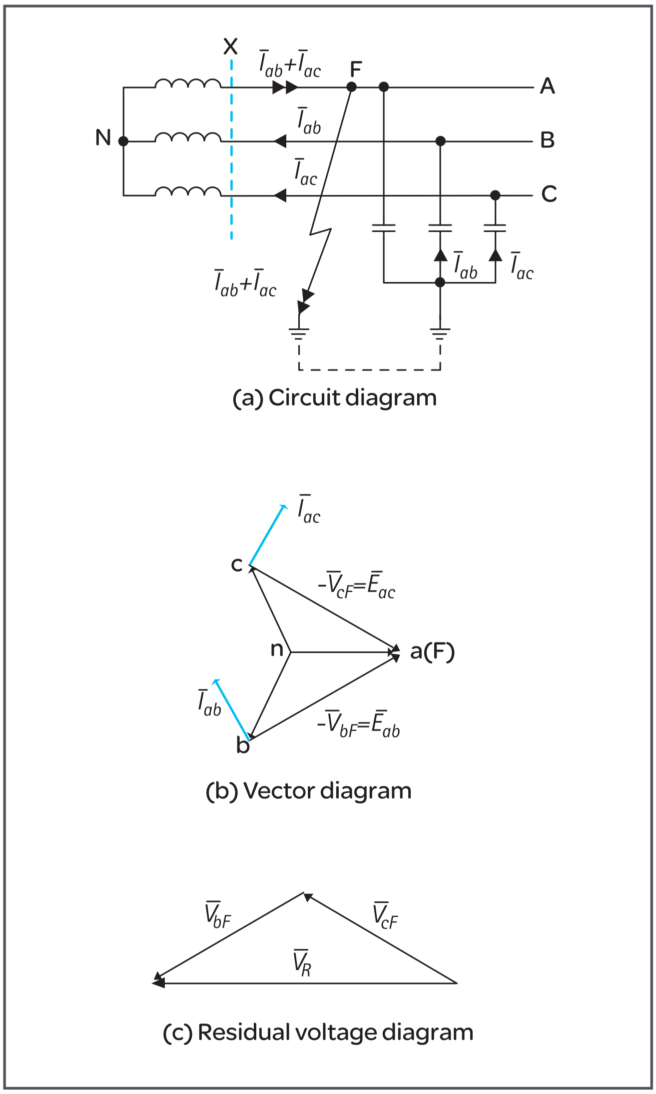

Figure A3.18:
Solid fault-isolated neutral

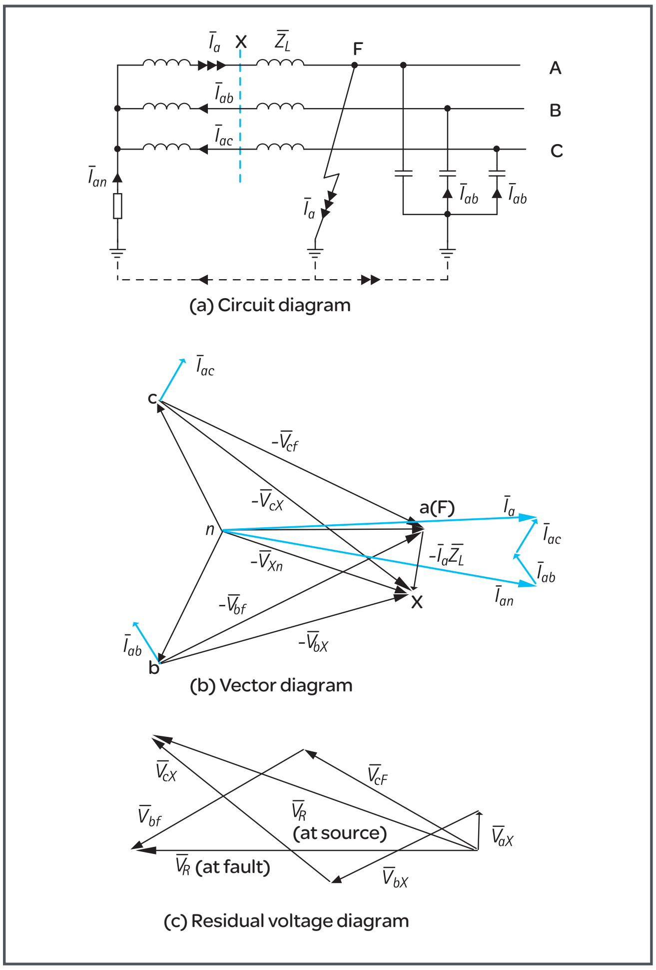

Figure A3.19:
Solid fault-resistance neutral

6.3.2 Solid fault-resistance neutral

Figure A3.19 shows that the capacitance of the faulted phase is short-circuited by the fault and the neutral current combines with the sound phase capacitive currents to give $\bar{I}_a$ in the faulted phase.

With a relay at X, residually connected as shown in Figure A3.16, the residual current will be $\bar{I}_{an}$, that is, the neutral earth loop current.

At the fault point:

$$\bar{V}_R = \bar{V}_{bF} + \bar{V}_{cF}, \text{ since } \bar{V}_{Fe} = 0$$

At source:

$$\bar{V}_R = \bar{V}_{aX} + \bar{V}_{bX} + \bar{V}_{cX}$$

From the residual voltage diagram it is clear that there is little variation in the residual voltages at source and fault, as most residual voltage is dropped across the neutral resistor. The degree of variation in residual quantities is therefore dependent on the neutral resistor value.

6.3.3 Resistance fault-solid neutral

Capacitance can be neglected because, since the capacitance of the faulted phase is not short-circuited, the circulating capacitance currents will be negligible.

At the fault point:

$$\bar{V}_R = \bar{V}_{Fn} + \bar{V}_{bn} + \bar{V}_{cn}$$

At relaying point X:

$$\bar{V}_R = \bar{V}_{Xn} + \bar{V}_{bn} + \bar{V}_{cn}$$

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6. Effect of system earthing on zero sequence quantities

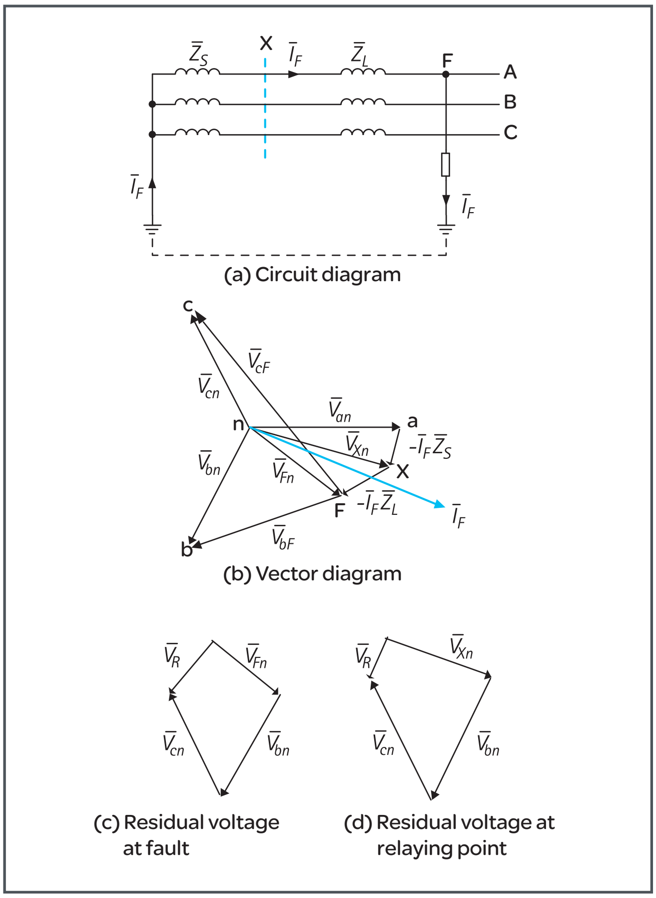

Figure A3.20:
Resistance fault-solid neutral

From the residual voltage diagrams shown in Figure A3.20, it is apparent that the residual voltage is greatest at the fault and reduces towards the source. If the fault resistance approaches zero, that is, the fault becomes solid, then $\bar{V}_{Fn}$ approaches zero and the voltage drops in $\bar{Z}_S$ and $\bar{Z}_L$ become greater. The ultimate value of $\bar{V}_{Fn}$ will depend on the effectiveness of the earthing, and this is a function of the system $\bar{Z}_0/\bar{Z}_1$ ratio.

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A4

Equivalent Circuits and Parameters of Power System Plant

Network Protection & Automation Guide

Life Is On | Schneider Electric

Chapter A4

Equivalent Circuits and Parameters of Power System Plant

1. Introduction

Knowledge of the behaviour of the principal electrical system plant items under normal and fault conditions is a prerequisite for the proper application of protection. This chapter summarises basic synchronous machine, transformer and transmission line theory and gives equivalent circuits and parameters so that a fault study can be successfully completed before the selection and application of the protection systems described in later chapters. Only what might be referred to as 'traditional' synchronous machine theory is covered, as that is all that calculations for fault level studies generally require. Readers interested in more advanced models of synchronous machines are referred to the numerous papers on the subject, of which [Ref A4.1: Physical significance of sub-subtransient quantities in dynamic behaviour of synchronous machines] is a good starting point.

Power system plant may be divided into two broad groups - static and rotating.

The modelling of static plant for fault level calculations provides few difficulties, as plant parameters generally do not change during the period of interest following fault inception. The problem in modelling rotating plant is that the parameters change depending on the response to a change in power system conditions.

2. Synchronous machines

There are two main types of synchronous machine: cylindrical rotor and salient pole. In general, the former is confined to 2 and 4 pole turbine generators, while salient pole types are built with 4 poles upwards and include most classes of duty. Both classes of machine are similar in so far that each has a stator carrying a three-phase winding distributed over its inner periphery. Within the stator bore is carried the rotor which is magnetised by a winding carrying d.c. current.

The essential difference between the two classes of machine lies in the rotor construction. The cylindrical rotor type has a uniformly cylindrical rotor that carries its excitation winding distributed over a number of slots around its periphery. This construction is unsuited to multi-polar machines but it is very sound mechanically. Hence it is particularly well adapted for the highest speed electrical machines and is universally employed for 2 pole units, plus some 4 pole units.

The salient pole type has poles that are physically separate, each carrying a concentrated excitation winding. This type of construction is in many ways complementary to that of the cylindrical rotor and is employed in machines having 4 poles or more. Except in special cases its use is exclusive in machines having more than 6 poles. Figure A4.1 illustrates a typical large cylindrical rotor generator installed in a power plant.

Two and four pole generators are most often used in applications where steam or gas turbines are used as the driver. This is because the steam turbine tends to be suited to high rotational speeds. Four pole steam turbine generators are most often found in nuclear power stations as the relative wetness of the steam makes the high rotational speed of a two-pole design unsuitable. Most generators with gas turbine drivers are four pole machines to obtain enhanced mechanical strength in the rotor, since a gearbox is often used to couple the power turbine to the generator, the choice of synchronous speed of the generator is not subject to the same constraints as with steam turbines.

Figure A4.1: Large synchronous generator

Generators with diesel engine drivers are invariably of four or more pole design, to match the running speed of the driver without using a gearbox. Four-stroke diesel engines usually have a higher running speed than two-stroke engines, so generators having four or six poles are most common. Two-stroke diesel engines are often derivatives of marine designs with relatively large outputs (circa 30MW is possible) and may have running speeds of the order of 125rpm. This requires a generator with a large number of poles (48 for a 125rpm, 50Hz generator) and consequently is of large diameter and short axial length. This is a contrast to turbine-driven machines that are of small diameter and long axial length.

3. Armature Reaction

Armature reaction has the greatest effect on the operation of a synchronous machine with respect both to the load angle at which it operates and to the amount of excitation that it needs. The phenomenon is most easily explained by considering a simplified ideal generator with full pitch winding operating at unity p.f., zero lag p.f. and zero lead p.f. When operating at unity p.f. (power factor), the voltage and current in the stator are in phase, the stator current producing a cross magnetising magneto-motive force (m.m.f.) which interacts with that of the rotor, resulting in a distortion of flux across the pole face. As can be seen from Figure A4.2(a) the tendency is to weaken the flux at the leading edge or effectively to distort the field in a manner equivalent to a shift against the direction of rotation.

If the power factor were reduced to zero lagging, the current in the stator would reach its maximum 90° after the voltage and the rotor would therefore be in the position shown in Figure A4.2(b). The stator m.m.f. is now acting in direct opposition to the field.

Similarly, for operation at zero leading power factor, the stator m.m.f. would directly assist the rotor m.m.f. This m.m.f. arising from current flowing in the stator is known as 'armature reaction'.

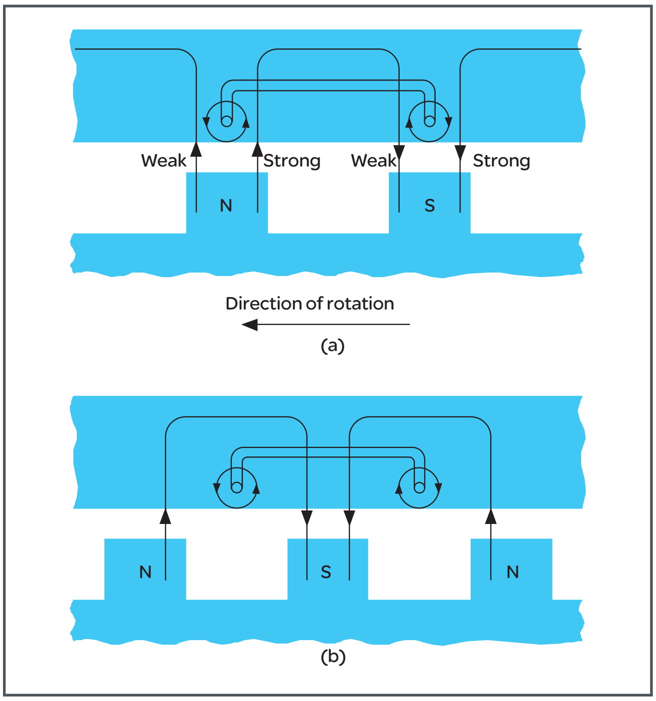

Figure A4.2:
Distortion of flux due to armature reaction

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4. Steady state theory

The vector diagram of a single cylindrical rotor synchronous machine is shown in Figure A4.3, assuming that the magnetic circuit is unsaturated, the air-gap is uniform and all variable quantities are sinusoidal. Further, since the reactance of machines is normally very much larger than the resistance, the latter has been neglected.

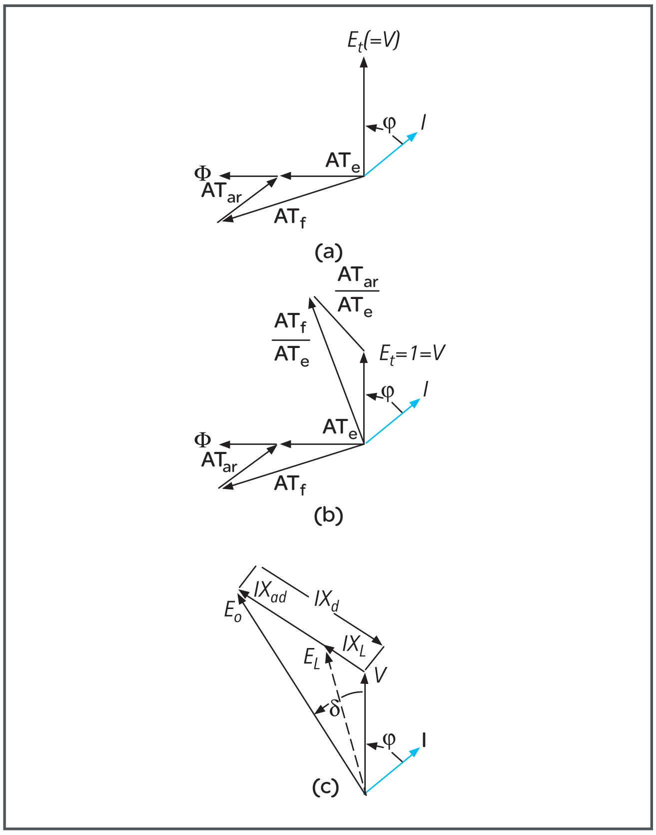

Figure A4.3:
Vector diagram of synchronous machine

The excitation ampere-turns, AT_e, produces a flux Φ across the air-gap thereby inducing a voltage, E_t, in the stator. This voltage drives a current I at a power factor $\cos^{-1}\Phi$ and gives rise to an armature reaction m.m.f. AT_{ar} in phase with it. The m.m.f. AT_f resulting from the combination of these two m.m.f. vectors (see Figure A4.3(a)) is the excitation which must be provided on the rotor to maintain flux Φ across the air-gap. Rotating the rotor m.m.f. diagram, Figure A4.3(a), clockwise until AT_e coincides with E_t and changing the scale of the diagram so that AT_e becomes the basic unit, where $AT_e = E_t = 1$, results in Figure A4.3(b). The m.m.f. vectors have thus become, in effect, voltage vectors.

For example AT_{ar}/AT_e is a unit of voltage that is directly proportional to the stator load current. This vector can be fully represented by a reactance and in practice this is called 'armature reaction reactance' and is denoted by X_{ad}. Similarly, the remaining side of the triangle becomes AT_f/AT_e, which is the per unit voltage produced on open circuit by ampere-turns AT_f. It can be considered as the internal generated voltage of the machine and is designated E_o.

The true leakage reactance of the stator winding which gives rise to a voltage drop or regulation has been neglected. This reactance is designated X_L (or X_a in some texts) and the voltage drop occurring in it, IX_L is the difference between the terminal voltage V and the voltage behind the stator leakage reactance, E_L.

IZ_L is exactly in phase with the voltage drop due to X_{ad}, as shown on the vector diagram Figure A4.3(c). It should be noted that X_{ad} and X_L can be combined to give a simple equivalent reactance; this is known as the 'synchronous reactance', denoted by X_d.

The power generated by the machine is given by the equation:

$$P = VI\cos\varphi = \frac{VE}{X_d}\sin\delta$$ ...Equation A4.1

where δ is the angle between the internal voltage and the terminal voltage and is known as the load angle of the machine.

It follows from the above analysis that, for steady state performance, the machine may be represented by the equivalent circuit shown in Figure A4.4, where X_L is a true reactance associated with flux leakage around the stator winding and X_{ad} is a fictitious reactance, being the ratio of armature reaction and open-circuit excitation magneto-motive forces.

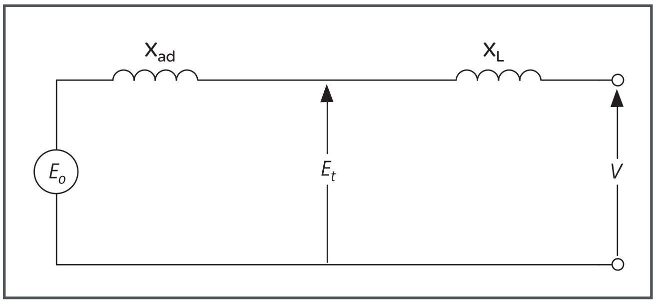

Figure A4.4:
Equivalent circuit of elementary machine

In practice, due to necessary constructional features of a cylindrical rotor to accommodate the windings, the reactance X_a is not constant irrespective of rotor position, and modelling proceeds as for a generator with a salient pole rotor. However, the numerical difference between the values of X_{ad} and X_{aq} is small, much less than for the salient pole machine.

5. Salient pole rotor

The preceding theory is limited to the cylindrical rotor generator. The basic assumption that the air-gap is uniform is very obviously not valid when a salient pole rotor is being considered. The effect of this is that the flux produced by armature reaction m.m.f. depends on the position of the rotor at any instant, as shown in Figure A4.5.

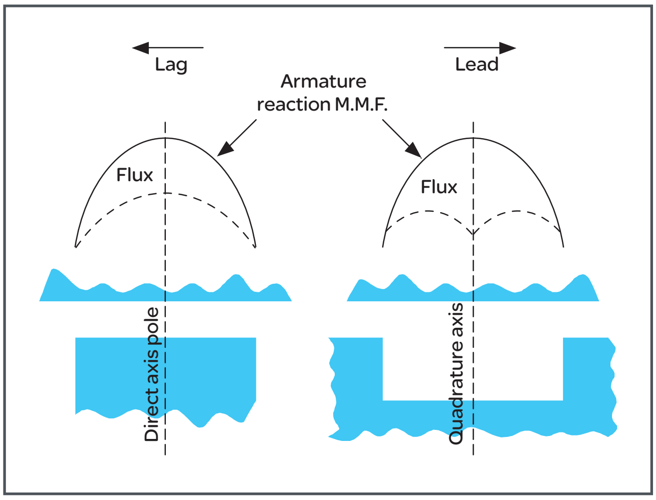

Figure A4.5:
Variation of armature reaction m.m.f. with pole position

When a pole is aligned with the assumed sine wave m.m.f. set up by the stator, a corresponding sine wave flux will be set up, but when an inter-polar gap is aligned very severe distortion is caused. The difference is treated by considering these two axes, that is those corresponding to the pole and the inter-polar gap, separately. They are designated the 'direct' and 'quadrature' axes respectively, and the general theory is known as the 'two axis' theory.

The vector diagram for the salient pole machine is similar to that for the cylindrical rotor except that the reactance and currents associated with them are split into two components. The synchronous reactance for the direct axis is $X_d = X_{ad} + X_L$, while that in the quadrature axis is $X_q = X_{aq} + X_L$. The vector diagram is constructed as before but the appropriate quantities in this case are resolved along two axes. The resultant internal voltage is E_0, as shown in Figure A4.6.

In passing it should be noted that E'_0 is the internal voltage which would be given, in cylindrical rotor theory, by vectorially adding the simple vectors IX_d and V. There is very little difference in magnitude between E_0 and E'_0 but a substantial difference in internal angle; the simple theory is perfectly adequate for calculation of excitation currents but not for stability considerations where load angle is significant.

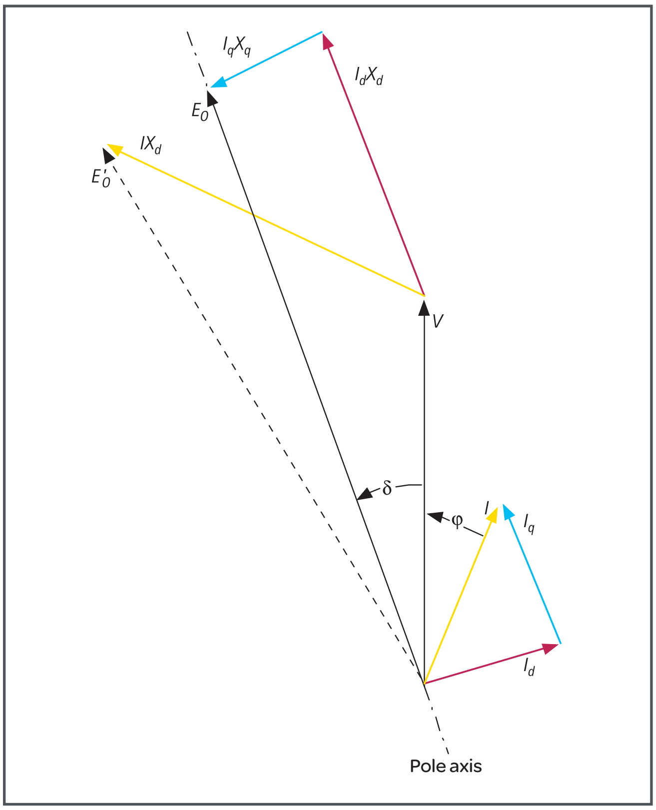

Figure A4.6:
Vector diagram for salient pole machine

6. Transient analysis

For normal changes in load conditions, steady state theory is perfectly adequate. However, there are occasions when almost instantaneous changes are involved, such as faults or switching operations. When this happens new factors are introduced within the machine and to represent these adequately a corresponding new set of machine characteristics is required.

The generally accepted and most simple way to appreciate the meaning and derivation of these characteristics is to consider a sudden three-phase short circuit applied to a machine initially running on open circuit and excited to normal voltage E_0.

This voltage will be generated by a flux crossing the air-gap. It is not possible to confine the flux to one path exclusively in any machine, and as a result there will be a leakage flux Φ_L that will leak from pole to pole and across the inter-polar gaps without crossing the main air-gap as shown in Figure A4.7. The flux in the pole will be $\Phi + \Phi_L$.

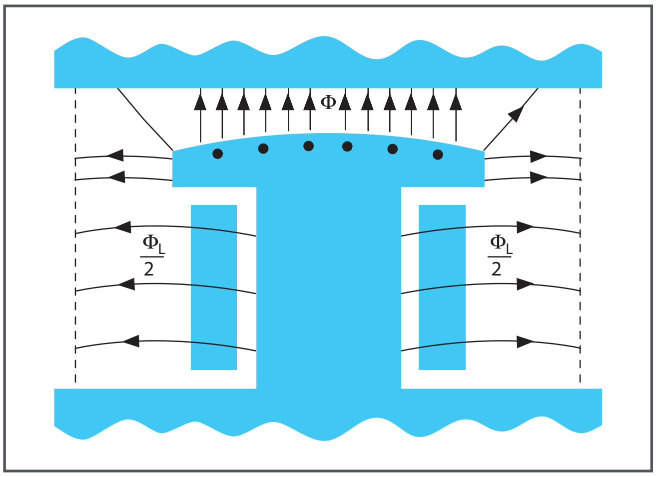

Figure A4.7:
Flux paths of salient pole machine

If the stator winding is then short-circuited, the power factor in it will be zero. A heavy current will tend to flow, as the resulting armature reaction m.m.f. is demagnetising. This will reduce the flux and conditions will settle until the armature reaction nearly balances the excitation m.m.f., the remainder maintaining a very much reduced flux across the air-gap which is just sufficient to generate the voltage necessary to overcome the stator leakage reactance (resistance neglected). This is the simple steady state case of a machine operating on short circuit and is fully represented by the equivalent of Figure A4.8(a); see also Figure A4.4.

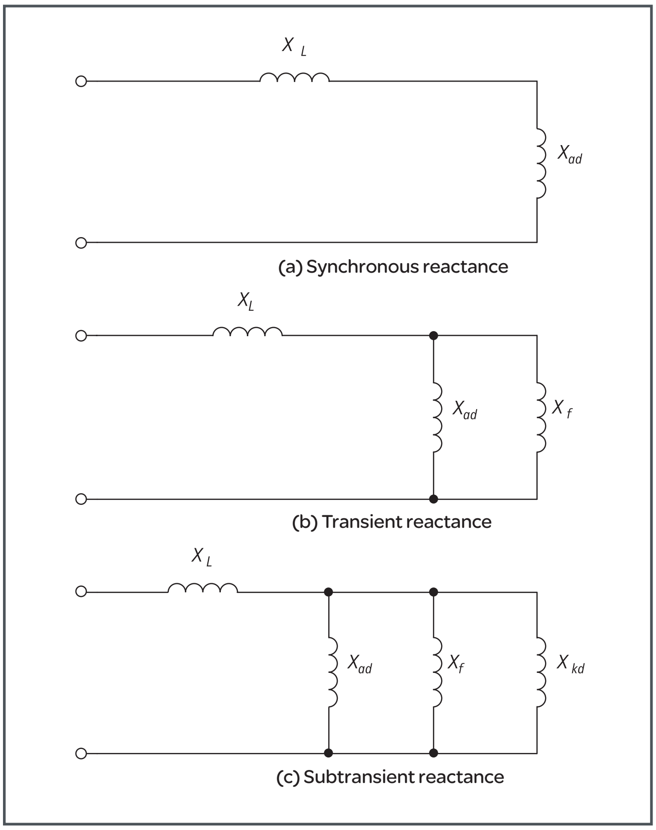

Figure A4.8:
Synchronous machine reactances

It might be expected that the fault current would be given by $E_0 / (X_L + X_{ad})$ equal to E_0 / X_d, but this is very much reduced, and the machine is operating with no saturation. For this reason, the value of voltage used is the value read from the air-gap line corresponding to normal excitation and is rather higher than the normal voltage. The steady state current is given by:

$$I_d = \frac{E_g}{X_d} \quad \text{...Equation A4.2}$$

where E_g = voltage on air gap line

An important point to note now is that between the initial and final conditions there has been a severe reduction of flux. The rotor carries a highly inductive winding which links the flux so that the rotor flux linkages before the short circuit are produced by $(\Phi + \Phi_L)$. In practice the leakage flux is distributed over the whole pole and all of it does not link all the winding. Φ_L is an equivalent concentrated flux imagined to link all the winding and of such a magnitude that the total linkages are equal to those actually occurring. It is a fundamental principle that any attempt to change the flux linked with such a circuit will cause current to flow in a direction that will oppose the change. In the present case the flux is being reduced and so the induced currents will tend to sustain it.

6. Transient analysis

For the position immediately following the application of the short circuit, it is valid to assume that the flux linked with the rotor remains constant, this being brought about by an induced current in the rotor which balances the heavy demagnetising effect set up by the short-circuited armature. So $(\Phi + \Phi_L)$ remains constant, but owing to the increased m.m.f. involved, the flux leakage will increase considerably. With a constant total rotor flux, this can only increase at the expense of that flux crossing the air-gap. Consequently, this generates a reduced voltage, which, acting on the leakage reactance, gives the short circuit current.

It is more convenient for machine analysis to use the rated voltage E_O and to invent a fictitious reactance that will give rise to the same current. This reactance is called the 'transient reactance' X'_d and is defined by the equation:

Transient current $I'_d = \dfrac{E_o}{X'_d}$ ...*Equation A4.3*

It is greater than X_L, and the equivalent circuit is represented by Figure A4.8(b) where:

$$X'_d = \frac{X_{ad} X_f}{X_{ad} + X_f} + X_L$$

and X_f is the leakage reactance of the field winding

The above equation may also be written as:

$$X'_d = X_L + X'_f$$

where X'_f = effective leakage reactance of field winding

The flux will only be sustained at its relatively high value while the induced current flows in the field winding. As this current decays, so conditions will approach the steady state. Consequently, the duration of this phase will be determined by the time constant of the excitation winding. This is usually of the order of a second or less - hence the term 'transient' applied to characteristics associated with it.

A further point now arises. All synchronous machines have what is usually called a 'damper winding' or windings. In some cases, this may be a physical winding (like a field winding, but of fewer turns and located separately), or an 'effective' one (for instance, the solid iron rotor of a cylindrical rotor machine). Sometimes, both physical and effective damper windings may exist (as in some designs of cylindrical rotor generators, having both a solid iron rotor and a physical damper winding located in slots in the pole faces).

Under short circuit conditions, there is a transfer of flux from the main air-gap to leakage paths. This diversion is, to a small extent, opposed by the excitation winding and the main transfer will be experienced towards the pole tips.

The damper winding(s) is subjected to the full effect of flux transfer to leakage paths and will carry an induced current tending to oppose it. As long as this current can flow, the air-gap flux will be held at a value slightly higher than would be the case if only the excitation winding were present, but still less than the original open circuit flux Φ.

As before, it is convenient to use rated voltage and to create another fictitious reactance that is considered to be effective over this period. This is known as the 'sub-transient reactance' X''_d and is defined by the equation:

$$I''_d = \frac{E_o}{X''_d} \qquad \text{...Equation A4.4}$$

where $X''_d = X_L + \dfrac{X_{ad} X_f X_{kd}}{X_{ad} X_f + X_{kd} X_f + X_{ad} X_{kd}}$

or $X''_d = X_L + X'_{kd}$

and X_{kd} = leakage reactance of damper winding(s)

X'_{kd} = effective leakage reactance of damper winding(s)

It is greater than X_L but less than X'_d and the corresponding equivalent circuit is shown in Figure A4.8(c).

Again, the duration of this phase depends upon the time constant of the damper winding. In practice this is approximately 0.05 seconds - very much less than the transient - hence the term 'sub-transient'.

Figure A4.9 shows the envelope of the symmetrical component of an armature short circuit current indicating the values described in the preceding analysis. The analysis of the stator current waveform resulting from a sudden short circuit test is traditionally the method by which these reactances are measured. However, the major limitation is that only direct axis parameters are measured. Detailed test methods for synchronous machines are given in references [Ref A4.2: IEC 60034-4] and [Ref A4.3: IEEE Standards 115/115A], and include other tests that are capable of providing more detailed parameter information.

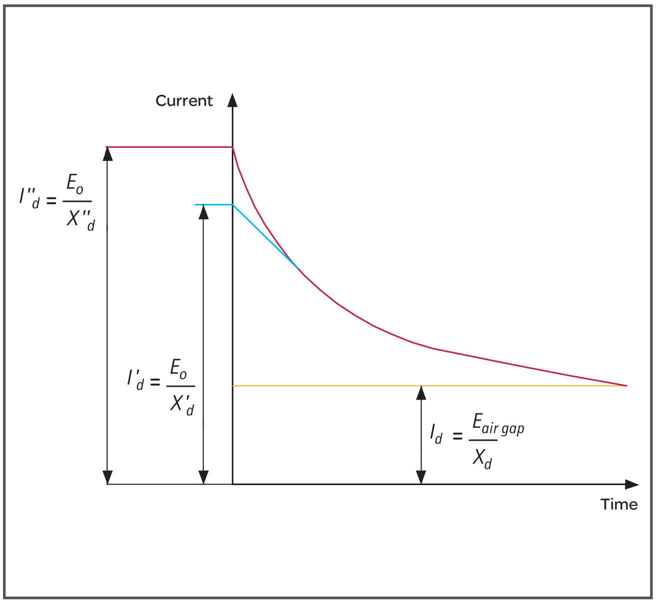

Figure A4.9:
Transient decay envelope of short-circuit current

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7. Asymmetry

The exact instant at which the short circuit is applied to the stator winding is of significance. If resistance is negligible compared with reactance, the current in a coil will lag the voltage by 90°, that is, at the instant when the voltage wave attains a maximum, any current flowing through would be passing through zero. If a short circuit were applied at this instant, the resulting current would rise smoothly and would be a simple a.c. component. However, at the moment when the induced voltage is zero, any current flowing must pass through a maximum (owing to the 90° lag). If a fault occurs at this moment, the resulting current will assume the corresponding relationship; it will be at its peak and in the ensuing 180° will go through zero to maximum in the reverse direction and so on. In fact the current must actually start from zero and so will follow a sine wave that is completely asymmetrical. Intermediate positions will give varying degrees of asymmetry.

This asymmetry can be considered to be due to a d.c. component of current which dies away because resistance is present.

The d.c. component of stator current sets up a d.c. field in the stator which causes a supply frequency ripple on the field current, and this alternating rotor flux has a further effect on the stator. This is best shown by considering the supply frequency flux as being represented by two half magnitude waves each rotating in opposite directions at supply frequency relative to the rotor. So, as viewed from the stator, one is stationary and the other rotating at twice supply frequency. The latter sets up second harmonic currents in the stator. Further development along these lines is possible but the resulting harmonics are usually negligible and normally neglected.

8. Machine reactances

Table A4.1 gives values of machine reactances for salient pole and cylindrical rotor machines typical of latest design practice. Also included are parameters for synchronous compensators – such machines are now rarely built, but significant numbers can still be found in operation.

Type of Machine	Salient pole synchronous condensers		Cylindrical rotor turbine generators			Salient pole generators	
	4 Pole	Multi-Pole	Air Cooled	Hydrogen Cooled	Hydrogen/ Water Cooled	4 Pole	Multi-Pole
Short circuit ratio	0.5-0.7	1.0-1.2	0.4-0.6	0.4-0.6	0.4-0.6	0.4-0.6	0.6-0.8
Direct axis synchronous reactance X_d (p.u.)	1.6-2.0	0.8-1.0	2.0-2.8	2.1-2.4	2.1-2.6	1.75-3.0	1.4-1.9
Quadrature axis synchronous reactance X_q (p.u.)	1.0-1.23	0.5-0.65	1.8-2.7	1.9-2.4	2.0-2.5	0.9-1.5	0.8-1.0
Direct axis transient reactance X'_d (p.u.)	0.3-0.5	0.2-0.35	0.2-0.3	0.27-0.33	0.3-0.36	0.26-0.35	0.24-0.4
Direct axis sub-transient reactance X''_d (p.u.)	0.2-0.4	0.12-0.25	0.15-0.23	0.19-0.23	0.21-0.27	0.19-0.25	0.16-0.25
Quadrature axis sub-transient reactance X''_q (p.u.)	0.25-0.6	0.15-0.25	0.16-0.25	0.19-0.23	0.21-0.28	0.19-0.35	0.18-0.24
Negative sequence reactance X_2 (p.u.)	0.25-0.5	0.14-0.35	0.16-0.23	0.19-0.24	0.21-0.27	0.16-0.27	0.16-0.23
Zero sequence reactance X_0 (p.u.)	0.12-0.16	0.06-0.10	0.06-0.1	0.1-0.15	0.1-0.15	0.01-0.1	0.045-0.23
Direct axis short circuit transient time constant T'_d (s)	1.5-2.5	1.0-2.0	0.6-1.3	0.7-1.0	0.75-1.0	0.4-1.1	0.25-1
Direct axis open circuit transient time constant T'_{do} (s)	5-10	3-7	6-12	6-10	6-9.5	3.0-9.0	1.7-4.0
Direct axis short circuit sub-transient time constant T''_d (s)	0.04-0.9	0.05-0.10	0.013-0.022	0.017-0.025	0.022-0.03	0.02-0.04	0.02-0.06
Direct axis open circuit sub-transient time constant T''_{do} (s)	0.07-0.11	0.08-0.25	0.018-0.03	0.023-0.032	0.025-0.035	0.035-0.06	0.03-0.1
Quadrature axis short circuit sub-transient time constant T''_q (s)	0.04-0.6	0.05-0.6	0.013-0.022	0.018-0.027	0.02-0.03	0.025-0.04	0.025-0.08
Quadrature axis open circuit sub-transient time constant T''_{qo} (s)	0.1-0.2	0.2-0.9	0.026-0.045	0.03-0.05	0.04-0.065	0.13-0.2	0.1-0.35

Table A4.1:
Typical synchronous generator parameters. Note: *all reactance values are unsaturated*

8. Machine reactances

8.1 Synchronous reactance $X_d = X_L + X_{ad}$

The order of magnitude of X_L is normally 0.1-0.25 p.u., while that of X_{ad} is 1.0-2.5 p.u. The leakage reactance X_L can be reduced by increasing the machine size (derating), or increased by artificially increasing the slot leakage, but it will be noted that X_L is only about 10% of the total value of X_d and cannot exercise much influence.

The armature reaction reactance can be reduced by decreasing the armature reaction of the machine, which in design terms means reducing the ampere conductor or electrical (as distinct from magnetic) loading - this will often mean a physically larger machine. Alternatively the excitation needed to generate open-circuit voltage may be increased; this is simply achieved by increasing the machine air-gap, but is only possible if the excitation system is modified to meet the increased requirements.

In general, control of X_d is obtained almost entirely by varying X_{ad} , and in most cases a reduction in X_d will mean a larger and more costly machine. It is also worth noting that X_L normally changes in sympathy with X_{ad} , but is completely overshadowed by it.

The value $1/X_d$ has a special significance as it approximates to the short circuit ratio (S.C.R.), the only difference being that the S.C.R. takes saturation into account whereas X_d is derived from the air-gap line.

8.2 Transient reactance $X'_d = X_L + X'_f$

The transient reactance covers the behaviour of a machine in the period 0.1-3.0 seconds after a disturbance. This generally corresponds to the speed of changes in a system and therefore has a major influence in transient stability studies.

Generally, the leakage reactance X_L is equal to the effective field leakage reactance X'_f, about 0.1-0.25 p.u. The principal factor determining the value of X'f is the field leakage. This is largely beyond the control of the designer, in that other considerations are at present more significant than field leakage and hence take precedence in determining the field design.

X_L can be varied as already outlined, and, in practice, control of transient reactance is usually achieved by varying X_L.

8.3 Sub-transient reactance $X''_d = X_L + X'_{kd}$

The sub-transient reactance determines the initial current peaks following a disturbance and in the case of a sudden fault is of importance for selecting the breaking capacity of associated circuit breakers. The mechanical stresses on the machine reach maximum values that depend on this constant. The effective damper winding leakage reactance X'_{kd} is largely determined by the leakage of the damper windings and control of this is only possible to a limited extent. X'_{kd} normally has a value between 0.05 and 0.15 p.u. The major factor is X_L which, as indicated previously, is of the order of 0.1-0.25 p.u., and control of the sub-transient reactance is normally achieved by varying X_L.

It should be noted that good transient stability is obtained by keeping the value of X'_d low, which therefore also implies a low value of X''_d. The fault rating of switchgear, etc. will therefore be relatively high. It is not normally possible to improve transient stability performance in a generator without adverse effects on fault levels, and vice versa.

A4

9. Negative sequence reactance

Negative sequence currents can arise whenever there is any unbalance present in the system. Their effect is to set up a field rotating in the opposite direction to the main field generated by the rotor winding, so subjecting the rotor to double frequency flux pulsations. This gives rise to parasitic currents and heating; most machines are quite limited in the amount of such current which they are able to carry, both in the steady-state and transiently.

An accurate calculation of the negative sequence current capability of a generator involves consideration of the current paths in the rotor body. In a turbine generator rotor, for instance, they include the solid rotor body, slot wedges, excitation winding and end-winding retaining rings. There is a tendency for local over-heating to occur and, although possible for the stator, continuous local temperature measurement is not practical in the rotor. Calculation requires complex mathematical techniques to be applied, and involves specialist software.

In practice an empirical method is used, based on the fact that a given type of machine is capable of carrying, for short periods, an amount of heat determined by its thermal capacity, and for a long period, a rate of heat input which it can dissipate continuously. Synchronous machines are designed to be capable of operating continuously on an unbalanced system such that, with none of the phase currents exceeding the rated current, the ratio of the negative sequence current I_2 to the rated current I_N does not exceed the values given in Table A4.2. Under fault conditions, the machine shall also be capable of operation with the result of $(I_2 / I_N)^2$ and time in seconds (t) not exceeding the values given.

Rotor construction	Rotor cooling	Machine Type (S_N) / Rating (MVA)	Maximum I_2/I_N for continuous operation	Maximum $(I_2/I_N)^2 t$ for continuous operation
Salient	Indirect	motors	0.1	20
		generators	0.08	20
		Synchronous condensers	0.1	20
	Direct	motors	0.08	15
		generators	0.05	15
		Synchronous condensers	0.08	15
Cylindrical	Indirectly cooled (air)	all	0.1	15
	Indirectly cooled (hydrogen)	all	0.1	10
	Directly cooled	<=350	0.08	8
		351-900	Note 1	Note 2
		901-1250	Note 1	5
		1251-1600	0.05	5

Note 1: Calculate as: $\frac{I_2}{I_N} = 0.08 - \frac{S_N - 350}{3 \times 10^4}$

Note 2: Calculate as: $\left(\frac{I_2}{I_N}\right)^2 t = 8 - 0.00545\,(S_N - 350)$

Table A4.2:
Unbalanced operating conditions for synchronous machines (from IEC 60034-1)

10. Zero sequence reactance

If a machine is operating with an earthed neutral, a system earth fault will give rise to zero sequence currents in the machine. This reactance represents the machine's contribution to the total impedance offered to these currents. In practice it is generally low and often outweighed by other impedances present in the circuit.

11. Direct and quadrature axis values

The transient reactance is associated with the field winding and since on salient pole machines this is concentrated on the direct axis, there is no corresponding quadrature axis value. The value of reactance applicable in the quadrature axis is the synchronous reactance, that is, $X'_q = X_q$.

The damper winding (or its equivalent) is more widely spread and hence the sub-transient reactance associated with this has a definite quadrature axis value X''_q, which differs significantly in many generators from X''_d.

12. Effect on saturation on machine reactances

In general, any electrical machine is designed to avoid severe saturation of its magnetic circuit. However, it is not economically possible to operate at such low flux densities as to reduce saturation to negligible proportions, and in practice a moderate degree of saturation is accepted.

Since the armature reaction reactance X_{ad} is a ratio AT_{ar}/AT_e it is evident that AT_e will not vary in a linear manner for different voltages, while AT_{ar} will remain unchanged. The value of X_{ad} will vary with the degree of saturation present in the machine, and for extreme accuracy should be determined for the particular conditions involved in any calculation.

All the other reactances, namely X_L, X'_d and X''_d are true reactances and actually arise from flux leakage. Much of this leakage occurs in the iron parts of the machines and hence must be affected by saturation. For a given set of conditions, the leakage flux exists as a result of the net m.m.f. which causes it. If the iron circuit is unsaturated its reactance is low and leakage flux is easily established. If the circuits are highly saturated the reverse is true and the leakage flux is relatively lower, so the reactance under saturated conditions is lower than when unsaturated.

Most calculation methods assume infinite iron permeability and for this reason lead to somewhat idealised unsaturated reactance values. The recognition of a finite and varying permeability makes a solution extremely laborious and in practice a simple factor of approximately 0.9 is taken as representing the reduction in reactance arising from saturation.

It is necessary to distinguish which value of reactance is being measured when on test. The normal instantaneous short circuit test carried out from rated open circuit voltage gives a current that is usually several times full load value, so that saturation is present and the reactance measured will be the saturated value. This value is also known as the 'rated voltage' value since it is measured by a short circuit applied with the machine excited to rated voltage.

In some cases, if it is wished to avoid the severe mechanical strain to which a machine is subjected by such a direct short circuit, the test may be made from a suitably reduced voltage so that the initial current is approximately full load value. Saturation is very much reduced and the reactance values measured are virtually unsaturated values. They are also known as 'rated current' values, for obvious reasons.

13. Transformers

A transformer may be replaced in a power system by an equivalent circuit representing the self-impedance of, and the mutual coupling between, the windings. A two-winding transformer can be simply represented as a '**T**' network in which the cross member is the short-circuit impedance, and the column the excitation impedance. It is rarely necessary in fault studies to consider excitation impedance as this is usually many times the magnitude of the short-circuit impedance. With these simplifying assumptions a three-winding transformer becomes a star of three impedances and a four-winding transformer a mesh of six impedances.

The impedances of a transformer, in common with other plant, can be given in ohms and qualified by a base voltage, or in per unit or percentage terms and qualified by a base MVA. Care should be taken with multi-winding transformers to refer all impedances to a common base MVA or to state the base on which each is given. The impedances of static apparatus are independent of the phase sequence of the applied voltage; in consequence, transformer negative sequence and positive sequence impedances are identical. In determining the impedance to zero phase sequence currents, account must be taken of the winding connections, earthing, and, in some cases, the construction type. The existence of a path for zero sequence currents implies a fault to earth and a flow of balancing currents in the windings of the transformer.

Practical three-phase transformers may have a phase shift between primary and secondary windings depending on the connections of the windings – delta or star. The phase shift that occurs is generally of no significance in fault level calculations as all phases are shifted equally. It is therefore ignored. It is normal to find delta-star transformers at the transmitting end of a transmission system and in distribution systems for the following reasons:

a. at the transmitting end, a higher step-up voltage ratio is possible than with other winding arrangements, while the insulation to ground of the star secondary winding does not increase by the same ratio

b. in distribution systems, the star winding allows a neutral connection to be made, which may be important in considering system earthing arrangements

c. the delta winding allows circulation of zero sequence currents within the delta, thus preventing transmission of these from the secondary (star) winding into the primary circuit. This simplifies protection considerations

14. Transformer positive sequence equivalent circuits

The transformer is a relatively simple device. However, the equivalent circuits for fault calculations need not necessarily be quite so simple, especially where earth faults are concerned. The following two sections discuss the equivalent circuits of various types of transformers.

14.1 Two-winding transformers

The two-winding transformer has four terminals, but in most system problems, two-terminal or three-terminal equivalent circuits as shown in Figure A4.10 can represent it. In Figure A4.10(a), terminals A' and B' are assumed to be at the same potential. Hence if the per unit self-impedances of the windings are Z_{11} and Z_{22} respectively and the mutual impedance between them Z_{12} , the transformer may be represented by Figure A4.10(b). The circuit in Figure A4.10(b) is similar to that shown in Figure A2.14(a), and can therefore be replaced by an equivalent '**T**' as shown in Figure A4.10(c) where:

$$\left.\begin{aligned} Z_1 &= Z_{11} - Z_{12} \\ Z_2 &= Z_{22} - Z_{12} \\ Z_3 &= Z_{12} \end{aligned}\right\} \qquad \textit{...Equation A4.5}$$

Z_1 is described as the leakage impedance of winding AA' and Z_2 the leakage impedance of winding BB'.

Impedance Z_3 is the mutual impedance between the windings, usually represented by X_M, the magnetising reactance paralleled with the hysteresis and eddy current loops as shown in Figure A4.10(d).

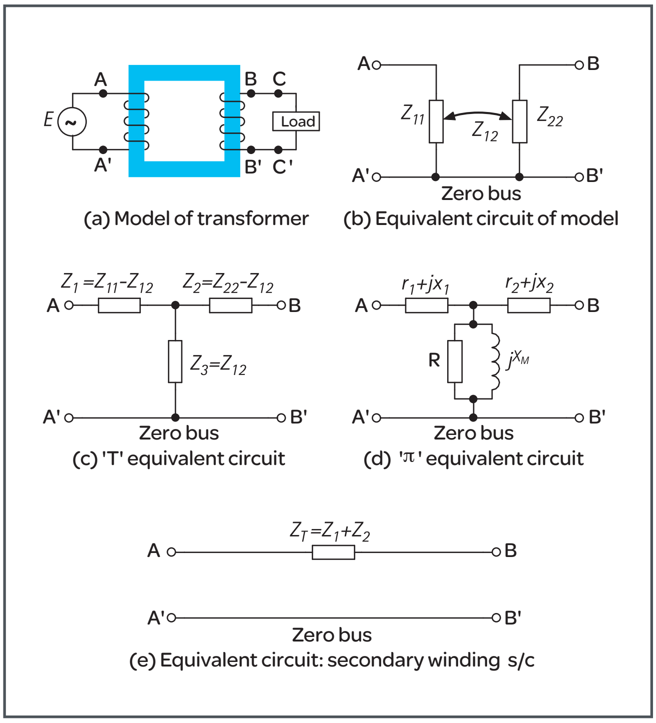

Figure A4.10:
Equivalent circuits for a two-winding transformer

If the secondary of the transformer is short-circuited, and Z_3 is assumed to be large with respect to Z_1 and Z_2, then the short-circuit impedance viewed from the terminals AA' is $Z_T = Z_1 + Z_2$ and the transformer can be replaced by a two-terminal equivalent circuit as shown in Figure A4.10(e).

The relative magnitudes of Z_T and X_M are of the order of 10% and 2000% respectively. Z_T and X_M rarely have to be considered together, so that the transformer may be represented either as a series impedance or as an excitation impedance, according to the problem being studied.

A typical power transformer is illustrated in Figure A4.11.

Figure A4.11:
Large transformer

14.2 Three-winding transformers

If excitation impedance is neglected the equivalent circuit of a three-winding transformer may be represented by a star of impedances, as shown in Figure A4.12, where P, T and S are the primary, tertiary and secondary windings respectively. The impedance of any of these branches can be determined by considering the short-circuit impedance between pairs of windings with the third open.

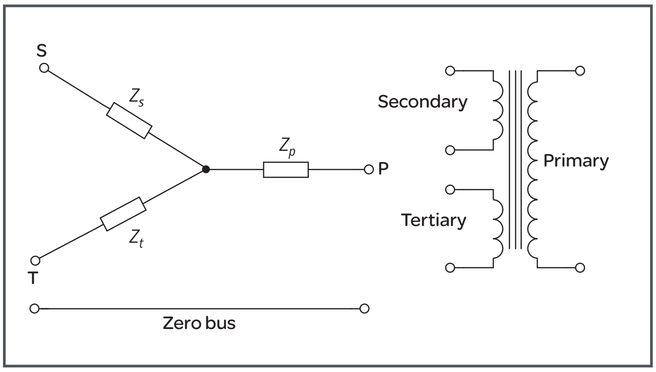

Figure A4.12:
Equivalent circuit for a three-winding transformer

15. Transformer zero sequence equivalent circuits

The flow of zero sequence currents in a transformer is only possible when the transformer forms part of a closed loop for uni-directional currents and ampere-turn balance is maintained between windings.

The positive sequence equivalent circuit is still maintained to represent the transformer, but now there are certain conditions attached to its connection into the external circuit. The order of excitation impedance is very much lower than for the positive sequence circuit; it will be roughly between 1 and 4 per unit, but still high enough to be neglected in most fault studies.

The mode of connection of a transformer to the external circuit is determined by taking account of each winding arrangement and its connection or otherwise to ground. If zero sequence currents can flow into and out of a winding, the winding terminal is connected to the external circuit (that is, link a is closed in Figure A4.13). If zero sequence currents can circulate in the winding without flowing in the external circuit, the winding terminal is connected directly to the zero bus (that is, link b is closed in Figure A4.13). Table A4.3 gives the zero sequence connections of some common two- and three-winding transformer arrangements applying the above rules.

The exceptions to the general rule of neglecting magnetising impedance occur when the transformer is star/star and either or both neutrals are earthed. In these circumstances the transformer is connected to the zero bus through the magnetising impedance. Where a three-phase transformer bank is arranged without interlinking magnetic flux (that is a three-phase shell type, or three single-phase units) and provided there is a path for zero sequence currents, the zero sequence impedance is equal to the positive sequence impedance. In the case of three-phase core type units, the zero sequence fluxes produced by zero sequence currents can find a high reluctance path, the effect being to reduce the zero sequence impedance to about 90% of the positive sequence impedance.

However, in hand calculations, it is usual to ignore this variation and consider the positive and zero sequence impedances to be equal. It is common when using software to perform fault calculations to enter a value of zero-sequence impedance in accordance with the above guidelines, if the manufacturer is unable to provide a value.

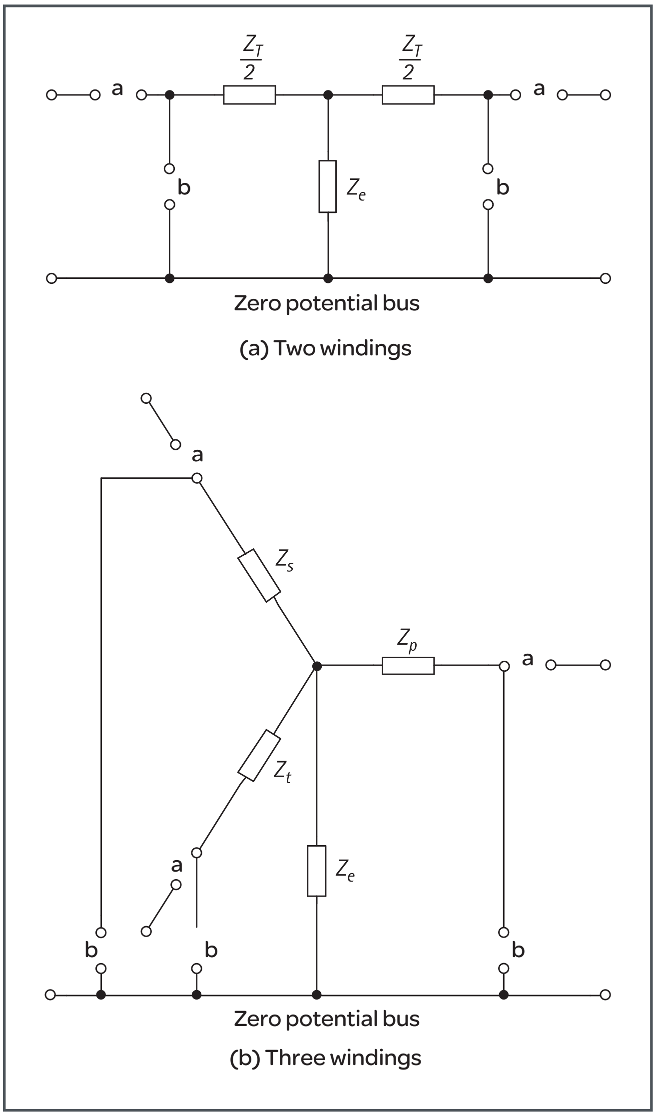

Figure A4.13:
Zero sequence equivalent circuits

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15. Transformer zero sequence equivalent circuits

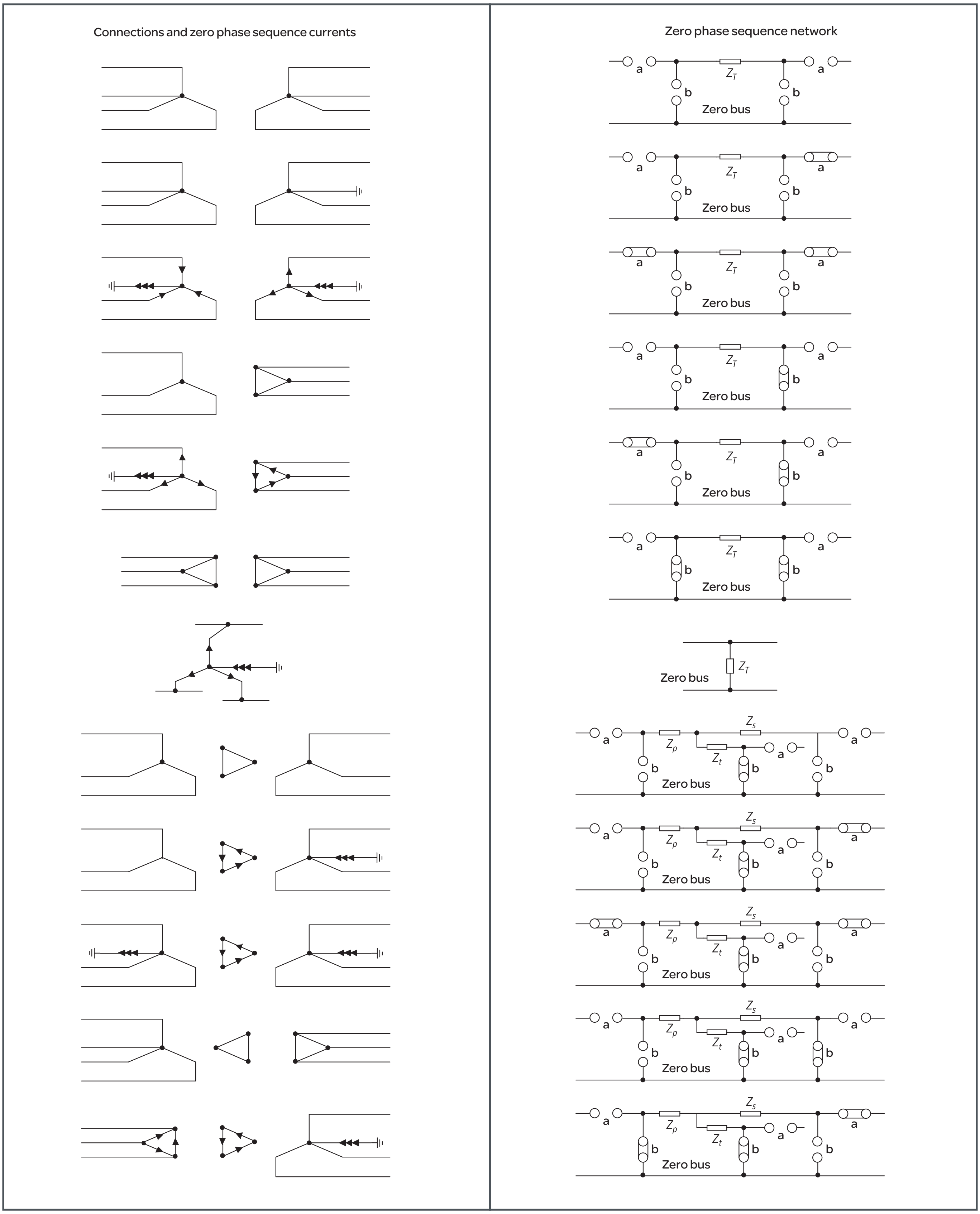

Table A4.3:
Zero sequence equivalent circuit connections

16. Auto-transformers

The auto-transformer is characterised by a single continuous winding, part of which is shared by both the high and low voltage circuits, as shown in Figure A4.14(a). The 'common' winding is the winding between the low voltage terminals whereas the remainder of the winding, belonging exclusively to the high voltage circuit, is designated the 'series' winding, and, combined with the 'common' winding, forms the 'series-common' winding between the high voltage terminals. The advantage of using an auto-transformer as opposed to a two-winding transformer is that the auto-transformer is smaller and lighter for a given rating. The disadvantage is that galvanic isolation between the two windings does not exist, giving rise to the possibility of large overvoltages on the lower voltage system in the event of major insulation breakdown.

Three-phase auto-transformer banks generally have star connected main windings, the neutral of which is normally connected solidly to earth. In addition, it is common practice to include a third winding connected in delta called the tertiary winding, as shown in Figure A4.14(b).

16.1 Positive sequence equivalent circuit

The positive sequence equivalent circuit of a three-phase auto- transformer bank is the same as that of a two- or three-winding transformer. The star equivalent for a three-winding transformer, for example, is obtained in the same manner, with the difference that the impedances between windings are designated as follows:

$$\left.\begin{aligned} Z_L &= \frac{1}{2}\left(Z_{sc-c} + Z_{c-t} - Z_{sc-t}\right) \\ Z_H &= \frac{1}{2}\left(Z_{sc-c} + Z_{sc-t} - Z_{c-t}\right) \\ Z_T &= \frac{1}{2}\left(Z_{sc-t} + Z_{c-t} - Z_{sc-c}\right) \end{aligned}\right\} \qquad \text{...Equation A4.8}$$

where:

Z_{sc-t} = impedance between 'series common' and tertiary windings

Z_{sc-c} = impedance between 'series common' and 'common' windings

Z_{sc-t} = impedance between 'common' and tertiary windings

When no load is connected to the delta tertiary, the point T will be open-circuited and the short-circuit impedance of the transformer becomes $Z_L + Z_H = Z_{sc-c}$, that is, similar to the equivalent circuit of a two-winding transformer, with magnetising impedance neglected; see Figure A4.14(c).

16.2 Zero sequence equivalent circuit

The zero sequence equivalent circuit is derived in a similar manner to the positive sequence circuit, except that, as there is no identity for the neutral point, the current in the neutral

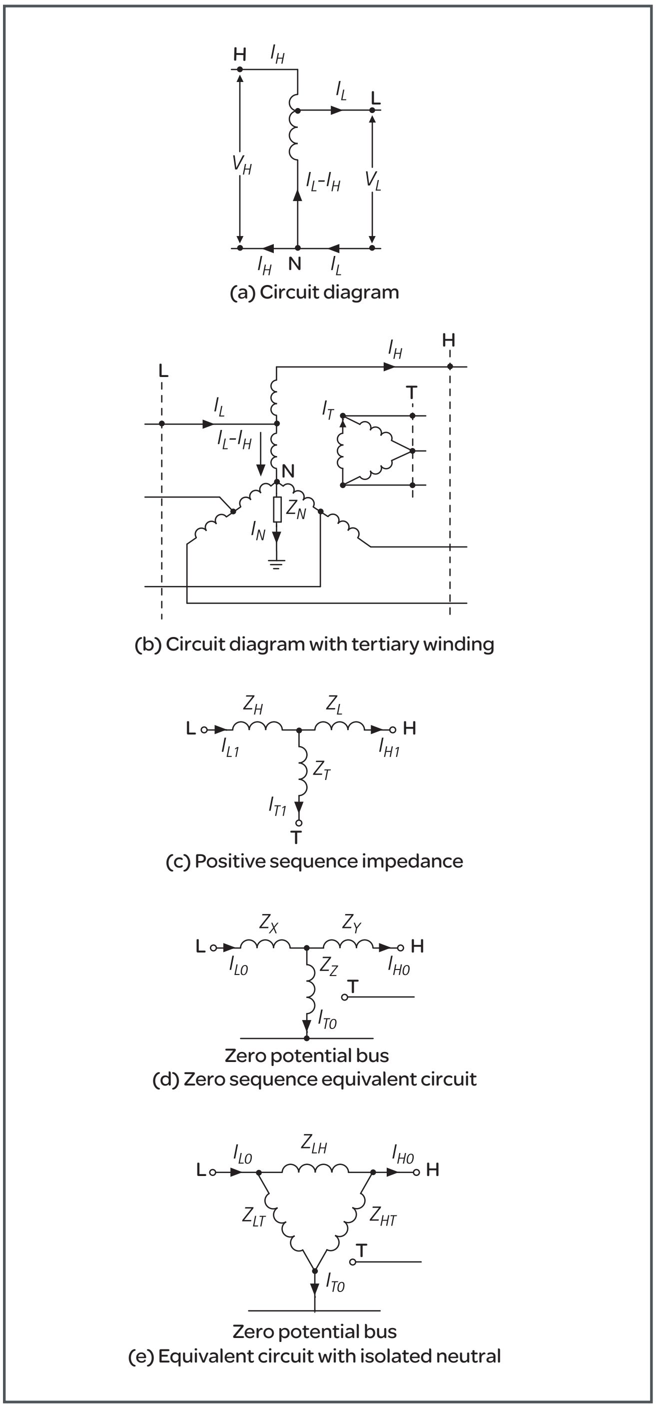

Figure A4.14:
Equivalent circuit of auto-transformer

and the neutral voltage cannot be given directly. Furthermore, in deriving the branch impedances, account must be taken of an impedance in the neutral Z_n, as shown in the following equations, where Z_x, Z_y and Z_z are the impedances of the low, high and tertiary windings respectively and N is the ratio between the series and common windings.

16. Auto-transformers

$$\left.\begin{aligned} Z_x &= Z_L + 3Z_n \frac{N}{(N+1)} \\ Z_y &= Z_H - 3Z_n \frac{N}{(N+1)^2} \\ Z_z &= Z_T + 3Z_n \frac{1}{(N+1)} \end{aligned}\right\} \quad \text{...Equation A4.9}$$

Figure A4.14(d) shows the equivalent circuit of the transformer bank. Currents I_{L0} and I_{H0} are those circulating in the low and high voltage circuits respectively. The difference between these currents, expressed in amperes, is the current in the common winding.

The current in the neutral impedance is three times the current in the common winding.

16.3 Special conditions of neutral earthing

With a solidly grounded neutral, $Z_n = 0$, the branch impedances Z_x , Z_y , Z_z , become Z_L , Z_H , Z_T , that is, identical to the corresponding positive sequence equivalent circuit, except that the equivalent impedance Z_T of the delta tertiary is connected to the zero potential bus in the zero sequence network.

When the neutral is ungrounded $Z_n = \mu$ and the impedances of the equivalent star also become infinite because there are apparently no paths for zero sequence currents between the windings, although a physical circuit exists and ampere-turn balance can be obtained. A solution is to use an equivalent delta circuit (see Figure A4.14(e)), and evaluate the elements of the delta directly from the actual circuit. The method requires three equations corresponding to three assumed operating conditions. Solving these equations will relate the delta impedances to the impedance between the series and tertiary windings, as follows:

$$\begin{aligned} Z_x &= Z_L + 3Z_n \frac{N}{(N+1)} \\ Z_y &= Z_H - 3Z_n \frac{N}{(N+1)^2} \qquad \text{...Equation A4.10} \\ Z_z &= Z_T + 3Z_n \frac{1}{(N+1)} \end{aligned}$$

With the equivalent delta replacing the star impedances in the auto-transformer zero sequence equivalent circuit the transformer can be combined with the system impedances in the usual manner to obtain the system zero sequence diagram.

17. Transformer impedances

In the vast majority of fault calculations, the Protection Engineer is only concerned with the transformer leakage impedance; the magnetising impedance is neglected, as it is very much higher. Impedances for transformers rated 200MVA or less are given in IEC 60076 and repeated in Table A4.4, together with an indication of X/R values (not part of IEC 60076). These impedances are commonly used for transformers installed in industrial plants. Some variation is possible to assist in controlling fault levels or motor starting, and typically up to ±10% variation on the impedance values given in the table is possible without incurring a significant cost penalty. For these transformers, the tapping range is small, and the variation of impedance with tap position is normally neglected in fault level calculations.

For transformers used in electricity distribution networks, the situation is more complex, due to an increasing trend to assign importance to the standing (or no-load) losses represented by the magnetising impedance. This can be adjusted at the design stage but there is often an impact on the leakage reactance in consequence. In addition, it may be more important to control fault levels on the LV side than to improve motor starting voltage drops. Therefore, departures from the IEC 60076 values are commonplace.

MVA	Z% HV/LV	X/R	Tolerance on Z%
<0.630	4.00	1.5	+/- 10.0
0.631-1.25	5.00	3.5	+/- 10.0
1.251 - 3.15	6.25	6.0	+/- 10.0
3.151 - 6.3	7.15	8.5	+/- 10.0
6.301-12.5	8.35	13.0	+/- 10.0
12.501- 25.0	10.00	20.0	+/- 7.5
25.001 - 200	12.50	45.0	+/- 7.5
>200	by agreement		

Table A4.4:
Transformer impedances - IEC 60076

IEC 60076 does not make recommendations of nominal impedance in respect of transformers rated over 200MVA, while generator transformers and a.c. traction supply transformers have impedances that are usually specified as a result of Power Systems Studies to ensure satisfactory performance. Typical values of transformer impedances covering a variety of transformer designs are given in Tables A4.5 – A4.8. Where appropriate, they include an indication of the impedance variation at the extremes of the taps given. Transformers designed to work at 60Hz will have substantially the same impedance as their 50Hz counterparts.

17. Transformer impedances

MVA	Primary kV	Primary Taps	Secondary kV	Z% HV/LV	X/R ratio	MVA	Primary kV	Primary Taps	Secondary kV	Z% HV/LV	X/R ratio
7.5	33	+5.72% -17.16%	11	7.5	15	24	33	±10%	6.9	24	25
7.5	33	+5.72% -17.16%	11	7.5	17	30	33	±10%	6.9	24	25
8	33	+5.72% -17.16%	11	8	9	30	132	+10% -20%	11	21.3	43
11.5	33	+5.72% -17.16%	6.6	11.5	24	30	132	+10% -20%	11	25	30
11.5	33	+5.72% -17.16%	6.6	11.5	24	30	132	+10% -20%	11	23.5	46
11.5	33	+5.72% -17.16%	11	11.5	24	40	132	+10% -20%	11	27.9	37
11.5	33	+5.72% -17.16%	11	11.5	26	45	132	+10% -20%	33	11.8	18
11.5	33	+4.5% -18%	6.6	11.5	24	60	132	+10% -20%	33	16.7	28
12	33	+5% -15%	11.5	12	27	60	132	+10% -20%	33	17.7	26
12	33	±10%	11.5	12	27	60	132	+10% -20%	33	14.5	25
12	33	±10%	11.5	12	25	60	132	+10% -20%	66	11	25
15	66	+9% -15%	11.5	15	14	60	132	+10% -20%	11/11	35.5	52
15	66	+9% -15%	11.5	15	16	60	132	+9.3% -24%	11/11	36	75
16	33	±10%	11.5	16	16	60	132	+9.3% -24%	11/11	35.9	78
16	33	+5.72% -17.16%	11	16	30	65	140	+7.5% -15%	11	12.3	28
16	33	+5.72% -17.16%	6.6	16	31	90	132	+10% -20%	33	24.4	60
19	33	+5.72% -17.16%	11	19	37	90	132	+10% -20%	66	15.1	41
30	33	+5.72% -17.16%	11	30	40						

Table A4.5:
Impedances of two winding distribution transformers – Primary voltage <200kV

MVA	Primary kV	Primary Taps	Secondary kV	Tertiary kV	Z% HV/LV	X/R ratio
20	220	+12.5% -7.5%	6.9	-	9.9	18
20	230	+12.5% -7.5%	6.9	-	10-14	13
57	275	±10%	11.8	7.2	18.2	34
74	345	+14.4% -10%	96	12	8.9	25
79.2	220	+10% -15%	11.6	11	18.9	35
120	275	+10% -15%	34.5	-	22.5	63
125	230	±16.8%	66	-	13.1	52
125	230	not known	150	-	10-14	22
180	275	±15%	66	13	22.2	38
255	230	+10%	16.5	-	14.8	43

Table A4.6: Impedances of two winding distribution transformers – Primary voltage >200kV

MVA	Primary Taps	Primary kV	Secondary Taps	Secondary kV	Tertiary kV	Z% HV/LV	X/R ratio
100	66	-	33	-	-	10.7	28
180	275	-	132	±15%	13	15.5	55
240	400	-	132	+15% -5%	13	20.2	83
240	400	-	132	+15% -5%	13	20.0	51
240	400	-	132	+15% -5%	13	20.0	61
250	400	-	132	+15% -5%	13	10-13	50
500	400	-	132	+0% -15%	22	14.3	51
750	400	-	275	-	13	12.1	90
1000	400	-	275	-	13	15.8	89
1000	400	-	275	-	33	17.0	91
333.3	$500\sqrt{3}$	±10%	$230\sqrt{3}$		22	18.2	101

Table A4.8:
Auto-transformer data

(a) Three-phase units

MVA	Primary kV	Primary Taps	Secondary kV	Z% HV/LV	X/R ratio
95	132	±10%	11	13.5	46
140	157.5	±10%	11.5	12.7	41
141	400	±5%	15	14.7	57
151	236	±5%	15	13.6	47
167	145	+7.5% -16.5%	15	25.7	71
180	289	±5%	16	13.4	34
180	132	±10%	15	13.8	40
247	432	+3.75% -16.25%	15.5	15.2	61
250	300	+11.2% -17.6%	15	28.6	70
290	420	±10%	15	15.7	43
307	432	+3.75% -16.25%	15.5	15.3	67
346	435	+5% -15%	17.5	16.4	81
420	432	+5.55% -14.45%	22	16	87
437.8	144.1	+10.8% -21.6%	21	14.6	50
450	132	±10%	19	14	49
600	420	±11.25%	21	16.2	74
716	525	±10%	19	15.7	61
721	362	+6.25% -13.75%	22	15.2	83
736	245	+7% -13%	22	15.5	73
900	525	+7% -13%	23	15.7	67

(b) Single-phase units

MVA / phase	Primary kV	Primary Taps	Secondary kV	Z% HV/LV	X/R ratio
266.7	$432/\sqrt{3}$	+6.67% -13.33%	23.5	15.8	92
266.7	$432/\sqrt{3}$	+6.6% -13.4%	23.5	15.7	79
277	$515/\sqrt{3}$	±5%	22	16.9	105
375	$525/\sqrt{3}$	+6.66% -13.32%	26	15	118
375	$420/\sqrt{3}$	+6.66% -13.32%	26	15.1	112

Table A4.7:
Impedances of generator transformers

A4

18. Overhead lines and cables

In this section a description of common overhead lines and cable systems is given, together with tables of their important characteristics. The formulae for calculating the characteristics are developed to give a basic idea of the factors involved, and to enable calculations to be made for systems other than those tabulated.

A transmission circuit may be represented by an equivalent π or T network using lumped constants as shown in Figure A4.15. Z is the total series impedance $(R + jX)\,L$ and Y is the total shunt admittance $(G + jB)\,L$, where L is the circuit length. The terms inside the brackets in Figure A4.15 are correction factors that allow for the fact that in the actual circuit the parameters are distributed over the whole length of the circuit and not lumped, as in the equivalent circuits.

With short lines it is usually possible to ignore the shunt admittance, which greatly simplifies calculations, but on longer lines it must be included. Another simplification that can be made is that of assuming the conductor configuration to be symmetrical. The self-impedance of each conductor becomes Z_p , and the mutual impedance between conductors becomes Z_m . However, for rigorous calculations a detailed treatment is necessary, with account being taken of the spacing of a conductor in relation to its neighbour and earth.

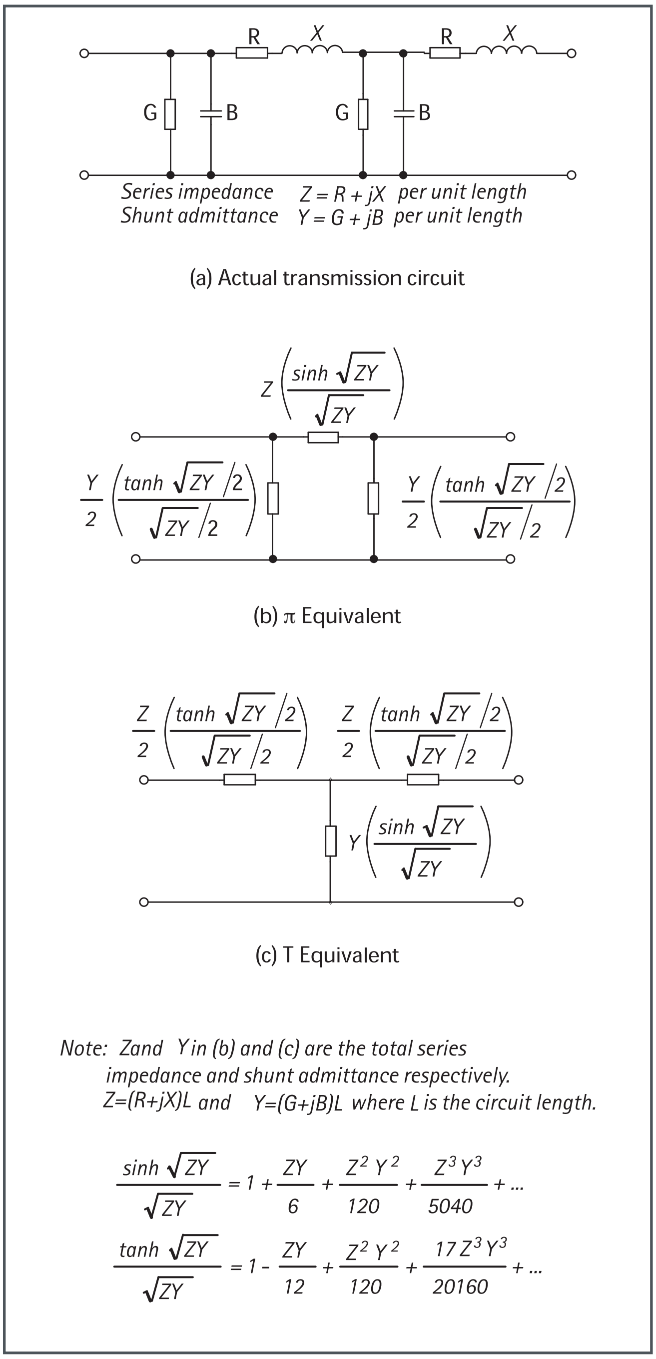

Figure A4.15:
Transmission circuit equivalents

19. Calculation of series impedance

The self impedance of a conductor with an earth return and the mutual impedance between two parallel conductors with a common earth return are given by the Carson equations:

$$\left.\begin{aligned} Z_p &= R + 0.000988\,f + j0.0029\,f\log_{10}\frac{D_e}{dc} \\ Z_p &= 0.000988\,f + j0.0029\,f\log_{10}\frac{D_e}{D} \end{aligned}\right\}$$

...Equation A4.11

where:

R = conductor a.c. resistance (ohms/km)

dc = geometric mean radius of a single conductor

D = spacing between the parallel conductors

f = system frequency

D_e = equivalent spacing of the earth return path

= 216 $\sqrt{p/f}$ where p is earth resistivity (ohms/cm^3)

The above formulae give the impedances in ohms/km. It should be noted that the last terms in Equation A4.11 are very similar to the classical inductance formulae for long straight conductors.

The geometric means radius (GMR) of a conductor is an equivalent radius that allows the inductance formula to be reduced to a single term. It arises because the inductance of a solid conductor is a function of the internal flux linkages in addition to those external to it. If the original conductor can be replaced by an equivalent that is a hollow cylinder with infinitesimally thin walls, the current is confined to the surface of the conductor, and there can be no internal flux. The geometric mean radius is the radius of the equivalent conductor. If the original conductor is a solid cylinder having a radius r its equivalent has a radius of 0.779 r.

It can be shown that the sequence impedances for a symmetrical three-phase circuit are:

$$\left.\begin{aligned} Z_1 &= Z_2 = Z_p - Z_m \\ Z_0 &= Z_p + 2Z_m \end{aligned}\right\}$$

...Equation A4.12

where Z_p and Z_m are given by Equation A4.11.

Substituting Equation A4.11 in Equation A4.12 gives:

$$\left.\begin{aligned} Z_1 &= Z_2 = R + j0.0029f\log_{10}\frac{D}{dc} \\ Z_o &= R + 0.00296f + j0.00869f\log_{10}\frac{D_e}{\sqrt[3]{dcD^2}} \end{aligned}\right\}$$

...Equation A4.13

In the formula for Z_0 the expression $\sqrt[3]{dcD^2}$ is the geometric mean radius of the conductor group.

Where the circuit is not symmetrical, the usual case, symmetry can be maintained by transposing the conductors so that each conductor is in each phase position for one third of the circuit length. If A, B and C are the spacings between conductors bc, ca and ab then D in the above equations becomes the geometric mean distance between conductors, equal to $\sqrt[3]{ABC}$.

Writing $D_c = \sqrt[3]{dcD^2}$, the sequence impedances in ohms/km at 50Hz become:

$$\left.\begin{aligned} Z_1 &= Z_2 = R + j0.145\log_{10}\frac{\sqrt[3]{ABC}}{dc} \\ Z_o &= (R + 0.148) + j0.434\log_{10}\frac{D_e}{D_c} \end{aligned}\right\}$$

...Equation A4.14

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20. Calculation of shunt impedance

It can be shown that the potential of a conductor a above ground due to its own charge qa and a charge $-qa$ on its image is:

$$V_a = 2\ qa\ log_e \frac{2h}{r} \qquad \text{...Equation A4.15}$$

where h is the height above ground of the conductor and r is the radius of the conductor, as shown in Figure A4.16.

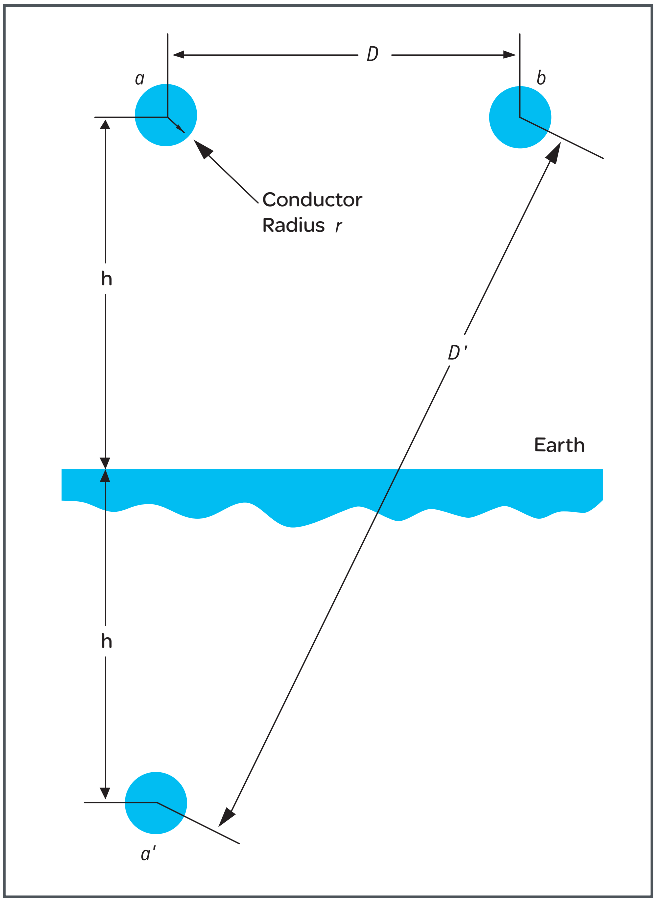

Figure A4.16:
Geometry of two parallel conductors a and b the image of a (a')

Similarly, it can be shown that the potential of a conductor a due to a charge qb on a neighbouring conductor b and the charge $-qb$ on its image is:

$$V'_a = 2\ qb\ log_e \frac{D'}{D} \qquad \text{...Equation A4.16}$$

where D is the spacing between conductors a and b and D' is the spacing between conductor b and the image of conductor a as shown in Figure A4.14.

Since the capacitance $C = q/V$ and the capacitive reactance $Xc = 1/\omega C$, it follows that the self and mutual capacitive reactance of the conductor system in Figure A4.16 can be obtained directly from Equations A4.15 and A4.16. Further, as leakage can usually be neglected, the self and mutual shunt impedances Z'_p and Z'_m in megohm-km at a system frequency of 50Hz are:

$$\left.\begin{aligned} Z'_p &= -j0.132\ log_{10} \frac{2h}{r} \\ Z'_m &= -j0.132\ log_{10} \frac{D'}{D} \end{aligned}\right\} \qquad \text{...Equation A4.17}$$

Where the distances above ground are great in relation to the conductor spacing, which is the case with overhead lines, $2h = D'$. From Equation A4.12, the sequence impedances of a symmetrical three-phase circuit are:

$$\left.\begin{aligned} Z_1 = Z_2 &= -j0.132\ log_{10} \frac{D}{r} \\ Z_0 &= -j0.396\ log_{10} \frac{D'}{\sqrt[3]{rD^2}} \end{aligned}\right\} \qquad \text{...Equation A4.18}$$

It should be noted that the logarithmic terms above are similar to those in Equation A4.13 except that r is the actual radius of the conductors and D' is the spacing between the conductors and their images.

Again, where the conductors are not symmetrically spaced but transposed, Equation A4.18 can be re-written making use of the geometric mean distance between conductors, $\sqrt[3]{ABC}$, and giving the distance of each conductor above ground, that is, h_a, h_b, h_c, as follows:

$$\left.\begin{aligned} Z_1 = Z_2 &= -j0.132\ log_{10} \frac{\sqrt[3]{ABC}}{r} \\ Z_0 &= -j0.132\ log_{10} \frac{8h_a h_b h_c}{r\sqrt[3]{A^2B^2C^2}} \end{aligned}\right\} \qquad \text{...Equation A4.19}$$

20. Calculation of shunt impedance

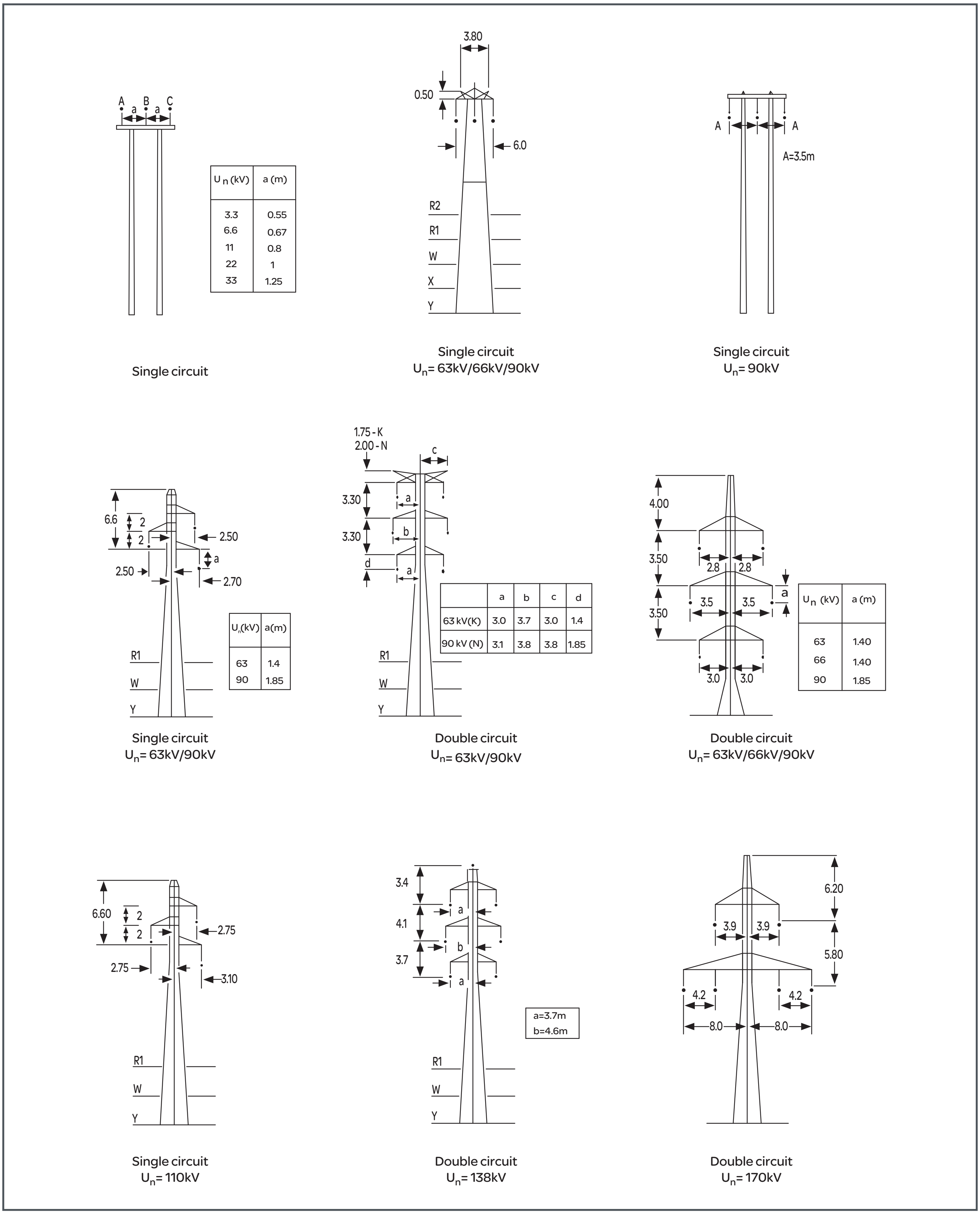

Figure A4.17:
Typical OHL configurations (not to scale)

A4

20. Calculation of shunt impedance

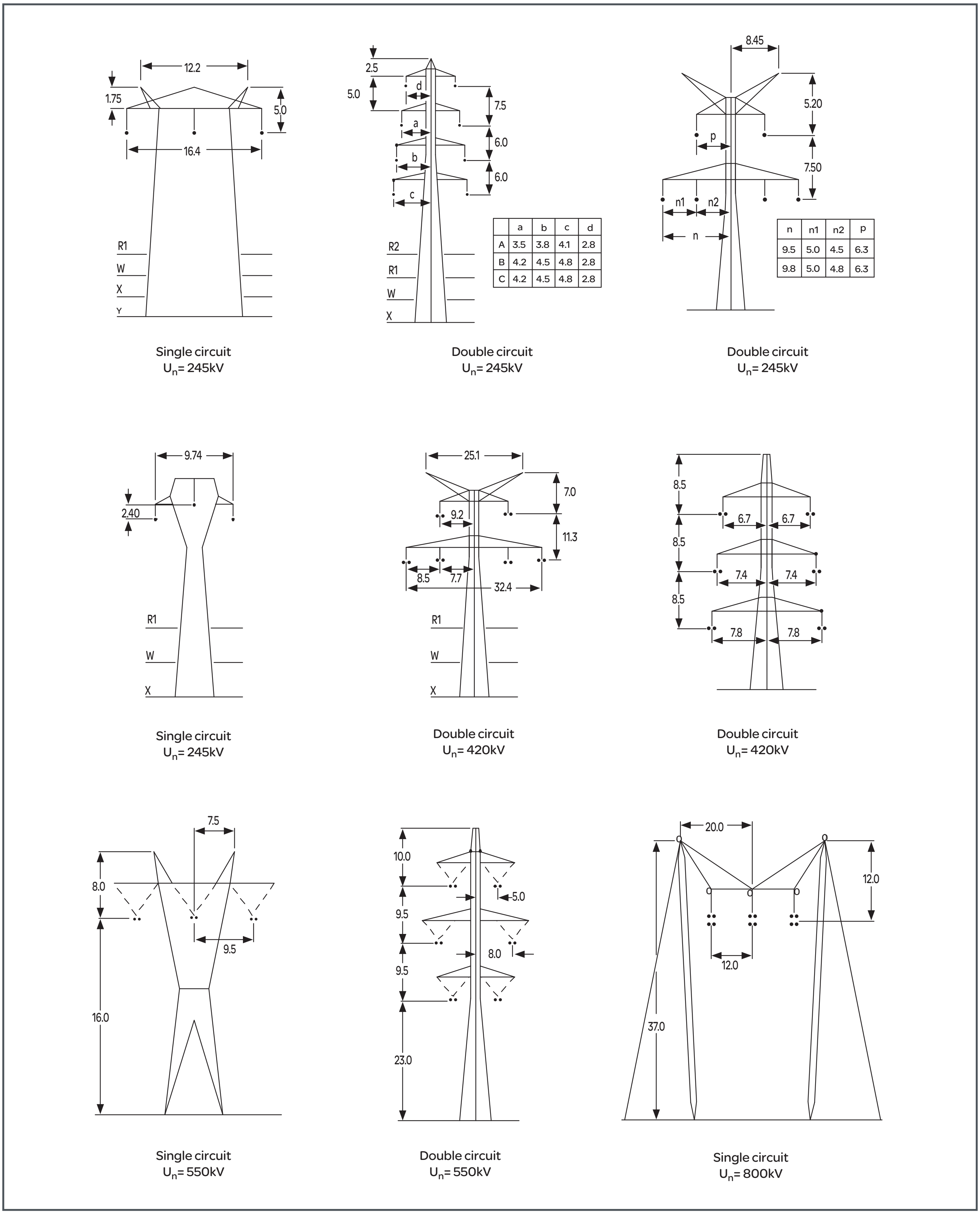

Figure A4.17 (cont.):
Typical OHL configurations (not to scale)

21. Overhead line circuits with or without earth wires

Typical configurations of overhead line circuits are given in Figure A4.17. Tower heights are not given as they vary considerably according to the design span and nature of the ground. As indicated in some of the tower outlines, some tower designs are designed with a number of base extensions for this purpose. Figure A4.18 shows a typical tower.

Figure A4.18: Typical overhead line tower

In some cases, the phase conductors are not symmetrically disposed to each other and therefore, as previously indicated, electrostatic and electromagnetic unbalance will result, which can be largely eliminated by transposition. Modern practice is to build overhead lines without transposition towers to reduce costs; this must be taken into account in rigorous calculations of the unbalances. In other cases, lines are formed of bundled conductors, that is conductors formed of two, three or four separate conductors. This arrangement minimises losses when voltages of 220kV and above are involved.

It should be noted that the line configuration and conductor spacings are influenced, not only by voltage, but also by many other factors including type of insulators, type of support, span length, conductor sag and the nature of terrain and external climatic loadings. Therefore, there can be large variations in spacings between different line designs for the same voltage level, so those depicted in Figure A4.17 are only typical examples.

When calculating the phase self and mutual impedances, Equations A4.11 and A4.17 may be used, but it should be remembered that in this case Z_p is calculated for each conductor and Z_m for each pair of conductors. This section is not, therefore, intended to give a detailed analysis, but rather to show the general method of formulating the equations, taking the calculation of series impedance as an example and assuming a single circuit line with a single earth wire.

The phase voltage drops V_a , V_b , V_c of a single circuit line with a single earth wire due to currents I_a , I_b , I_c flowing in the phases and I_e in the earth wire are:

$$\left.\begin{aligned} V_a &= Z_{aa}I_a + Z_{ab}I_b + Z_{ac}I_c + Z_{ae}I_e \\ V_b &= Z_{ba}I_a + Z_{bb}I_b + Z_{bc}I_c + Z_{be}I_e \\ V_c &= Z_{ca}I_a + Z_{cb}I_b + Z_{cc}I_c + Z_{ce}I_e \\ 0 &= Z_{ea}I_a + Z_{eb}I_b + Z_{ec}I_c + Z_{ee}I_e \end{aligned}\right\} \quad \text{...Equation A4.20}$$

where:

$$Z_{aa} = R + 0.000988\, f + j0.0029\, f \log_{10}\frac{D_e}{dc}$$

$$Z_{ab} = 0.000988\, f + j0.0029\, f \log_{10}\frac{D_e}{D}$$

and so on.

The equation required for the calculation of shunt voltage drops is identical to Equation A4.20 in form, except that primes must be included, the impedances being derived from Equation A4.17.

From Equation A4.20 it can be seen that:

$$-I_e = \frac{Z_{ea}}{Z_{ee}}I_a + \frac{Z_{eb}}{Z_{ee}}I_b + \frac{Z_{ec}}{Z_{ee}}I_c$$

Making use of this relation, the self and mutual impedances of the phase conductors can be modified using the following formula:

$$J_{nm} = Z_{nm} - \frac{Z_{ne}Z_{me}}{Z_{ee}} \quad \text{...Equation A4.21}$$

For example:

$$J_{aa} = Z_{aa} - \frac{Z_{ae}^2}{Z_{ee}}$$

$$J_{ab} = Z_{ab} - \frac{Z_{ae}Z_{be}}{Z_{ee}} \quad \text{and so on.}$$

So Equation A4.20 can be simplified while still taking account of the effect of the earth wire by deleting the fourth row and fourth column and substituting J_{aa} for Z_{aa} , J_{ab} for Z_{ab} , and so on, calculated using Equation A4.21. The single circuit line

21. Overhead line circuits with or without earth wires

with a single earth wire can therefore be replaced by an equivalent single circuit line having phase self and mutual impedances J_{aa} , J_{ab} and so on.

It can be shown from the symmetrical component theory given in Chapter [A3: Fault Calculations] that the sequence voltage drops of a general three-phase circuit are:

$$\left.\begin{aligned} V_0 &= Z_{00} I_0 + Z_{01} I_1 + Z_{02} I_2 \\ V_1 &= Z_{10} I_0 + Z_{11} I_1 + Z_{12} I_2 \\ V_2 &= Z_{20} I_0 + Z_{21} I_1 + Z_{22} I_2 \end{aligned}\right\}$$

...Equation A4.22

And, from Equation A4.20 modified as indicated above and Equation A4.22, the sequence impedances are:

$$\left.\begin{aligned} Z_{00} &= \frac{1}{3}\left(J_{aa} + J_{bb} + J_{cc}\right) + \frac{2}{3}\left(J_{ab} + J_{bc} + J_{ac}\right) \\ Z_{11} &= \frac{1}{3}\left(J_{aa} + J_{bb} + J_{cc}\right) - \frac{1}{3}\left(J_{ab} + J_{bc} + J_{ac}\right) \\ Z_{12} &= \frac{1}{3}\left(J_{aa} + a^2 J_{bb} + a J_{cc}\right) + \frac{2}{3}\left(a J_{ab} + a^2 J_{ac} + J_{bc}\right) \\ Z_{21} &= \frac{1}{3}\left(J_{aa} + a J_{bb} + a^2 J_{cc}\right) + \frac{2}{3}\left(a^2 J_{ab} + a J_{ac} + J_{bc}\right) \\ Z_{20} &= \frac{1}{3}\left(J_{aa} + a^2 J_{bb} + a J_{cc}\right) - \frac{1}{3}\left(a J_{ab} + a^2 J_{ac} + J_{bc}\right) \\ Z_{10} &= \frac{1}{3}\left(J_{aa} + a J_{bb} + a^2 J_{cc}\right) - \frac{1}{3}\left(a^2 J_{ab} + a J_{ac} + J_{bc}\right) \\ Z_{22} &= Z_{11} \\ Z_{01} &= Z_{20} \\ Z_{02} &= Z_{10} \end{aligned}\right\}$$

...Equation A4.23

The development of these equations for double circuit lines with two earth wires is similar except that more terms are involved.

The sequence mutual impedances are very small and can usually be neglected; this also applies for double circuit lines except for the mutual impedance between the zero sequence circuits, namely $(Z_{00'} = Z_{0'0})$. Table A4.9 gives typical values of all sequence self and mutual impedances some single and double circuit lines with earth wires. All conductors are 400mm^2 ACSR, except for the 132kV double circuit example where they are 200mm^2.

Sequence impedance	132kV Single circuit line (400 mm^2)	380kV Single circuit line (400 mm^2)	132kV Double circuit line (200 mm^2)	275kV Double circuit line (400 mm^2)
$Z_{00} = (Z_{0'0'})$	1.0782 < 73°54'	0.8227 < 70°36'	1.1838 < 71°6'	0.9520 < 76°46'
$Z_{11} = Z_{22} = (Z_{1'1'})$	0.3947 < 78°54'	0.3712 < 75°57'	< 66°19'	0.3354 < 74°35'
$(Z_{0'0} = Z_{00'})$			0.6334 < 71°2'	0.5219 < 75°43'
$Z_{01} = Z_{20} = (Z_{0'1'} = Z_{2'0'})$	0.0116 < -166°52'	0.0094 < -39°28'	0.0257 < -63°25'	0.0241 < -72°14'
$Z_{02} = Z_{10} = (Z_{0'2'} = Z_{1'0'})$	< 5°8'	0.0153 < 28°53'	0.0197 < -94°58'	0.0217 < -100°20'
$Z_{12} = (Z_{1'2'})$	0.0255 < -40°9'	0.0275 < 147°26'	0.0276 < 161°17'	0.0281 < 149°46'
$Z_{21} = (Z_{2'1'})$	0.0256 < -139°1'	0.0275 < 27°29'	0.0277 < 37°13'	0.0282 < 29°6'
$(Z_{11'} = Z_{1'1} = Z_{22'} = Z_{2'2})$			0.0114 < 88°6'	0.0129 < 88°44'
$(Z_{02'} = Z_{0'2} = Z_{1'0} = Z_{10'})$			0.0140 < -93°44'	0.0185 < -91°16'
$(Z_{02'} = Z_{0'2} = Z_{1'0} = Z_{10'}$			0.0150 < -44°11'	0.0173 < -77°2'
$(Z_{1'2} = Z_{12'})$			0.0103 < 145°10'	0.0101 < 149°20'
$(Z_{21'} = Z_{2'1})$			0.0106 < 30°56'	0.0102 < 27°31'

Table A4.9:
Sequence self and mutual impedances for various lines

22. OHL equivalent circuits

Consider an earthed, infinite busbar source behind a length of transmission line as shown in Figure A4.19(a). An earth fault involving phase A is assumed to occur at F. If the driving voltage is E and the fault current is I_a then the earth fault impedance is Z_e.

From symmetrical component theory (see Chapter [A3: Fault Calculations]:

$$I_a = \frac{3E}{Z_1 + Z_2 + Z_0}$$

thus

$$Z_e = \frac{2Z_1 + Z_0}{3}$$

since, as shown, $Z_1 = Z_2$ for a transmission circuit. From Equations A4.12, $Z_1 = Z_p - Z_m$ and $Z_0 = Z_p + 2Z_m$. Thus, substituting these values in the above equation gives $Z_e = Z_p$. This relation is physically valid because Z_p is the self-impedance of a single conductor with an earth return. Similarly, for a phase fault between phases B and C at F :

$$I_b = -I_c = \frac{\sqrt{3}E}{2Z_1}$$

where $\sqrt{3}E$ is the voltage between phases and $2Z$ is the impedance of the fault loop.

Making use of the above relations a transmission circuit may be represented, without any loss in generality, by the equivalent of Figure A4.19(b), where Z_1 is the phase impedance to the fault and $(Z_0 - Z_1)/3$ is the impedance of the earth path, there being no mutual impedance between the phases or between phase and earth. The equivalent is valid for single and double circuit lines except that for double circuit lines there is zero sequence mutual impedance, hence $Z_0 = (Z_{00} - Z_{0'0})$.

The equivalent circuit of Figure A4.19(b) is valuable in distance relay applications because the phase and earth fault relays are set to measure Z_2 and are compensated for the earth return impedance $(Z_0 - Z_1)/3$.

It is customary to quote the impedances of a transmission circuit in terms of Z_1 and the ratio Z_0/Z_1 , since in this form they are most directly useful. By definition, the positive sequence impedance Z_1 is a function of the conductor spacing and radius, whereas the Z_0/Z_1 ratio is dependent primarily on the level of earth resistivity ρ.

Further details may be found in Chapter [C4: Distance Protection Schemes].

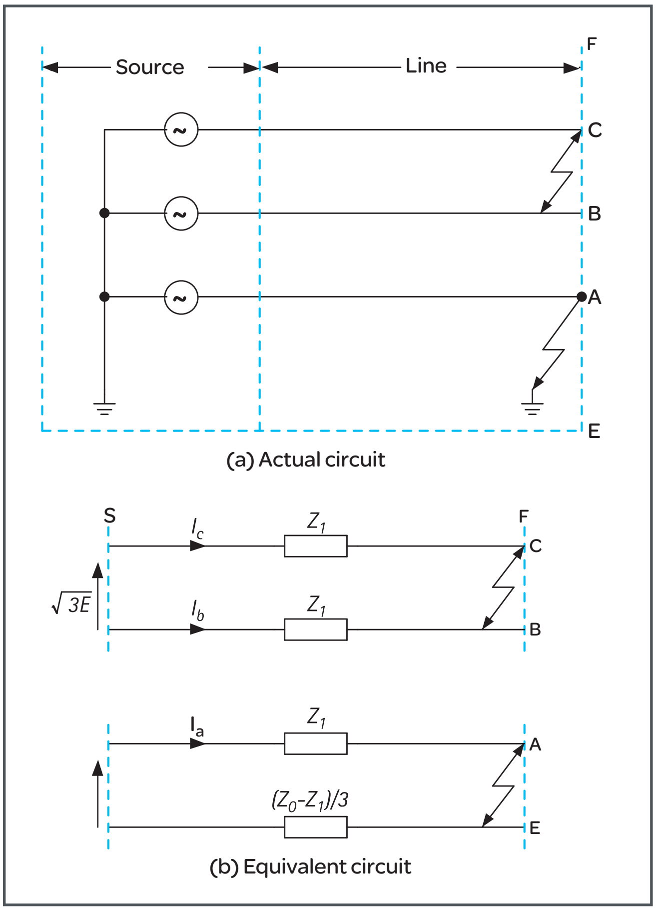

Figure A4.19:
Three-phase equivalent of a transmission circuit

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23. Cable circuits

The basic formulae for calculating the series and shunt impedances of a transmission circuit, Equations A4.11 and A4.17, may be applied for evaluating cable parameters; since the conductor configuration is normally symmetrical, GMD and GMR values can be used without risk of appreciable errors. However, the formulae must be modified by the inclusion of empirical factors to take account of sheath and screen effects. A useful general reference on cable formulae is given in reference [Ref A4.4: Power System Analysis]; more detailed information on particular types of cables should be obtained direct from the manufacturers. The equivalent circuit for determining the positive and negative sequence series impedances of a cable is shown in Figure A4.20.

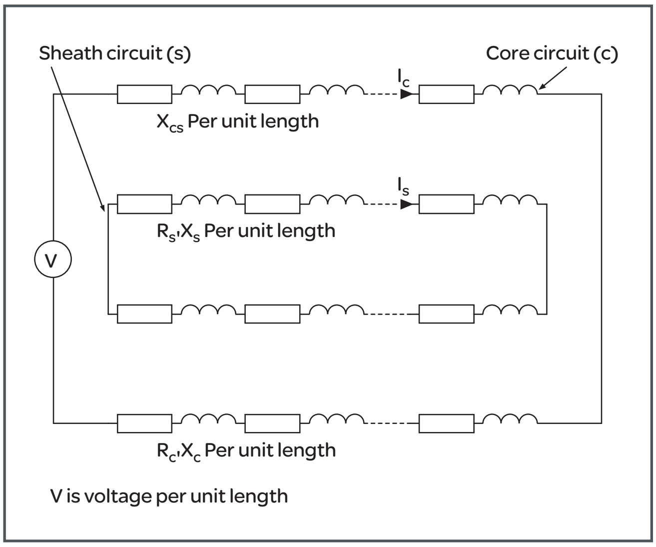

Figure A4.20:
Equivalent circuit for determining positive or negative impedance of cables

From this circuit it can be shown that:

$$Z_1 = Z_2 = \left\{ R_c + R_s \frac{X_{cs}^2}{R_s^2 + X_s^2} \right\} + j\left\{ X_c - X_s \frac{X_{cs}^2}{R_s^2 + X_s^2} \right\}$$ ...Equation A4.24

where R_c and R_s are the core and sheath (screen) resistances per unit length, X_c and X_s core and sheath (screen) reactances per unit length and X_{cs} the mutual reactance between core and sheath (screen) per unit length. X_{cs} is in general equal to X_s.

The zero sequence series impedances are obtained directly using Equation A4.11 and account can be taken of the sheath in the same way as an earth wire in the case of an overhead line.

The shunt capacitances of a sheathed cable can be calculated from the simple formula:

$$C = 0.0241\varepsilon \left\{ \frac{1}{\log \frac{d+2T}{d}} \right\} \mu F/km$$ ...Equation A4.25

where d is the overall diameter for a round conductor, T core insulation thickness and ε permittivity of dielectric. When the conductors are oval or shaped, an equivalent diameter d' may be used where $d' = (1/\pi)$ x periphery of conductor. No simple formula exists for belted or unscreened cables, but an empirical formula that gives reasonable results is:

$$C = \frac{0.0555\varepsilon}{G} \mu F/km$$ ...Equation A4.26

where G is a geometric factor which is a function of core and belt insulation thickness and overall conductor diameter.

24. Overhead line and cable data

The following tables contain typical data on overhead lines and cables that can be used in conjunction with the various equations quoted in this text. It is not intended that this data should replace that supplied by manufacturers. Where the results of calculations are important, reliance should not be placed on the data in these tables and data should be sourced directly from a manufacturer/supplier.

At the conceptual design stage, initial selection of overhead line conductor size will be determined by four factors:

a. maximum load to be carried in MVA

b. length of line

c. conductor material and hence maximum temperature

d. cost of losses

Table A4.20 gives indicative details of the capability of various sizes of overhead lines using the above factors, for AAAC (All Aluminium Alloy Conductors) and ACSR (Aluminium Conductor Steel Reinforced) conductor materials. It is based on commonly used standards for voltage drop and ambient temperature. Since these factors may not be appropriate for any particular project, the table should only be used as a guide for initial sizing, with appropriately detailed calculations carried out to arrive at a final proposal.

Number of Strands	GMR
7	0.726r
19	0.758r
37	0.768r
61	0.772r
91	0.774r
127	0.776r
169	0.776r
Solid	0.779r

Table A4.10:
GMR for stranded copper, aluminium and aluminium alloy conductors (r = conductor radius)

Number of Layers	Number of Al Strands	GMR
1	6	0.5r *
1	12	0.75r *
2	18	0.776r
2	24	0.803r
2	26	0.812r
2	30	0.826r
2	32	0.833r
3	36	0.778r
3	45	0.794r
3	48	0.799r
3	54	0.81r
3	66	0.827r
4	72	0.789r
4	76	0.793r
4	84	0.801r

Note: Indicative values only, since GMR for single layer conductors is affected by cyclic magnetic flux, which depends on various factors.*

Table A4.11:
GMR for aluminium conductor steel reinforced (ACSR) (r = conductor radius)

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24. Overhead line and cable data

(a) ASTM (American Society for Testing and Materials) standards

Stranding area (mm^2)	Wire	Overall diameter (mm)	R_{DC} diameter (mm)	(20°C) (Ω/km)
10.6	7	1.38	4.17	1.734
21.2	7	1.96	5.89	0.865
26.7	7	2.20	6.60	0.686
33.6	7	7.00	7.42	0.544
42.4	7	2.77	8.33	0.431
53.5	7	3.12	9.35	0.342
67.4	7	3.50	10.52	0.271
85.0	7	3.93	11.79	0.215
107.2	7	4.42	13.26	0.171
126.6	19	2.91	14.58	0.144
152.0	19	3.19	15.98	0.120
177.3	19	3.45	17.25	0.103
202.7	19	3.69	18.44	0.090
228.0	37	2.80	19.61	0.080
253.3	37	2.95	20.65	0.072
278.7	37	3.10	21.67	0.066
304.3	37	3.23	22.63	0.060
329.3	61	2.62	23.60	0.056
354.7	61	2.72	24.49	0.052
380.0	61	2.82	25.35	0.048
405.3	61	2.91	26.19	0.045
456.0	61	3.09	27.79	0.040
506.7	61	3.25	29.26	0.036

(b) BS (British Standards) standards

Stranding area (mm^2)	Wire	Overall diameter (mm)	R_{DC} diameter (mm)	(20°C) (Ω/km)
11.0	1	3.73	3.25	1.617
13.0	1	4.06	4.06	1.365
14.0	1	4.22	4.22	1.269
14.5	7	1.63	4.88	1.231
16.1	1	4.52	4.52	1.103
18.9	1	4.90	4.90	0.938
23.4	1	5.46	5.46	0.756
32.2	1	6.40	6.40	0.549
38.4	7	2.64	7.92	0.466
47.7	7	2.95	8.84	0.375
65.6	7	3.45	10.36	0.273
70.1	1	9.45	9.45	0.252
97.7	7	4.22	12.65	0.183
129.5	19	2.95	14.73	0.139
132.1	7	4.90	14.71	0.135
164.0	7	5.46	16.38	0.109
165.2	19	3.33	16.64	0.109

Table A4.12:
Overhead line conductor - hard drawn copper

(a) to ASTM B232

Designation	Stranding and wire diameter (mm)				Sectional area (mm^2)		Total area (mm^2)	Approxi. overall diameter (mm)	RDC at 20°C (Ω/km)
	Aluminium		Steel		Aluminium	Steel			
Sparrow	6	2.67	1	2.67	33.6	5.6	39.2	8.01	0.854
Robin	6	3	1	3	42.4	7.1	49.5	9	0.677
Raven	6	3.37	1	3.37	53.5	8.9	62.4	10.11	0.536
Quail	6	3.78	1	3.78	67.4	11.2	78.6	11.34	0.426
Pigeon	6	4.25	1	4.25	85.0	14.2	99.2	12.75	0.337
Penguin	6	4.77	1	4.77	107.2	17.9	125.1	14.31	0.268
Partridge	26	2.57	7	2	135.2	22.0	157.2	16.28	0.214
Ostrich	26	2.73	7	2.21	152.0	26.9	178.9	17.28	0.191
Merlin	18	3.47	1	3.47	170.5	9.5	179.9	17.35	0.169
Lark	30	2.92	7	2.92	201.4	46.9	248.3	20.44	0.144
Hawk	26	3.44	7	2.67	241.7	39.2	280.9	21.79	0.120
Dove	26	3.72	7	2.89	282.0	45.9	327.9	23.55	0.103
Teal	30	3.61	19	2.16	306.6	69.6	376.2	25.24	0.095
Swift	36	3.38	1	3.38	322.3	9.0	331.2	23.62	0.089
Tern	45	3.38	7	2.25	402.8	27.8	430.7	27.03	0.072
Canary	54	3.28	7	3.28	456.1	59.1	515.2	29.52	0.064
Curlew	54	3.52	7	3.52	523.7	68.1	591.8	31.68	0.055
Finch	54	3.65	19	2.29	565.0	78.3	643.3	33.35	0.051
Bittern	45	4.27	7	2.85	644.5	44.7	689.2	34.17	0.045
Falcon	54	4.36	19	2.62	805.7	102.4	908.1	39.26	0.036
Kiwi	72	4.41	7	2.94	1100.0	47.5	1147.5	44.07	0.027

(b) to BS 215.2

Designation	Stranding and wire diameter (mm)				Sectional area (mm^2)		Total area (mm^2)	Approxi. overall diameter (mm)	RDC at 20°C (Ω/km)
	Aluminium		Steel		Aluminium	Steel			
Gopher	6	2.36	1	2.36	26.2	4.4	30.6	7.08	1.093
Weasel	6	2.59	1	2.59	31.6	5.3	36.9	7.77	0.908
Ferret	6	3	1	3	42.4	7.1	49.5	9	0.676
Rabbit	6	3.35	1	3.35	52.9	8.8	61.7	10.05	0.542
Horse	12	2.79	7	2.79	73.4	42.8	116.2	13.95	0.393
Dog	6	4.72	7	1.57	105.0	13.6	118.5	14.15	0.273
Tiger	30	2.36	7	2.36	131.2	30.6	161.9	16.52	0.220
Wolf	30	2.59	7	2.59	158.1	36.9	194.9	18.13	0.182
Dingo	18	3.35	1	3.35	158.7	8.8	167.5	16.75	0.181
Lynx	30	2.79	7	2.79	183.4	42.8	226.2	19.53	0.157
Caracal	18	3.61	1	3.61	184.2	10.2	194.5	18.05	0.156
Jaguar	18	3.86	1	3.86	210.6	11.7	222.3	19.3	0.137
Panther	30	3	7	3	212.1	49.5	261.5	21	0.136
Zebra	54	3.18	7	3.18	428.9	55.6	484.5	28.62	0.067

Table A4.13:
Overhead line conductor data - aluminium conductors steel reinforced (ACSR).

24. Overhead line and cable data

(c) to DIN 48204

Designation	Stranding and wire diameter (mm)				Sectional area (mm^2)		Total area (mm^2)	Approxi. overall diameter (mm)	RDC at 20°C (Ω/km)
	Aluminium		Steel		Aluminium	Steel			
35/6	6	2.7	1	2.7	34.4	5.7	40.1	8.1	0.834
44/32	14	2	7	2.4	44.0	31.7	75.6	11.2	0.652
50/8	6	3.2	1	3.2	48.3	8.0	56.3	9.6	0.594
70/12	26	1.85	7	1.44	69.9	11.4	81.3	11.7	0.413
95/15	26	2.15	7	1.67	94.4	15.3	109.7	13.6	0.305
95/55	12	3.2	7	3.2	96.5	56.3	152.8	16	0.299
120/70	12	3.6	7	3.6	122.1	71.3	193.4	18	0.236
150/25	26	2.7	7	2.1	148.9	24.2	173.1	17.1	0.194
170/40	30	2.7	7	2.7	171.8	40.1	211.8	18.9	0.168
185/30	26	3	7	2.33	183.8	29.8	213.6	19	0.157
210/50	30	3	7	3	212.1	49.5	261.5	21	0.136
265/35	24	3.74	7	2.49	263.7	34.1	297.7	22.4	0.109
305/40	54	2.68	7	2.68	304.6	39.5	344.1	24.1	0.095
380/50	54	3	7	3	381.7	49.5	431.2	27	0.076
550/70	54	3.6	7	3.6	549.7	71.3	620.9	32.4	0.052
560/50	48	3.86	7	3	561.7	49.5	611.2	32.2	0.051
650/45	45	4.3	7	2.87	653.5	45.3	698.8	34.4	0.044
1045/45	72	4.3	7	2.87	1045.6	45.3	1090.9	43	0.028

(d) to NF C34-120

Designation	Stranding and wire diameter (mm)				Sectional area (mm^2)		Total area (mm^2)	Approxi. overall diameter (mm)	RDC at 20°C (Ohm/km)
	Aluminium		Steel		Aluminium	Steel			
CANNA 59.7	12	2	7	2	37.7	22.0	59.7	10	0.765
CANNA 75.5	12	2.25	7	2.25	47.7	27.8	75.5	11.25	0.604
CANNA 93.3	12	2.5	7	2.5	58.9	34.4	93.3	12.5	0.489
CANNA 116.2	30	2	7	2	94.2	22.0	116.2	14	0.306
CROCUS 116.2	30	2	7	2	94.2	22.0	116.2	14	0.306
CANNA 147.1	30	2.25	7	2.25	119.3	27.8	147.1	15.75	0.243
CROCUS 181.6	30	2.5	7	2.5	147.3	34.4	181.6	17.5	0.197
CROCUS 228	30	2.8	7	2.8	184.7	43.1	227.8	19.6	0.157
CROCUS 297	36	2.8	19	2.25	221.7	75.5	297.2	22.45	0.131
CANNA 288	30	3.15	7	3.15	233.8	54.6	288.3	22.05	0.124
CROCUS 288	30	3.15	7	3.15	233.8	54.6	288.3	22.05	0.124
CROCUS 412	32	3.6	19	2.4	325.7	86.0	411.7	26.4	0.089
CROCUS 612	66	3.13	19	2.65	507.8	104.8	612.6	32.03	0.057
CROCUS 865	66	3.72	19	3.15	717.3	148.1	865.4	38.01	0.040

Table A4.13 (cont):
Overhead line conductor data - aluminium conductors steel reinforced (ACSR).

(a) ASTM

Standard	Designation	No. of Al strands	Wire diameter (mm)	Sectional area (mm2)	Overall diameter (mm)	R_{DC} at 20°C (Ω/km)
ASTM B-397	Kench	7	2.67	39.2	8.0	0.838
	Kibe	7	3.37	62.4	10.1	0.526
	Kayak	7	3.78	78.6	11.4	0.418
	Kopeck	7	4.25	99.3	12.8	0.331
	Kittle	7	4.77	125.1	14.3	0.262
	Radian	19	3.66	199.9	18.3	0.164
	Rede	19	3.78	212.6	18.9	0.155
	Ragout	19	3.98	236.4	19.9	0.140
	Rex	19	4.14	255.8	19.9	0.129
	Remex	19	4.36	283.7	21.8	0.116
	Ruble	19	4.46	296.8	22.4	0.111
	Rune	19	4.7	330.6	23.6	0.100
	Spar	37	3.6	376.6	25.2	0.087
	Solar	37	4.02	469.6	28.2	0.070
ASTM B-399	-	19	3.686	202.7	18.4	0.165
	-	19	3.909	228.0	19.6	0.147
	-	19	4.12	253.3	20.6	0.132
	-	37	3.096	278.5	21.7	0.120
	-	37	3.233	303.7	22.6	0.110
	-	37	3.366	329.2	23.6	0.102
	-	37	3.493	354.6	24.5	0.094
	-	37	3.617	380.2	25.3	0.088
	-	37	3.734	405.2	26.1	0.083
	-	37	3.962	456.2	27.7	0.073
	-	37	4.176	506.8	29.2	0.066

(b) BS

Standard	Designation	No. of Al strands	Wire diameter (mm)	Sectional area (mm2)	Overall diameter (mm)	R_{DC} at 20°C (Ω/km)
BS 3242	Box	7	1.85	18.8	5.6	1.750
	Acacia	7	2.08	23.8	6.2	1.384
	Almond	7	2.34	30.1	7.0	1.094
	Cedar	7	2.54	35.5	7.6	0.928
	Fir	7	2.95	47.8	8.9	0.688
	Hazel	7	3.3	59.9	9.9	0.550
	Pine	7	3.61	71.6	10.8	0.460
	Willow	7	4.04	89.7	12.1	0.367
	-	7	4.19	96.5	12.6	0.341
	-	7	4.45	108.9	13.4	0.302
	Oak	7	4.65	118.9	14.0	0.277
	Mullberry	19	3.18	150.9	15.9	0.219
	Ash	19	3.48	180.7	17.4	0.183
	Elm	19	3.76	211.0	18.8	0.157
	Poplar	37	2.87	239.4	20.1	0.139
	Sycamore	37	3.23	303.2	22.6	0.109
	Upas	37	3.53	362.1	24.7	0.092
	Yew	37	4.06	479.0	28.4	0.069
	Totara	37	4.14	498.1	29.0	0.067
	Rubus	61	3.5	586.9	31.5	0.057
	Araucaria	61	4.14	821.1	28.4	0.040

Table A4.14:
Overhead line conductor data - aluminium alloy.

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24. Overhead line and cable data

(c) CSA (Canadian Standards Association)

Standard	Designation	No. of Al strands	Wire diameter (mm)	Sectional area (mm2)	Overall diameter (mm)	R_{DC} at 20°C (Ω/km)
CSA C49.1-M87	10	7	1.45	11.5	4.3	2.863
	16	7	1.83	18.4	5.5	1.788
	25	7	2.29	28.8	6.9	1.142
	40	7	2.89	46.0	8.7	0.716
	63	7	3.63	72.5	10.9	0.454
	100	19	2.78	115.1	13.9	0.287
	125	19	3.1	143.9	15.5	0.230
	160	19	3.51	184.2	17.6	0.180
	200	19	3.93	230.2	19.6	0.144
	250	19	4.39	287.7	22.0	0.115
	315	37	3.53	362.1	24.7	0.092
	400	37	3.98	460.4	27.9	0.072
	450	37	4.22	517.9	29.6	0.064
	500	37	4.45	575.5	31.2	0.058
	560	37	4.71	644.5	33.0	0.051
	630	61	3.89	725.0	35.0	0.046
	710	61	4.13	817.2	37.2	0.041
	800	61	4.38	920.8	39.5	0.036
	900	61	4.65	1035.8	41.9	0.032
	1000	91	4.01	1150.9	44.1	0.029
	1120	91	4.25	1289.1	46.7	0.026
	1250	91	4.49	1438.7	49.4	0.023
	1400	91	4.75	1611.3	52.2	0.021
	1500	91	4.91	1726.4	54.1	0.019

(d) DIN: (Deutsche Industrie Norm, Germany)

Standard	Designation	No. of Al strands	Wire diameter (mm)	Sectional area (mm2)	Overall diameter (mm)	R_{DC} at 20°C (Ω/km)
DIN 48201	16	7	1.7	15.9	5.1	2.091
	25	7	2.1	24.3	6.3	1.370
	35	7	2.5	34.4	7.5	0.967
	50	19	1.8	48.4	9.0	0.690
	50	7	3	49.5	9.0	0.672
	70	19	2.1	65.8	10.5	0.507
	95	19	2.5	93.3	12.5	0.358
	120	19	2.8	117.0	14.0	0.285
	150	37	2.25	147.1	15.7	0.228
	185	37	2.5	181.6	17.5	0.184
	240	61	2.25	242.5	20.2	0.138
	300	61	2.5	299.4	22.5	0.112
	400	61	2.89	400.1	26.0	0.084
	500	61	3.23	499.8	29.1	0.067

(e) NF (Association Francaise de Normalisation - AFNOR)

Standard	Designation	No. of Al strands	Wire diameter (mm)	Sectional area (mm2)	Overall diameter (mm)	R_{DC} at 20°C (Ω/km)
NF C34-125	ASTER 22	7	2	22.0	6.0	1.497
	ASTER 34-4	7	2.5	34.4	7.5	0.958
	ASTER 54-6	7	3.15	54.6	9.5	0.604
	ASTER 75-5	19	2.25	75.5	11.3	0.438
	ASTER 93,3	19	2.5	93.3	12.5	0.355
	ASTER 117	19	2.8	117.0	14.0	0.283
	ASTER 148	19	3.15	148.1	15.8	0.223
	ASTER 181-6	37	2.5	181.6	17.5	0.183
	ASTER 228	37	2.8	227.8	19.6	0.146
	ASTER 288	37	3.15	288.3	22.1	0.115
	ASTER 366	37	3.55	366.2	24.9	0.091
	ASTER 570	61	3.45	570.2	31.1	0.058
	ASTER 851	91	3.45	850.7	38.0	0.039
	ASTER 1144	91	4	1143.5	44.0	0.029
	ASTER 1600	127	4	1595.9	52.0	0.021

Table A4.14 (cont):
Overhead line conductor data - aluminium alloy.

24. Overhead line and cable data

(a) ASTM

Standard	Designation	Stranding and wire diameter (mm)				Sectional area (mm2)		Total area (mm2)	Approxi. overall diameter (mm)	R_{DC} at 20°C (Ω / km)
		Alloy		Steel		Alloy	Steel			
ASTM B711		26	2.62	7	2.04	140.2	22.9	163.1	7.08	0.240
		26	2.97	7	2.31	180.1	29.3	209.5	11.08	0.187
		30	2.76	7	2.76	179.5	41.9	221.4	12.08	0.188
		26	3.13	7	2.43	200.1	32.5	232.5	13.08	0.168
		30	3.08	7	3.08	223.5	52.2	275.7	16.08	0.151
		26	3.5	7	2.72	250.1	40.7	290.8	17.08	0.135
		26	3.7	7	2.88	279.6	45.6	325.2	19.08	0.120
		30	3.66	19	2.2	315.6	72.2	387.9	22.08	0.107
		30	3.88	19	2.33	354.7	81.0	435.7	24.08	0.095
		30	4.12	19	2.47	399.9	91.0	491.0	26.08	0.084
		54	3.26	19	1.98	450.7	58.5	509.2	27.08	0.075
		54	3.63	19	2.18	558.9	70.9	629.8	29.08	0.060
		54	3.85	19	2.31	628.6	79.6	708.3	30.08	0.054
		54	4.34	19	2.6	798.8	100.9	899.7	32.08	0.042
		84	4.12	19	2.47	1119.9	91.0	1210.9	35.08	0.030
		84	4.35	19	2.61	1248.4	101.7	1350.0	36.08	0.027

(b) DIN

Standard	Designation	Stranding and wire diameter (mm)				Sectional area (mm2)		Total area (mm2)	Approxi. overall diameter (mm)	R_{DC} at 20°C (Ω / km)
		Alloy		Steel		Alloy	Steel			
DIN 48206	70/12	26	1.85	7	1.44	69.9	11.4	81.3	11.7	0.479
	95/15	26	2.15	7	1.67	94.4	15.3	109.7	13.6	0.355
	125/30	30	2.33	7	2.33	127.9	29.8	157.8	16.3	0.262
	150/25	26	2.7	7	2.1	148.9	24.2	173.1	17.1	0.225
	170/40	30	2.7	7	2.7	171.8	40.1	211.8	18.9	0.195
	185/30	26	3	7	2.33	183.8	29.8	213.6	19	0.182
	210/50	30	3	7	3	212.1	49.5	261.5	21	0.158
	230/30	24	3.5	7	2.33	230.9	29.8	260.8	21	0.145
	265/35	24	3.74	7	2.49	263.7	34.1	297.7	22.4	0.127
	305/40	54	2.68	7	2.68	304.6	39.5	344.1	24.1	0.110
	380/50	54	3	7	3	381.7	49.5	431.2	27	0.088
	450/40	48	3.45	7	2.68	448.7	39.5	488.2	28.7	0.075
	560/50	48	3.86	7	3	561.7	49.5	611.2	32.2	0.060
	680/85	54	4	19	2.4	678.6	86.0	764.5	36	0.049

(c) NF

Standard	Designation	Stranding and wire diameter (mm)				Sectional area (mm2)		Total area (mm2)	Approxi. overall diameter (mm)	R_{DC} at 20°C (Ω / km)
		Alloy		Steel		Alloy	Steel			
NF C34-125	PHLOX 116.2	18	2	19	2	56.5	59.7	116.2	14	0.591
	PHLOX 147.1	18	2.25	19	2.25	71.6	75.5	147.1	15.75	0.467
	PASTEL 147.1	30	2.25	7	2.25	119.3	27.8	147.1	15.75	0.279
	PHLOX 181.6	18	2.5	19	2.5	88.4	93.3	181.6	17.5	0.378
	PASTEL 181.6	30	2.5	7	2.5	147.3	34.4	181.6	17.5	0.226
	PHLOX 228	18	2.8	19	2.8	110.8	117.0	227.8	19.6	0.300
	PASTEL 228	30	2.8	7	2.8	184.7	43.1	227.8	19.6	0.180
	PHLOX 288	18	3.15	19	3.15	140.3	148.1	288.3	22.05	0.238
	PASTEL 288	30	3.15	7	3.15	233.8	54.6	288.3	22.05	0.142
	PASTEL 299	42	2.5	19	2.5	206.2	93.3	299.4	22.45	0.162
	PHLOX 376	24	2.8	37	2.8	147.8	227.8	375.6	26.4	0.226

Table A4.15:
Overhead line conductor data - aluminium alloy conductors, steel re-inforced (AACSR)

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24. Overhead line and cable data

Sectional area of Aluminium mm^2	R_{DC} at 20°C Ω / km	R_{DC} at 50 Hz @ 20°C Ω / km	X_{AC} at 50 Hz				X_{AC} at 50 Hz and shunt capacitance														
			3.3 kV Ω / km	6.6 kV Ω / km	11 kV Ω / km	22 kV Ω / km	33 kV		66 kV						132 kV					
									Rat circuit		Double vertical		Triangle		Double vertical		Double triangle		Rat circuit	
							X Ω / km	C nF / km	X Ω / km	C nF / km	X Ω / km	C nF / km	X Ω / km	C nF / km	X Ω / km	C nF / km	X Ω / km	C nF / km	X Ω / km	C nF / km
13.3	2.1586	2.159	0.395	0.409	0.420	0.434	0.445	8.7	0.503	7.6	0.513	7.4	0.520	7.3	0.541	7.0	0.528	7.2	0.556	6.8
15.3	1.8771	1.877	0.391	0.405	0.415	0.429	0.441	8.8	0.499	7.7	0.508	7.5	0.515	7.4	0.537	7.1	0.523	7.3	0.552	6.9
21.2	1.3557	1.356	0.381	0.395	0.405	0.419	0.430	9.0	0.488	7.8	0.498	7.7	0.505	7.6	0.527	7.2	0.513	7.4	0.542	7.0
23.9	1.2013	1.201	0.376	0.390	0.401	0.415	0.426	9.1	0.484	7.9	0.494	7.8	0.501	7.6	0.522	7.3	0.509	7.5	0.537	7.1
26.2	1.0930	1.093	0.374	0.388	0.398	0.412	0.424	9.2	0.482	8.0	0.491	7.8	0.498	7.7	0.520	7.3	0.506	7.5	0.535	7.1
28.3	1.0246	1.025	0.352	0.366	0.377	0.391	0.402	9.4	0.460	8.2	0.470	8.0	0.477	7.8	0.498	7.5	0.485	7.7	0.513	7.3
33.6	0.8535	0.854	0.366	0.380	0.390	0.404	0.416	9.4	0.474	8.1	0.484	7.9	0.491	7.8	0.512	7.5	0.499	7.7	0.527	7.2
37.7	0.7647	0.765	0.327	0.341	0.351	0.365	0.376	9.7	0.435	8.4	0.444	8.2	0.451	8.1	0.473	7.7	0.459	7.9	0.488	7.4
42.4	0.6768	0.677	0.359	0.373	0.383	0.397	0.409	9.6	0.467	8.3	0.476	8.1	0.483	7.9	0.505	7.6	0.491	7.8	0.520	7.3
44.0	0.6516	0.652	0.320	0.334	0.344	0.358	0.369	9.9	0.427	8.5	0.437	8.3	0.444	8.2	0.465	7.8	0.452	8.0	0.481	7.5
47.7	0.6042	0.604	0.319	0.333	0.344	0.358	0.369	9.9	0.427	8.5	0.437	8.3	0.444	8.2	0.465	7.8	0.452	8.1	0.480	7.6
51.2	0.5634	0.564	0.317	0.331	0.341	0.355	0.367	10.0	0.425	8.6	0.434	8.4	0.441	8.2	0.463	7.9	0.449	8.1	0.478	7.6
58.9	0.4894	0.490	0.313	0.327	0.337	0.351	0.362	10.1	0.421	8.7	0.430	8.5	0.437	8.3	0.459	7.9	0.445	8.2	0.474	7.7
63.1	0.4545	0.455	0.346	0.360	0.371	0.385	0.396	9.9	0.454	8.5	0.464	8.3	0.471	8.2	0.492	7.8	0.479	8.0	0.507	7.5
67.4	0.4255	0.426	0.344	0.358	0.369	0.383	0.394	10.0	0.452	8.5	0.462	8.3	0.469	8.2	0.490	7.8	0.477	8.1	0.505	7.6
73.4	0.3930	0.393	0.306	0.320	0.330	0.344	0.356	10.3	0.414	8.8	0.423	8.6	0.430	8.5	0.452	8.1	0.438	8.3	0.467	7.8
79.2	0.3622	0.362	0.339	0.353	0.363	0.377	0.389	10.1	0.447	8.7	0.457	8.4	0.464	8.3	0.485	7.9	0.472	8.2	0.500	7.6
85.0	0.3374	0.338	0.337	0.351	0.361	0.375	0.387	10.2	0.445	8.7	0.454	8.5	0.461	8.4	0.483	7.9	0.469	8.2	0.498	7.7
94.4	0.3054	0.306	0.302	0.316	0.327	0.341	0.352	10.3	0.410	8.8	0.420	8.6	0.427	8.4	0.448	8.0	0.435	8.3	0.463	7.8
105.0	0.2733	0.274	0.330	0.344	0.355	0.369	0.380	10.4	0.438	8.8	0.448	8.6	0.455	8.5	0.476	8.1	0.463	8.3	0.491	7.8
121.6	0.2371	0.237	0.294	0.308	0.318	0.332	0.344	10.6	0.402	9.0	0.412	8.8	0.419	8.6	0.440	8.2	0.427	8.4	0.455	7.9
127.9	0.2254	0.226	0.290	0.304	0.314	0.328	0.340	10.7	0.398	9.0	0.407	8.8	0.414	8.7	0.436	8.2	0.422	8.5	0.451	8.0
131.2	0.2197	0.220	0.289	0.303	0.313	0.327	0.339	10.7	0.397	9.1	0.407	8.8	0.414	8.7	0.435	8.3	0.421	8.5	0.450	8.0
135.2	0.2133	0.214	0.297	0.311	0.322	0.336	0.347	10.5	0.405	9.0	0.415	8.8	0.422	8.6	0.443	8.2	0.430	8.4	0.458	7.9
148.9	0.1937	0.194	0.288	0.302	0.312	0.326	0.338	10.8	0.396	9.1	0.406	8.9	0.413	8.7	0.434	8.3	0.420	8.6	0.449	8.0
158.7	0.1814	0.182	0.292	0.306	0.316	0.330	0.342	10.7	0.400	9.1	0.410	8.9	0.417	8.7	0.438	8.3	0.425	8.5	0.453	8.0
170.5	0.1691	0.170	0.290	0.304	0.314	0.328	0.340	10.8	0.398	9.1	0.407	8.9	0.414	8.8	0.436	8.3	0.422	8.6	0.451	8.0
184.2	0.1565	0.157	0.287	0.302	0.312	0.326	0.337	10.9	0.395	9.2	0.405	9.0	0.412	8.8	0.433	8.4	0.420	8.6	0.449	8.1
201.4	0.1438	0.144	0.280	0.294	0.304	0.318	0.330	11.0	0.388	9.3	0.398	9.1	0.405	8.9	0.426	8.5	0.412	8.8	0.441	8.2
210.6	0.1366	0.137	0.283	0.297	0.308	0.322	0.333	11.0	0.391	9.3	0.401	9.1	0.408	8.9	0.429	8.4	0.416	8.7	0.444	8.1
221.7	0.1307	0.131	0.274	0.288	0.298	0.312	0.323	11.3	0.381	9.5	0.391	9.3	0.398	9.1	0.419	8.6	0.406	8.9	0.435	8.3
230.9	0.1249	0.126	0.276	0.290	0.300	0.314	0.326	11.2	0.384	9.4	0.393	9.2	0.400	9.0	0.422	8.6	0.408	8.9	0.437	8.3
241.7	0.1193	0.120	0.279	0.293	0.303	0.317	0.329	11.2	0.387	9.4	0.396	9.2	0.403	9.0	0.425	8.5	0.411	8.8	0.440	8.2
263.7	0.1093	0.110	0.272	0.286	0.296	0.310	0.321	11.3	0.380	9.5	0.389	9.3	0.396	9.1	0.418	8.6	0.404	8.9	0.433	8.3
282.0	0.1022	0.103	0.274	0.288	0.298	0.312	0.324	11.3	0.382	9.5	0.392	9.3	0.399	9.1	0.420	8.6	0.406	8.9	0.435	8.3
306.6	0.0945	0.095	0.267	0.281	0.291	0.305	0.317	11.5	0.375	9.7	0.384	9.4	0.391	9.2	0.413	8.7	0.399	9.1	0.428	8.4
322.3	0.0895	0.090	0.270	0.284	0.294	0.308	0.320	11.5	0.378	9.6	0.387	9.4	0.394	9.2	0.416	8.7	0.402	9.0	0.431	8.4
339.3	0.085	0.086	0.265	0.279	0.289	0.303	0.315	11.6	0.373	9.7	0.383	9.5	0.390	9.3	0.411	8.8	0.398	9.1	0.426	8.5
362.6	0.0799	0.081	0.262	0.276	0.286	0.300	0.311	11.7	0.369	9.8	0.379	9.6	0.386	9.4	0.408	8.9	0.394	9.2	0.423	8.5
386.0	0.0747	0.076	0.261	0.275	0.285	0.299	0.311	11.8	0.369	9.8	0.379	9.6	0.386	9.4	0.407	8.9	0.393	9.2	0.422	8.6
402.8	0.0719	0.073	0.261	0.275	0.285	0.299	0.310	11.8	0.368	9.9	0.378	9.6	0.385	9.4	0.407	8.9	0.393	9.2	0.422	8.6
428.9	0.0671	0.068	0.267	0.281	0.291	0.305	0.316	11.5	0.374	9.7	0.384	9.4	0.391	9.2	0.413	8.7	0.399	9.0	0.428	8.4
448.7	0.0642	0.066	0.257	0.271	0.281	0.295	0.306	11.9	0.364	10.0	0.374	9.7	0.381	9.5	0.402	9.0	0.389	9.3	0.418	8.7
456.1	0.0635	0.065	0.257	0.271	0.281	0.295	0.307	12.0	0.365	10.0	0.374	9.7	0.381	9.5	0.403	9.0	0.389	9.3	0.418	8.7
483.4	0.0599	0.061	0.255	0.269	0.279	0.293	0.305	12.0	0.363	10.0	0.372	9.8	0.379	9.6	0.401	9.0	0.387	9.4	0.416	8.7
494.4	0.0583	0.060	0.254	0.268	0.279	0.293	0.304	12.1	0.362	10.0	0.372	9.8	0.379	9.6	0.400	9.0	0.387	9.4	0.415	8.7
510.5	0.0565	0.058	0.252	0.266	0.277	0.291	0.302	12.1	0.360	10.1	0.370	9.8	0.377	9.6	0.398	9.1	0.385	9.4	0.413	8.7
523.7	0.0553	0.057	0.252	0.266	0.277	0.291	0.302	12.1	0.360	10.1	0.370	9.8	0.377	9.6	0.398	9.1	0.385	9.4	0.413	8.7

Table A4.16:
Feeder circuits data - overhead lines at 50Hz

24. Overhead line and cable data

Sectional area of Aluminium mm^2	R_{DC} at 20°C Ω / km	R_{DC} at 50 Hz @ 20°C Ω / km	X_{AC} at 60 Hz				X_{AC} at 60 Hz and shunt capacitance															
			3.3 kV Ω / km	6.6 kV Ω / km	11 kV Ω / km	22 kV Ω / km	33 kV		66 kV						132 kV					
									Rat circuit		Double vertical		Triangle		Double vertical		Double triangle		Rat circuit	
							X Ω / km	C nF / km	X Ω / km	C nF / km	X Ω / km	C nF / km	X Ω / km	C nF / km	X Ω / km	C nF / km	X Ω / km	C nF / km	X Ω / km	C nF / km
13.3	2.1586	2.159	0.474	0.491	0.503	0.520	0.534	8.7	0.604	7.6	0.615	7.4	0.624	7.3	0.649	7.0	0.633	7.2	0.668	6.8
15.3	1.8771	1.877	0.469	0.486	0.498	0.515	0.529	8.8	0.598	7.7	0.610	7.5	0.619	7.4	0.644	7.1	0.628	7.3	0.662	6.9
21.2	1.3557	1.356	0.457	0.474	0.486	0.503	0.516	9.0	0.586	7.8	0.598	7.7	0.606	7.6	0.632	7.2	0.616	7.4	0.650	7.0
23.9	1.2013	1.201	0.452	0.469	0.481	0.498	0.511	9.1	0.581	7.9	0.593	7.8	0.601	7.6	0.627	7.3	0.611	7.5	0.645	7.1
26.2	1.0930	1.093	0.449	0.466	0.478	0.495	0.508	9.2	0.578	8.0	0.590	7.8	0.598	7.7	0.624	7.3	0.608	7.5	0.642	7.1
28.3	1.0246	1.025	0.423	0.440	0.452	0.469	0.483	9.4	0.552	8.2	0.564	8.0	0.572	7.8	0.598	7.5	0.582	7.7	0.616	7.3
33.6	0.8535	0.854	0.439	0.456	0.468	0.485	0.499	9.4	0.569	8.1	0.580	7.9	0.589	7.8	0.614	7.5	0.598	7.7	0.633	7.2
37.7	0.7647	0.765	0.392	0.409	0.421	0.438	0.452	9.7	0.521	8.4	0.533	8.2	0.541	8.1	0.567	7.7	0.551	7.9	0.585	7.4
42.4	0.6768	0.677	0.431	0.447	0.460	0.477	0.490	9.6	0.560	8.3	0.572	8.1	0.580	7.9	0.606	7.6	0.589	7.8	0.624	7.3
44.0	0.6516	0.652	0.384	0.400	0.413	0.429	0.443	9.9	0.513	8.5	0.525	8.3	0.533	8.2	0.559	7.8	0.542	8.0	0.577	7.5
47.7	0.6042	0.604	0.383	0.400	0.412	0.429	0.443	9.9	0.513	8.5	0.524	8.3	0.533	8.2	0.558	7.8	0.542	8.1	0.576	7.6
51.2	0.5634	0.564	0.380	0.397	0.409	0.426	0.440	10.0	0.510	8.6	0.521	8.4	0.530	8.2	0.555	7.9	0.539	8.1	0.573	7.6
58.9	0.4894	0.490	0.375	0.392	0.404	0.421	0.435	10.1	0.505	8.7	0.516	8.5	0.525	8.3	0.550	7.9	0.534	8.2	0.568	7.7
63.1	0.4545	0.455	0.416	0.432	0.445	0.462	0.475	9.9	0.545	8.5	0.557	8.3	0.565	8.2	0.591	7.8	0.574	8.0	0.609	7.5
67.4	0.4255	0.426	0.413	0.430	0.442	0.459	0.473	10.0	0.543	8.5	0.554	8.3	0.563	8.2	0.588	7.8	0.572	8.1	0.606	7.6
73.4	0.3930	0.393	0.367	0.384	0.396	0.413	0.427	10.3	0.496	8.8	0.508	8.6	0.516	8.5	0.542	8.1	0.526	8.3	0.560	7.8
79.2	0.3622	0.362	0.407	0.424	0.436	0.453	0.467	10.1	0.536	8.7	0.548	8.4	0.556	8.3	0.582	7.9	0.566	8.2	0.600	7.6
85.0	0.3374	0.338	0.404	0.421	0.433	0.450	0.464	10.2	0.534	8.7	0.545	8.5	0.554	8.4	0.579	7.9	0.563	8.2	0.598	7.7
94.4	0.3054	0.306	0.363	0.380	0.392	0.409	0.423	10.3	0.492	8.8	0.504	8.6	0.512	8.4	0.538	8.0	0.522	8.3	0.556	7.8
105.0	0.2733	0.274	0.396	0.413	0.426	0.442	0.456	10.4	0.526	8.8	0.537	8.6	0.546	8.5	0.572	8.1	0.555	8.3	0.590	7.8
121.6	0.2371	0.238	0.353	0.370	0.382	0.399	0.413	10.6	0.482	9.0	0.494	8.8	0.502	8.6	0.528	8.2	0.512	8.4	0.546	7.9
127.9	0.2254	0.226	0.348	0.365	0.377	0.394	0.408	10.7	0.477	9.0	0.489	8.8	0.497	8.7	0.523	8.2	0.507	8.5	0.541	8.0
131.2	0.2197	0.220	0.347	0.364	0.376	0.393	0.407	10.7	0.476	9.1	0.488	8.8	0.496	8.7	0.522	8.3	0.506	8.5	0.540	8.0
135.2	0.2133	0.214	0.357	0.374	0.386	0.403	0.416	10.5	0.486	9.0	0.498	8.8	0.506	8.6	0.532	8.2	0.516	8.4	0.550	7.9
148.9	0.1937	0.194	0.346	0.362	0.375	0.392	0.405	10.8	0.475	9.1	0.487	8.9	0.495	8.7	0.521	8.3	0.504	8.6	0.539	8.0
158.7	0.1814	0.182	0.351	0.367	0.380	0.397	0.410	10.7	0.480	9.1	0.492	8.9	0.500	8.7	0.526	8.3	0.509	8.5	0.544	8.0
170.5	0.1691	0.170	0.348	0.365	0.377	0.394	0.408	10.8	0.477	9.1	0.489	8.9	0.497	8.8	0.523	8.3	0.507	8.6	0.541	8.0
184.2	0.1565	0.157	0.345	0.362	0.374	0.391	0.405	10.9	0.474	9.2	0.486	9.0	0.494	8.8	0.520	8.4	0.504	8.6	0.538	8.1
201.4	0.1438	0.145	0.336	0.353	0.365	0.382	0.396	11.0	0.466	9.3	0.477	9.1	0.486	8.9	0.511	8.5	0.495	8.8	0.529	8.2
210.6	0.1366	0.137	0.340	0.357	0.369	0.386	0.400	11.0	0.469	9.3	0.481	9.1	0.489	8.9	0.515	8.4	0.499	8.7	0.533	8.1
221.7	0.1307	0.132	0.328	0.345	0.357	0.374	0.388	11.3	0.458	9.5	0.469	9.3	0.478	9.1	0.503	8.6	0.487	8.9	0.522	8.3
230.9	0.1249	0.126	0.331	0.348	0.360	0.377	0.391	11.2	0.460	9.4	0.472	9.2	0.480	9.0	0.506	8.6	0.532	8.9	0.524	8.3
241.7	0.1193	0.120	0.335	0.351	0.364	0.381	0.394	11.2	0.464	9.4	0.476	9.2	0.484	9.0	0.510	8.5	0.493	8.8	0.528	8.2
263.7	0.1093	0.110	0.326	0.343	0.355	0.372	0.386	11.3	0.455	9.5	0.467	9.3	0.476	9.1	0.501	8.6	0.485	8.9	0.519	8.3
282.0	0.1022	0.103	0.329	0.346	0.358	0.375	0.389	11.3	0.458	9.5	0.470	9.3	0.478	9.1	0.504	8.6	0.488	8.9	0.522	8.3
306.6	0.0945	0.096	0.320	0.337	0.349	0.366	0.380	11.5	0.450	9.7	0.461	9.4	0.470	9.2	0.495	8.7	0.479	9.1	0.514	8.4
322.3	0.0895	0.091	0.324	0.341	0.353	0.370	0.384	11.5	0.453	9.6	0.465	9.4	0.473	9.2	0.499	8.7	0.483	9.0	0.517	8.4
339.3	0.0850	0.086	0.318	0.335	0.347	0.364	0.378	11.6	0.448	9.7	0.459	9.5	0.468	9.3	0.493	8.8	0.477	9.1	0.511	8.5
362.6	0.0799	0.081	0.314	0.331	0.343	0.360	0.374	11.7	0.443	9.8	0.455	9.6	0.463	9.4	0.489	8.9	0.473	9.2	0.507	8.5
386.0	0.0747	0.076	0.313	0.330	0.342	0.359	0.373	11.8	0.443	9.8	0.454	9.6	0.463	9.4	0.488	8.9	0.472	9.2	0.506	8.6
402.8	0.0719	0.074	0.313	0.330	0.342	0.359	0.372	11.8	0.442	9.9	0.454	9.6	0.462	9.4	0.488	8.9	0.472	9.2	0.506	8.6
428.9	0.0671	0.069	0.320	0.337	0.349	0.366	0.380	11.5	0.449	9.7	0.461	9.4	0.469	9.2	0.495	8.7	0.479	9.0	0.513	8.4
448.7	0.0642	0.066	0.308	0.325	0.337	0.354	0.367	11.9	0.437	10.0	0.449	9.7	0.457	9.5	0.483	9.0	0.467	9.3	0.501	8.7
456.1	0.0635	0.065	0.305	0.322	0.334	0.351	0.364	12.0	0.434	10.0	0.446	9.7	0.454	9.6	0.480	9.0	0.463	9.4	0.498	8.7
483.4	0.0599	0.062	0.306	0.323	0.335	0.352	0.366	12.0	0.435	10.0	0.447	9.8	0.455	9.6	0.481	9.0	0.465	9.4	0.499	8.7
494.4	0.0583	0.060	0.305	0.322	0.334	0.351	0.365	12.1	0.435	10.0	0.446	9.8	0.455	9.6	0.480	9.0	0.464	9.4	0.498	8.7
510.5	0.0565	0.059	0.303	0.320	0.332	0.349	0.362	12.1	0.432	10.1	0.444	9.8	0.452	9.6	0.478	9.1	0.462	9.4	0.496	8.7
523.7	0.0553	0.057	0.303	0.320	0.332	0.349	0.363	12.1	0.432	10.1	0.444	9.8	0.452	9.6	0.478	9.1	0.462	9.4	0.496	8.7

Table A4.16 (cont):
Feeder circuits data - overhead lines at 60Hz

A4

24. Overhead line and cable data

		Conductor size (mm2)																
		25	35	50	70	95	120	150	185	240	300	400	500*	630*	800*	1000*	1200*	1600*
3.3kV	Series Resistance R (Ω / km)	0.927	0.669	0.494	0.342	0.247	0.196	0.158	0.127	0.098	0.08	0.064	0.051	0.042				
	Series Reactance X (Ω / km)	0.097	0.092	0.089	0.083	0.08	0.078	0.076	0.075	0.073	0.072	0.071	0.088	0.086				
	Susceptance ω C (mS / km)	0.059	0.067	0.079	0.09	0.104	0.111	0.122	0.133	0.146	0.16	0.179	0.19	0.202				
6.6kV	Series Resistance R (Ω / km)	0.927	0.669	0.494	0.342	0.247	0.196	0.158	0.127	0.098	0.08	0.064	0.057	0.042				
	Series Reactance X (Ω / km)	0.121	0.113	0.108	0.102	0.096	0.093	0.091	0.088	0.086	0.085	0.083	0.088	0.086				
	Susceptance ω C (mS / km)	0.085	0.095	0.104	0.12	0.136	0.149	0.16	0.177	0.189	0.195	0.204	0.205	0.228				
11kV	Series Resistance R (Ω / km)	0.927	0.669	0.494	0.342	0.247	0.196	0.158	0.127	0.098	0.08	0.064	0.051	0.042				
	Series Reactance X (Ω / km)	0.128	0.119	0.114	0.107	0.101	0.098	0.095	0.092	0.089	0.087	0.084	0.089	0.086				
	Susceptance ω C (mS / km)	0.068	0.074	0.082	0.094	0.105	0.115	0.123	0.135	0.15	0.165	0.182	0.194	0.216				
22kV	Series Resistance R (Ω / km)		0.669	0.494	0.348	0.247	0.196	0.158	0.127	0.098	0.08	0.064	0.051	0.042				
	Series Reactance X (Ω / km)		0.136	0.129	0.121	0.114	0.11	0.107	0.103	0.1	0.094	0.091	0.096	0.093				
	Susceptance ω C (mS / km)		0.053	0.057	0.065	0.072	0.078	0.084	0.091	0.1	0.109	0.12	0.128	0.141				
33kV	Series Resistance R (Ω / km)		0.669	0.494	0.348	0.247	0.196	0.158	0.127	0.098	0.08	0.064	0.051	0.042				
	Series Reactance X (Ω / km)		0.15	0.143	0.134	0.127	0.122	0.118	0.114	0.109	0.105	0.102	0.103	0.1				
	Susceptance ω C (mS / km)		0.042	0.045	0.05	0.055	0.059	0.063	0.068	0.075	0.081	0.089	0.094	0.103				
66kV*	Series Resistance R (Ω / km)												0.0387	0.031	0.0254	0.0215		
	Series Reactance X (Ω / km)												0.117	0.113	0.109	0.102		
	Susceptance ω C (mS/km)												0.079	0.082	0.088	0.11		
145kV*	Series Resistance R (Ω / km)												0.0387	0.031	0.0254	0.0215		
	Series Reactance X (Ω / km)												0.13	0.125	0.12	0.115		
	Susceptance ω C (mS / km)												0.053	0.06	0.063	0.072		
245kV*	Series Resistance R (Ω / km)											0.0487	0.0387	0.0310	0.0254	0.0215	0.0161	0.0126
	Series Reactance X (Ω / km)											0.145	0.137	0.134	0.128	0.123	0.119	0.113
	Susceptance ω C (mS/km)											0.044	0.047	0.05	0.057	0.057	0.063	0.072
420kV*	Series Resistance R (Ω / km)													0.0310	0.0254	0.0215	0.0161	0.0126
	Series Reactance X (Ω / km)													0.172	0.162	0.156	0.151	0.144
	Susceptance ω C (mS / km)													0.04	0.047	0.05	0.057	0.063

For aluminium conductors of the same cross-section, the resistance increases by 60-65 percent, the series reactance and shunt capacitance are virtually unaltered.
** - single core cables in trefoil.*
Different values apply if laid in spaced flat formation.
Series resistance - a.c. resistance @ 90°C. Series reactance - equivalent star reactance.
Data for 245kV and 420kV cables may vary significantly from that given, dependent on manufacturer and construction.

Table A4.17:
Characteristics of polyethylene insulated cables (XLPE)

24. Overhead line and cable data

		Conductor size (mm2)																
		10	16	25	35	50	70	95	120	150	185	240	300	400	500*	630*	800*	1000*
3.3kV	Series Resistance R (Ω / km)	2063	1289	825.5	595	439.9	304.9	220.4	174.5	142.3	113.9	87.6	70.8	56.7	45.5	37.1	31.2	27.2
	Series Reactance X (Ω / km)	87.7	83.6	76.7	74.8	72.5	70.2	67.5	66.6	65.7	64.7	63.8	62.9	62.4	73.5	72.1	71.2	69.8
	Susceptance ωC (mS / km)																	
6.6kV	Series Resistance R (Ω / km)	514.2	326	206.4	148.8	110	76.2	55.1	43.6	35.6	28.5	21.9	17.6	14.1	11.3	9.3	7.8	6.7
	Series Reactance X (Ω / km)	26.2	24.3	22	21.2	20.4	19.6	18.7	18.3	17.9	17.6	17.1	16.9	16.5	18.8	18.4	18	17.8
	Susceptance ωC (mS / km)																	
11kV	Series Resistance R (Ω / km)		111	0.87	0.63	0.46	0.32	0.23	0.184	0.15	0.12	0.092	0.074	0.059	0.048	0.039	0.033	0.028
	Series Reactance X (Ω / km)		9.26	0.107	0.1	0.096	0.091	0.087	0.085	0.083	0.081	0.079	0.077	0.076	0.085	0.083	0.081	0.08
	Susceptance ωC (mS / km)																	
22kV	Series Resistance R (Ω / km)			17.69	12.75	9.42	6.53	4.71	3.74	3.04	2.44	1.87	1.51	1.21	0.96	0.79	0.66	0.57
	Series Reactance X (Ω / km)			2.89	2.71	2.6	2.46	2.36	2.25	2.19	2.11	2.04	1.97	1.92	1.9	1.84	1.8	1.76
	Susceptance ωC (mS / km)																	
33kV	Series Resistance R (Ω / km)					4.19	2.9	2.09	0.181	0.147	0.118	0.09	0.073	0.058	0.046	0.038	0.031	0.027
	Series Reactance X (Ω / km)					1.16	1.09	1.03	0.107	0.103	0.101	0.097	0.094	0.09	0.098	0.097	0.092	0.089
	Susceptance ωC (mS / km)								0.104	0.116	0.124	0.194	0.151	0.281	0.179	0.198	0.22	0.245

*Cables are of the solid type, 3 core except for those marked *. Impedances at 50Hz frequency*

Table A4.18:
Characteristics of paper insulated cables

Conductor size (mm2)	3.3kV	
	R Ω / km	X Ω / km
16	1.380	0.106
25	0.870	0.100
35	0.627	0.094
50	0.463	0.091
70	0.321	0.086
95	0.232	0.084
120	0.184	0.081
150	0.150	0.079
185	0.121	0.077
240	0.093	0.076
300	0.075	0.075
400	0.060	0.075
500*	0.049	0.089
630*	0.041	0.086
800*	0.035	0.086
1000*	0.030	0.084

3 core copper conductors, 50Hz values
** - single core cables in trefoil*

Table A4.19:
3.3 kV PVC insulated cables

A4

24. Overhead line and cable data

Voltage level		Cross Sectional area (mm^2)	Conductors per phase	Surge Impedance loading	Voltage Drop loading	Indicative Thermal loading	
U_n kV	U_m kV			MVA	MWkm	MV	A
11	12	30	1	0.3	11	2.9	151
		50	1	0.3	17	3.9	204
		90	1	0.4	23	5.1	268
		120	1	0.5	27	6.2	328
		150	1	0.5	30	7.3	383
24	30	1	1.2	44	5.8	151	
		50	1	1.2	66	7.8	204
		90	1	1.2	92	10.2	268
		120	1	1.4	106	12.5	328
		150	1	1.5	119	14.6	383
33	36	50	1	2.7	149	11.7	204
		90	1	2.7	207	15.3	268
		120	1	3.1	239	18.7	328
		150	1	3.5	267	21.9	383
66	72.5	90	1	11	827	41	268
		150	1	11	1068	59	383
		250	1	11	1240	77	502
		250	2	15	1790	153	1004
132	145	150	1	44	4070	85	370
		250	1	44	4960	115	502
		250	2	58	7160	230	1004
		400	1	56	6274	160	698
		400	2	73	9057	320	1395
220	245	400	1	130	15600	247	648
		400	2	184	22062	494	1296
		400	4	260	31200	988	2592
380	420	400	2	410	58100	850	1296
		400	4	582	82200	1700	2590
		550	2	482	68200	1085	1650
		550	3	540	81200	1630	2475

Table A4.20:
OHL capabilities

25. References

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I.M. Canay.
Proc. IEE, Vol. 135, Pt. B, November 1988.

[A4.2] IEC 60034-4.
Methods for determining synchronous machine quantities from tests.

[A4.3] IEEE Standards 115/115A.
IEEE Test Procedures for Synchronous Machines.

[A4.4] Power System Analysis.
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(Chapman & Hall, London).

B1

Relay Technology

Network Protection & Automation Guide

Life Is On | Schneider Electric

Chapter B1

Relay Technology

1. Introduction

Since the 1960s there have been enormous changes in relay technology. The electromechanical relay in all of its different forms has been replaced successively by static, digital and numerical relays, each change bringing with it reductions in size and improvements in functionality. At the same time, reliability levels have been maintained or even improved and availability significantly increased due to techniques not available with older relay types. This represents a tremendous achievement for all those involved in relay design and manufacture.

This chapter charts the course of relay technology through the years. As the purpose of the book is to describe modern protection relay practice, it is natural to concentrate on digital and numerical relay technology. The vast number of electromechanical and static relays are still giving dependable service, but descriptions on the technology used must necessarily be somewhat brief.

2. Electromechanical relays

These relays were the earliest forms of relay used for the protection of power systems, and they date back nearly 100 years. They work on the principle of a mechanical force causing operation of a relay contact in response to a stimulus. The mechanical force is generated through current flow in one or more windings on a magnetic core or cores, hence the term electromechanical relay. The principle advantage of such relays is that they provide galvanic isolation between the inputs and outputs in a simple, cheap and reliable form – therefore for simple on/off switching functions where the output contacts have to carry substantial currents, they are still used.

Electromechanical relays can be classified into several different types as follows:

a. attracted armature

b. moving coil

c. induction

d. thermal

e. motor operated

f. mechanical

2.1 Attracted armature relays

These generally consist of an iron-cored electromagnet that attracts a hinged armature when energised. A restoring force is provided by means of a spring or gravity so that the armature will return to its original position when the electromagnet is de-energised. Typical forms of an attracted armature relay are shown in Figure B1.1. Movement of the armature causes contact closure or opening, the armature either carrying a moving contact that engages with a fixed one, or causes a rod to move that brings two contacts together. It is very easy to mount multiple contacts in rows or stacks, and hence cause a single input to actuate a number of outputs. The contacts can be made quite robust and hence able to make, carry and break relatively large currents under quite onerous conditions (highly inductive circuits). This is still a significant advantage of this type of relay that ensures its continued use.

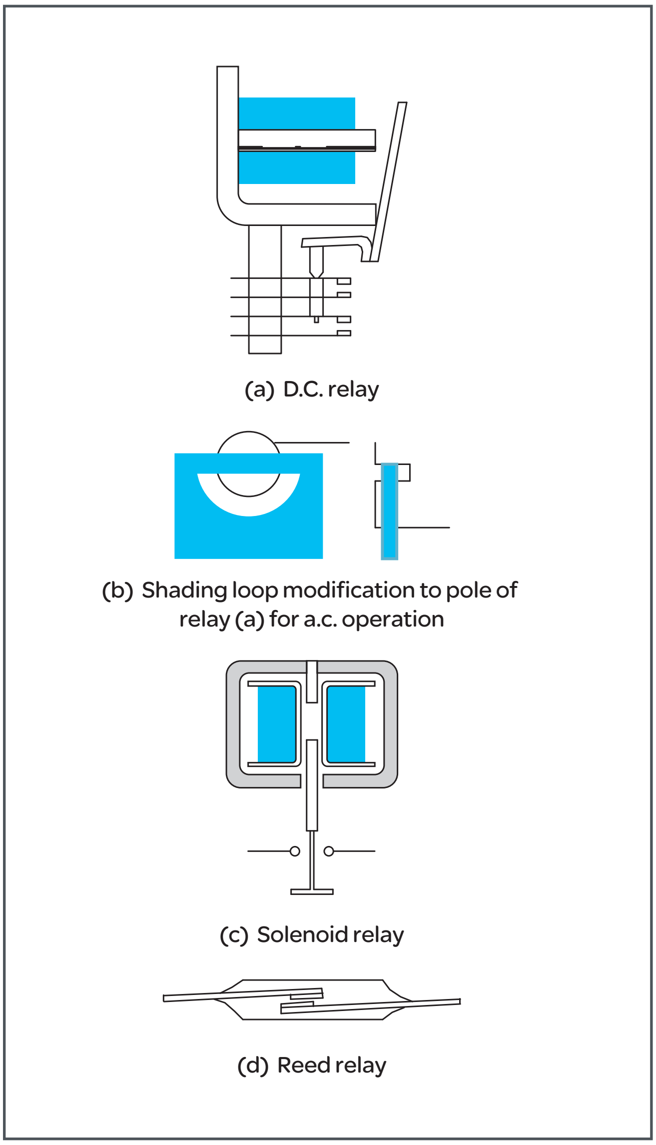

Figure B1.1:
Typical attracted armature relays

2. Electromechanical relays

The energising quantity can be either an a.c. or a d.c. current. If an a.c. current is used, means must be provided to prevent the chatter that would occur from the flux passing through zero every half cycle. A common solution to the problem is to split the magnetic pole and provide a copper loop round one half. The flux change is now phase-shifted in this pole, so that at no time is the total flux equal to zero. Conversely, for relays energised using a d.c. current, remanent flux may prevent the relay from releasing when the actuating current is removed. This can be avoided by preventing the armature from contacting the electromagnet by a non-magnetic stop, or constructing the electromagnet using a material with very low remanent flux properties.

Operating speed, power consumption and the number and type of contacts required are a function of the design. The typical attracted armature relay has an operating speed of between 100ms and 400ms, but reed relays (whose use spanned a relatively short period in the history of protection relays) with light current contacts can be designed to have an operating time of as little as 1msec. Operating power is typically 0.05-0.2 watts, but could be as large as 80 watts for a relay with several heavy-duty contacts and a high degree of resistance to mechanical shock.

Some applications require the use of a polarised relay. This can be simply achieved by adding a permanent magnet to the basic electromagnet. Both self-reset and bi-stable forms can be achieved. Figure.B1.2 shows the basic construction. One possible example of use is to provide very fast operating times for a single contact, speeds of less than 1ms being possible.

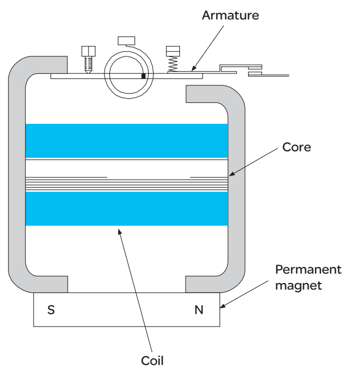

Figure B1.2:
Typical polarised relay

3. Static relays

The term ‘static’ implies that the relay has no moving parts. This is not strictly the case for a static relay, as the output contacts are still generally attracted armature relays. In a protection relay, the term ‘static’ refers to the absence of moving parts to create the relay characteristic.

Introduction of static relays began in the early 1960’s. Their design is based on the use of analogue electronic devices instead of coils and magnets to create the relay characteristic. Early versions used discrete devices such as transistors and diodes in conjunction with resistors, capacitors, inductors, etc., but advances in electronics enabled the use of linear and digital integrated circuits in later versions for signal processing and implementation of logic functions. While basic circuits may be common to a number of relays, the packaging was still essentially restricted to a single protection function per case, while complex functions required several cases of hardware suitably interconnected. User programming was restricted to the basic functions of adjustment of relay characteristic curves. They therefore can be viewed in simple terms as an analogue electronic replacement for electromechanical relays, with some additional flexibility in settings and some saving in space requirements. In some cases, relay burden is reduced, making for reduced CT/VT output requirements.

A number of design problems had to be solved with static relays. In particular, the relays generally require a reliable source of d.c. power and measures to prevent damage to vulnerable electronic circuits had to be devised. Substation environments are particularly hostile to electronic circuits due to electrical interference of various forms that are commonly found (e.g. switching operations and the effect of faults). While it is possible to arrange for the d.c. supply to be generated from the measured quantities of the relay, this has the disadvantage of increasing the burden on the CT’s or VT’s, and there will be a minimum primary current or voltage below which the relay will not operate. This directly affects the possible sensitivity of the relay. So provision of an independent, highly reliable and secure source of relay power supply was an important consideration. To prevent maloperation or destruction of electronic devices during faults or switching operations, sensitive circuitry is housed in a shielded case to exclude common mode and radiated interference. The devices may also be sensitive to static charge, requiring special precautions during handling, as damage from this cause may not be immediately apparent, but become apparent later in the form of premature failure of the relay. Therefore, radically different relay manufacturing facilities are required compared to electromechanical relays. Calibration and repair

3. Static relays

is no longer a task performed in the field without specialised equipment. Figure B1.3 shows the circuit board for a simple static relay. An example of static relay is shown in Figure B1.4.

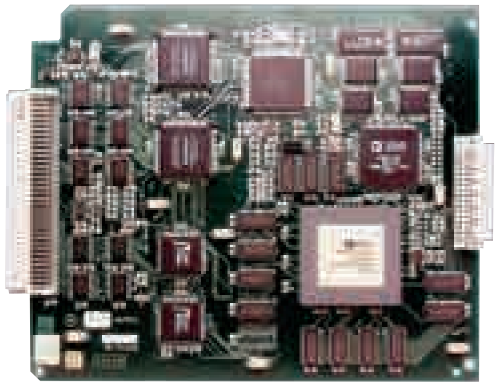

Figure B1.3:
Circuit board of static relay

Figure B1.4:
Example of static relay

4. Digital relays

Digital protection relays introduced a step change in technology. Microprocessors and microcontrollers replaced analogue circuits used in static relays to implement relay functions. Early examples began to be introduced into service around 1980. However, such technology has been completely superseded by numerical relays.

Compared to static relays, digital relays introduce Analogue to Digital (A/D) conversion of all measured analogue quantities and use a microprocessor to implement the protection algorithm. The microprocessor may use some kind of counting technique, or use the Discrete Fourier Transform (DFT) to implement the algorithm. However, the typical microprocessors used have limited processing capacity and memory compared to that provided in numerical relays. The functionality tends therefore to be limited and restricted largely to the protection function itself. Additional functionality compared to that provided by an electromechanical or static relay is usually available, typically taking the form of a wider range of settings, and greater accuracy. A communications link to a remote computer may also be provided.

The limited power of the microprocessors used in digital relays restricts the number of samples of the waveform that can be measured per cycle. This, in turn, limits the speed of operation of the relay in certain applications. Therefore, a digital relay for a particular protection function may have a longer operation time than the static relay equivalent. However, the extra time is not significant in terms of overall tripping and possible effects of power system stability. An example of a digital relay is shown in Figure B1.5.

Figure B1.5:
Example of digital relays

5. Numerical relays

The distinction between digital and numerical relay rests on points of fine technical detail, and is rarely found in areas other than Protection. They can be viewed as natural developments of digital relays as a result of advances in technology. Typically, they use either a specialised digital signal processor (DSP) as the computational hardware or a high performance microcontroller, together with the associated software tools. The input analogue signals are converted into a digital representation and processed according to the appropriate mathematical algorithm.

In addition, the continuing reduction in the cost of microprocessors and related digital devices (memory, I/O, etc.) naturally leads to an approach where a single item of hardware is used to provide a range of functions ('one-box solution' approach). By using multiple microprocessors to provide the necessary computational performance, a large number of functions previously implemented in separate items of hardware can now be included within a single item. Table B1.1 provides a list of typical functions available, while Table B1.2 summarises the advantages of a modern numerical relay over the static equivalent.

Distance Protection (several schemes including user definable)
Overcurrent Protection (directional/non-directional)
Several Setting Groups for protection values
Switch-on-to-Fault Protection
Power Swing Blocking
Voltage Transformer Supervision
Negative Sequence Current Protection
Undervoltage Protection
Overvoltage Protection
CB Fail Protection
Fault Location
CT Supervision
VT Supervision
Check Synchronisation
Autoreclose
CB Condition Monitoring
CB State Monitoring
User-Definable Logic
Broken Conductor Detection
Measurement of Power System Quantities (Current, Voltage, etc.)
Fault/Event/Disturbance recorder

Table B1.1:
Numerical distance relay features

Several setting groups
Wider range of parameter adjustment
Remote communications built in
Internal Fault diagnosis
Power system measurements available
Distance to fault locator
Disturbance recorder
Auxiliary protection functions (broken conductor, negative sequence, etc.)
CB monitoring (state, condition)
User-definable logic
Backup protection functions in-built
Consistency of operation times - reduced grading margin

Table B1.2:
Advantages of numerical protection relays over static

Figure B1.6 shows typical numerical relays, and a circuit board is shown in Figure B1.7. Figure B1.8 provides an illustration of the savings in space possible on a HV feeder showing the space requirement for relays with electromechanical and numerical relay technology to provide the same functionality.

Figure B1.6:
Typical numerical relays

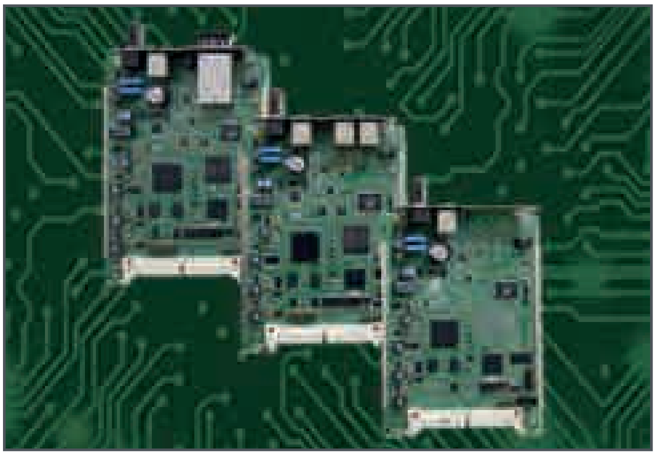

Figure B1.7:
Circuit board for numerical relay

Figure B1.8 :
Space requirements of different relay technologies for same functionality

5. Numerical relays

Because a numerical relay may implement the functionality that used to require several discrete relays, the relay functions (overcurrent, earth fault, etc.) are now referred to as being 'relay elements', so that a single relay (i.e. an item of hardware housed in a single case) may implement several functions using several relay elements. Each relay element will typically be a software routine or routines.

The argument against putting many features into one piece of hardware centres on the issues of reliability and availability. A failure of a numerical relay may cause many more functions to be lost, compared to applications where different functions are implemented by separate hardware items. Comparison of reliability and availability between the two methods is complex, as inter-dependency of elements of an application provided by separate relay elements needs to be taken into account.

With the experience gained with static and digital relays, most hardware failure mechanisms are now well understood and suitable precautions taken at the design stage. Software problems are minimised by rigorous use of software design techniques, extensive prototype testing (see Chapter [E1: Type Testing, Offer Safety and Reliability]) and the ability to download amended software into memory (possibly using a remote link for download). Practical experience indicates that numerical relays are at least as reliable and have at least as good a record of availability as relays of earlier technologies. In addition relays are now available that are certified for Safety Integrity Level 2.

An overview of the concepts behind a numerical relay is presented in the following sections.

5.1 Hardware architecture

The typical architecture of a numerical relay is shown in Figure B1.9. It consists of one or more DSP microprocessors, some memory, digital and analogue input/output (I/O), and a power supply. Where multiple processors are provided, it is usual for one of them to be dedicated to executing the protection relay algorithms, while the remainder implements any associated logic and handles the Human Machine Interface (HMI) interfaces. By organising the I/O on a set of plug-in printed circuit boards (PCBs), additional I/O up to the limits of the hardware/software can be easily added. The internal communications bus links the hardware and therefore is critical component in the design.

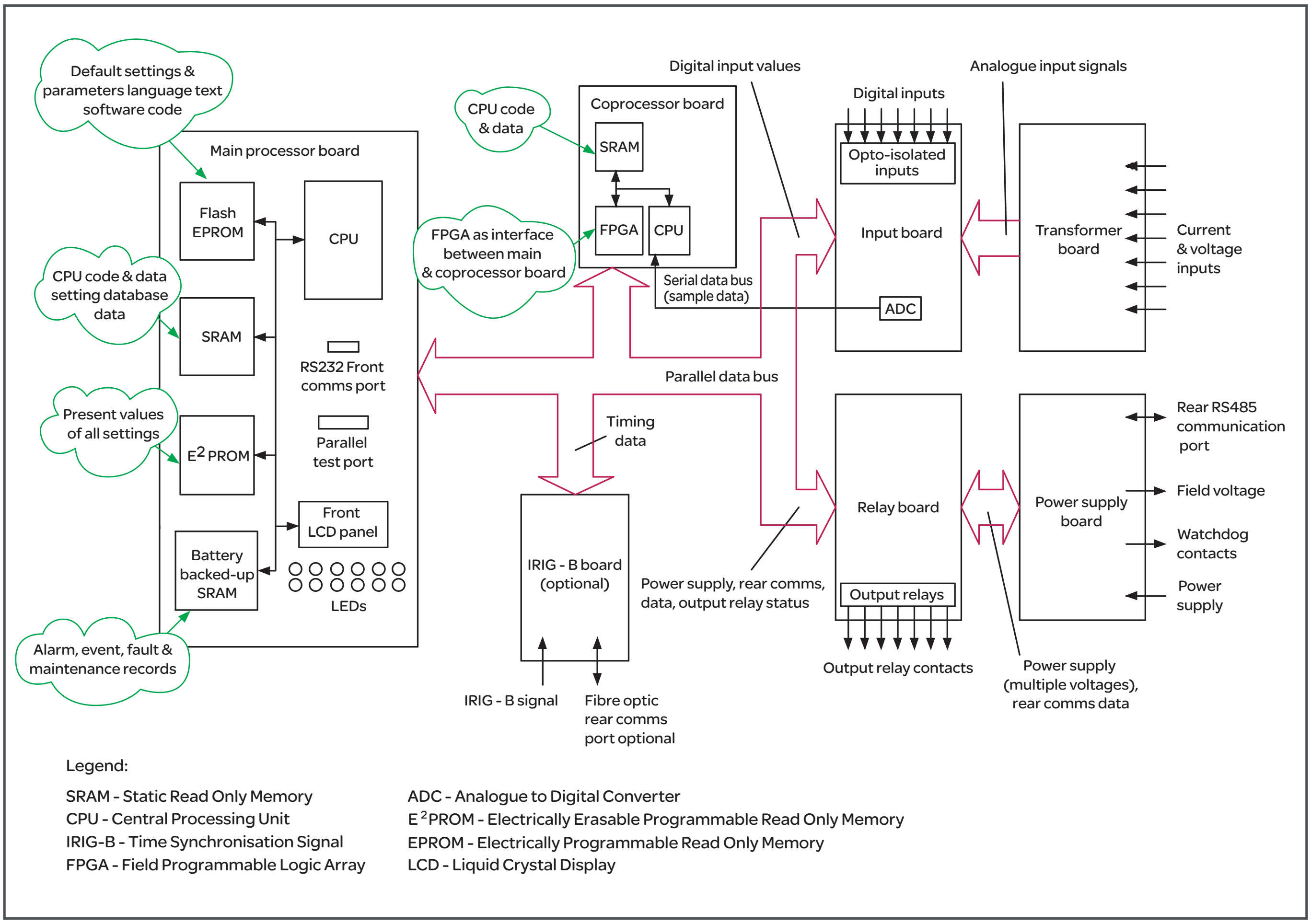

Figure B1.9:
Relay modules and information flow

It must work at high speed, use low voltage levels and yet be immune to conducted and radiated interference from the electrically noisy substation environment. Excellent shielding of the relevant areas is therefore required. Digital inputs are optically isolated to prevent transients being transmitted to the internal circuitry. Analogue inputs are isolated using precision transformers to maintain measurement accuracy while removing harmful transients. Additionally, the input signals must be amplitude limited to avoid them exceeding the power supply voltages, as otherwise the waveform will appear distorted, as shown in Figure B1.10.

Analogue signals are converted to digital form using an A/D converter. The cheapest method is to use a single A/D converter, preceded by a multiplexer to connect each of the input signals

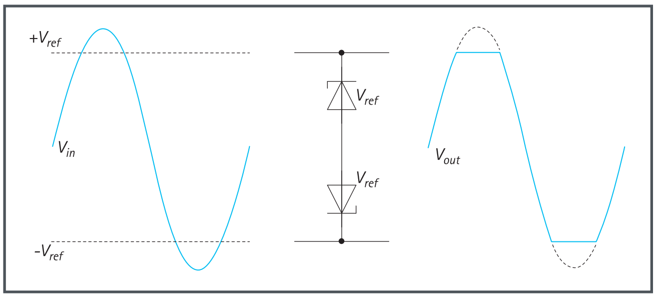

Figure B1.10:
Signal distortion due to excessive amplitude

in turn to the converter. The signals may be initially input to a number of simultaneous sample-and–hold circuits prior to multiplexing, or the time relationship between successive samples must be known if the phase relationship between signals is important. The alternative is to provide each input with a dedicated A/D converter, and logic to ensure that all converters perform the measurement simultaneously.

The frequency of sampling must be carefully considered, as the Nyquist criterion applies:

$$f_s \geq 2 \times f_h$$

where:

f_s = sampling frequency

f_h = highest frequency of interest

If too low a sampling frequency is chosen, aliasing of the input signal can occur (Figure B1.11), resulting in high frequencies appearing as part of signal in the frequency range of interest. Incorrect results will then be obtained. The solution is to apply an anti-aliasing filter, coupled with an appropriate choice of sampling frequency, to the analogue signal, so those frequency components that could cause aliasing are filtered out. Digital sine and cosine filters are used (Figure B1.12), with a frequency response shown in Figure B1.13, to extract the real and imaginary components of the signal.

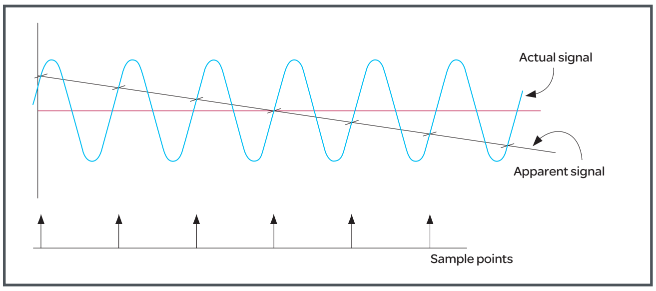

Figure B1.11:
Signal aliasing problem

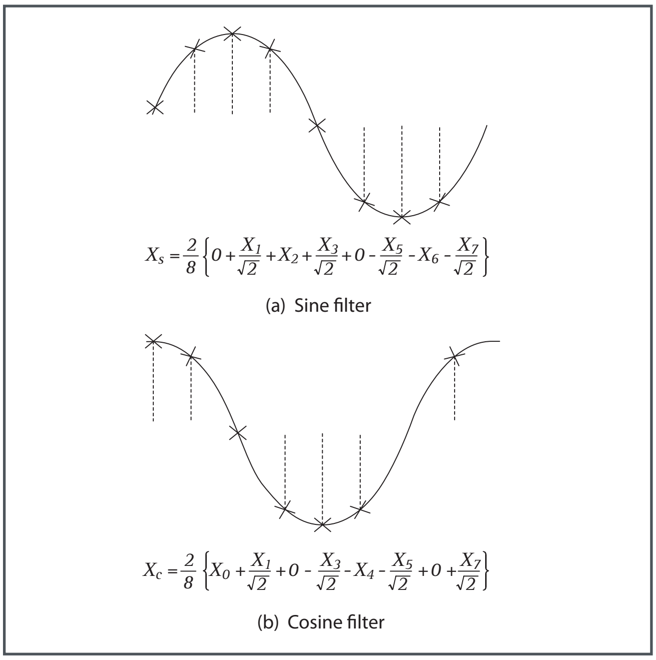

Figure B1.12:
Digital filters

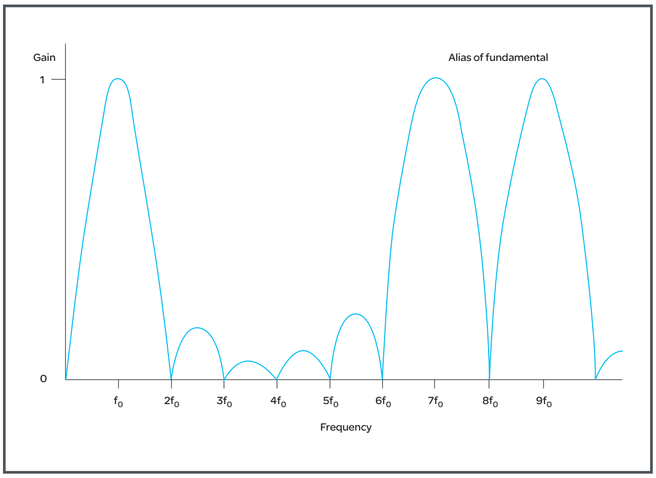

Figure B1.13:
Filter frequency response

B1

5. Numerical relays

Frequency tracking of the input signals is applied to adjust the sampling frequency so that the desired number of samples/cycle is always obtained. A modern numerical relay may sample each analogue input quantity at between 16 and 48 samples per cycle.

All subsequent signal processing is carried out digitally in software, final digital outputs use relays to provide isolation or are sent via an external communications bus to other devices.

5.2 Relay software

The software provided is commonly organised into a series of tasks, operating in real time. An essential component is the Real Time Operating System (RTOS), whose function is to ensure that the other tasks are executed as and when required, on a priority basis.

Other task software provided will naturally vary according to the function of the specific relay, but can be generalised as follows:

a. system services software – this is akin to the BIOS of an ordinary PC, and controls the low-level I/O for the relay (i.e. drivers for the relay hardware, boot-up sequence, etc.)

b. HMI interface software – the high level software for communicating with a user, via the front panel controls or through a data link to another computer running suitable software, storage of setting data, etc.

c. application software – this is the software that defines the protection function of the relay

d. auxiliary functions – software to implement other features offered in the relay – often structured as a series of modules to reflect the options offered to a user by the manufacturer

5.3 Application software

The relevant software algorithm is then applied. Firstly, the values of the quantities of interest have to be determined from the available information contained in the data samples. This is conveniently done by the application of the Discrete Fourier Transform (DFT), and the result is magnitude and phase information for the selected quantity. This calculation is repeated for all of the quantities of interest. The quantities can then be compared with the relay characteristic, and a decision made in terms of the following:

a. value above setting – start timers, etc.

b. timer expired – action alarm/trip

c. value returned below setting – reset timers, etc.

d. value below setting – do nothing

e. value still above setting – increment timer, etc.

Since the overall cycle time for the software is known, timers are generally implemented as counters.

6. Additional features of numerical relays

The processor in a numerical relay is normally of sufficient processing capacity that calculation of the relay protection function only occupies part of the processing capacity. The excess capacity is therefore available to perform other functions. Of course, care must be taken never to load the processor beyond capacity, for if this happens, the protection algorithm will not complete its calculation in the required time and the protection function will be compromised.

Typical functions that may be found in a numerical relay besides protection functions are described in this section. Note that not all functions may be found in a particular relay. In common with earlier generations of relays, manufacturers, in accordance with their perceived market segmentation, will offer different versions offering a different set of functions. Function parameters will generally be available for display on the front panel of the relay and also via an external communications port, but some by their nature may only be available at one output interface.

6.1 Measured values display

This is perhaps the most obvious and simple function to implement, as it involves the least additional processor time. The values that the relay must measure to perform its protection function have already been acquired and processed. It is therefore a simple task to display them on the front panel, and/or transmit as required to a remote computer/HMI station. Less obvious is that a number of extra quantities may be able to be derived from the measured quantities, depending on the input signals available. These might include:

a. sequence quantities (positive, negative, zero)

b. power, reactive power and power factor

c. energy (kWh, kvarh)

d. max. demand in a period (kW, kvar; average and peak values)

e. harmonic quantities

f. frequency

g. temperatures/RTD status

h. motor start information (start time, total no. of starts/reaccelerations, total running time)

i. distance to fault

The accuracy of the measured values can only be as good as the accuracy of the transducers used (VTs CTs, A/D converter, etc.). As CTs and VTs for protection functions may have a different accuracy specification to those for metering functions, such data may not be sufficiently accurate for tariff purposes. However, it will be sufficiently accurate for an operator to assess system conditions and make appropriate decisions.

6.2 VT/CT supervision

If suitable VTs are used, supervision of the VT/CT supplies can be made available. VT supervision is made more complicated by the different conditions under which there may be no VT signal – some of which indicate VT failure and some occur because of a power system fault having occurred.

CT supervision is carried out more easily, the general principle being the calculation of a level of negative sequence current that is inconsistent with the calculated value of negative sequence voltage.

6.3 CB control/state indication/condition monitoring

System operators will normally require knowledge of the state of all circuit breakers under their control. The CB position-switch outputs can be connected to the relay digital inputs and hence provide the indication of state via the communications bus to a remote control centre.

Circuit breakers also require periodic maintenance of their operating mechanisms and contacts to ensure they will operate when required and that the fault capacity is not affected adversely. The requirement for maintenance is a function of the number of trip operations, the cumulative current broken and the type of breaker. A numerical relay can record all of these parameters and hence be configured to send an alarm when maintenance is due. If maintenance is not carried out within defined criteria (such as a pre-defined time or number of trips) after maintenance is required, the CB can be arranged to trip and lockout, or inhibit certain functions such as auto-reclose.

As the numerical relay is monitoring the state of the breaker it can also detect a failure of the breaker to open or close when requested. This information can then be used to alarm and to provide signals to other devices upstream to trip.

Finally, as well as tripping the CB as required under fault conditions, it can also be arranged for a digital output to be used for CB closure, so that separate CB close control circuits can be eliminated.

6.4 Disturbance recorder

The relay memory requires a certain minimum number of cycles of measured data to be stored for correct signal processing and detection of events. The memory can easily be expanded to allow storage of a greater time period of input data, both analogue and digital, plus the state of the relay outputs. It then has the capability to act as a disturbance recorder for the circuit being monitored, so that by freezing the memory at the instant of fault detection or trip, a record of the disturbance is available for later download and analysis. It may be inconvenient to download the record immediately, so facilities may be provided to capture and store a number of disturbances. In industrial and small distribution networks, this may be all that is required. In transmission networks, it may be necessary to provide a single recorder to monitor a number of circuits simultaneously, and in this case, a separate disturbance recorder will still be required.

B1

6. Additional features of numerical relays

6.5 Time synchronisation

Disturbance records and data relating to energy consumption require time tagging to serve any useful purpose. Although an internal clock will normally be present, this is of limited accuracy and use of this clock to provide time information may cause problems if the disturbance record has to be correlated with similar records from other sources to obtain a complete picture of an event. Many numerical relays have the facility for time synchronisation from an external clock. The standard normally used is an IRIG-B signal, which may be derived from a number of sources, the latest being from a GPS satellite system.

6.6 Programmable logic

Logic functions are well suited to implementation using microprocessors. The implementation of logic in a relay is not new, as functions such as intertripping and auto-reclose require a certain amount of logic. However, by providing a substantial number of digital I/O and making the logic capable of being programmed using suitable off-line software, the functionality of such schemes can be enhanced and/or additional features provided. For instance, an overcurrent relay at the receiving end of a transformer feeder could use the temperature inputs provided to monitor transformer winding temperature and provide alarm/trip facilities to the operator/ upstream relay, eliminating the need for a separate winding temperature relay. This is an elementary example, but other advantages are evident to the relay manufacturer – different logic schemes required by different Utilities, etc., no longer need separate relay versions or some hard-wired logic to implement, reducing the cost of manufacture. It is also easier to customise a relay for a specific application and eliminate other devices that would otherwise be required.

6.7 Provision of setting groups

Historically, electromechanical and static relays have been provided with only one group of settings to be applied to the relay. Unfortunately, power systems change their topology due to operational reasons on a regular basis. (e.g. supply from normal/ emergency generation). The different configurations may require different relay settings to maintain the desired level of network protection (since, for the above example, the fault levels will be significantly different on parts of the network that remain energised under both conditions).

This problem can be overcome by the provision within the relay of a number of setting groups, only one of which is in use at any one time. Changeover between groups can be achieved from a remote command from the operator, or possibly through the programmable logic system. This may obviate the need for duplicate relays to be fitted with some form of switching arrangement of the inputs and outputs depending on network configuration. The operator will also have the ability to remotely program the relay with a group of settings if required.

6.8 Conclusions

The provision of extra facilities in numerical relays may avoid the need for other measurement/control devices to be fitted in a substation. A trend can therefore be discerned in which protection relays are provided with functionality that in the past has been provided using separate equipment. The protection relay no longer performs a basic protection function; but is becoming an integral and major part of a substation automation scheme. The choice of a protection relay rather than some other device is logical, as the protection relay is probably the only device that is virtually mandatory on circuits of any significant rating. Thus, the functions previously carried out by separate devices such as bay controllers, discrete metering transducers and similar devices are now found in a protection relay. It is now possible to implement a substation automation scheme using numerical relays as the principal or indeed only hardware provided at bay level. As the power of microprocessors continues to grow and pressure on operators to reduce costs continues, this trend will probably continue, one obvious development being the provision of RTU facilities in designated relays that act as local concentrators of information within the overall network automation scheme.

7. Numerical relay issues

The introduction of numerical relays replaces some of the issues of previous generations of relays with new ones. Some of the new issues that must be addressed are as follows:

a. software version control

b. relay data management

c. testing and commissioning

7.1 Software version control

Numerical relays perform their functions by means of software. The process used for software generation is no different in principle to that for any other device using real-time software, and includes the difficulties of developing code that is error-free. Manufacturers must therefore pay particular attention to the methodology used for software generation and testing to ensure that as far as possible, the code contains no errors. However, it is virtually impossible to perform internal tests that cover all possible combinations of external effects, etc., and therefore it must be accepted that errors may exist. In this respect, software used in relays is no different to any other software, where users accept that field use may uncover errors that may require changes to the software. Obviously, type testing can be expected to prove that the protection functions implemented by the relay are carried out properly, but it has been known for failures of rarely used auxiliary functions to occur under some conditions.

Where problems are discovered in software subsequent to the release of a numerical relay for sale, a new version of the software may be considered necessary. This process then requires some form of software version control to be implemented to keep track of:

a. the different software versions in existence

b. the differences between each version

c. the reasons for the change

d. relays fitted with each of the versions

With an effective version control system, manufacturers are able to advise users in the event of reported problems if the problem is a known software related problem and what remedial action is required. With the aid of suitable software held by a user, it may be possible to download the new software version instead of requiring a visit from a service engineer.

7.2 Relay data management

A numerical relay usually provides many more features than a relay using static or electromechanical technology. To use these features, the appropriate data must be entered into the memory of the relay. Users must also keep a record of all of the data, in case of data loss within the relay, or for use in system studies, etc. The amount of data per numerical relay may be 10-50 times that of an equivalent electromechanical relay, to which must be added the possibility of user-defined logic functions. The task of entering the data correctly into a numerical relay becomes a much more complex task than previously, which adds to the possibility of a mistake being made. Similarly, the amount of data that must be recorded is much larger, giving rise potentially to problems of storage.

The problems have been addressed by the provision of software to automate the preparation and download of relay setting data from a portable computer connected to a communications port of the relay. As part of the process, the setting data can be read back from the relay and compared with the desired settings to ensure that the download has been error-free. A copy of the setting data (including user defined logic schemes where used) can also be stored on the computer, for later printout and/or upload to the users database facilities.

More advanced software is available to perform the above functions from an Engineering Computer in a substation automation scheme.

7.3 Relay testing and commissioning

The testing of relays based on software is of necessity radically different from earlier generations of relays. The topic is dealt with in detail in Chapter "Relay Testing and Commissioning", but it can be mentioned here that site commissioning is usually restricted to the in-built software self-check and verification that currents and voltages measured by the relay are correct. Problems revealed by such tests require specialist equipment to resolve, and hence field policy is usually on a repair-by-replacement basis.

B2

Current and Voltage Transformers

Network Protection & Automation Guide

Life Is On | Schneider Electric

Chapter B2

Current and Voltage Transformers

B2

1. Introduction

Whenever the values of voltage or current in a power circuit are too high to permit convenient direct connection of measuring instruments or relays, coupling is made through transformers. Such 'measuring' transformers are required to produce a scaled down replica of the input quantity to the accuracy expected for the particular measurement; this is made possible by the high efficiency of the transformer. The performance of measuring transformers during and following large instantaneous changes in the input quantity is important, in that this quantity may depart from the sinusoidal waveform. The deviation may consist of a step change in magnitude, or a transient component that persists for an appreciable period, or both. The resulting effect on instrument performance is usually negligible, although for precision metering a persistent change in the accuracy of the transformer may be significant.

However, many protection systems are required to operate during the period of transient disturbance in the output of the measuring transformers that follows a system fault. The errors in transformer output may abnormally delay the operation of the protection, or cause unnecessary operations. The functioning of such transformers must, therefore, be examined analytically.

It can be shown that the transformer can be represented by the equivalent circuit of Figure B2.1, where all quantities are referred to the secondary side.

When the transformer is not 1/1 ratio, this condition can be represented by energising the equivalent circuit with an ideal transformer of the given ratio but having no losses.

1.1 Measuring transformers

Voltage and current transformers for low primary voltage or current ratings are not readily distinguishable; for higher ratings, dissimilarities of construction are usual. Nevertheless the differences between these devices lie principally in the way they are connected into the power circuit. Voltage transformers are much like small power transformers, differing only in details of design that control ratio accuracy over the specified range of output. Current transformers have their primary windings connected in series with the power circuit, and so also in series with the system impedance. The response of the transformer is radically different in these two modes of operation.

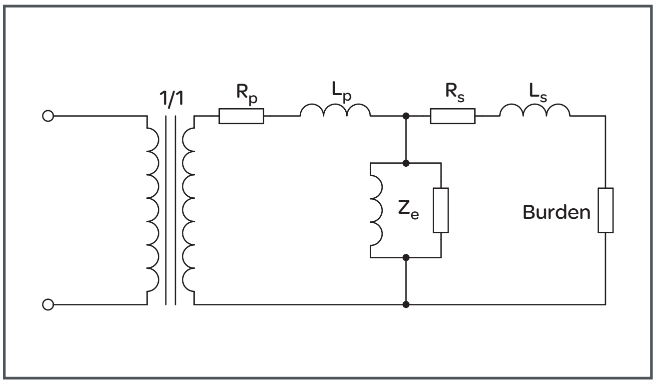

Figure B2.1:
Equivalent circuit of transformer

2. Electromagnetic voltage transformers

In the shunt mode, the system voltage is applied across the input terminals of the equivalent circuit of Figure B2.1. The vector diagram for this circuit is shown in Figure B2.2.

The secondary output voltage V_s is required to be an accurate scaled replica of the input voltage V_p over a specified range of output. To this end, the winding voltage drops are made small, and the normal flux density in the core is designed to be well below the saturation density, in order that the exciting current may be low and the exciting impedance substantially constant with a variation of applied voltage over the desired operating range including some degree of overvoltage. These limitations in design result in a VT for a given burden being much larger than a typical power transformer of similar rating. The exciting current, in consequence, will not be as small, relative to the rated burden, as it would be for a typical power transformer.

2.1 Errors

The ratio and phase errors of the transformer can be calculated using the vector diagram of Figure B2.2.

The ratio error is defined as:

$$\frac{(K_n V_s\ )}{V_p} \times 100\%$$

where:

K_n is the nominal ratio

V_p is the primary voltage

V_s is the secondary voltage

If the error is positive, the secondary voltage exceeds the nominal value. The turns ratio of the transformer need not be equal to the nominal ratio; a small turns compensation will usually be employed, so that the error will be positive for low burdens and negative for high burdens.

2. Electromagnetic voltage transformers

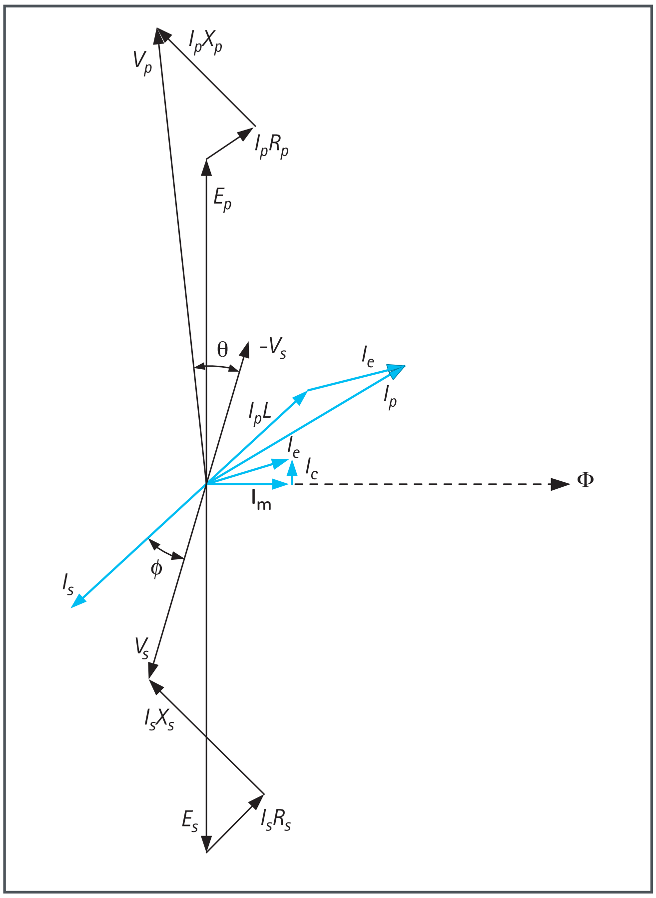

Figure B2.2:
Vector diagram for voltage transformer

V_p = primary applied voltage

E_p = primary induced e.m.f.

V_s = secondary output voltage

F = flux

I_e = exciting current

I_m = magnetizing component

I_c = iron loss component

Φ = phase angle error

θ = secondary burden angle

$I_p R_p$ = primary resistance voltage drop

$I_p X_p$ = primary reactance voltage drop

$I_s R_s$ = secondary resistance voltage drop

$I_s X_s$ = secondary reactance voltage drop

I_s = secondary current

I_pL = load component of primary current

I_p = primary current

The phase error is the phase difference between the reversed secondary and the primary voltage vectors. It is positive when the reversed secondary voltage leads the primary vector. Requirements in this respect are set out in IEC 60044-2.

All voltage transformers are required to comply with one of the classes in Table B2.1.

Accuracy Class	0.8 - 1.2 x rated voltage	
	0.25 - 1.0 x rated burden at 0.8pf	
	voltage ratio error (%)	phase displacement (minutes)
0.1	+/- 0.1	+/- 5
0.2	+/- 0.2	+/- 10
0.5	+/- 0.5	+/- 20
1.0	+/- 1.0	+/- 40
3.0	+/- 3.0	not specified

Table B2.1:
Measuring voltage transformer error limits

For protection purposes, accuracy of voltage measurement may be important during fault conditions, as the system voltage might be reduced by the fault to a low value. Voltage transformers for such types of service must comply with the extended range of requirements set out in Table B2.2.

Accuracy Class	0.8 - 1.2 x rated voltage	
	0.25 - 1.0 x rated burden at 0.8pf	
	voltage ratio error (%)	phase displacement (minutes)
3P	+/- 3.0	+/- 120
6P	+/- 6.0	+/- 240

Table B2.2:
Additional limits for protection voltage transformers

2.2 Voltage factors

The quantity V_f in Table B2.3 is an upper limit of operating voltage, expressed in per unit of rated voltage. This is important for correct relay operation and operation under unbalanced fault conditions on unearthed or impedance earthed systems, resulting in a rise in the voltage on the healthy phases.

Voltage factors, with the permissible duration of the maximum voltage, are given in Table B2.3.

B2

2. Electromagnetic voltage transformers

Voltage factor V_f	Time rating	Primary winding connection / system earthing conditions
1.2	continuous	Between lines in any network. Between transformer star point and earth in any network.
1.2	continuous	Between line and earth in an effectively earthed network .
1.5	30 s	
1.2	continuous	Between line and earth in a non-effectively earthed neutral system with automatic earth fault tripping.
1.9	30 s	
1.2	continuous	Between line and earth in an isolated neutral system without automatic earth fault tripping, or in a resonant earthed system without automatic earth fault tripping.
1.9	8 hours	

Table B2.3:
Voltage transformers: Permissible duration of maximum voltage

2.3 Secondary leads

Voltage transformers are designed to maintain the specified accuracy in voltage output at their secondary terminals. To maintain this if long secondary leads are required, a distribution box can be fitted close to the VT to supply relay and metering burdens over separate leads. If necessary, allowance can be made for the resistance of the leads to individual burdens when the particular equipment is calibrated.

2.4 Protection of voltage transformers

Voltage Transformers can be protected by H.R.C. fuses on the primary side for voltages up to 66kV. Fuses do not usually have a sufficient interrupting capacity for use with higher voltages. Practice varies, and in some cases protection on the primary is omitted.

The secondary of a Voltage Transformer should always be protected by fuses or a miniature circuit breaker (MCB). The device should be located as near to the transformer as possible. A short circuit on the secondary circuit wiring will produce a current of many times the rated output and cause excessive heating. Even where primary fuses can be fitted, these will usually not clear a secondary side short circuit because of the low value of primary current and the minimum practicable fuse rating.

2.5 Construction

The construction of a voltage transformer takes into account the following factors:

a. output – seldom more than 200-300VA.
Cooling is rarely a problem

b. insulation – designed for the system impulse voltage level. Insulation volume is often larger than the winding volume

c. mechanical design – not usually necessary to withstand short-circuit currents. Must be small to fit the space available within switchgear

Three-phase units are common up to 36kV but for higher voltages single-phase units are usual. Voltage transformers for medium voltage circuits will have dry type insulation, but for high and extra high voltage systems, oil immersed units are general. Resin encapsulated designs are in use on systems up to 33kV. Figure B2.3 shows a typical voltage transformer.

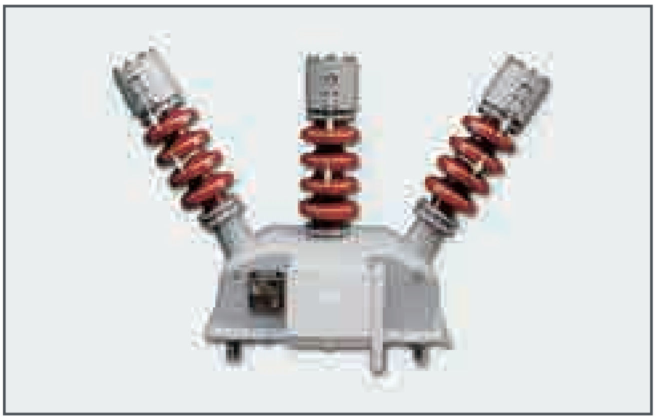

Figure B2.3:
Typical voltage transformer

2.6 Residually connected voltage transformers

The three voltages of a balanced system summate to zero, but this is not so when the system is subject to a single-phase earth fault. The residual voltage of a system is measured by connecting the secondary windings of a VT in 'broken delta' as shown in Figure B2.4.

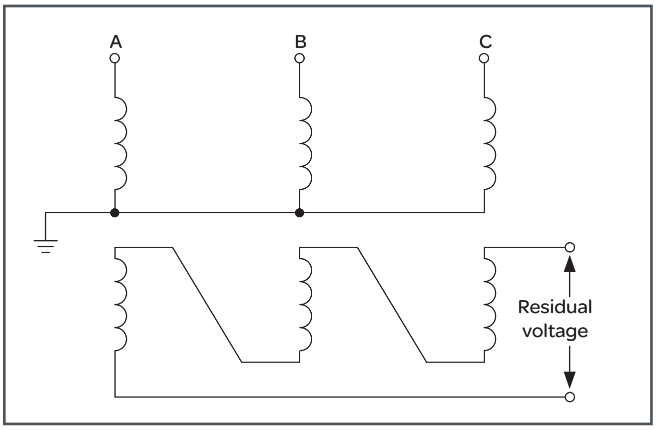

Figure B2.4:
Residual voltage connection

2. Electromagnetic voltage transformers

The output of the secondary windings connected in broken delta is zero when balanced sinusoidal voltages are applied, but under conditions of unbalance a residual voltage equal to three times the zero sequence voltage of the system will be developed.

In order to measure this component, it is necessary for a zero sequence flux to be set up in the VT, and for this to be possible there must be a return path for the resultant summated flux. The VT core must have one or more unwound limbs linking the yokes in addition to the limbs carrying windings. Usually the core is made symmetrically, with five limbs, the two outermost ones being unwound. Alternatively, three single-phase units can be used. It is equally necessary for the primary winding neutral to be earthed, for without an earth, zero sequence exciting current cannot flow.

A VT should be rated to have an appropriate voltage factor as described in Section 2.2 and Table B2.3, to cater for the voltage rise on healthy phases during earth faults.

Voltage transformers are often provided with a normal star-connected secondary winding and a broken-delta connected 'tertiary' winding. Alternatively the residual voltage can be extracted by using a star/broken-delta connected group of auxiliary voltage transformers energised from the secondary winding of the main unit, providing the main voltage transformer fulfils all the requirements for handling a zero sequence voltage as previously described. The auxiliary VT must also be suitable for the appropriate voltage factor. It should be noted that third harmonics in the primary voltage wave, which are of zero sequence, summate in the broken-delta winding.

2.7 Transient performance

Transient errors cause few difficulties in the use of conventional voltage transformers, although some do occur. Errors are generally limited to short time periods following the sudden application or removal of voltage from the VT primary.

If a voltage is suddenly applied, an inrush transient will occur, as with power transformers. The effect will, however, be less severe than for power transformers because of the lower flux density for which the VT is designed. If the VT is rated to have a fairly high voltage factor, little inrush effect will occur. An error will appear in the first few cycles of the output current in proportion to the inrush transient that occurs.

When the supply to a voltage transformer is interrupted, the core flux will not readily collapse; the secondary winding will tend to maintain the magnetising force to sustain this flux, and will circulate a current through the burden which will decay more or less exponentially, possibly with a superimposed audio-frequency oscillation due to the capacitance of the winding. Bearing in mind that the exciting quantity, expressed in ampere-turns, may exceed the burden, the transient current may be significant.

2.8 Cascade voltage transformers

The capacitor VT Section 3 was developed because of the high cost of conventional electromagnetic voltage transformers but, as shown in Section 3.2, the frequency and transient responses are less satisfactory than those of the orthodox voltage transformers. Another solution to the problem is the cascade VT (Figure B2.5).

The conventional type of VT has a single primary winding, the insulation of which presents a great problem for voltages above about 132kV. The cascade VT avoids these difficulties by breaking down the primary voltage in several distinct and separate stages.

The complete VT is made up of several individual transformers, the primary windings of which are connected in series, as shown in Figure B2.5. Each magnetic core has primary windings (P) on two opposite sides. The secondary winding (S) consists of a single winding on the last stage only. Coupling windings (C) connected in pairs between stages, provide low impedance circuits for the transfer of load ampere-turns between stages and ensure that the power frequency voltage is equally distributed over the several primary windings.

The potentials of the cores and coupling windings are fixed at definite values by connecting them to selected points on the primary windings. The insulation of each winding is sufficient for the voltage developed in that winding, which is a fraction of the total according to the number of stages. The individual transformers are mounted on a structure built of insulating material, which provides the interstage insulation, accumulating to a value able to withstand the full system voltage across the complete height of the stack.

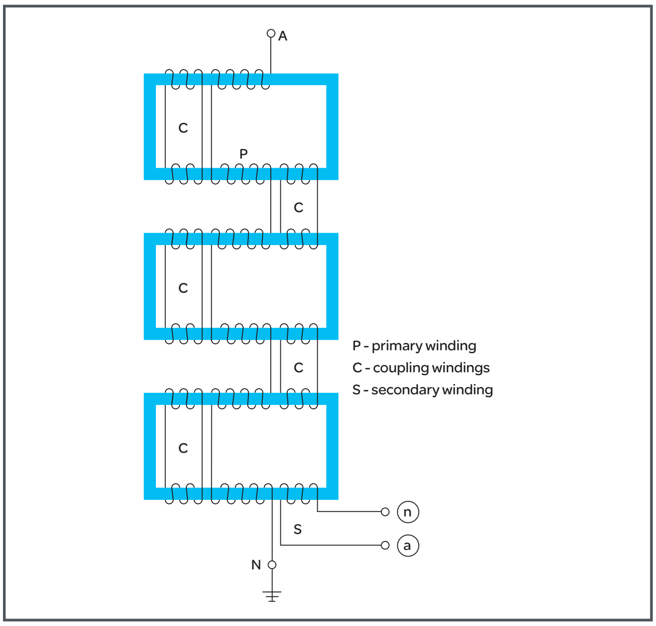

Figure B2.5:
Schematic diagram of typical cascade voltage transformer

3. Capacitor voltage transformers

The entire assembly is contained in a hollow cylindrical porcelain housing with external weather-sheds; the housing is filled with oil and sealed, an expansion bellows being included to maintain hermetic sealing and to permit expansion with temperature change.

The size of electromagnetic voltage transformers for the higher voltages is largely proportional to the rated voltage; the cost tends to increase at a disproportionate rate. The capacitor voltage transformer (CVT) is often more economic.

This device is basically a capacitance potential divider. As with resistance-type potential dividers, the output voltage is seriously affected by load at the tapping point. The capacitance divider differs in that its equivalent source impedance is capacitive and can therefore be compensated by a reactor connected in series with the tapping point. With an ideal reactor, such an arrangement would have no regulation and could supply any value of output.

A reactor possesses some resistance, which limits the output that can be obtained. For a secondary output voltage of 110V, the capacitors would have to be very large to provide a useful output while keeping errors within the usual limits. The solution is to use a high secondary voltage and further transform the output to the normal value using a relatively inexpensive electromagnetic transformer. The successive stages of this reasoning are indicated in Figure B2.6.

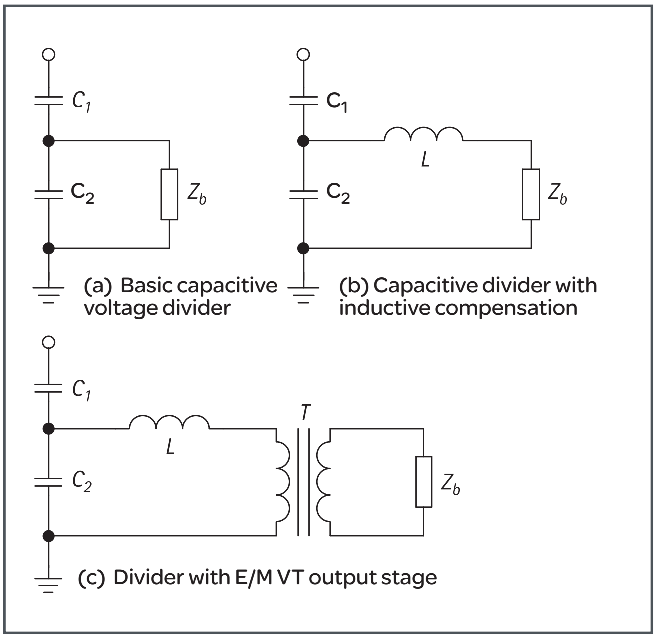

Figure B2.6:
Development of capacitor voltage transformer

There are numerous variations of this basic circuit. The inductance L may be a separate unit or it may be incorporated in the form of leakage reactance in the transformer T. Capacitors C_1 and C_2 cannot conveniently be made to close tolerances, so tappings are provided for ratio adjustment, either on the transformer T, or on a separate auto-transformer in the secondary circuit. Adjustment of the tuning inductance L is also needed; this can be done with tappings, a separate tapped inductor in the secondary circuit, by adjustment of gaps in the iron cores, or by shunting with variable capacitance. A simplified equivalent circuit is shown in Figure B2.7.

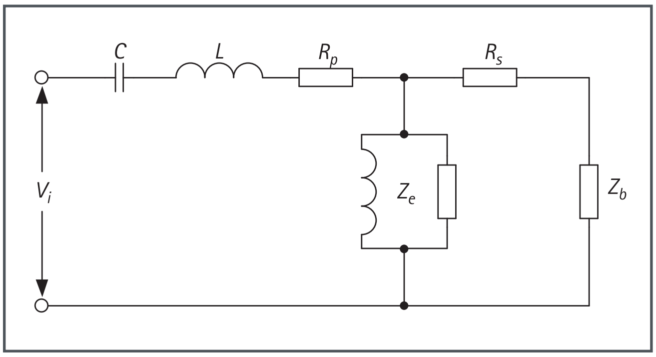

Figure B2.7:
Simplified equivalent circuit of capacitor voltage transformer

It will be seen that the basic difference between Figure B2.7 and Figure B2.1 is the presence of C and L. At normal frequency when C and L are in resonance and therefore cancel, the circuit behaves in a similar manner to a conventional VT. At other frequencies, however, a reactive component exists which modifies the errors.

Standards generally require a CVT used for protection to conform to accuracy requirements of Table B2.2 within a frequency range of 97-103% of nominal. The corresponding frequency range of measurement CVT's is much less, 99%-101%, as reductions in accuracy for frequency deviations outside this range are less important than for protection applications.

L = tuning inductance

R_p = primary winding resistance (plus losses)

Z_e = exciting impedance of transformer T

R_s = secondary circuit resistance

Z_b = burden impedance

C = $C_1 + C_2$ (in Figure B2.6)

3.1 Voltage protection of auxiliary capacitor

If the burden impedance of a CVT were to be short-circuited, the rise in the reactor voltage would be limited only by the reactor losses and possible saturation, that is, to $Q \times E_2$ where E_2 is the no-load tapping point voltage and Q is the amplification factor of the resonant circuit. This value would be excessive and is therefore limited by a spark gap connected across the

3. Capacitor voltage transformers

auxiliary capacitor. The voltage on the auxiliary capacitor is higher at full rated output than at no load, and the capacitor is rated for continuous service at this raised value. The spark gap will be set to flash over at about twice the full load voltage.

The effect of the spark gap is to limit the short-circuit current which the VT will deliver and fuse protection of the secondary circuit has to be carefully designed with this point in mind. Facilities are usually provided to earth the tapping point, either manually or automatically, before making any adjustments to tappings or connections.

3.2 Transient behaviour of capacitor voltage transformers

A CVT is a series resonant circuit. The introduction of the electromagnetic transformer between the intermediate voltage and the output makes possible further resonance involving the exciting impedance of this unit and the capacitance of the divider stack. When a sudden voltage step is applied, oscillations in line with these different modes take place, and will persist for a period governed by the total resistive damping that is present. Any increase in resistive burden reduces the time constant of a transient oscillation, although the chance of a large initial amplitude is increased.

For very high-speed protection, transient oscillations should be minimised. Modern capacitor voltage transformers are much better in this respect than their earlier counterparts, but high performance protection schemes may still be adversely affected.

3.3 Ferro-resonance

The exciting impedance Z_e of the auxiliary transformer T and the capacitance of the potential divider together form a resonant circuit that will usually oscillate at a sub-normal frequency. If this circuit is subjected to a voltage impulse, the resulting oscillation may pass through a range of frequencies. If the basic frequency of this circuit is slightly less than one-third of the system frequency, it is possible for energy to be absorbed from the system and cause the oscillation to build up. The increasing flux density in the transformer core reduces the inductance, bringing the resonant frequency nearer to the one-third value of the system frequency.

The result is a progressive build-up until the oscillation stabilises as a third sub-harmonic of the system, which can be maintained indefinitely. Depending on the values of components, oscillations at fundamental frequency or at other sub-harmonics or multiples of the supply frequency are possible but the third sub-harmonic is the one most likely to be encountered.

The principal manifestation of such an oscillation is a rise in output voltage, the r.m.s. value being perhaps 25%-50% above the normal value; the output waveform would generally be of the form shown in Figure B2.8.

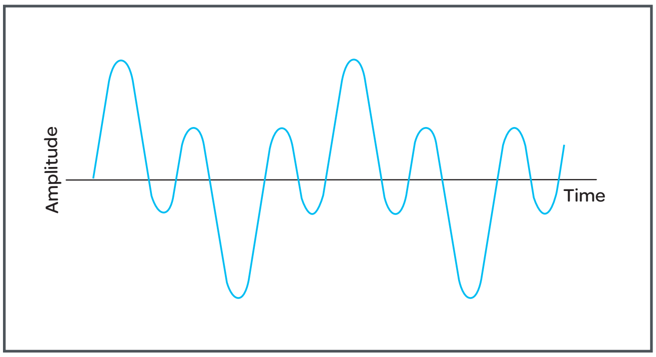

Figure B2.8:
Typical secondary voltage waveform with third sub-harmonic oscillation.

Such oscillations are less likely to occur when the circuit losses are high, as is the case with a resistive burden, and can be prevented by increasing the resistive burden. Special anti-ferro-resonance devices that use a parallel-tuned circuit are sometimes built into the VT. Although such arrangements help to suppress ferro-resonance, they tend to impair the transient response, so that the design is a matter of compromise.

Correct design will prevent a CVT that supplies a resistive burden from exhibiting this effect, but it is possible for non-linear inductive burdens, such as auxiliary voltage transformers, to induce ferro- resonance. Auxiliary voltage transformers for use with capacitor voltage transformers should be designed with a low value of flux density that prevents transient voltages from causing core saturation, which in turn would bring high exciting currents.

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4. Current transformers

The primary winding of a current transformer is connected in series with the power circuit and the impedance is negligible compared with that of the power circuit. The power system impedance governs the current passing through the primary winding of the current transformer. This condition can be represented by inserting the load impedance, referred through the turns ratio, in the input connection of Figure B2.1.

This approach is developed in Figure B2.9, taking the numerical example of a 300/5A CT applied to an 11kV power system. The system is considered to be carrying rated current (300A) and the CT is feeding a burden of 10VA.

A study of the final equivalent circuit of Figure B2.9(c), taking note of the typical component values, will reveal all the properties of a current transformer. It will be seen that:

a. the secondary current will not be affected by change of the burden impedance over a considerable range

b. the secondary circuit must not be interrupted while the primary winding is energised. The induced secondary e.m.f. under these circumstances will be high enough to present a danger to life and insulation

c. the ratio and phase angle errors can be calculated easily if the magnetising characteristics and the burden impedance are known

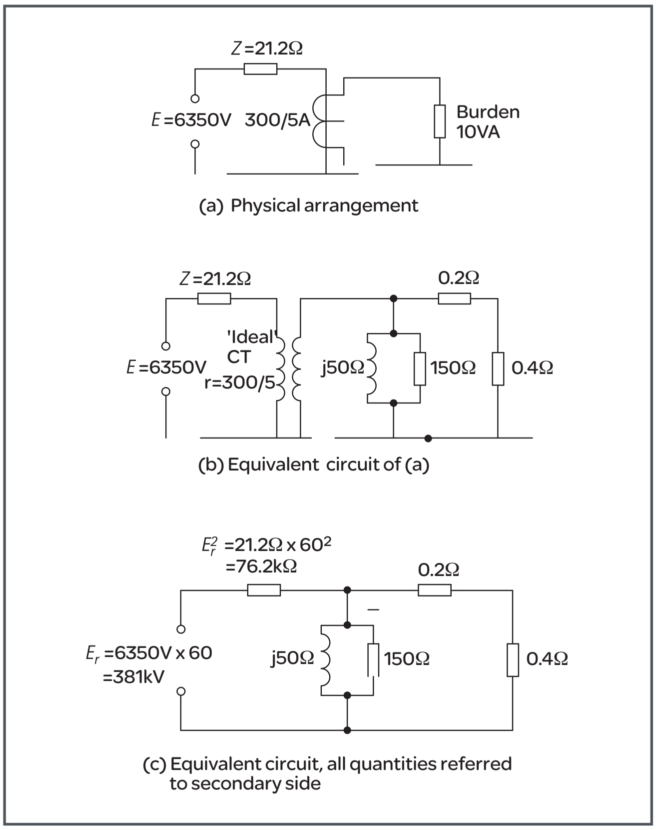

Figure B2.9:
Derivation of equivalent circuit of a current transformer

4.1 Errors

The general vector diagram (Figure B2.2) can be simplified by the omission of details that are not of interest in current measurement; see Figure B2.10. Errors arise because of the shunting of the burden by the exciting impedance. This uses a small portion of the input current for exciting the core, reducing the amount passed to the burden. So $I_s = I_p - I_e$, where I_e is dependent on Z_e, the exciting impedance and the secondary e.m.f. E_s, given by the equation

$E_s = I_s\,(Z_s + Z_b)$, where:

Z_s = the self-impedance of the secondary winding, which can generally be taken as the resistive component R_s only

Z_b = the impedance of the burden

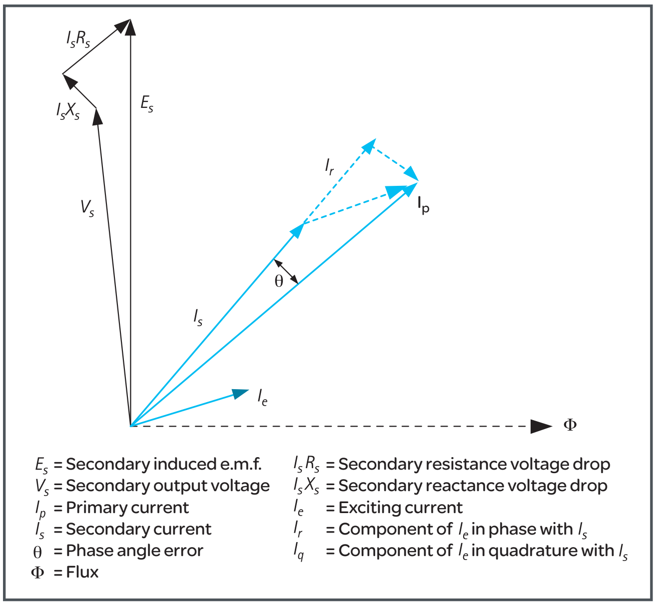

Figure B2.10:
Vector diagram for current transformer (referred to secondary)

4.1.1 Current or ratio error

This is the difference in magnitude between I_p and I_s and is equal to I_r, the component of I_e which is in phase with I_s.

4.1.2 Phase error

This is represented by I_q, the component of I_e in quadrature with I_s and results in the phase error Φ.

The values of the current error and phase error depend on the phase displacement between I_s and I_e, but neither current nor phase error can exceed the vectorial error I_e. It will be seen that with a moderately inductive burden, resulting in I_s and I_e approximately in phase, there will be little phase error and the exciting component will result almost entirely in ratio error.

4. Current transformers

A reduction of the secondary winding by one or two turns is often used to compensate for this. For example, in the CT corresponding to Figure B2.9, the worst error due to the use of an inductive burden of rated value would be about 1.2%. If the nominal turns ratio is 2:120, removal of one secondary turn would raise the output by 0.83% leaving the overall current error as -0.37%.

For lower value burden or a different burden power factor, the error would change in the positive direction to a maximum of +0.7% at zero burden; the leakage reactance of the secondary winding is assumed to be negligible. No corresponding correction can be made for phase error, but it should be noted that the phase error is small for moderately reactive burdens.

4.2 Composite error

This is defined in IEC 60044-1 as the r.m.s. value of the difference between the ideal secondary current and the actual secondary current. It includes current and phase errors and the effects of harmonics in the exciting current. The accuracy class of measuring current transformers is shown in Table B2.4.

(a) Limits of error accuracy for error classes 0.1 - 1.0

Accuracy class	+/- Percentage current (ratio) error			
	% current			
	5	20	100	120
0.1	0.4	0.2	0.1	0.1
0.2	0.75	0.35	0.2	0.2
0.5	1.5	0.75	0.5	0.5
1	3	1.5	1.0	1.0

Accuracy class	+/- Phase displacement (minutes)			
	% current			
	5	20	100	120
0.1	15	8	5	5
0.2	30	15	10	10
0.5	90	45	30	30
1	180	90	60	60

(b) Limits of error for error classes 3 and 5

Accuracy class	+/- Percentage current (ratio) error	
	% current	
	50	120
3	3	5
5	3	5

Table B2.4:
CT error classes

4.3 Accuracy limit current of protection current transformers

Protection equipment is intended to respond to fault conditions, and is for this reason required to function at current values above the normal rating. Protection class current transformers must retain a reasonable accuracy up to the largest relevant current. This value is known as the 'accuracy limit current' and may be expressed in primary or equivalent secondary terms. The ratio of the accuracy limit current to the rated current is known as the 'accuracy limit factor'.

The accuracy class of protection current transformers is shown in Table B2.5.

Class	Current error at rated primary current (%)	Phase displacement at rated current (minutes)	Composite error at rated accuracy limit primary current (%)
5P	+/-1	+/-60	5
10P	+/-3		10
Standard accuracy limit factors are 5, 10, 15, 20, and 30			

Table B2.5:
Protection CT error limits for classes 5P and 10P

Even though the burden of a protection CT is only a few VA at rated current, the output required from the CT may be considerable if the accuracy limit factor is high. For example, with an accuracy limit factor of 30 and a burden of 10VA, the CT may have to supply 9000VA to the secondary circuit.

Alternatively, the same CT may be subjected to a high burden. For overcurrent and earth fault protection, with elements of similar VA consumption at setting, the earth fault element of an electromechanical relay set at 10% would have 100 times the impedance of the overcurrent elements set at 100%. Although saturation of the relay elements somewhat modifies this aspect of the matter, it will be seen that the earth fault element is a severe burden, and the CT is likely to have a considerable ratio error in this case. So it is not much use applying turns compensation to such current transformers; it is generally simpler to wind the CT with turns corresponding to the nominal ratio.

Current transformers can be used for the dual duty of measurement and protection. They will then need to be rated according to a class selected from both Tables B2.4 and B2.5. The applied burden is the total of instrument and relay burdens. Turns compensation may well be needed to achieve the measurement performance. Measurement ratings are expressed in terms of rated burden and class, for example 15VA Class 0.5. Protection ratings are expressed in terms of rated burden, class, and accuracy limit factor, for example 10VA Class 10P10.

4. Current transformers

4.4 Class PX current transformers

The classification of Table B2.5 is only used for overcurrent protection. Class PX is the definition in IEC 60044-1 for the quasi-transient current transformers formerly covered by Class X of BS 3938, commonly used with unit protection schemes.

Guidance was given in the specifications to the application of current transformers to earth fault protection, but for this and for the majority of other protection applications it is better to refer directly to the maximum useful e.m.f. that can be obtained from the CT. In this context, the 'knee-point' of the excitation curve is defined as 'that point at which a further increase of 10% of secondary e.m.f. would require an increment of exciting current of 50%'; see Figure B2.11.

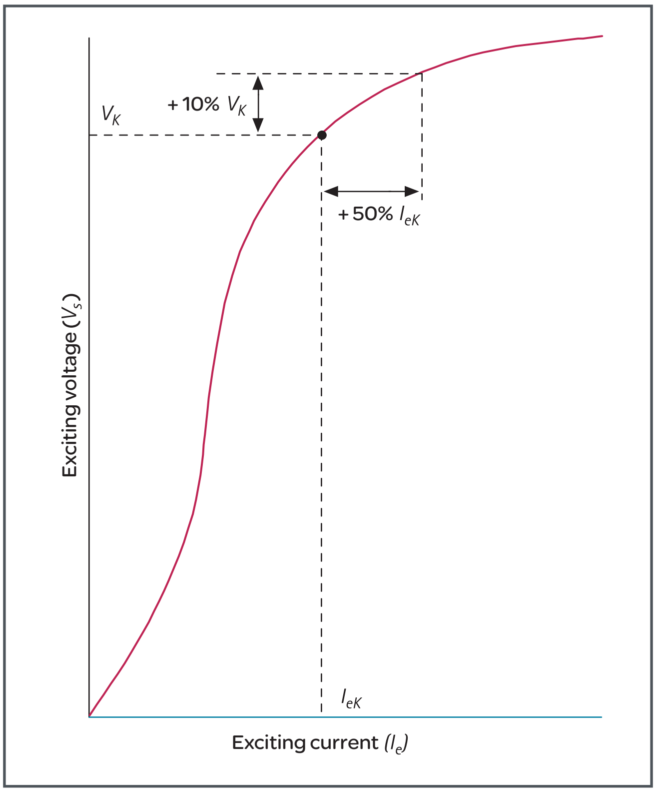

Figure B2.11:
Definition of knee-point of excitation curve

Design requirements for current transformers for general protection purposes are frequently laid out in terms of knee-point e.m.f., exciting current at the knee-point (or some other specified point) and secondary winding resistance. Such current transformers are designated Class PX.

4.5 CT winding arrangements

A number of CT winding arrangements are used. These are described in the following sections.

4.5.1 Wound primary type

This type of CT has conventional windings formed of copper wire wound round a core. It is used for auxiliary current transformers and for many low or moderate ratio current transformers used in switchgear of up to 11kV rating.

4.5.2 Bushing or bar primary type

Many current transformers have a ring-shaped core, sometimes built up from annular stampings, but often consisting of a single length of strip tightly wound to form a close-turned spiral. The distributed secondary winding forms a toroid which should occupy the whole perimeter of the core, a small gap being left between start and finish leads for insulation.

Such current transformers normally have a single concentrically placed primary conductor, sometimes permanently built into the CT and provided with the necessary primary insulation. In other cases, the bushing of a circuit breaker or power transformer is used for this purpose. At low primary current ratings it may be difficult to obtain sufficient output at the desired accuracy. This is because a large core section is needed to provide enough flux to induce the secondary e.m.f. in the small number of turns, and because the exciting ampere-turns form a large proportion of the primary ampere-turns available. The effect is particularly pronounced when the core diameter has been made large so as to fit over large EHV bushings.

4.5.3 Core-balance current transformers

The core-balance CT (or CBCT) is normally of the ring type, through the centre of which is passed cable that forms the primary winding. An earth fault relay, connected to the secondary winding, is energised only when there is residual current in the primary system.

The advantage in using this method of earth fault protection lies in the fact that only one CT core is used in place of three phase CTs whose secondary windings are residually connected. In this way the CT magnetising current at relay operation is reduced by approximately three-to-one, an important consideration in sensitive earth fault relays where a low effective setting is required. The number of secondary turns does not need to be related to the cable rated current because no secondary current would flow under normal balanced conditions. This allows the number of secondary turns to be chosen such as to optimise the effective primary pick-up current.

Core-balance transformers are normally mounted over a cable at a point close up to the cable gland of switchgear or other apparatus. Physically split cores ('slip-over' types) are normally available for applications in which the cables are already made up, as on existing switchgear.

4.5.4 Summation current transformers

The summation arrangement is a winding arrangement used in a measuring relay or on an auxiliary current transformer to give a single-phase output signal having a specific relationship to the three-phase current input.

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4.5.5 Air-gapped current transformers

These are auxiliary current transformers in which a small air gap is included in the core to produce a secondary voltage output proportional in magnitude to current in the primary winding. Sometimes termed 'transactors' and 'quadrature current transformers', this form of current transformer has been used as an auxiliary component of unit protection schemes in which the outputs into multiple secondary circuits must remain linear for and proportioned to the widest practical range of input currents.

4.6 Line current CTs

CT's for measuring line currents fall into one of three types.

4.6.1 Overdimensioned CTs

Overdimensioned CTs are capable of transforming fully offset fault currents without distortion. In consequence, they are very large, as can be deduced from Section 4.10. They are prone to errors due to remanent flux arising, for instance, from the interruption of heavy fault currents.

4.6.2 Anti-remanence CTs

This is a variation of the overdimensioned current transformer and has small gap(s) in the core magnetic circuit, thus reducing the possible remanent flux from approximately 90% of saturation value to approximately 10%. These gap(s) are quite small, for example 0.12mm total, and so the excitation characteristic is not significantly changed by their presence. However, the resulting decrease in possible remanent core flux confines any subsequent d.c. flux excursion, resulting from primary current asymmetry, to within the core saturation limits. Errors in current transformation are therefore significantly reduced when compared with those with the gapless type of core.

Transient protection current transformers are included in IEC 60044-6 as types TPX, TPY and TPZ and this specification gives good guidance to their application and use.

4.6.3 Linear current transformers

The 'linear' current transformer constitutes an even more radical departure from the normal solid core CT in that it incorporates an appreciable air gap, for example 7.5-10mm. As its name implies the magnetic behaviour tends to linearisation by the inclusion of this gap in the magnetic circuit. However, the purpose of introducing more reluctance into the magnetic circuit is to reduce the value of magnetising reactance. This in turn reduces the secondary time- constant of the CT, thereby reducing the overdimensioning factor necessary for faithful transformation. Figure B2.12 shows a typical modern CT for use on MV systems.

4.7 Secondary winding impedance

As a protection CT may be required to deliver high values of secondary current, the secondary winding resistance must be made as low as practicable. Secondary leakage reactance also occurs, particularly in wound primary current transformers, although its precise measurement is difficult. The non-linear nature of the CT magnetic circuit makes it difficult to assess the definite ohmic value representing secondary leakage reactance.

Figure B2.12:
Typical modern CT for use on MV systems

It is, however, normally accepted that a current transformer is of the low reactance type provided that the following conditions prevail:

a. the core is of the jointless ring type (including spirally wound cores)

b. the secondary turns are substantially evenly distributed along the whole length of the magnetic circuit

c. the primary conductor(s) passes through the approximate centre of the core aperture or, if wound, is approximately evenly distributed along the whole length of the magnetic circuit

d. flux equalising windings, where fitted to the requirements of the design, consist of at least four parallel-connected coils, evenly distributed along the whole length of the magnetic circuit, each coil occupying one quadrant

Alternatively, when a current transformer does not obviously comply with all of the above requirements, it may be proved to be of low- reactance where:

e. the composite error, as measured in the accepted way, does not exceed by a factor of 1.3 that error obtained directly from the V-I excitation characteristic of the secondary winding

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4. Current transformers

4.8 Secondary current rating

The choice of secondary current rating is determined largely by the secondary winding burden and the standard practice of the user. Standard CT secondary current ratings are 5A and 1A. The burden at rated current imposed by digital or numerical relays or instruments is largely independent of the rated value of current. This is because the winding of the device has to develop a given number of ampere-turns at rated current, so that the actual number of turns is inversely proportional to the current, and the impedance of the winding varies inversely with the square of the current rating. However, electromechanical or static earth-fault relays may have a burden that varies with the current tapping used.

Interconnection leads do not share this property, however, being commonly of standard cross-section regardless of rating. Where the leads are long, their resistance may be appreciable, and the resultant burden will vary with the square of the current rating. For example a CT lead run of the order of 200 metres, a typical distance for outdoor EHV switchgear, could have a loop resistance of approximately 3 Ω.

The CT lead VA burden if a 5A CT is used would be 75VA, to which must be added the relay burden (up to perhaps 10VA for an electromechanical relay, but less than 1VA for a numerical relay), making a total of 85VA. Such a burden would require the CT to be very large and expensive, particularly if a high accuracy limit factor were also applicable.

With a 1A CT secondary rating, the lead burden is reduced to 3VA, so that with the same relay burden the total becomes a maximum of 13VA. This can be provided by a CT of normal dimensions, resulting in a saving in size, weight and cost. Hence modern CT's tend to have secondary windings of 1A rating. However, where the primary rating is high, say above 2000A, a CT of higher secondary rating may be used, to limit the number of secondary turns. In such a situation secondary ratings of 5A may be used. In extreme cases a 20A secondary CT may be used, followed by a 20/1 interposing CT.

4.9 Rated short-time current

A current transformer is overloaded while system short-circuit currents are flowing and will be short-time rated. Standard times for which the CT must be able to carry rated short-time currents (STC) are 0.25, 0.5, 1.0, 2.0 or 3.0 seconds.

A CT with a particular short-time current/ time rating will carry a lower current for a longer time in inverse proportion to the square of the ratio of current values. The converse, however, cannot be assumed, and larger current values than the S.T.C. rating are not permissible for any duration unless justified by a new rating test to prove the dynamic capability.

4.10 Transient response of a current transformer

When accuracy of response during very short intervals is being studied, it is necessary to examine what happens when the primary current is suddenly changed. The effects are most important, and were first observed in connection with balanced forms of protection, which were liable to operate unnecessarily when short-circuit currents were suddenly established.

4.10.1 Primary current transient

The power system, neglecting load circuits, is mostly inductive, so that when a short circuit occurs, the fault current that flows is given by:

$$i_p = \frac{E_p}{\sqrt{R^2 + \omega^2 L^2}} \left[sin\left(\omega t + \beta - \alpha\right) + sin\left(\alpha - \beta\right) e^{-(R/L)t} \right]$$

...Equation B2.1

where:

E_p = peak system e.m.f.

R = system resistance

L = system inductance

β = initial phase angle governed by instant of fault occurrence

α = system power factor angle

$= tan^{-1} \omega L/R$

The first term of Equation B2.1 represents the steady state alternating current, while the second is a transient quantity responsible for displacing the waveform asymmetrically.

$\frac{E_p}{\sqrt{R^2 + \omega^2 L^2}}$ is the steady state peak current I_p.

The maximum transient occurs when $sin = (\alpha - \beta) = 1$; no other condition need be examined.

So:

$$i_p = I_p \left[sin\left(\omega t - \frac{\pi}{2}\right) + e^{-(R/L)t} \right]$$

...Equation B2.2

When the current is passed through the primary winding of a current transformer, the response can be examined by replacing the CT with an equivalent circuit as shown in Figure B2.9(b).

As the 'ideal' CT has no losses, it will transfer the entire function, and all further analysis can be carried out in terms of equivalent secondary quantities (i_s and I_s). A simplified solution is obtainable by neglecting the exciting current of the CT.

The flux developed in an inductance is obtained by integrating the applied e.m.f. through a time interval:

$$\phi = K \int_{t_1}^{t_2} v dt$$

...Equation B2.3

For the CT equivalent circuit, the voltage is the drop on the burden resistance R_b.

4. Current transformers

Integrating for each component in turn, the steady state peak flux is given by:

$$\phi_A = KR_b I_s \int_{\pi/\omega}^{3\pi/2\omega} \sin\left(\omega t - \frac{\pi}{2}\right) dt$$

$$= \frac{KR_b I_s}{\omega} \qquad \text{...Equation B2.4}$$

The transient flux is given by:

$$\phi_B = KR_b I_s \int_0^{\alpha} e^{-(R/L)t} dt = \frac{KR_b I_s L}{R} \qquad \text{...Equation B2.5}$$

Hence, the ratio of the transient flux to the steady state value is:

$$\frac{\phi_B}{\phi_A} = \frac{wL}{R} = \frac{X}{R}$$

where X and R are the primary system reactance and resistance values.

The CT core has to carry both fluxes, so that:

$$\phi_C = \phi_A + \phi_B = \phi_A\left(1 + \frac{X}{R}\right) \qquad \text{...Equation B2.6}$$

The term $(1+X/R)$ has been called the 'transient factor' (TF), the core flux being increased by this factor during the transient asymmetric current period. From this it can be seen that the ratio of reactance to resistance of the power system is an important feature in the study of the behaviour of protection relays.

Alternatively, L/R is the primary system time constant T, so that the transient factor can be written:

$$= 1 + \frac{\omega L}{R} = 1 + \omega T$$

Again, fT is the time constant expressed in cycles of the a.c. quantity T', so that:

$$TF = 1 + 2\pi f T = 1 + 2\pi T'$$

This latter expression is particularly useful when assessing a recording of a fault current, because the time constant in cycles can be easily estimated and leads directly to the transient factor.

For example, a system time constant of three cycles results in a transient factor of $(1+6\pi)$, or 19.85; that is, the CT would be required to handle almost twenty times the maximum flux produced under steady state conditions.

The above theory is sufficient to give a general view of the problem. In this simplified treatment, no reverse voltage is applied to demagnetise the CT, so that the flux would build up as shown in Figure B2.13.

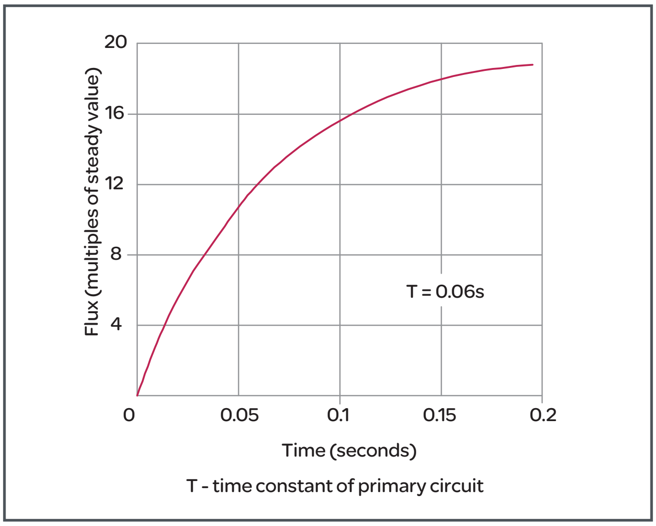

Figure B2.13:
Response of a CT of infinite shunt impedance to transient asymmetric primary current

Since a CT requires a finite exciting current to maintain a flux, it will not remain magnetised (neglecting hysteresis), and for this reason a complete representation of the effects can only be obtained by including the finite inductance of the CT in the calculation. The response of a current transformer to a transient asymmetric current is shown in Figure B2.14.

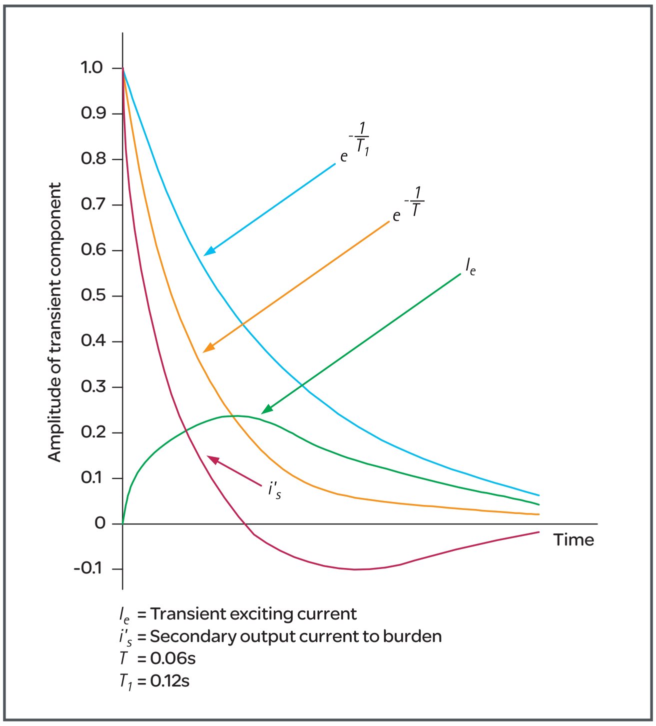

Figure B2.14:
Response of a current transformer to a transient asymmetric current

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4. Current transformers

Let:

i_s = the nominal secondary current

i'_s = the actual secondary output current

i_e = the exciting current

then:

$$i_s = i_e + i'_s \qquad \text{...Equation B2.7}$$

also,

$$L_e \frac{di_e}{dt} = R_b i'_s \qquad \text{...Equation B2.8}$$

whence:

$$\frac{di_e}{dt} + \frac{R_b i_e}{L_e} = \frac{R_b i_s}{L_e} \qquad \text{...Equation B2.9}$$

which gives for the transient term

$$i_e = I_1 \frac{T}{T_1 - T}\left(e^{-t/T_1} - e^{-t/T}\right)$$

where:

T = primary system time constant L/R

T_1 = CT secondary circuit time constant L_e/R_b

I_1 = prospective peak secondary current

4.10.2 Practical conditions

Practical conditions differ from theory for the following reasons:

a. no account has been taken of secondary leakage or burden inductance. This is usually small compared with L_e so that it has little effect on the maximum transient flux

b. iron loss has not been considered. This has the effect of reducing the secondary time constant, but the value of the equivalent resistance is variable, depending upon both the sine and exponential terms. Consequently, it cannot be included in any linear theory and is too complicated for a satisfactory treatment to be evolved

c. the theory is based upon a linear excitation characteristic. This is only approximately true up to the knee-point of the excitation curve. A precise solution allowing for non-linearity is not practicable. Solutions have been sought by replacing the excitation curve with a number of chords; a linear analysis can then be made for the extent of each chord

The above theory is sufficient, however, to give a good insight into the problem and to allow most practical issues to be decided.

d. the effect of hysteresis, apart from loss as discussed under (b) above, is not included. Hysteresis makes the inductance different for flux build up and decay, so that the secondary time constant is variable. Moreover, the ability of the core to retain a 'remanent' flux means that the value of B developed in Equation B2.5 has to be regarded as an increment of flux from any possible remanent value positive or negative. The formula would then be reasonable provided the applied current transient did not produce saturation

It will be seen that a precise calculation of the flux and excitation current is not feasible; the value of the study is to explain the observed phenomena. The asymmetric (or d.c.) component can be regarded as building up the mean flux over a period corresponding to several cycles of the sinusoidal component, during which period the latter component produces a flux swing about the varying 'mean level' established by the former. The asymmetric flux ceases to increase when the exciting current is equal to the total asymmetric input current, since beyond this point the output current, and hence the voltage drop across the burden resistance, is negative. Saturation makes the point of equality between the excitation current and the input occur at a flux level lower than would be expected from linear theory.

When the exponential component drives the CT into saturation, the magnetising inductance decreases, causing a large increase in the alternating component i_e.

The total exciting current during the transient period i_s of the form shown in Figure B2.15 and the corresponding resultant distortion in the secondary current output, due to saturation, is shown in Figure B2.16.

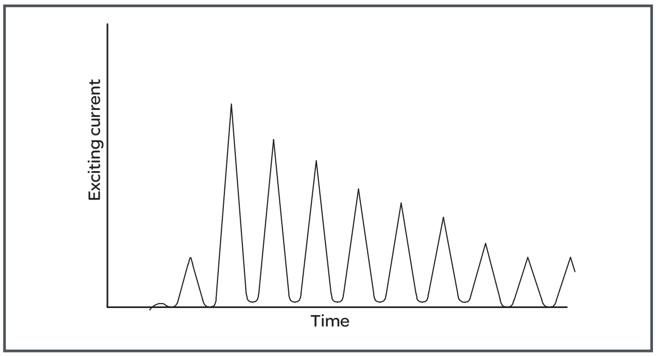

Figure B2.15:
Typical exciting current of CT during transient asymmetric input current

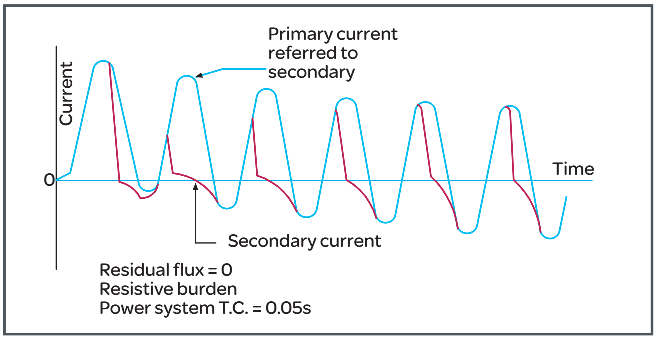

Figure B2.16:
Distortion in secondary current due to saturation

4. Current transformers

The presence of residual flux varies the starting point of the transient flux excursion on the excitation characteristic. Remanence of like polarity to the transient will reduce the value of symmetric current of given time constant which the CT can transform without severe saturation; conversely, reverse remanence will greatly increase the ability of a CT to transform transient current.

If the CT were the linear non-saturable device considered in the analysis, the sine current would be transformed without loss of accuracy. In practice the variation in excitation inductance caused by transferring the centre of the flux swing to other points on the excitation curve causes an error that may be very large. The effect on measurement is of little consequence, but for protection equipment that is required to function during fault conditions, the effect is more serious. The output current is reduced during transient saturation, which may prevent the relays from operating if the conditions are near to the relay setting. This must not be confused with the increased r.m.s. value of the primary current due to the asymmetric transient, a feature which sometimes offsets the increase ratio error. In the case of balanced protection, during through faults the errors of the several current transformers may differ and produce an out-of-balance quantity, causing unwanted operation.

4.11 Harmonics during the transient period

When a CT is required to develop a high secondary e.m.f. under steady state conditions, the non-linearity of the excitation impedance causes some distortion of the output waveform; such a waveform will contain, in addition to the fundamental current, odd harmonics only.

When, however, the CT is saturated uni-directionally while being simultaneously subjected to a small a.c. quantity, as in the transient condition discussed above, the output will contain both odd and even harmonics. Usually the lower numbered harmonics are of greatest amplitude and the second and third harmonic components may be of considerable value. This may affect relays that are sensitive to harmonics.

4.12 Test windings

On-site conjunctive testing of current transformers and the apparatus that they energise is often required. It may be difficult, however, to pass a suitable value of current through the primary windings, because of the scale of such current and in many cases because access to the primary conductors is difficult. Additional windings may be provided to make such tests easier, these windings usually being rated at 10A. The test winding will inevitably occupy appreciable space and the CT will cost more. This fact should be weighed against the convenience achieved; very often it will be found that the tests in question can be replaced by alternative procedures.

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5. Novel instrument transformers

The preceding types of instrument transformers have all been based on electromagnetic principles using a magnetic core. There are now available several new methods of transforming the measured quantity using optical and mass state methods.

5.1 Optical instrument transducers

The key features of a freestanding optical instrument transducer can be illustrated with the functional diagram of Figure B2.17.

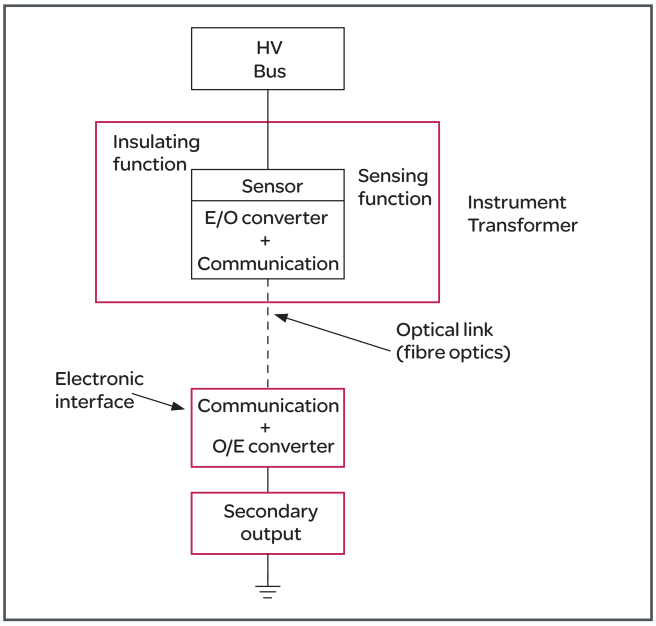

Figure B2.17:
Functional diagram of optical instrument transducer

Optical converters and optical glass fibre channels implement the link between the sensor and the low-voltage output. The fundamental difference between an instrument transducer and a conventional instrument transformer is the electronic interface needed for its operation, providing a low power signal (voltage or current or digital) for connection to protection devices. This type of interface is not practical for 1 or 5A conventional inputs. This interface is required both for the sensing function and for adapting the new sensor technology to that of the secondary output in low current, low voltage or digital communication format (IEC 61850-9-2).

Non-conventional optical transducers lend themselves to smaller, lighter devices where the overall size and power rating of the unit does not have any significant bearing on the size and the complexity of the sensor. Small, lightweight insulator structures may be tailor-made to fit optical sensing devices as an integral part of the insulator. Additionally, the non-linear effects and electromagnetic interference problems in the secondary wiring of conventional VTs and CTs are minimised.

Optical transducers can be separated into two families: firstly the hybrid transducers, making use of conventional electrical circuit techniques to which are coupled various optical converter systems, and secondly the 'all-optical' transducers that are based on fundamental, optical sensing principles.

5.1.1 Optical sensor concepts

Certain optical sensing media (glass, crystals, plastics) show a sensitivity to electric and magnetic fields and some properties of a probing light beam can be altered when passing through them. One simple optical transducer description is given in Figure. B2.18.

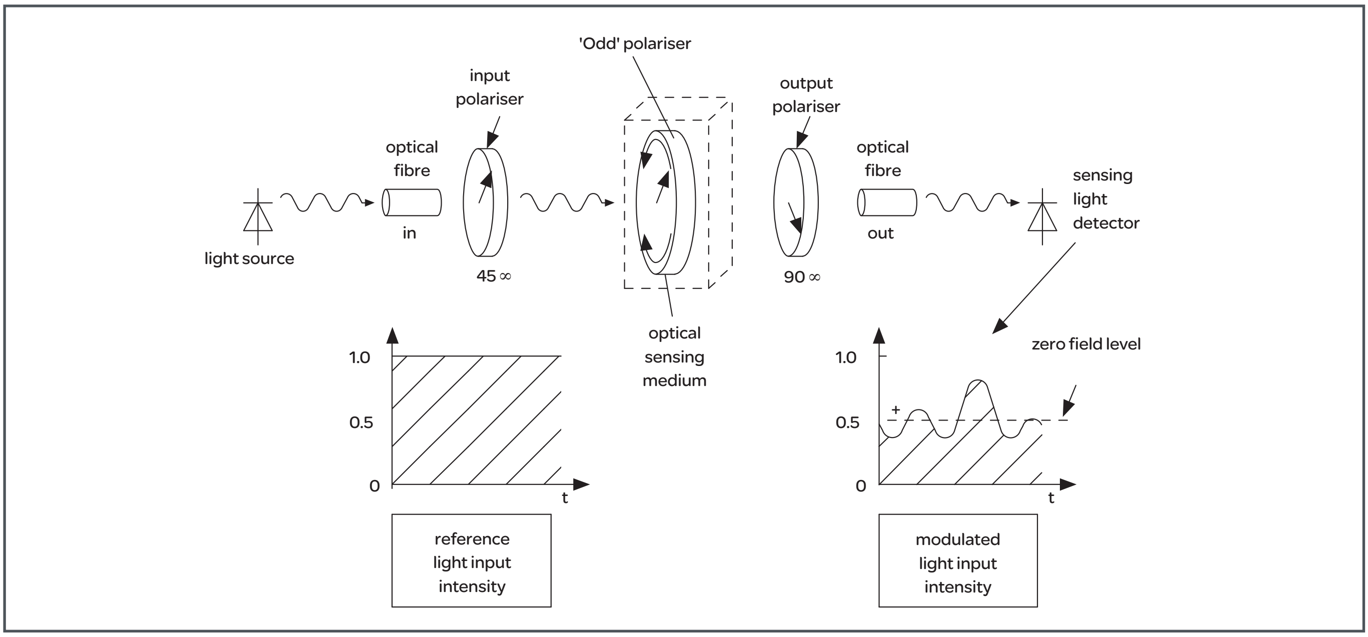

Figure. B2.18:
Schematic representation of the concepts behind the optical sensing of varying electric and magnetic fields

5. Novel instrument transformers

Consider the case of a beam of light passing through a pair of polarising filters. If the input and output polarising filters have their axes rotated 45° from each other, only half the light will come through. The reference light input intensity is maintained constant over time. Now if these two polarising filters remain fixed and a third polarising filter is placed in between them, a random rotation of this middle polariser either clockwise or counter-clockwise will be monitored as a varying or modulated light output intensity at the light detector.

When a block of optical sensing material (glass or crystal) is immersed in a varying magnetic or electric field, it plays the role of the 'odd' polariser. Changes in the magnetic or electric field in which the optical sensor is immersed are monitored as a varying intensity of the probing light beam at the light detector. The light output intensity fluctuates around the zero-field level equal to 50% of the reference light input. This modulation of the light intensity due to the presence of varying fields is converted back to time-varying currents or voltages.

A transducer uses a magneto-optic effect sensor for optical current measuring applications. This reflects the fact that the sensor is not basically sensitive to a current but to the magnetic field generated by this current. Although 'all-fibre' approaches are feasible, most commercially available optical current transducers rely on a bulk-glass sensor. Most optical voltage transducers, on the other hand, rely on an electro-optic effect sensor. This reflects the fact that the sensor used is sensitive to the imposed electric field.

5.1.2 Hybrid transducers

The hybrid family of non-conventional instrument transducers can be divided into two types: those with active sensors and those with passive sensors. The idea behind a transducer with an active sensor is to change the existing output of the conventional instrument transformer into an optically isolated output by adding an optical conversion system (Figure B2.18). This conversion system may require a power supply of its own: this is the active sensor type. The use of an optical isolating system serves to de-couple the instrument transformer output secondary voltages and currents from earthed or galvanic links. Thus the only link that remains between the control room and the switchyard is a fibre optic cable.

Another type of hybrid non-conventional instrument transformer is achieved by retrofitting a passive optical sensing medium into a conventional 'hard-wire secondary' instrument transformer. This can be termed as a passive hybrid type since no power supply of any kind is needed at the secondary level.

5.1.3 'All-optical' transducers

These instrument transformers are based entirely on optical materials and are fully passive. The sensing function is achieved directly by the sensing material and a simple fibre optic cable running between the base of the unit and the sensor location provides the communication link.

The sensing element is made of an optical material that is positioned in the electric or magnetic field to be sensed. In the case of a current measuring device the sensitive element is either located free in the magnetic field (Figure B2.19(a)) or it can be immersed in a field-shaping magnetic 'gap' (Figure B2.19(b)). In the case of a voltage-sensing device (Figure B2.20) the same alternatives exist, this time for elements that are sensitive to electric fields. The possibility exists of combining both sensors within a single housing, thus providing both a CT and VT within a single compact housing that gives rise to space savings within a substation.

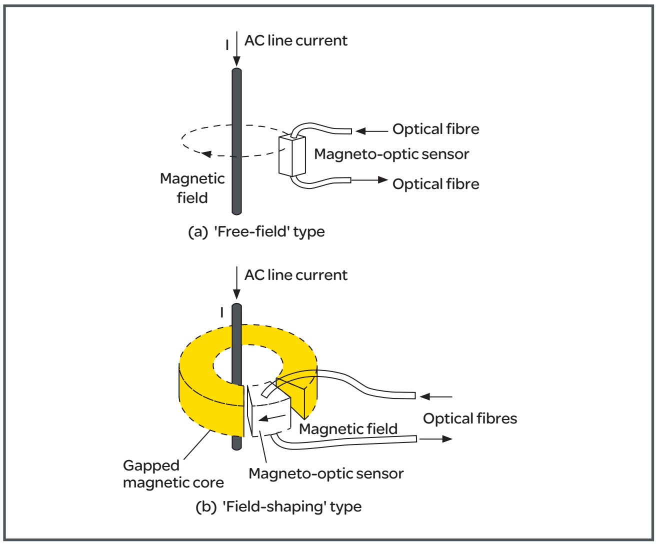

Figure B2.19:
Optical current sensor based on the magnetic properties of optical materials

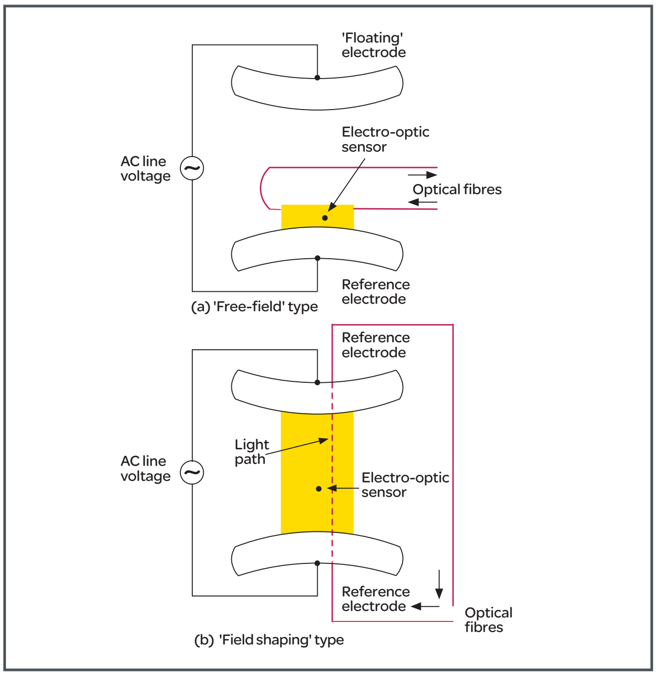

Figure B2.20:
Optical voltage sensor based on the electrical properties of optical materials

5. Novel instrument transformers

In all cases there is an optical fibre that channels the probing reference light from a source into the medium and another fibre that channels the light back to analysing circuitry. In sharp contrast with a conventional free-standing instrument transformer, the optical instrument transformer needs an electronic interface module in order to function. Therefore its sensing principle (the optical material) is passive but its operational integrity relies on the interface that is powered in the control room (Figure B2.21).

Similar to conventional instrument transformers there are 'live tank' and 'dead tank' optical transducers. Typically, current transducers take the shape of a closed loop of light-transparent material, fitted around a straight conductor carrying the line current (Figure B2.22). In this case a bulk-glass sensor unit is depicted (Figure B2.22(a)), along with an 'all-optical' sensor example, as shown in Figure B2.22(b).

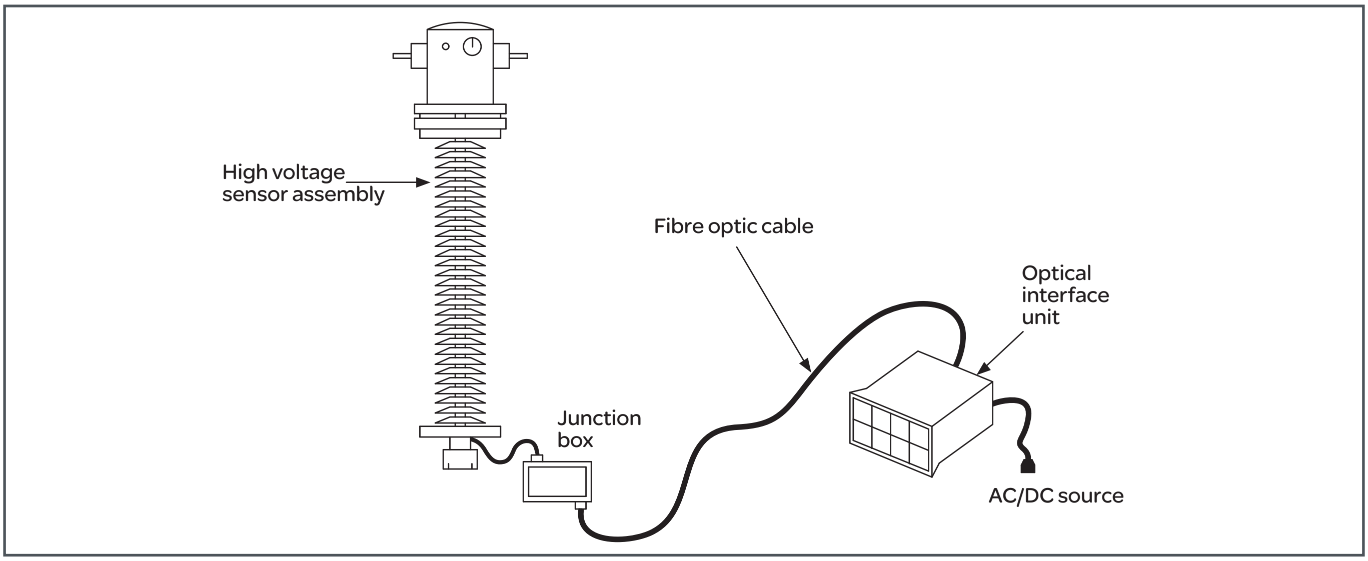

Figure B2.21:
Novel instrument transducer concept requiring an electronic interface in the control room

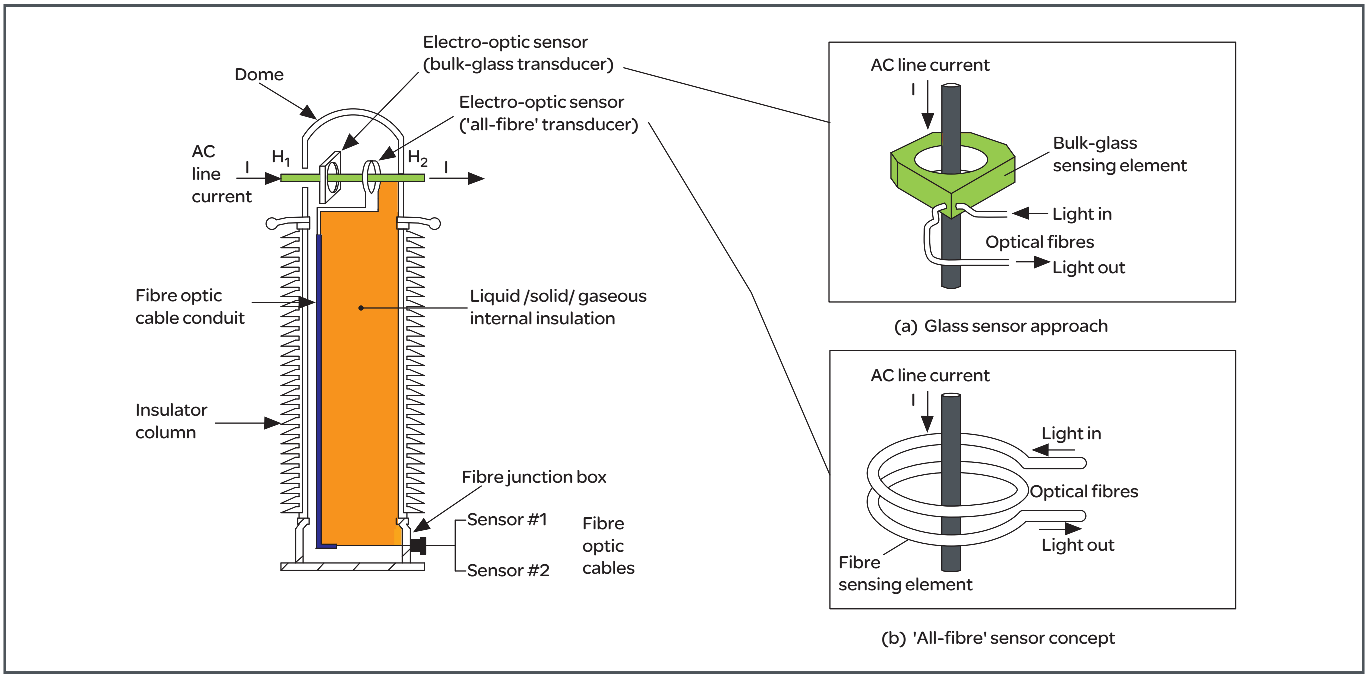

Figure B2.22:
Conceptual design of a double-sensor optical CT

5. Novel instrument transformers

Light detectors are basically very sensitive devices and the sensing material can thus be selected in such a way as to scale-up readily for larger currents. 'All-optical' voltage transducers however do not lend themselves easily for extremely high line voltages. Two concepts using a 'full-voltage' sensor are shown in Figure B2.23.

Although 'all-optical' instrument transformers were first introduced 10-15 years ago, there are still only a few in service nowadays. Figure B2.24 shows a field installation of a combined optical CT/VT.

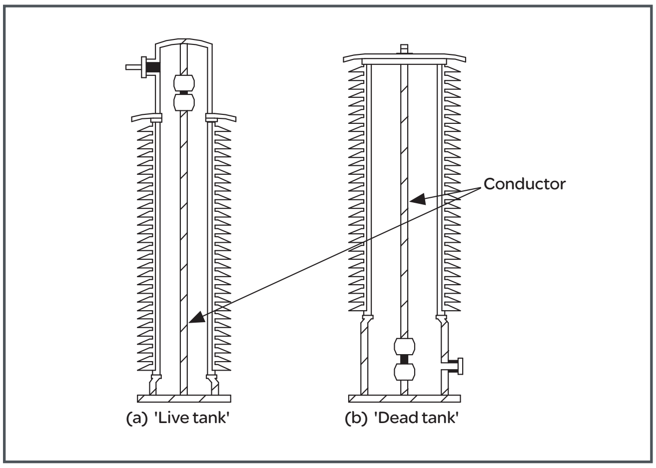

Figure B2.23:
Optical voltage transducer concepts, using a 'full-voltage' sensor

Figure B2.24:
Field installation of a combined optical CT/VT

B2

5. Novel instrument transformers

5.2 Other sensing systems

There are a number of other sensing systems that can be used, as described below.

5.2.1 Zero-flux (Hall Effect) current transformer

In this case the sensing element is a semi-conducting wafer that is placed in the gap of a magnetic concentrating ring. This type of transformer is also sensitive to d.c. currents. The transformer requires a power supply that is fed from the line or from a separate power supply. The sensing current is typically 0.1% of the current to be measured. In its simplest shape, the Hall effect voltage is directly proportional to the magnetising current to be measured. For more accurate and more sensitive applications, the sensing current is fed through a secondary, multiple-turn winding, placed around the magnetic ring in order to balance out the gap magnetic field. This zero-flux, or null-flux, version allows very accurate current measurements in both d.c. and high-frequency applications. A schematic representation of the sensing part is shown in Figure B2.25.

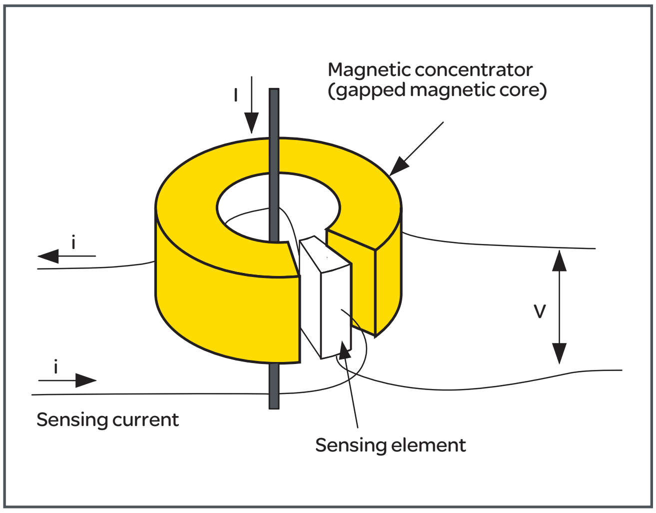

Figure B2.25:
Conceptual design of a Hall-effect current sensing element fitted in a field-shaping gap

5.2.2 Hybrid magnetic-optical sensor

This type of transformer is mostly used in applications such as series capacitive compensation of long transmission lines, where a non-grounded measurement of current is required. In this case, several current sensors are required on each phase in order to achieve capacitor surge protection and balance. The preferred solution is to use small toroidally wound magnetic core transformers connected to fibre optic isolating systems. These sensors are usually active sensors in the sense that the isolated systems require a power supply. This is illustrated in Figure B2.26.

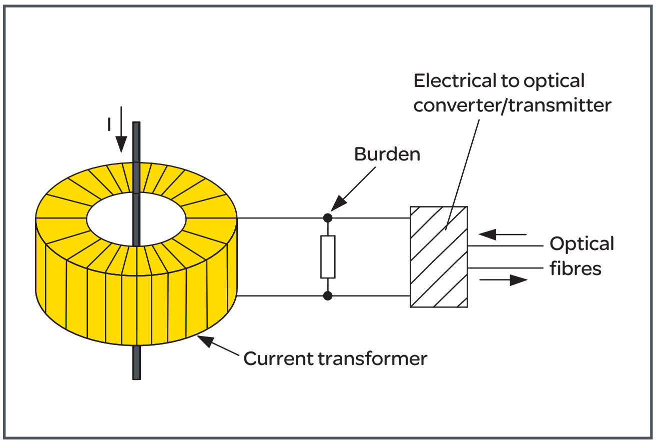

Figure B2.26:
Design principle of a hybrid magnetic current transformer fitted with an optical transmitter

5.2.3 Rogowski coils

The Rogowski coil is based on the principle of an air-cored current transformer with a very high load impedance. The secondary winding is wound on a toroid of insulation material. In most cases the Rogowski coil will be connected to an amplifier, in order to deliver sufficient power to the connected measuring or protection equipment and to match the input impedance of this equipment. The Rogowski coil requires integration of the magnetic field and therefore has a time and phase delay whilst the integration is completed. This can be corrected for within a digital protection relay. The schematic representation of the Rogowski coil sensor is shown in Figure B2.27.

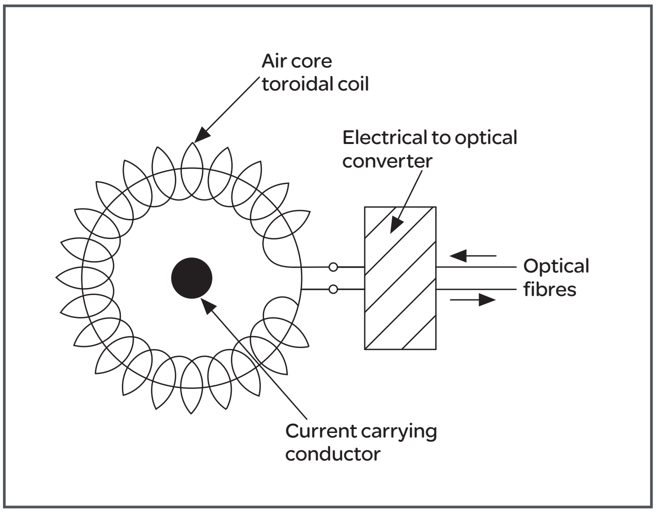

Figure B2.27:
Schematic representation of a Rogowski coil, used for current sensing

B3

Industrial & Commercial Power System Protection

Network Protection & Automation Guide

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Chapter B3

Industrial & Commercial Power System Protection

B3

1. Introduction

As industrial and commercial operations processes and plants have become more complex and extensive (Figure B3.1), the requirement for improved reliability of electrical power supplies has also increased. The potential costs of outage time following a failure of the power supply to a plant have risen dramatically as well. The introduction of automation techniques into industry and commerce has naturally led to a demand for the deployment of more power system automation, to improve reliability and efficiency.

The protection and control of industrial power supply systems must be given careful attention. Many of the techniques that have been evolved for EHV power systems may be applied to lower voltage systems also, but typically on a reduced scale. However, industrial systems have many special problems that have warranted individual attention and the development of specific solutions.

Many industrial plants have their own generation installed. Sometimes it is for emergency use only, feeding a limited number of busbars and with limited capacity. This arrangement is often adopted to ensure safe shutdown of process plant and personnel safety. In other plants, the nature of the process allows production of a substantial quantity of electricity, perhaps allowing export of any surplus to the public supply system – at either sub-transmission or distribution voltage levels. Plants that run generation in parallel with the public supply distribution network are often referred to as co-generation or embedded generation. Special protection arrangements may be demanded for the point of connection between the private and public Utility plant see Chapter [C8: Generator and Generator-Transformer Protection] for further details).

Industrial systems typically comprise numerous cable feeders and transformers. Chapter [C7: Transformer and Transformer-Feeder Protection] covers the protection of transformers and Chapters [C1: Overcurrent Protection for Phase and Earth Faults] and [C2: Line Differential Protection], the protection of feeders.

Figure B3.1:
Large modern industrial plant

2. Busbar arrangement

The arrangement of the busbar system is obviously very important, and it can be quite complex for some very large industrial systems. However, in most systems a single busbar divided into sections by a bus-section circuit breaker is common, as illustrated in Figure B3.2. Main and standby drives for a particular item of process equipment will be fed from different sections of the switchboard, or sometimes from different switchboards.

The main power system design criterion is that single outages on the electrical network within the plant will not cause loss of both the main and standby drives simultaneously. Considering a medium sized industrial supply system as shown in Figure B3.3, with duplicated supplies and transformers. Certain important loads are segregated and fed from 'Essential Services Board(s)' or 'Emergency Boards' distributed throughout the plant. This enables maximum utilisation of the standby generator facility.

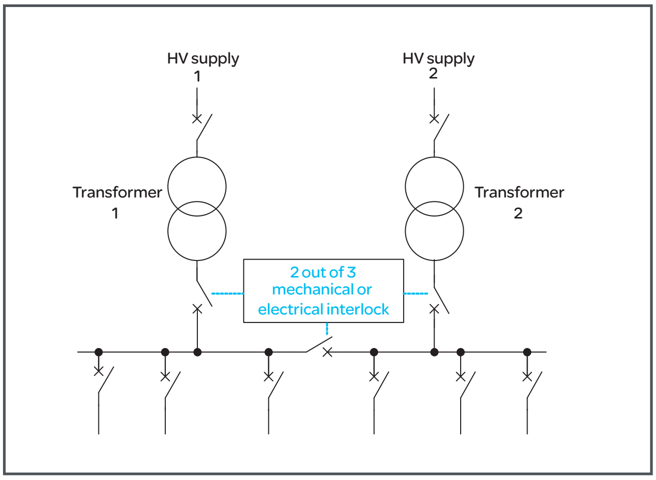

Figure B3.2:
Typical switchboard configuration for an industrial plant

2. Busbar arrangement

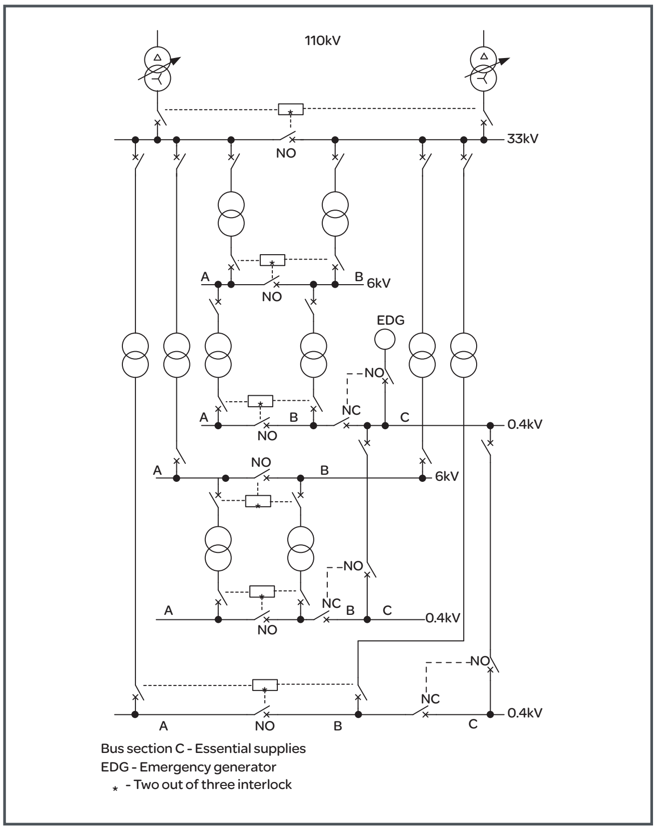

Figure B3.3:
Typical industrial power system

A standby generator is usually of the turbo-charged diesel-driven type. On detection of loss of incoming supply at any switchboard with an emergency section, the generator is automatically started. The appropriate circuit breakers will close once the generating set is up to speed and rated voltage to restore supply to the Essential Services sections of the switchboards affected, provided that the normal incoming supply is absent - for a typical diesel generator set, the emergency supply would be available within 10-20 seconds from the start sequence command being issued.

The Essential Services Boards are used to feed equipment that is essential for the safe shut down, limited operation or preservation of the plant and for the safety of personnel.

This will cover process drives essential for safe shutdown, venting systems, UPS loads feeding emergency lighting, process control computers, etc. The emergency generator may range in size from a single unit rated 20-30kW in a small plant up to several units of 2-10MW rating in a large oil refinery or similar plant. Large financial trading institutions may also have standby power requirements of several MW to maintain computer services.

3. Discrimination

Protection equipment works in conjunction with switchgear. For a typical industrial system, feeders and plant will be protected mainly by circuit breakers of various types and by fused contactors. Circuit breakers will have their associated overcurrent and earth fault relays. A contactor may also be equipped with a protection device (e.g. motor protection), but associated fuses are provided to break fault currents in excess of the contactor interrupting capability. The rating of fuses and selection of relay settings is carried out to ensure that discrimination is achieved – i.e. the ability to select and isolate only the faulty part of the system.

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4. HRC fuses

The protection device nearest to the actual point of power utilisation is most likely to be a fuse or a system of fuses and it is important that consideration is given to the correct application of this important device.

The HRC fuse is a key fault clearance device for protection in industrial and commercial installations, whether mounted in a distribution fuseboard or as part of a contactor or fuse-switch. The latter is regarded as a vital part of LV circuit protection, combining safe circuit making and breaking with an isolating capability achieved in conjunction with the reliable short-circuit protection of the HRC fuse. Fuses combine the characteristics of economy and reliability; factors that are most important in industrial applications.

HRC fuses remain consistent and stable in their breaking characteristics in service without calibration and maintenance. This is one of the most significant factors for maintaining fault clearance discrimination. Lack of discrimination through incorrect fuse grading will result in unnecessary disconnection of supplies, but if both the major and minor fuses are HRC devices of proper design and manufacture, this need not endanger personnel or cables associated with the plant.

4.1 Fuse characteristics

The time required for melting the fusible element depends on the magnitude of current. This time is known as the 'pre-arcing' time of the fuse. Vaporisation of the element occurs on melting and there is fusion between the vapour and the filling powder leading to rapid arc extinction.

Fuses have a valuable characteristic known as 'cut-off', illustrated in Figure B3.4. When an unprotected circuit is subjected to a short circuit fault, the r.m.s. current rises towards a 'prospective' (or maximum) value. The fuse usually interrupts the short circuit current before it can reach the prospective value, in the first quarter to half cycle of the short circuit. The rising current is interrupted by the melting of the fusible element, subsequently dying away to zero during the arcing period.

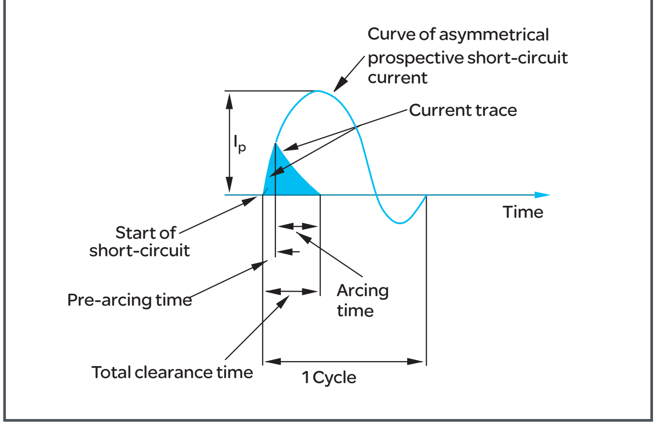

Figure B3.4:
HRC fuse cut-off feature

Since the electromagnetic forces on busbars and connections carrying short circuit current are related to the square of the current, it will be appreciated that 'cut-off' significantly reduces the mechanical forces produced by the fault current and which may distort the busbars and connections if not correctly rated. A typical example of 'cut-off' current characteristics is illustrated in Figure B3.5.

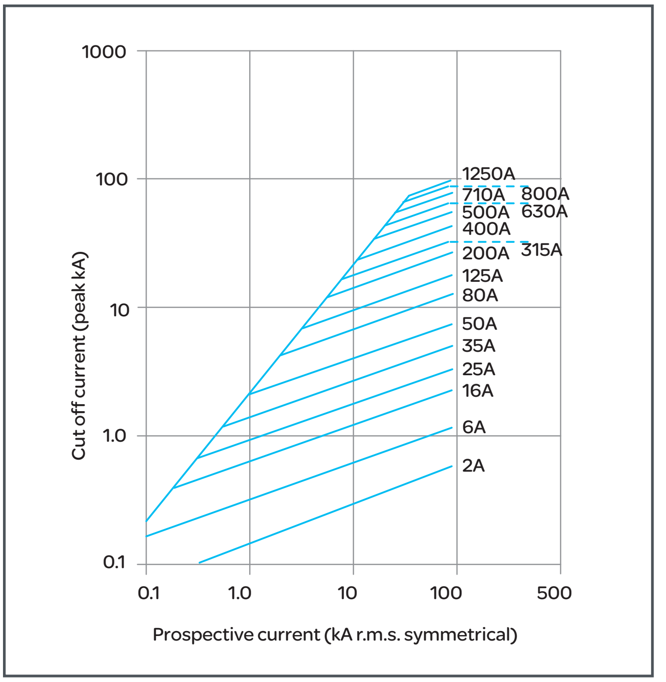

Figure B3.5:
Typical fuse cut-off current characteristics

It is possible to use this characteristic during the design stage of a project to utilise equipment with a lower fault withstand rating downstream of the fuse, than would be the case if 'cut-off' was ignored. This may save on costs, but appropriate documentation and maintenance controls are required to ensure that only replacement fuses of very similar characteristics are used throughout the lifetime of the plant concerned – otherwise a safety hazard may arise.

4.2 Discrimination between fuses

Fuses are often connected in series electrically and it is essential that they should be able to discriminate with each other at all current levels. Discrimination is obtained when the larger ('major') fuse remains unaffected by fault currents that are cleared by the smaller ('minor') fuse.

The fuse operating time can be considered in two parts:

a. the time taken for fault current to melt the element, known as the 'pre-arcing time'

b. the time taken by the arc produced inside the fuse to extinguish and isolate the circuit, known as the 'arcing time'

4. HRC fuses

The total energy dissipated in a fuse during its operation consists of 'pre-arcing energy' and 'arc energy'. The values are usually expressed in terms of I^2t, where I is the current passing through the fuse and t is the time in seconds. Expressing the quantities in this manner provides an assessment of the heating effect that the fuse imposes on associated equipment during its operation under fault conditions.

To obtain positive discrimination between fuses, the total I^2t value of the minor fuse must not exceed the pre-arcing I^2t value of the major fuse. In practice, this means that the major fuse will have to have a rating significantly higher than that of the minor fuse, and this may give rise to problems of discrimination. Typically, the major fuse must have a rating of at least 160% of the minor fuse for discrimination to be obtained.

4.3 Protection of cables by fuses

PVC cable is allowed to be loaded to its full nominal rating only if it has 'close excess current protection'. This degree of protection can be given by means of a fuse link having a 'fusing factor' not exceeding 1.5, where:

$$\text{Fusing factor} = \frac{\textit{Minimum Fusing Current}}{\textit{Current Rating}}$$

Cables constructed using other insulating materials (e.g. paper, XLPE) have no special requirements in this respect.

4.4 Effect of ambient temperature

High ambient temperatures can influence the capability of HRC fuses. Most fuses are suitable for use in ambient temperatures up to 35 °C, but for some fuse ratings, derating may be necessary at higher ambient temperatures. Manufacturers' published literature should be consulted for the de-rating factor to be applied.

4.5 Protection of motors

The manufacturers' literature should also be consulted when fuses are to be applied to motor circuits. In this application, the fuse provides short circuit protection but must be selected to withstand the starting current (possibly up to 8 times full load current) and also carry the normal full load current continuously without deterioration. Tables of recommended fuse sizes for both 'direct on line' and 'assisted start' motor applications are usually given. Examples of protection using fuses are given in Section 12.1.

5. Industrial circuit breakers

Some parts of an industrial power system are most effectively protected by HRC fuses, but the replacement of blown fuse links can be particularly inconvenient in others. In these locations, circuit breakers are used instead, the requirement being for the breaker to interrupt the maximum possible fault current successfully without damage to itself. In addition to fault current interruption, the breaker must quickly disperse the resulting ionised gas away from the breaker contacts, to prevent re-striking of the arc, and away from other live parts of equipment to prevent breakdown. The breaker, its cable or busbar connections, and the breaker housing, must all be constructed to withstand the mechanical forces resulting from the magnetic fields and internal arc gas pressure produced by the highest levels of fault current to be encountered.

The types of circuit breaker most frequently encountered in industrial systems are described in the following sections.

5.1 Miniature Circuit Breakers (MCBs)

MCBs are small circuit breakers, both in physical size but more importantly, in ratings. The basic single pole unit is a small, manually closed, electrically or manually opened switch housed in a moulded plastic casing. They are suitable for use on 230V a.c. single-phase/400V a.c. three-phase systems and for d.c. auxiliary supply systems, with current ratings of up to 125A. Contained within each unit is a thermal element, in which a bimetal strip will trip the switch when excessive current passes through it. This element operates with a predetermined inverse-time/current characteristic. Higher currents, typically those exceeding 3-10 times rated current, trip the circuit breaker without intentional delay by actuating a magnetic trip overcurrent element. The operating time characteristics of MCBs are not adjustable. European Standard EN 60898-2 defines the instantaneous trip characteristics, while the manufacturer can define the inverse time thermal trip characteristic. Therefore, a typical tripping characteristic does not exist. The maximum a.c. breaking current permitted by the standard is 25kA.

Single-pole units may be coupled mechanically in groups to form 2, 3 or 4 pole units, when required, by assembly on to a rail in a distribution board. The available ratings make MCBs suitable for industrial, commercial or domestic applications,

5. Industrial circuit breakers

for protecting equipment such as cables, lighting and heating circuits, and also for the control and protection of low power motor circuits. They may be used instead of fuses on individual circuits, and they are usually 'backed-up' by a device of higher fault interrupting capacity.

Various accessory units, such as isolators, timers, and undervoltage or shunt trip release units, may be combined with an MCB to suit the particular circuit to be controlled and protected. When personnel or fire protection is required, a residual current device (RCD) may be combined with the MCB. The RCD contains a miniature core balance current transformer that embraces all of the phase and neutral conductors to provide sensitivity to earth faults within a typical range of 0.05% to 1.5% of rated current, dependent on the RCD selected. The core balance CT energises a common magnetic trip actuator for the MCB assembly.

It is also possible to obtain current-limiting MCBs. These types open prior to the prospective fault current being reached, and therefore have similar properties to HRC fuses. It is claimed that the extra initial cost is outweighed by lifetime savings in replacement costs after a fault has occurred, plus the advantage of providing improved protection against electric shock if an RCD is used. As a result of the increased safety provided by MCBs fitted with an RCD device, they are tending to replace fuses, especially in new installations.

5.2 Moulded Case Circuit Breakers (MCCBs)

These circuit breakers are broadly similar to MCBs but have the following important differences:

a. the maximum ratings are higher, with voltage ratings up to 1000V a.c./1200V d.c. Current ratings of 2.5kA continuous/180kA r.m.s break are possible, dependent upon power factor

b. the breakers are larger, commensurate with the level of ratings. Although available as single, double or triple pole units, the multiple pole units have a common housing for all the poles. Where fitted, the switch for the neutral circuit is usually a separate device, coupled to the multi-pole MCCB

c. the operating levels of the magnetic and thermal protection elements may be adjustable, particularly in the larger MCCBs

d. because of their higher ratings, MCCBs are usually positioned in the power distribution system nearer to the power source than the MCBs

e. the appropriate European specification is EN 60947-2

Care must be taken in the short-circuit ratings of MCCBs. MCCBs are given two breaking capacities, the higher of which is its ultimate breaking capacity. The significance of this is that after breaking such a current, the MCCB may not be fit for continued use. The lower, or service, short circuit breaking capacity permits continued use without further detailed examination of the device. The standard permits a service breaking capacity of as little as 25% of the ultimate breaking capacity. While there is no objection to the use of MCCBs to break short-circuit currents between the service and ultimate values, the inspection required after such a trip reduces the usefulness of the device in such circumstances. It is also clearly difficult to determine if the magnitude of the fault current was in excess of the service rating.

The time-delay characteristics of the magnetic or thermal timed trip, together with the necessity for, or size of, a back-up device varies with make and size of breaker. Some MCCBs are fitted with microprocessor-controlled programmable trip characteristics offering a wide range of such characteristics. Time–delayed overcurrent characteristics may not be the same as the standard characteristics for dependent-time protection stated in IEC 60255-3. Hence, discrimination with other protection must be considered carefully.

There can be problems where two or more MCBs or MCCBs are electrically in series, as obtaining selectivity between them may be difficult. There may be a requirement that the major device should have a rating of k times the minor device to allow discrimination, in a similar manner to fuses – the manufacturer should be consulted as to value of k. Careful examination of manufacturers' literature is always required at the design stage to determine any such limitations that may be imposed by particular makes and types of MCCBs. An example of co-ordination between MCCBs, fuses and relays is given in Section 12.2.

5.3 Air Circuit Breakers (ACBs)

Air circuit breakers are frequently encountered on industrial systems rated at 3.3kV and below. Modern LV ACBs are available in current ratings of up to 6.3kA with maximum breaking capacities in the range of 85kA-120kA r.m.s., depending on system voltage.

This type of breaker operates on the principle that the arc produced when the main contacts open is controlled by directing it into an arc chute. Here, the arc resistance is increased and hence the current reduced to the point where the circuit voltage cannot maintain the arc and the current reduces to zero. To assist in the quenching of low current arcs, an air cylinder may be fitted to each pole to direct a blast of air across the contact faces as the breaker opens, so reducing contact erosion.

Air circuit breakers for industrial use are usually withdrawable and are constructed with a flush front plate making them ideal for inclusion together with fuse switches and MCBs/MCCBs in modular multi-tier distribution switchboards, so maximising the number of circuits within a given floor area.

Older types using a manual or dependent manual closing mechanism are regarded as being a safety hazard. This arises under conditions of closing the CB when a fault exists on the circuit being controlled. During the close-trip operation, there is a danger of egress of the arc from the casing of the CB, with

5. Industrial circuit breakers

a consequent risk of injury to the operator. Such types may be required to be replaced with modern equivalents. ACBs are normally fitted with integral overcurrent protection, thus avoiding the need for separate protection devices. However, the operating time characteristics of the integral protection are often designed to make discrimination with MCBs/MCCBs/fuses easier and so they may not be in accordance with the standard dependent time characteristics given in IEC 60255-3. Therefore, problems in co-ordination with discrete protection relays may still arise, but modern numerical relays have more flexible characteristics to alleviate such difficulties. ACBs will also have facilities for accepting an external trip signal, and this can be used in conjunction with an external relay if desired. Figure B3.6 illustrates the typical tripping characteristics available.

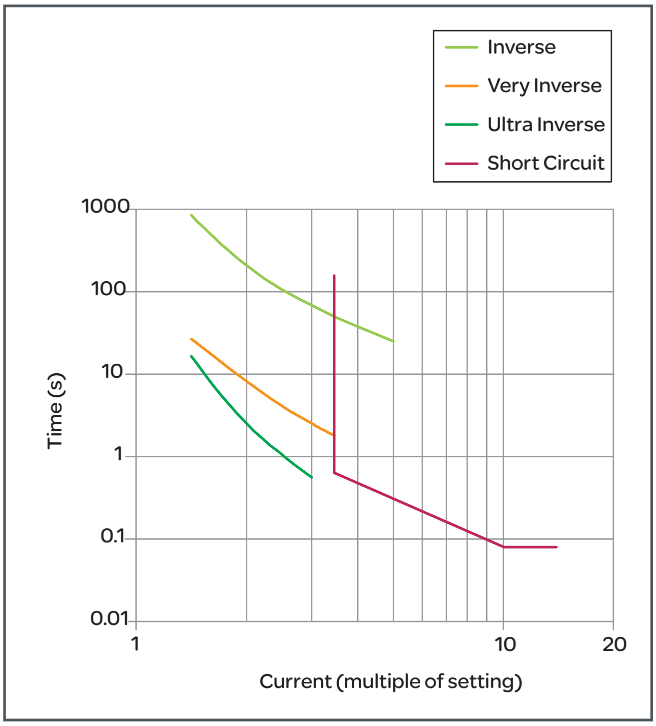

Figure B3.6:
Typical tripping characteristics of an ACB

5.4 Oil Circuit Breakers (OCBs)

Oil circuit breakers have been very popular for many years for industrial supply systems at voltages of 3.3kV and above. They are found in both 'bulk oil' and 'minimum oil' types, the only significant difference being the volume of oil in the tank.

In this type of breaker, the main contacts are housed in an oil-filled tank, with the oil acting as the both the insulation and the arc-quenching medium. The arc produced during contact separation under fault conditions causes dissociation of the hydrocarbon insulating oil into hydrogen and carbon. The hydrogen extinguishes the arc. The carbon produced mixes with the oil. As the carbon is conductive, the oil must be changed after a prescribed number of fault clearances, when the degree of contamination reaches an unacceptable level.

Because of the fire risk involved with oil, precautions such as the construction of fire/blast walls may have to be taken when OCBs are installed.

5.5 Vacuum Circuit Breakers (VCBs)

Since the introduction of vacuum switching technology in the 1960's, Vacuum switchgear has all but replaced Air Circuit Breaker (ACBs) and Oil Circuit Breaker (OCBs) at medium voltage levels.

Vacuum switchgear is rated for fault level up to 63kA with continuous ratings of greater than 5000A.

The vacuum interrupter is a compact, inherently reliable and maintenance free device with an expected life of more than 10,000 operations and is capable of interrupting full fault currents up to 100 times.

These characteristics have resulted in a dramatic reduction in switchgear maintenance compared to ACBs or OCBs and are used in a wide range of applications, including Distribution networks and medium to large industry.

The reduction in maintenance requirements and smaller dimensions have allowed the configuration of switchgear to be adapted from the conventional withdrawable pattern to a fixed pattern Air Insulated Switchgear (AIS, See Fig B3.7). Fixed pattern switchgear is generally more compact, easier to install and has simpler operation.

Figure B3.7:
Typical air insulated vacuum contactor switchgear

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5. Industrial circuit breakers

The fixed pattern is also available in a gas insulated configuration (GIS) where the Vacuum Interrupter and main current carrying parts are insulated with SF6 gas. This further enhances the compact nature of the design. Typically 36kV GIS has similar dimensions to 12kV AIS (See Figure B3.8).

Figure B3.8:
Typical gas insulated vacuum contactor switchgear

Gas Insulated Switchgear is normally found in higher voltage applications. i.e. 24kV and above.

A variation of vacuum switchgear is the vacuum contactor. This device has a limited fault interrupting rating and is used in conjunction with High Rupturing Capacity (HRC) fuses, The contactor has a very high operating duty – up to 1 million operations, and is typically used to switch MV motors.

5.6 SF6 circuit breakers

Circuit breakers using SF6 gas as the arc-quenching medium are also available and in some countries and for some applications are preferred. Generally these have similar ratings to those of vacuum switchgear and in some cases can be incorporated into the same cubicle as vacuum circuit breakers.

5.7 Improved safety

Changes in International Standards have resulted in improvements to operator safety. One area is Internal Arc (Arc Flash) protection. Many switchgear designs have passive protection 'built in' and are capable of controlling the effects of an internal arc fault even at the highest fault levels available.

To supplement this, or to improve the performance of existing switchgear, active solutions, which detect the occurrence of an arc fault and then initiate the disconnection of the supply, are available in conjunction with protection relay systems. For more details on arc protection solutions please refer to Chapter [C11: Arc Protection].

6. Protection relays

When the circuit breaker itself does not have integral protection, then a suitable external relay will have to be provided. For an industrial system, the most common protection relays are time- delayed overcurrent and earth fault relays. Chapter [C1: Overcurrent Protection for Phase and Earth Faults] provides details of the application of overcurrent relays.

Traditionally, for three wire systems, overcurrent relays have often been applied to two phases only for relay element economy. Even with modern multi-element relay designs, economy is still a consideration in terms of the number of analogue current inputs that have to be provided. Two overcurrent elements will detect any interphase fault, so it is conventional to apply two elements on the same phases at all relay locations. The phase CT residual current connections for an earth fault relay element are unaffected by this convention. Figure B3.9 illustrates the possible relay connections and limitations on settings.

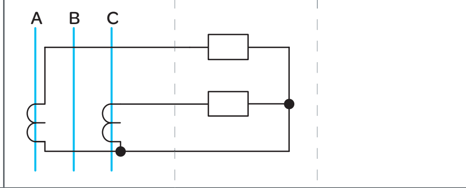
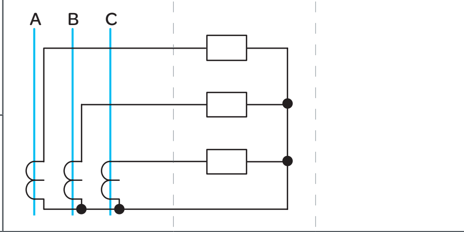
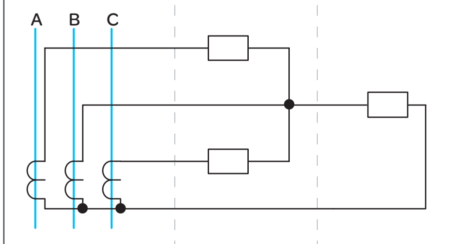
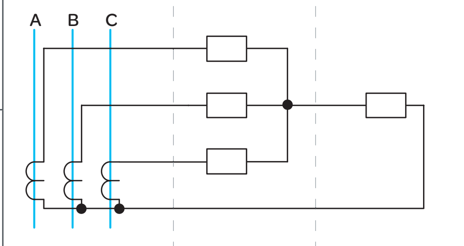
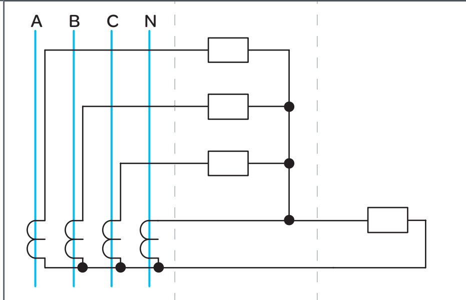
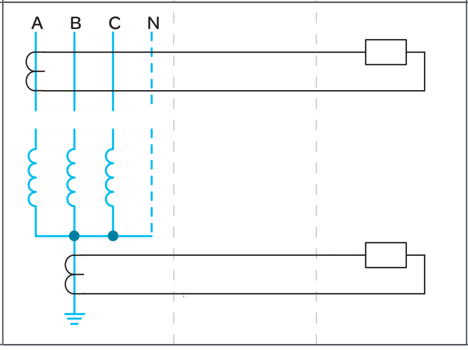
	CT connections	Phase elements	Residual current elements	System	Type of fault	Notes
(a)				3Ph. 3w	Ph. - Ph.	Petersen coil and unearthed systems
(b)				3Ph. 3w	(a) Ph. - Ph. (b) Ph. - E*	* Earth-fault protection only if earth-fault current is not less than twice primary operating current
(c)				3Ph. 4w	(a) Ph. - Ph. (b) Ph. - E* (c) Ph. - N	
(d)				3Ph. 3w	(a) Ph. - Ph. (b) Ph. - E	Phase elements must be in same phases at all stations. Earth-fault settings may be less than full load
(e)				3Ph. 3w	(a) Ph. - Ph. (b) Ph. - E	Earth-fault settings may be less than full load
(f)				3Ph. 4w	(a) Ph. - Ph. (b) Ph. - E (c) Ph. - N	Earth-fault settings may be less than full load, but must be greater than largest Ph. - N load
(g)				3Ph. 4w	(a) Ph. - Ph. (b) Ph. - E (c) Ph. - N	Earth-fault settings may be less than full load
(h)				3Ph. 3w or 3Ph. 4w	Ph. - E	Earth-fault settings may be less than full load
Ph. = phase ; w = wire ; E = earth ; N = neutral						

Figure B3.9:
Overcurrent and earth fault relay connections

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7. Co-ordination problems

There are a number of problems that commonly occur in industrial and commercial networks that are covered in the following sections.

7.1. Earth fault protection with residually-connected CTs

For four-wire systems, the residual connection of three phase CTs to an earth fault relay element will offer earth fault protection, but the earth fault relay element must be set above the highest single- phase load current to avoid nuisance tripping. Harmonic currents (which may sum in the neutral conductor) may also result in spurious tripping. The earth fault relay element will also respond to a phase-neutral fault for the phase that is not covered by an overcurrent element where only two overcurrent elements are applied. Where it is required that the earth fault protection should respond only to earth fault current, the protection element must be residually connected to three phase CTs and to a neutral CT or to a core-balance CT. In this case, overcurrent protection must be applied to all three phases to ensure that all phase-neutral faults will be detected by overcurrent protection. Placing a CT in the neutral earthing connection to drive an earth fault relay provides earth fault protection at the source of supply for a 4-wire system. If the neutral CT is omitted, neutral current is seen by the relay as earth fault current and the relay setting would have to be increased to prevent tripping under normal load conditions.

When an earth fault relay is driven from residually connected CTs, the relay current and time settings must be such that that the protection will be stable during the passage of transient CT spill current through the relay. Such spill current can flow in the event of transient, asymmetric CT saturation during the passage of offset fault current, inrush current or motor starting current. The risk of such nuisance tripping is greater with the deployment of low impedance electronic relays rather than electromechanical earth CBCT connection for four-wire system fault relays which presented significant relay circuit impedance. Energising a relay from a core balance type CT generally enables more sensitive settings to be obtained without the risk of nuisance tripping with residually connected phase CTs. When this method is applied to a four-wire system, it is essential that both the phase and neutral conductors are passed through the core balance CT aperture. For a 3-wire system, care must be taken with the arrangement of the cable sheath, otherwise cable faults involving the sheath may not result in relay operation (Figure B3.10).

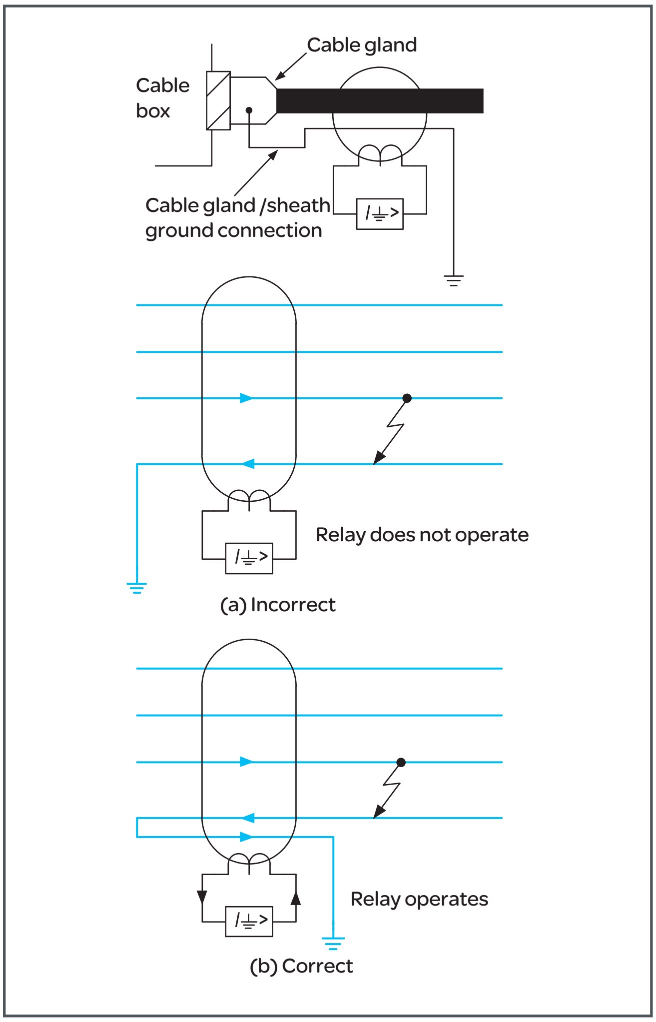

Figure B3.10:
CBCT connection for four-wire system

7.2 Four-wire dual-fed substations

The co-ordination of earth fault relays protecting four-wire systems requires special consideration in the case of low voltage, dual-fed installations. Horcher [Ref B3.1: Overcurrent Relay Co-ordination for Double Ended Substations] has suggested various methods of achieving optimum co-ordination. Problems in achieving optimum protection for common configurations are described below.

7.2.1 Use of 3-pole CBs

When both neutrals are earthed at the transformers and all circuit breakers are of the 3-pole type, the neutral busbar in the switchgear creates a double neutral to earth connection, as shown in Figure B3.11. In the event of an uncleared feeder earth fault or busbar earth fault, with both the incoming supply breakers closed and the bus section breaker open, the earth fault current will divide between the two earth connections. Earth fault relay R_{E2} may operate, tripping the supply to the healthy section of the switchboard as well as relay R_{E1} tripping the supply to the faulted section.

If only one incoming supply breaker is closed, the earth fault relay on the energised side will see only a proportion of the fault current flowing in the neutral busbar. This not only significantly increases the relay operating time but also reduces its sensitivity to low-level earth faults.

7. Co-ordination problems

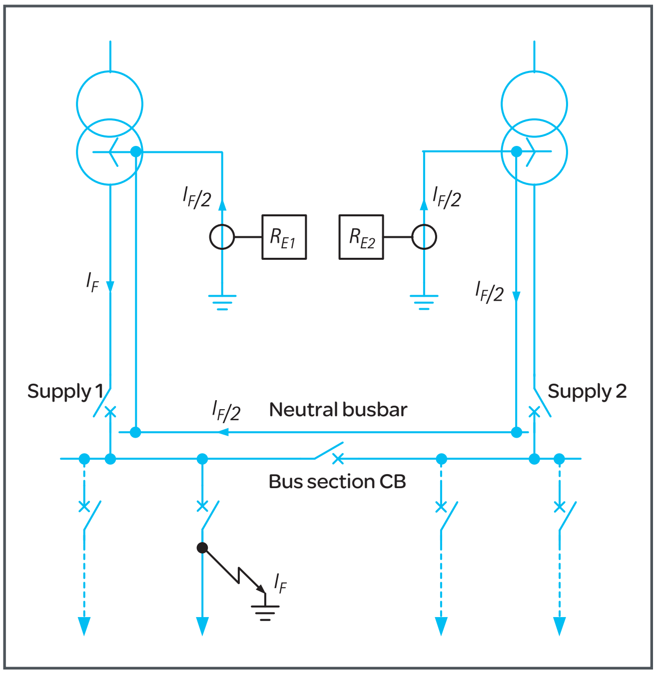

Figure B3.11:
Dual fed four-wire systems: use of 3-pole CBs

The solution to this problem is to utilise 4-pole CBs that switch the neutral as well as the three phases. Then there is only a single earth fault path and relay operation is not compromised.

7.2.2 Use of single earth electrode

A configuration sometimes adopted with four-wire dual-fed substations where only a 3-pole bus section CB is used is to use a single earth electrode connected to the mid-point of the neutral busbar in the switchgear, as shown in Figure B3.12.

When operating with both incoming main circuit breakers and the bus section breaker closed, the bus section breaker must be opened first should an earth fault occur, in order to achieve discrimination. The co-ordination time between the earth fault relays R_F and R_E should be established at fault level F_2 for a substation with both incoming supply breakers and bus section breaker closed.

When the substation is operated with the bus section switch closed and either one or both of the incoming supply breakers closed, it is possible for unbalanced neutral busbar load current caused by single phase loading to operate relay R_{S1} and/or R_{S2} and inadvertently trip the incoming breaker. Interlocking the trip circuit of each R_S relay with normally closed auxiliary contacts on the bus section breaker can prevent this.

However, should an earth fault occur on one side of the busbar when relays R_S are already operated, it is possible for a contact race to occur. When the bus section breaker opens, its break contact may close before the R_S relay trip contact on the healthy side can open (reset). Raising the pick-up level of relays R_{S1} and R_{S2} above the maximum unbalanced neutral current may prevent the tripping of both supply breakers in this case. However, the best solution is to use 4-pole circuit breakers, and independently earth both sides of the busbar.

If, during a busbar earth fault or uncleared feeder earth fault, the bus section breaker fails to open when required, the interlocking break auxiliary contact will also be inoperative. This will prevent relays R_{S1} and R_{S2} from operating and providing back-up protection, with the result that the fault must be cleared eventually by slower phase overcurrent relays. An alternative method of obtaining back-up protection could be to connect a second relay R'_E , in series with relay R_E , having an operation time set longer than that of relays R_{S1} and R_{S2} . But since the additional relay must be arranged to trip both of the incoming supply breakers, back-up protection would be obtained but busbar selectivity would be lost.

An example of protection of a typical dual-fed switchboard is given in Section 12.3.

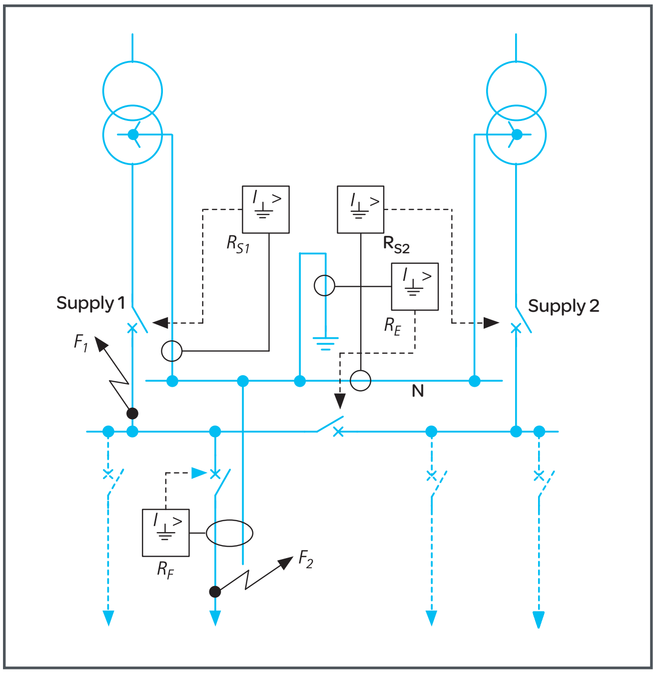

Figure B3.12:
Dual fed four-wire systems: use of single point neutral earthing

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8. Fault current contribution from induction motors

When an industrial system contains motor loads, the motors will contribute fault current for a short time. They contribute to the total fault current via the following mechanism.

When an induction motor is running, a flux, generated by the stator winding, rotates at synchronous speed and interacts with the rotor. If a large reduction in the stator voltage occurs for any reason, the flux in the motor cannot change instantaneously and the mechanical inertia of the machine will tend to inhibit speed reduction over the first few cycles of fault duration. The trapped flux in the rotor generates a stator voltage equal initially to the back e.m.f. induced in the stator before the fault and decaying according to the X/R ratio of the associated flux and current paths. The induction motor therefore acts as a generator, resulting in a contribution of current having both a.c. and d.c. components decaying exponentially. Typical 50Hz motor a.c. time constants lie in the range 10ms-60ms for LV motors and 60-200ms for HV motors. This motor contribution has often been neglected in the calculation of fault levels.

Industrial systems usually contain a large component of motor load, so this approach is incorrect. The contribution from motors to the total fault current may well be a significant fraction of the total in systems having a large component of motor load. Standards relating to fault level calculations, such as IEC 60909, require the effect of motor contribution to be included where appropriate. They detail the conditions under which this should be done, and the calculation method to be used. Guidance is provided on typical motor fault current contribution for both HV and LV motors if the required data is not known. Therefore, it is now relatively easy, using appropriate calculation software, to determine the magnitude and duration of the motor contribution, so enabling a more accurate assessment of the fault level for:

a. discrimination in relay co-ordination

b. determination of the required switchgear/busbar fault rating

For protection calculations, motor fault level contribution is not an issue that is generally is important. In industrial networks, fault clearance time is often assumed to occur at 5 cycles after fault occurrence, and at this time, the motor fault level contribution is much less than just after fault occurrence. In rare cases, it may have to be taken into consideration for correct time grading for through-fault protection considerations, and in the calculation of peak voltage for high-impedance differential protection schemes.

It is more important to take motor contribution into account when considering the fault rating of equipment (busbars, cables, switchgear, etc.). In general, the initial a.c. component of current from a motor at the instant of fault is of similar magnitude to the direct-on-line starting current of the motor. For LV motors, 5xFLC is often assumed as the typical fault current contribution (after taking into account the effect of motor cable impedance), with 5.5xFLC for HV motors, unless it is known that low starting current HV motors are used. It is also accepted that similar motors connected to a busbar can be lumped together as one equivalent motor.

In doing so, motor rated speed may need to be taken into consideration, as 2 or 4 pole motors have a longer fault current decay than motors with a greater number of poles. The kVA rating of the single equivalent motor is taken as the sum of the kVA ratings of the individual motors considered. It is still possible for motor contribution to be neglected in cases where the motor load on a busbar is small in comparison to the total load (again IEC 60909 provides guidance in this respect). However, large LV motor loads and all HV motors should be considered when calculating fault levels.

9. Automatic changeover systems

Induction motors are often used to drive critical loads. In some industrial applications, such as those involving the pumping of fluids and gases, this has led to the need for a power supply control scheme in which motor and other loads are transferred automatically on loss of the normal supply to an alternative supply. A quick changeover, enabling the motor load to be re-accelerated, reduces the possibility of a process trip occurring. Such schemes are commonly applied for large generating units to transfer unit loads from the unit transformer to the station supply/start-up transformer.

When the normal supply fails, induction motors that remain connected to the busbar slow down and the trapped rotor flux generates a residual voltage that decays exponentially. All motors connected to a busbar will tend to decelerate at the same rate when the supply is lost if they remain connected to the busbar. This is because the motors will exchange energy between themselves, so that they tend to stay 'synchronised' to each other. As a result, the residual voltages of all the motors decay at nearly the same rate. The magnitude of this voltage and its phase displacement with respect to the healthy alternative supply voltage is a function of time and the speed of the motors. The angular displacement between the residual motor voltage and the incoming voltage will be 180° at some instant. If the healthy alternative supply is switched on to motors which are running down under these conditions, very high inrush currents may result, producing stresses which could be of sufficient magnitude to cause mechanical damage, as well as a severe dip in the alternative supply voltage.

Two methods of automatic transfer are used:

a. in-phase transfer system

b. residual voltage system

The in-phase transfer method is illustrated in Figure B3.13(a). Normal and standby feeders from the same power source are used.

Phase angle measurement is used to sense the relative phase angle between the standby feeder voltage and the motor busbar voltage. When the voltages are approximately in phase, or just prior to this condition through prediction, a high-speed circuit breaker is used to complete the transfer. This method is restricted to large high inertia drives where the gradual run down characteristic upon loss of normal feeder supply can be predicted accurately.

Figure B3.13(b) illustrates the residual voltage method, which is more common, especially in the petrochemical industry.

Two feeders are used, supplying two busbar sections connected by a normally open bus section breaker. Each feeder is capable of carrying the total busbar load. Each bus section voltage is monitored and loss of supply on either section causes the relevant incomer CB to open. Provided there are no protection operations to indicate the presence of a busbar fault, the bus section breaker is closed automatically to restore the supply to the unpowered section of busbar after the residual voltage generated by the motors running down on that section has fallen to a an acceptable level. This is between 25% and 40%, of nominal voltage, dependent on the characteristics of the power system. The choice of residual voltage setting will influence the re-acceleration current after the bus section breaker closes. For example, a setting of 25% may be expected to result in an inrush current of around 125% of the starting current at full voltage. Alternatively, a time delay could be used as a substitute for residual voltage measurement, which would be set with knowledge of the plant to ensure that the residual voltage would have decayed sufficiently before transfer is initiated.

The protection relay settings for the switchboard must take account of the total load current and the voltage dip during the re- acceleration period in order to avoid spurious tripping during this time. This time can be several seconds where large inertia HV drives are involved.

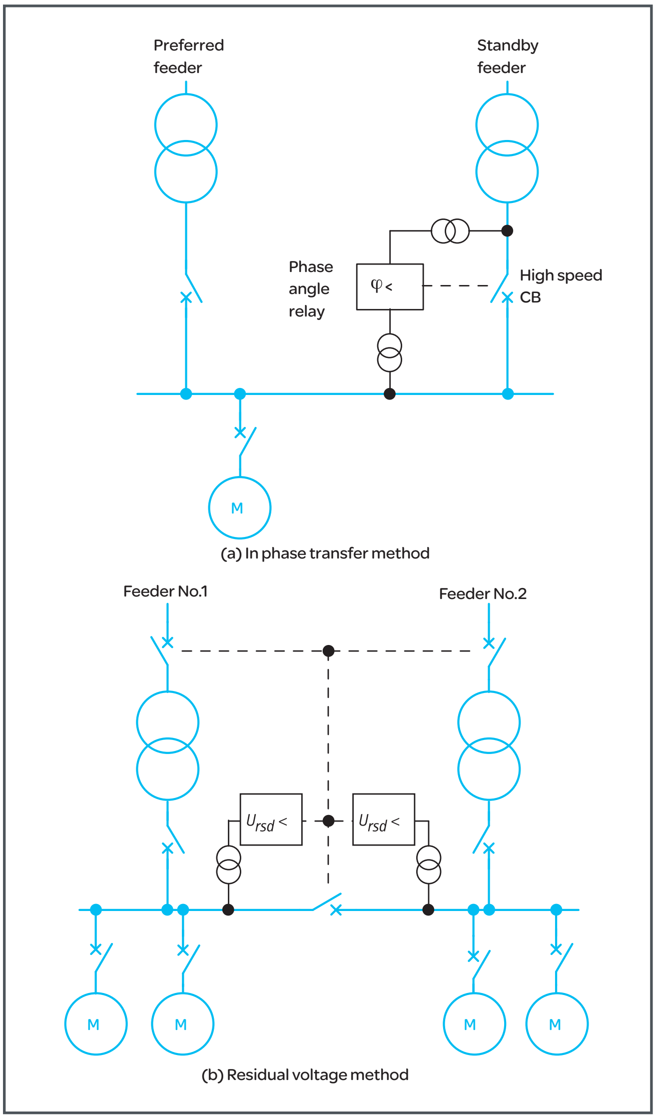

Figure B3.13: Auto-transfer systems

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10. Voltage and phase reversal protection

Voltage relays have been widely used in industrial power supply systems. The principle purposes are to detect undervoltage and/or overvoltage conditions at switchboards to disconnect supplies before damage can be caused from these conditions or to provide interlocking checks. Prolonged overvoltage may cause damage to voltage-sensitive equipment (e.g. electronics), while undervoltage may cause excessive current to be drawn by motor loads. Motors are provided with thermal overload protection to prevent damage with excessive current, but undervoltage protection is commonly applied to disconnect motors after a prolonged voltage dip. With a voltage dip caused by a source system fault, a group of motors could decelerate to such a degree that their aggregate re-acceleration currents might keep the recovery voltage depressed to a level where the machines might stall. Modern numerical motor protection relays typically incorporate voltage protection functions, thus removing the need for discrete undervoltage relays for this purpose. See Chapter [C.9: A.C. Motor Protection]. Older installations may still utilise discrete undervoltage relays, but the setting criteria remain the same.

Reverse phase sequence voltage protection should be applied where it may be dangerous for a motor to be started with rotation in the opposite direction to that intended. Incorrect rotation due to reverse phase sequence might be set up following some error after power system maintenance or repairs, e.g. to a supply cable. Older motor control boards might have been fitted with discrete relays to detect this condition. Modern motor protection relays may incorporate this function. If reverse phase sequence is detected, motor starting can be blocked. If reverse phase sequence voltage protection is not provided, the high-set negative phase sequence current protection in the relay would quickly detect the condition once the starting device is closed – but initial reverse rotation of the motor could not be prevented.

11. Power factor correction and protection of capacitors

Loads such as induction motors draw significant reactive power from the supply system, and a poor overall power factor may result. The flow of reactive power increases the voltage-drops through series reactances such as transformers and reactors, it uses up some of the current carrying capacity of power system plant and it increases the resistive losses in the power system.

To offset the losses and restrictions in plant capacity they incur and to assist with voltage regulation, Utilities usually apply tariff penalties to large industrial or commercial customers for running their plant at excessively low power factor. The customer is thereby induced to improve the power factor of his system and it may be cost-effective to install fixed or variable power factor correction equipment to raise or regulate the plant power factor to an acceptable level.

Shunt capacitors are often used to improve power factor. The basis for compensation is illustrated in Figure B3.14, where $\angle\varphi_1$ represents the uncorrected power factor angle and $\angle\varphi_2$ the angle relating to the desired power factor, after correction.

The following may be deduced from this vector diagram:

a. Uncorrected power factor $= \dfrac{kW}{kVA_1} = \cos\angle\varphi_1$

b. Corrected power factor $= \dfrac{kW}{kVA_2} = \cos\angle\varphi_2$

c. Reduction in $kVA = kVA_1 - kVA_2$

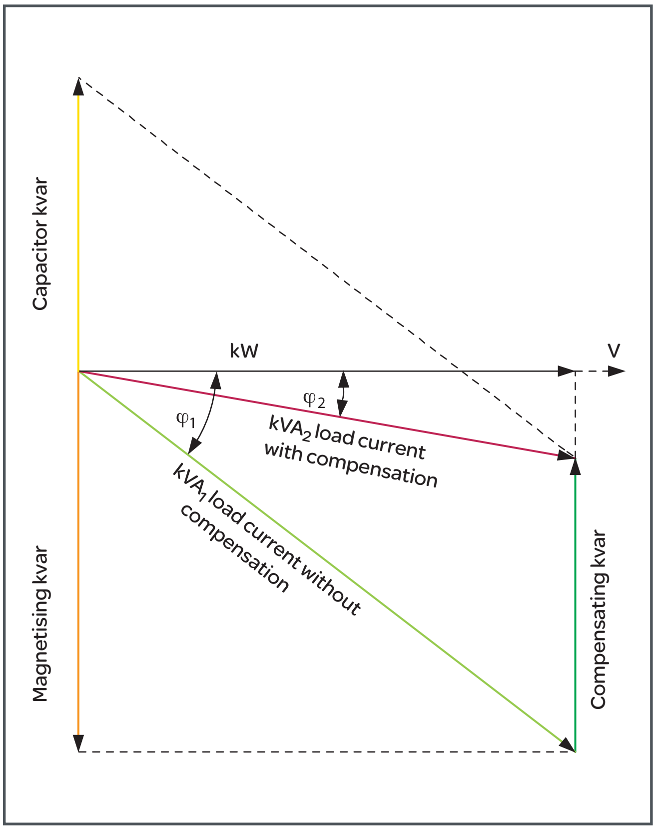


Figure B3.14:
Power factor correction principle

11. Power factor correction and protection of capacitors

If the kW load and uncorrected power factors are known, then the capacitor rating in kvar to achieve a given degree of correction may be calculated from:

Capacitor $kvar = kW \times (tan\angle\varphi_1 - tan\angle\varphi_2)$

A spreadsheet can easily be constructed to calculate the required amount of compensation to achieve a desired power factor.

11.1 Capacitor control

Where the plant load or the plant power factor varies considerably, it is necessary to control the power factor correction, since over-correction will result in excessive system voltage and unnecessary losses. In a few industrial systems, capacitors are switched in manually when required, but automatic controllers are standard practice. A controller provides automatic power factor correction, by comparing the running power factor with the target value. Based on the available groupings, an appropriate amount of capacitance is switched in or out to maintain an optimum average power factor. The controller is fitted with a 'loss of voltage' relay element to ensure that all selected capacitors are disconnected instantaneously if there is a supply voltage interruption. When the supply voltage is restored, the capacitors are reconnected progressively as the plant starts up. To ensure that capacitor groups degrade at roughly the same rate, the controller usually rotates selection or randomly selects groups of the same size in order to even out the connected time. The provision of overvoltage protection to trip the capacitor bank is also desirable in some applications. This would be to prevent a severe system overvoltage if the power factor correction (PFC) controller fails to take fast corrective action.

The design of PFC installations must recognise that many industrial loads generate harmonic voltages, with the result that the PFC capacitors may sink significant harmonic currents. A harmonic study may be necessary to determine the capacitor thermal ratings or whether series filters are required.

11.2 Motor power factor correction

When dealing with power factor correction of motor loads, group correction is not always the most economical method. Some industrial consumers apply capacitors to selected motor substations rather than applying all of the correction at the main incoming substation busbars. Sometimes, power factor correction may even be applied to individual motors, resulting in optimum power factor being obtained under all conditions of aggregate motor load. In some instances, better motor starting may also result, from the improvement in the voltage regulation due to the capacitor. Motor capacitors are often six-terminal units, and a capacitor may be conveniently connected directly across each motor phase winding.

Capacitor sizing is important, such that a leading power factor does not occur under any load condition. If excess capacitance is applied to a motor, it may be possible for self-excitation to occur when the motor is switched off or suffers a supply failure. This can result in the production of a high voltage or in mechanical damage if there is a sudden restoration of supply. Since most star/delta or auto-transformer starters other than the 'Korndorffer' types involve a transitional break in supply, it is generally recommended that the capacitor rating should not exceed 85% of the motor magnetising reactive power.

11.3 Capacitor protection

When considering protection for capacitors, allowance should be made for the transient inrush current occurring on switch-on, since this can reach peak values of around 20 times normal current. Switchgear for use with capacitors is usually de-rated considerably to allow for this. Inrush currents may be limited by a resistor in series with each capacitor or bank of capacitors.

Protection equipment is required to prevent rupture of the capacitor due to an internal fault and also to protect the cables and associated equipment from damage in case of a capacitor failure. If fuse protection is contemplated for a three-phase capacitor, HRC fuses should be employed with a current rating of not less than 1.5 times the rated capacitor current.

Medium voltage capacitor banks can be protected by the scheme shown in Figure B3.15. Since harmonics increase capacitor current, the relay will respond more correctly if it does not have in-built tuning for harmonic rejection.

Double star capacitor banks are employed at medium voltage. As shown in Figure B3.16, a current transformer in the inter star-point connection can be used to drive a protection relay to detect the out-of-balance currents that will flow when capacitor elements become short-circuited or open-circuited. The relay will have adjustable current settings, and it might contain a bias circuit, fed from an external voltage transformer, that can be adjusted to compensate for steady-state spill current in the inter star-point connection.

Some industrial loads such as arc furnaces involve large inductive components and correction is often applied using very large high voltage capacitors in various configurations.

Another high voltage capacitor configuration is the 'split phase' arrangement where the elements making up each phase of the capacitor are split into two parallel paths. Figure B3.17 shows two possible connection methods for the relay. A differential relay can be applied with a current transformer for each parallel branch, comparing the currents in the split phases. Alternatively an overcurrent relay can be applied with a current transformer in the bridge link, where normally no current should flow. Both relays use sensitive current settings but also adjustable compensation for the unbalance currents arising from initial capacitor mismatch.

The difference of current through the split phases or the increase of the current through the bridge link indicates a defect of a single capacitor unit 'can' where the amount of additional current is directly dependent on the can dimensions.

B3

11. Power factor correction and protection of capacitors

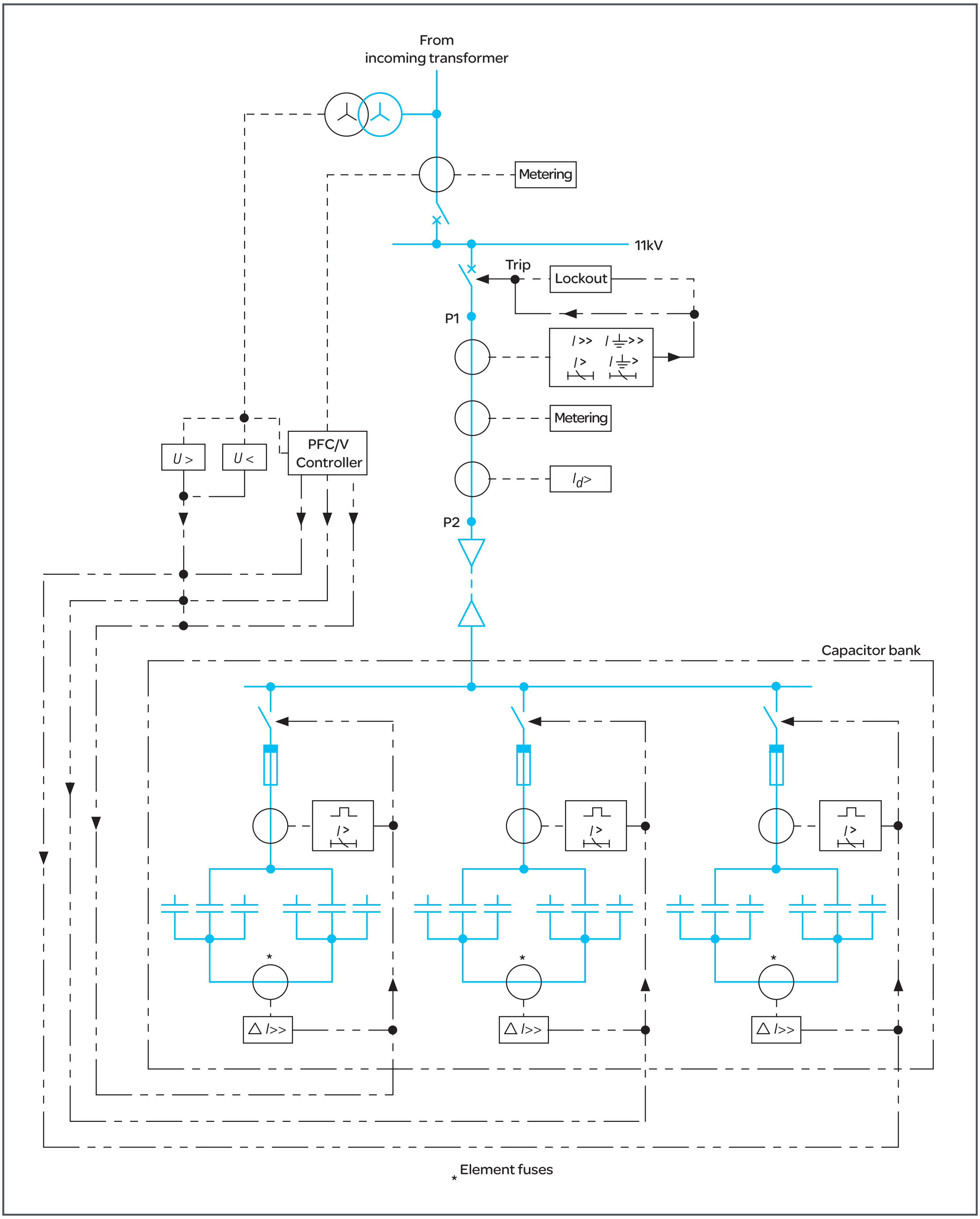


Figure B3.15:
Protection of capacitor banks

11. Power factor correction and protection of capacitors

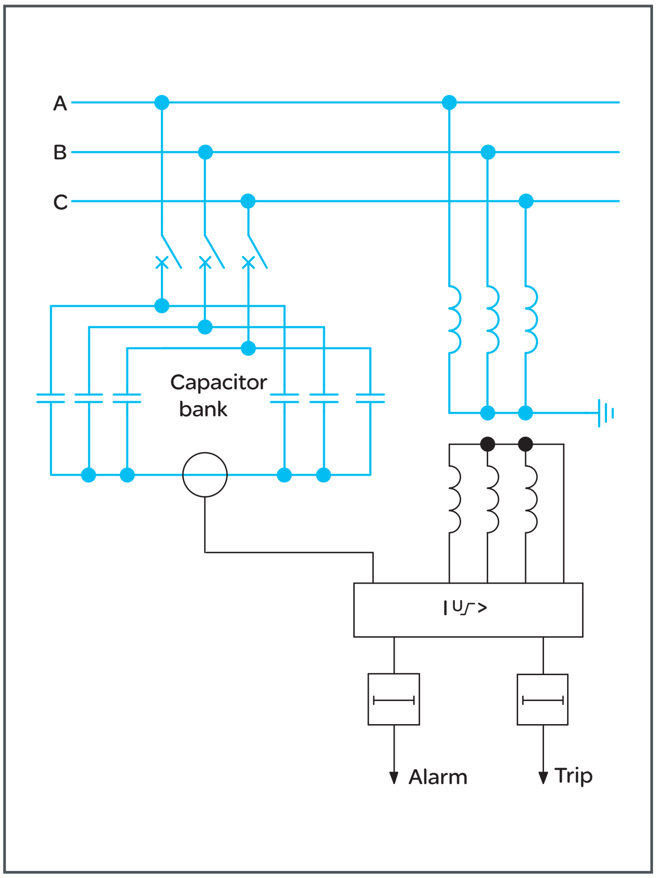


Figure B3.16:
Protection of double star capacitor banks without and with grounded starpoint

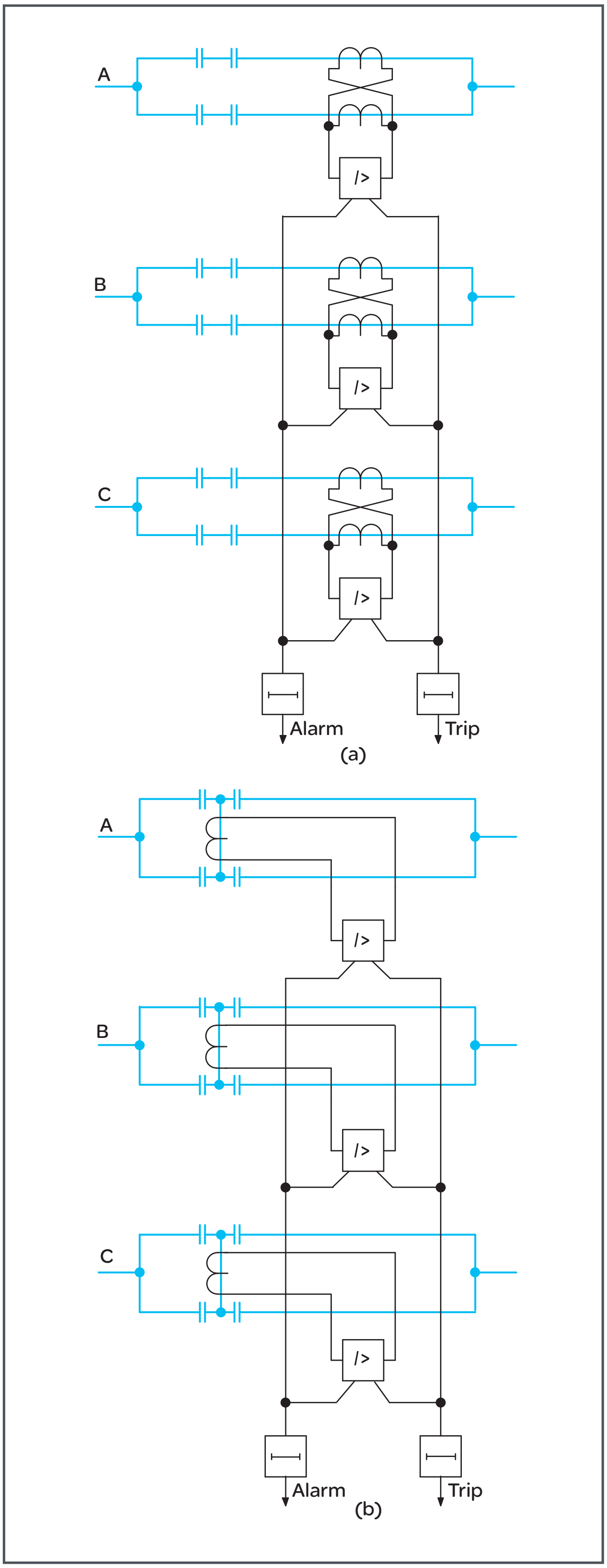


Figure B3.17:
Differential protection of split phase capacitor banks

The usual aim is to get an alarm if one of the cans is defective and to trip the bank if a second can becomes defective. It is possible to deduce which can is defective from the phase relationships of the current and hence help to reduce repair time.

Capacitor units shall be suitable for continuous operation at an r.m.s. current of 1,30 times the current that occurs at rated sinusoidal voltage and rated frequency. In order to prevent thermal damage under load conditions a protection with a 1st order thermal model using the maximum phase current r.m.s. value is typical. Optionally this can be biased by measured ambient (coolant) temperature. Depending on the design/size of the capacitor bank, a dedicated overload protection may be required for current limiting reactors connected in series.

The usual design of capacitor banks allows a continuous sinusoidal voltage of 110% of rated nominal voltage at nominal frequency, in line with normal operation limits of power systems. So by design, the rated voltage of a capacitor bank would be chosen as 121 kV for a 110 kV nominal system.

B3

11. Power factor correction and protection of capacitors

A short-time overvoltage is permitted where duration naturally gets shorter with higher voltage. This results in an inverse-time characteristic per IEC 60871-1 or ANSI/IEEE 37.99, as shown in Figure B3.18. Accordingly, overvoltage protection should consist of a high set definite time delayed and inverse timed element. Due to the "memory effect" of capacitances, a reset characteristic should also be considered to prevent damage from repetitive overvoltages.

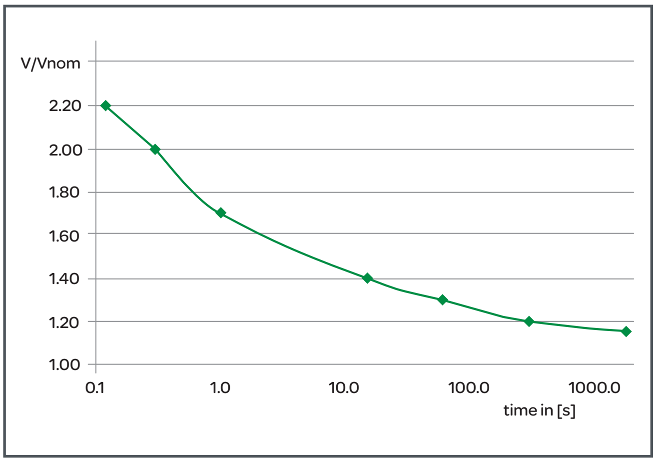


Figure B3.18:
Capacitor bank overvoltage characteristic

As voltage across the capacitor bank is usually not directly accessible through voltage transformers, the voltage is evaluated by integration of the phase currents:

$$v = \frac{1}{c} \int i \, dt$$

Voltage protection requires coordination with nearby generators. Capacitor banks should be disconnected to reduce system overvoltage prior to operation of generator under-excitation protection.

Time-staged tripping of capacitor banks is recommended if banks are installed nearby (the same or neighbouring substation). This is done to avoid simultaneous tripping that might result in a sudden loss of capacitance, which may provoke a subsequent critical undervoltage situation in the power system.

The residual voltage of a capacitor bank prior to energisation shall not exceed 10 % of its rated voltage to minimise the voltage transients when switching due to the network impedances. For this purpose resistors are connected in parallel to the capacitors and designed to internally discharge them when becoming disconnected from the power grid. The resistors are sized to ensure that the capacitor residual voltage occurs within 5 minutes. Therefore after switching off the capacitor bank a suitably long (re-)close blocking time should be provided in the capacitor control and/or protection circuit.

In this section, examples of the topics dealt with in the Chapter are considered.

12.1 Fuse co-ordination

An example of the application of fuses is based on the arrangement in Figure B3.19(a). This shows an unsatisfactory scheme with commonly encountered shortcomings. It can be seen that fuses B, C and D will discriminate with fuse A, but the 400A sub-circuit fuse E may not discriminate, with the 500A sub-circuit fuse D at higher levels of fault current.

The solution, illustrated in Figure B3.19(b), is to feed the 400A circuit direct from the busbars.

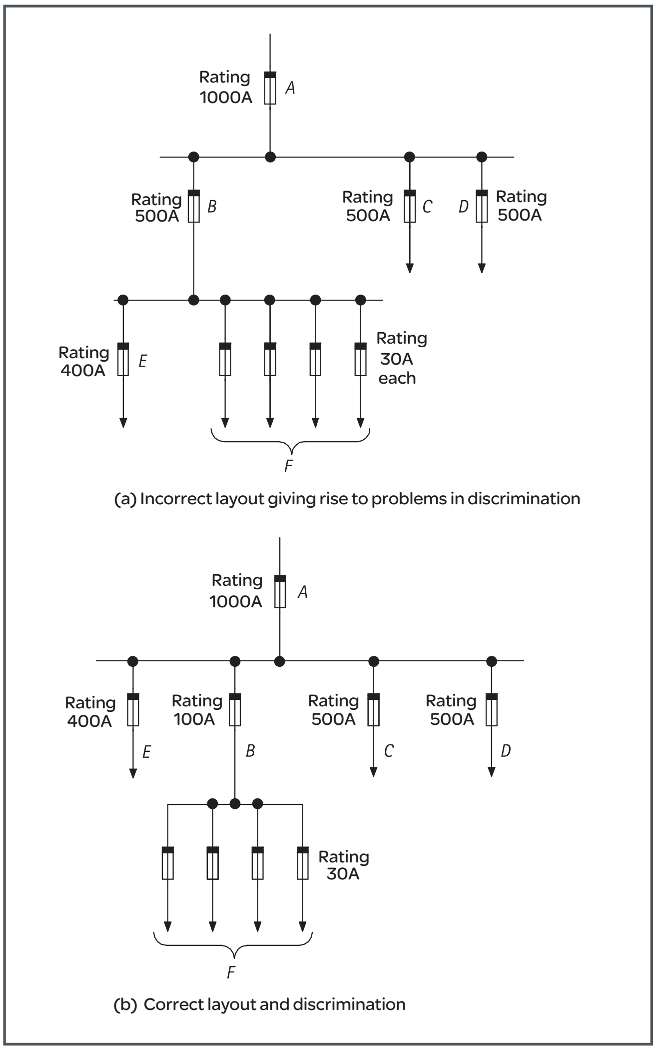


Figure B3.19:
Fuse protection: effect of layout on discrimination

The sub-circuit fuse D may now have its rating reduced from 500A to a value, of say 100A, appropriate to the remaining sub-circuit. This arrangement now provides a discriminating fuse distribution scheme satisfactory for an industrial system.

However, there are industrial applications where discrimination is a secondary factor. In the application shown in Figure B3.20, a contactor having a fault rating of 20kA controls the load in one sub-circuit. A fuse rating of 630A is selected for the minor fuse in the contactor circuit to give protection within the through-fault capacity of the contactor.

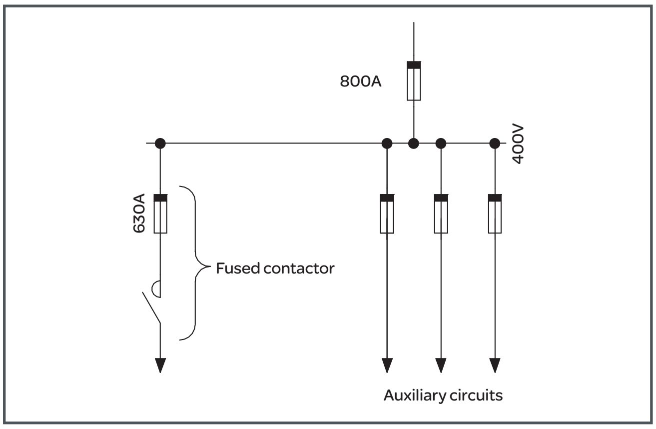


Figure B3.20:
Example of back-up protection

The major fuse of 800A is chosen as the minimum rating that is greater than the total load current on the switchboard. Discrimination between the two fuses is not obtained, as the pre-arcing I^2t of the 800A fuse is less than the total I^2t of the 630A fuse. Therefore, the major fuse will blow as well as the minor one, for most faults so that all other loads fed from the switchboard will be lost. This may be acceptable in some cases. In most cases, however, loss of the complete switchboard for a fault on a single outgoing circuit will not be acceptable, and the design will have to be revised.

12.2 Grading of fuses/MCCBs/overcurrent relays

An example of an application involving a moulded case circuit breaker, fuse and a protection relay is shown in Figure B3.21. A 1MVA 3.3kV/400V transformer feeds the LV board via a circuit breaker, which is equipped with a MiCOM P141 numerical relay having a setting range of 8-400% of rated current and fed from 2000/1A CTs.

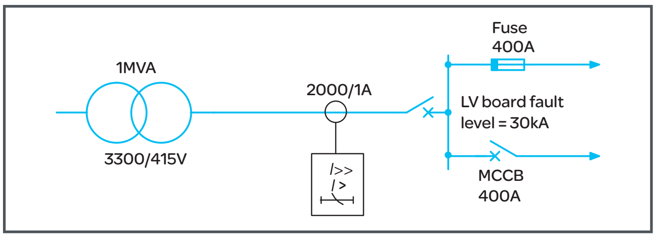


Figure B3.21:
Network diagram for protection co-ordination example – fuse/MCCB/relay

12. Examples

Discrimination is required between the relay and both the fuse and MCCB up to the 40kA fault rating of the board. To begin with, the time/current characteristics of both the 400A fuse and the MCCB are plotted in Figure B3.22.

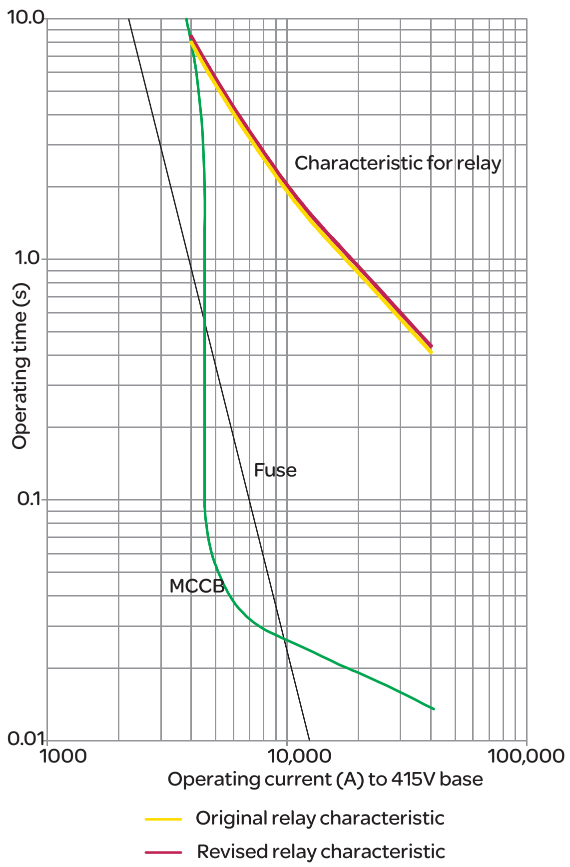


Figure B3.22:
Grading curves for Fuse/MCCB/relay grading example

12.2.1 Determination of relay current setting

The relay current setting chosen must not be less than the full load current level and must have enough margin to allow the relay to reset with full load current flowing. The latter may be determined from the transformer rating:

$$FLC = \frac{kVA}{kV \times \sqrt{3}}$$

$$= \frac{1000}{0.4 \times \sqrt{3}} = 1443A$$

With the CT ratio of 2000/1A and a relay reset ratio of 95% of the nominal current setting, a current setting of at least 80% would be satisfactory, to avoid tripping and/or failure to reset with the transformer carrying full load current. However, choice of a value at the lower end of this current setting range would move the relay characteristic towards that of the MCCB and discrimination may be lost at low fault currents. It is therefore prudent to select initially a relay current setting of 100%.

12.2.2 Relay characteristic and time multiplier selection

An EI characteristic is selected for the relay to ensure discrimination with the fuse (see Chapter [C1: Overcurrent Protection for Phase and Earth Faults] for details). From Figure B3.20, it may be seen that at the fault level of 40kA the fuse will operate in less than 0.01s and the MCCB operates in approximately 0.014s. Using a fixed grading margin of 0.4s, the required relay operating time becomes 0.4 + 0.014 = 0.414s. With a CT ratio of 2000/1A, a relay current setting of 100%, and a relay TMS setting of 1.0, the extremely inverse curve gives a relay operating time of 0.2s at a fault current of 40kA. This is too fast to give adequate discrimination and indicates that the EI curve is too severe for this application. Turning to the VI relay characteristic, the relay operation time is found to be 0.71s at a TMS of 1.0. To obtain the required relay operating time of 0.414s:

$$TMS\ setting = \frac{0.414}{0.71}$$

$$= 0.583$$

Use a TMS of 0.6, nearest available setting.

The use of a different form of inverse time characteristic makes it advisable to check discrimination at the lower current levels also at this stage. At a fault current of 4kA, the relay will operate in 8.1s, which does not give discrimination with the MCCB. A relay operation time of 8.3s is required. To overcome this, the relay characteristic needs to be moved away from the MCCB characteristic, a change that may be achieved by using a TMS of 0.625. The revised relay characteristic is also shown in Figure B3.22.

12.3 Protection of a dual-fed substation

As an example of how numerical protection relays can be used in an industrial system, consider the typical large industrial substation of Figure B3.23. Two 1.6MVA, 11/0.4kV transformers feed a busbar whose bus-section CB is normally open. The LV system is solidly earthed. The largest outgoing feeder is to a motor rated 160kW, 193kVA, and a starting current of 7 x FLC.

The transformer impedance is to IEC standards. The LV switchgear and bus bars are fault rated at 50kA r.m.s. To simplify the analysis, only the phase-fault LV protection is considered.

12.3.1 General considerations

Analysis of many substations configured as in Figure B3.23 shows that the maximum fault level and feeder load current are obtained with the bus-section circuit breaker closed and one of the infeeding CBs open. This applies so long as the switchboard has a significant amount of motor load. The contribution of motor load to the fault level at the switchboard is usually larger than that from a single infeeding transformer, as the transformer restricts the amount of fault current infeed from the primary side. The three-phase break fault level at the switchboard under these conditions is assumed to be 40kA r.m.s.

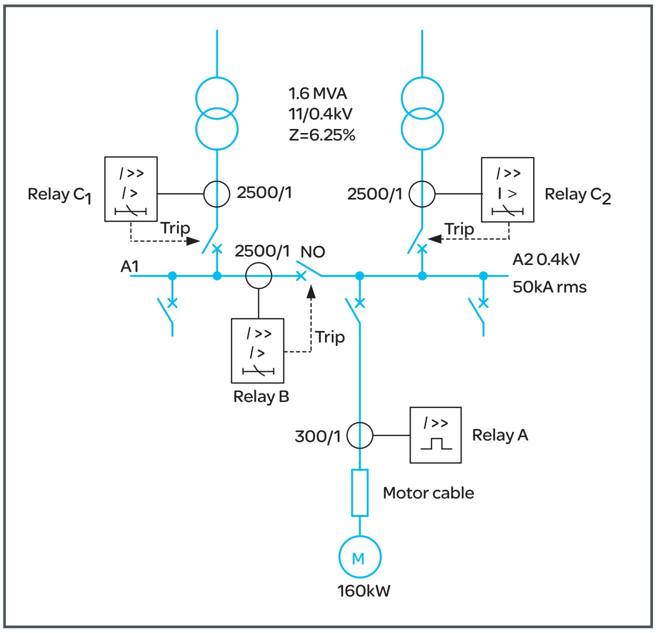


Figure B3.23:
Relay grading example for dual-fed switchboard

Relays C are not required to have directional characteristics see Chapter [C1: Overcurrent Protection for Phase and Earth Faults, Section 14.3] as all three circuit breakers are only closed momentarily during transfer from a single infeeding transformer to a two infeeding transformers configuration. This transfer is normally an automated sequence, and the chance of a fault occurring during the short period (of the order of 1s) when all three CBs are closed is taken to be negligibly small. Similarly, although this configuration gives the largest fault level at the switchboard, it is not considered from either a switchboard fault rating or protection viewpoint.

It is assumed that modern numerical relays are used. For simplicity, a fixed grading margin of 0.3s is used.

12.3.2 Motor protection relay settings

From the motor characteristics given, the overcurrent relay settings (Relay A) can be found using the guidelines set out in Chapter [C9: A.C. Motor Protection] as:

a. Thermal element:

current setting: 300A

time constant: 20 mins

b. Instantaneous element:

current setting: 2.32kA

These are the only settings relevant to the upstream relays.

12.3.3 Relay B settings

Relay B settings are derived from consideration of the loading and fault levels with the bus-section breaker between busbars $A1$ and $A2$ closed. No information is given about the load split between the two busbars, but it can be assumed in the absence of definitive information that each busbar is capable of supplying the total load of 1.6MVA. With fixed tap transformers, the bus voltage may fall to 95% of nominal under these conditions, leading to a load current of 2430A. The IDMT current setting must be greater than this, to avoid relay operation on normal load currents and (ideally) with aggregate starting/re-acceleration currents. If the entire load on the busbar was motor load, an aggregate starting current in excess of 13kA would occur, but a current setting of this order would be excessively high and lead to grading problems further upstream. It is unlikely that the entire load is motor load (though this does occur, especially where a supply voltage of 690V is chosen for motors – an increasingly common practice) or that all motors are started simultaneously (but simultaneous re-acceleration may well occur).

What is essential is that relay B does not issue a trip command under these circumstances – i.e. the relay current/time characteristic is in excess of the current/time characteristic of the worst-case starting/re-acceleration condition. It is therefore assumed that 50% of the total bus load is motor load, with an average starting current of 600% of full load current (= 6930A), and that re-acceleration takes 3s. A current setting of 3000A is therefore initially used. The SI characteristic is used for grading the relay, as co-ordination with fuses is not required. The TMS is required to be set to grade with the thermal protection of relay A under 'cold' conditions, as this gives the longest operation time of Relay A, and the re-acceleration conditions. A TMS value of 0.41 is found to provide satisfactory grading, being dictated by the motor starting/ re-acceleration transient. Adjustment of both current and TMS settings may be required depending on the exact re-acceleration conditions. Note that lower current and TMS settings could be used if motor starting/re-acceleration did not need to be considered.

The high-set setting needs to be above the full load current and motor starting/re-acceleration transient current, but less than the fault current by a suitable margin. A setting of 12.5kA is initially selected. A time delay of 0.3s has to used to ensure grading with relay A at high fault current levels; both relays A and B may see a current in excess of 25kA for faults on the cable side of the CB feeding the 160kW motor. The relay curves are illustrated in Figure B3.24.

12. Examples

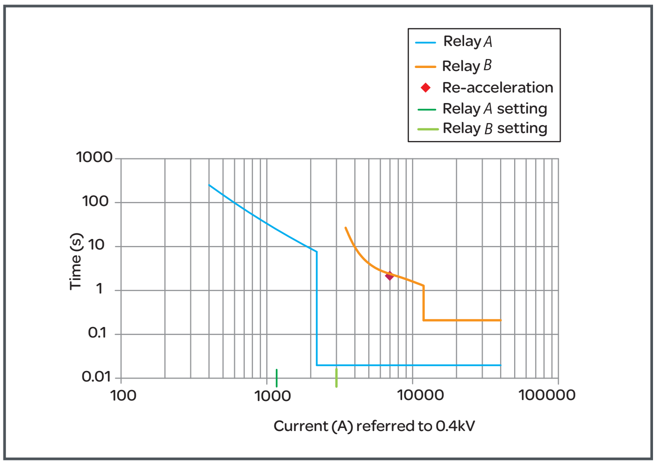
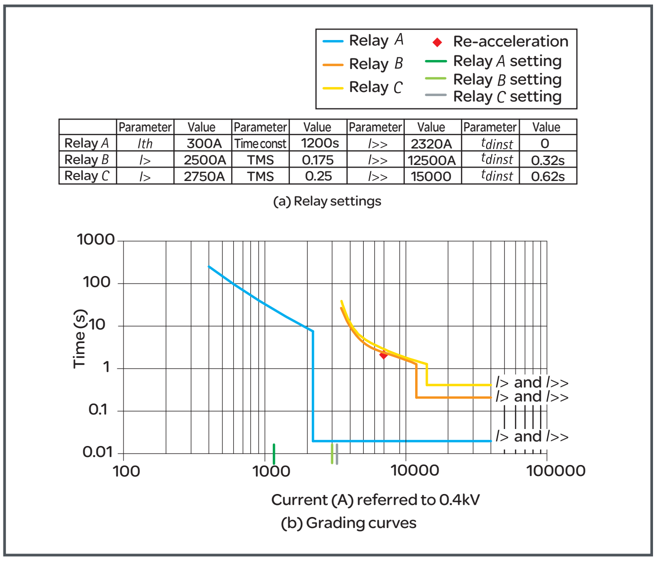


Figure B3.24:
Grading of relays A and B

12.3.4 Relays C settings

The setting of the IDMT element of relays C_1 and C_2 has to be suitable for protecting the busbar while grading with relay B. The limiting condition is grading with relay B, as this gives the longest operation time for relays C.

The current setting has to be above that for relay B to achieve full co-ordination, and a value of 3250A is suitable. The TMS setting using the SI characteristic is chosen to grade with that of relay B at a current of 12.5kA (relay B instantaneous setting), and is found to be 0.45. The high-set element must grade with that of relay B, so a time delay of 0.62sec is required. The current setting must be higher than that of relay B, so use a value of 15kA. The final relay grading curves and settings are illustrated in Figure B3.25.



	Parameter	Value	Parameter	Value	Parameter	Value	Parameter	Value
Relay *A*	*Ith*	300A	Time const	1200s	*I>>*	2320A	t_{dinst}	0
Relay *B*	*I>*	2500A	TMS	0.175	*I>>*	12500A	t_{dinst}	0.32s
Relay *C*	*I>*	2750A	TMS	0.25	*I>>*	15000	t_{dinst}	0.62s

(a) Relay settings

Figure B3.25:
Final relay grading curves

12.3.5 Comments on grading

While the above grading may appear satisfactory, the protection on the primary side of the transformer has not been considered. IDMT protection at this point will have to grade with relays C and with the through-fault short-time withstand curves of the transformer and cabling. This may result in excessively long operation times. Even if the operation time at the 11kV level is satisfactory, there is probably a Utility infeed to consider, which will involve a further set of relays and another stage of time grading, and the fault clearance time at the utility infeed will almost certainly be excessive. One solution is to accept a total loss of supply to the 0.4kV bus under conditions of a single infeed and bus section CB closed. This is achieved by setting relays C such that grading with relay B does not occur at all current levels, or omitting relay B from the protection scheme. The argument for this is that network operation policy is to ensure loss of supply to both sections of the switchboard does not occur for single contingencies. As single infeed operation is not normal, a contingency (whether fault or maintenance) has already occurred, so that a further fault causing total loss of supply to the switchboard through tripping of one of relays B is a second contingency. Total loss of supply is therefore acceptable. The alternative is to accept a lack of discrimination at some point on the system, as already noted in Chapter [C1: Overcurrent Protection for Phase and Earth Faults]. Another solution is to employ partial differential protection to remove the need for Relay A, but this is seldom used. The strategy adopted will depend on the individual circumstances.

13. References

[B3.1] Overcurrent Relay Co-ordination for Double Ended Substations

George R Horcher
IEEE. Vol. 1A-14, No. 6, 1978

C1

Overcurrent Protection for Phase and Earthfaults

Network Protection & Automation Guide

Life Is On | Schneider Electric

Chapter C1

Overcurrent Protection for Phase and Earthfaults

1. Introduction

Protection against excess current was naturally the earliest protection system to evolve. From this basic principle, the graded overcurrent system, a discriminative fault protection, has been developed. This should not be confused with 'overload' protection, which normally makes use of relays that operate in a time related in some degree to the thermal capability of the plant to be protected.

Overcurrent protection, on the other hand, is directed entirely to the clearance of faults, although with the settings usually adopted some measure of overload protection may be obtained.

2. Co-ordination procedure

Correct overcurrent relay application requires knowledge of the fault current that can flow in each part of the network. Since large-scale tests are normally impracticable, system analysis must be used – see Chapter [A3: Fault Calculations] for details. The data required for a relay setting study are:

a. a one-line diagram of the power system involved, showing the type and rating of the protection devices and their associated current transformers

b. the impedances in ohms, per cent or per unit, of all power transformers, rotating machine and feeder circuits

c. the maximum and minimum values of short circuit currents that are expected to flow through each protection device

d. the maximum load current through protection devices

e. the starting current requirements of motors and the starting and locked rotor/stalling times of induction motors

f. the transformer inrush, thermal withstand and damage characteristics

g. decrement curves showing the rate of decay of the fault current supplied by the generators

h. performance curves of the current transformers

The relay settings are first determined to give the shortest operating times at maximum fault levels and then checked to see if operation will also be satisfactory at the minimum fault current expected. It is always advisable to plot the curves of relays and other protection devices, such as fuses, that are to operate in series, on a common scale. It is usually more convenient to use a scale corresponding to the current expected at the lowest voltage base, or to use the predominant voltage base. The alternatives are a common MVA base or a separate current scale for each system voltage.

The basic rules for correct relay co-ordination can generally be stated as follows:

a. whenever possible, use relays with the same operating characteristic in series with each other

b. make sure that the relay farthest from the source has current settings equal to or less than the relays behind it, that is, that the primary current required to operate the relay in front is always equal to or less than the primary current required to operate the relay behind it

3. Principles of time/current grading

Among the various possible methods used to achieve correct relay co-ordination are those using either time or overcurrent, or a combination of both. The common aim of all three methods is to give correct discrimination. That is to say, each one must isolate only the faulty section of the power system network, leaving the rest of the system undisturbed.

3.1 Discrimination by time

In this method, an appropriate time setting is given to each of the relays controlling the circuit breakers in a power system to ensure that the breaker nearest to the fault opens first. A simple radial distribution system is shown in Figure C1.1, to illustrate the principle.

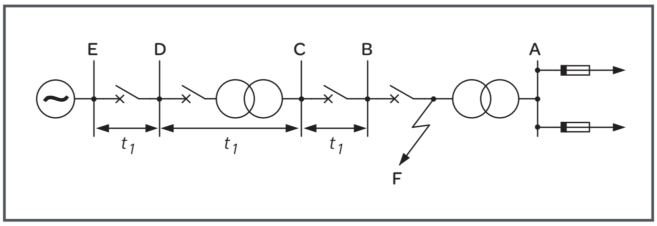


Figure C1.1:
Radial system with time discrimination

Overcurrent protection is provided at B, C, D and E, that is, at the infeed end of each section of the power system. Each protection unit comprises a definite-time delay overcurrent relay in which the operation of the current sensitive element simply initiates the time delay element. Provided the setting of the current element is below the fault current value, this element plays no part in the achievement of discrimination. For this reason, the relay is sometimes described as an 'independent definite-time delay relay', since its operating time is for practical purposes independent of the level of overcurrent.

It is the time delay element, therefore, which provides the means of discrimination. The relay at B is set at the shortest time delay possible to allow the fuse to blow for a fault at A on the secondary side of the transformer. After the time delay has expired, the relay output contact closes to trip the circuit breaker. The relay at C has a time delay setting equal to t_1 seconds, and similarly for the relays at D and E.

If a fault occurs at F, the relay at B will operate in t seconds and the subsequent operation of the circuit breaker at B will clear the fault before the relays at C, D and E have time to operate. The time interval between each relay time setting must be long enough to ensure that the upstream relays do not operate before the circuit breaker at the fault location has tripped and cleared the fault.

The main disadvantage of this method of discrimination is that the longest fault clearance time occurs for faults in the section closest to the power source, where the fault level (MVA) is highest.

3.2 Discrimination by current

Discrimination by current relies on the fact that the fault current varies with the position of the fault because of the difference in impedance values between the source and the fault. Hence, typically, the relays controlling the various circuit breakers are set to operate at suitably tapered values of current such that only the relay nearest to the fault trips its breaker. Figure C1.2 illustrates the method.

For a fault at F_1, the system short-circuit current is given by:

$$I = \frac{6350}{Z_S + Z_{L1}} A$$

where

Z_s = source impedance

$$= \frac{11^2}{250} = 0.485\,\Omega$$

Z_{L1} = cable impedance between C and B = $0.24\ \Omega$

Hence

$$I = \frac{11}{\sqrt{3} \times 0.725} = 8800\ A$$

So, a relay controlling the circuit breaker at C and set to operate at a fault current of 8800 A would in theory protect the whole of the cable section between C and B. However, there are two important practical points that affect this method of co-ordination:

a. it is not practical to distinguish between a fault at F_1 and a fault at F_2, since the distance between these points may be only a few metres, corresponding to a change in fault current of approximately 0.1%

b. in practice, there would be variations in the source fault level, typically from 250 MVA to 130 MVA. At this lower fault level the fault current would not exceed 6800 A, even for a cable fault close to C. A relay set at 8800 A would not protect any part of the cable section concerned

Discrimination by current is therefore not a practical proposition for correct grading between the circuit breakers at C and B. However, the problem changes appreciably when there is significant impedance between the two circuit breakers concerned. Consider the grading required between the circuit breakers at C and A in Figure C1.2.

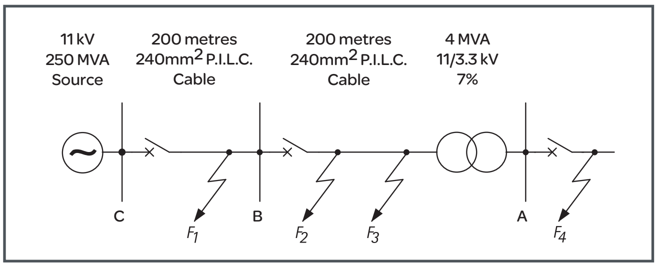


Figure C1.2:
Radial system with current discrimination

C1

3. Principles of time/current grading

Assuming a fault at F_4, the short-circuit current is given by:

$$I = \frac{6350}{Z_S + Z_{L1}} A$$

where

Z_S = source impedance = $0.485\ \Omega$

Z_{L1} = cable impedance between C and B = $0.24\ \Omega$

Z_{L2} = cable impedance between B and 4 MVA transformer = $0.04\ \Omega$

Z_T = transformer impedance = $0.07\left(\frac{11^2}{4}\right) = 2.12\ \Omega$

Hence $I = \frac{11}{\sqrt{3} \times 2.885} = 2200\ A$

For this reason, a relay controlling the circuit breaker at B and set to operate at a current of 2200 A plus a safety margin would not operate for a fault at F_4 and would thus discriminate with the relay at A. Assuming a safety margin of 20% to allow for relay errors and a further 10% for variations in the system impedance values, it is reasonable to choose a relay setting of 1.3 x 2200 A, that is 2860 A, for the relay at B.

Now, assuming a fault at F_3, at the end of the 11 kV cable feeding the 4 MVA transformer, the short-circuit current is given by:

$$I = \frac{11}{\sqrt{3}\left(Z_s + Z_{L1} + Z_{L2}\right)}$$

Thus, assuming a 250 MVA source fault level:

$$I = \frac{11}{\sqrt{3}\left(0.485 + 0.24 + 0.04\right)} = 8300\ A$$

Alternatively, assuming a source fault level of 130 MVA:

$$I = \frac{11}{\sqrt{3}\left(0.93 + 0.214 + 0.04\right)} = 5250\ A$$

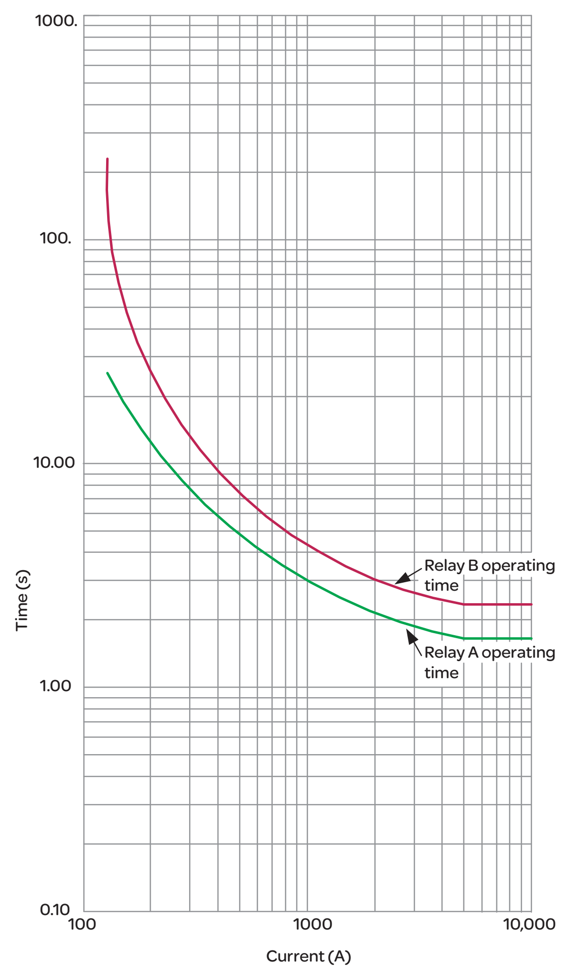
In other words, for either value of source level, the relay at B would operate correctly for faults anywhere on the 11 kV cable feeding the transformer.

3.3 Discrimination by both time and current

Each of the two methods described so far has a fundamental disadvantage. In the case of discrimination by time alone, the disadvantage is due to the fact that the more severe faults are cleared in the longest operating time. On the other hand, discrimination by current can be applied only where there is appreciable impedance between the two circuit breakers concerned.

It is because of the limitations imposed by the independent use of either time or current co-ordination that the inverse time overcurrent relay characteristic has evolved. With this characteristic, the time of operation is inversely proportional to the fault current level and the actual characteristic is a function of both 'time'and 'current' settings. Figure C1.3 illustrates the characteristics of two relays given different current/time settings. For a large variation in fault current between the two ends of the feeder, faster operating times can be achieved by the relays nearest to the source, where the fault level is the highest. The disadvantages of grading by time or current alone are overcome.

The selection of overcurrent relay characteristics generally starts with selection of the correct characteristic to be used for each relay, followed by choice of the relay current settings. Finally the grading margins and hence time settings of the relays are determined. An iterative procedure is often required to resolve conflicts, and may involve use of non-optimal characteristics, current or time grading settings.



Relay A: Current setting = 100 A, TMS = 1.0
Relay B: Current setting = 125 A, TMS = 1.3

Figure C1.3:
Relay characteristics for different settings

4. Standard I.D.M.T. overcurrent relays

The current/time tripping characteristics of IDMT relays may need to be varied according to the tripping time required and the characteristics of other protection devices used in the network. For these purposes, IEC 60255 defines a number of standard characteristics as follows:

a. standard inverse (SI)

b. very inverse (VI)

c. extremely inverse (EI)

d. long time inverse

Relay characteristic	Equation
Standard inverse (SI)	$t = TMS \times \dfrac{0.14}{I_r^{0.02} - 1}$
Very inverse (VI)	$t = TMS \times \dfrac{13.5}{I_r - 1}$
Extremely inverse (EI)	$t = TMS \times \dfrac{80}{I_r^2 - 1}$
Long time inverse	$t = TMS \times \dfrac{120}{I_r - 1}$

(a): IDMT relay characteristics to IEC 60255-151

(b): North American IDMT relay characteristics

Relay characteristic	Equation
IEEE C37.112 Moderately inverse	$t = TMS\left\{\left(\dfrac{0.0515}{I_r^{0.02}-1}\right) + 0.114\right\}$
IEEE C37.112 Very inverse	$t = TMS\left\{\left(\dfrac{19.61}{I_r^{2}-1}\right) + 0.491\right\}$
IEEE C37.112 Extremely inverse	$t = TMS\left\{\left(\dfrac{28.2}{I_r^{2}-1}\right) + 0.1217\right\}$
US CO8 inverse	$t = TMS\left\{\left(\dfrac{5.95}{I_r^{2}-1}\right) + 0.18\right\}$
US CO2 short time inverse	$t = TMS\left\{\left(\dfrac{0.16758}{I_r^{0.02}-1}\right) + 0.11858\right\}$
($I_r = (I/I_s)$, where Is = relay setting current *TMS = Time multiplier setting* *TD = Time dial setting*	

Table C1.1: Definitions of standard relay characteristics

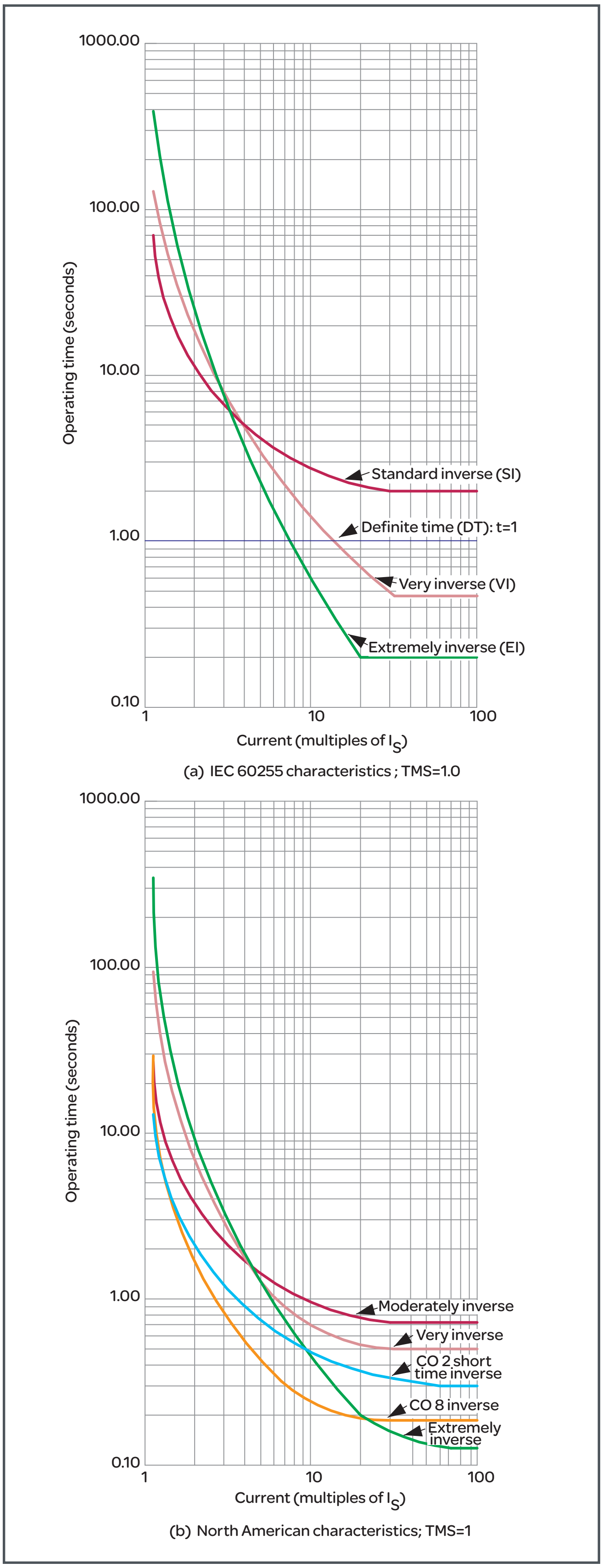


Figure C1.4:
IDMT relay characteristics

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4. Standard I.D.M.T. overcurrent relays

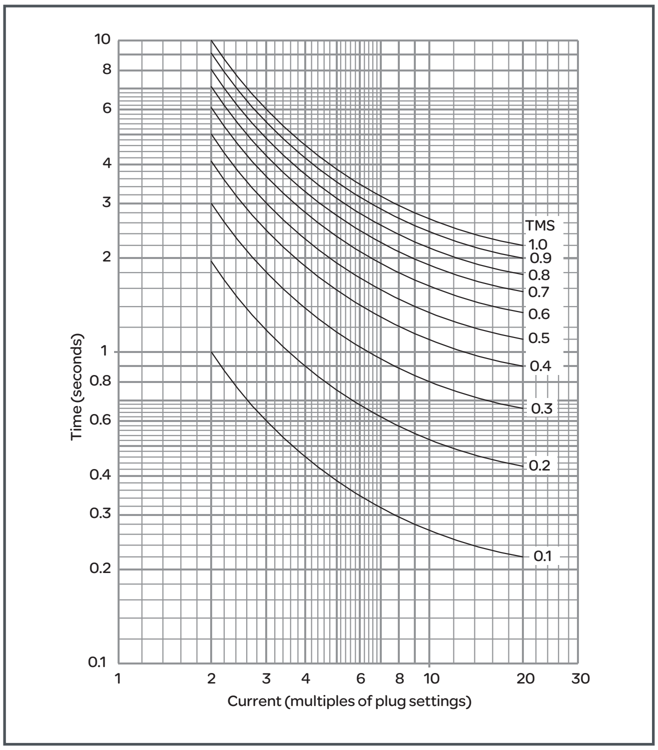


Figure C1.5:
Typical time/current characteristics of standard IDMT relay

The mathematical descriptions of the curves are given in Table C1.1(a), and the curves based on a common setting current and time multiplier setting of 1 second are shown in Figure C1.4(a). The tripping characteristics for different TMS settings using the SI curve are illustrated in Figure C1.5. Although the curves are only shown for discrete values of TMS, continuous adjustment may be possible in an electromechanical relay. For other relay types, the setting steps may be so small as to effectively provide continuous adjustment. In addition, almost all overcurrent relays are also fitted with a high-set instantaneous element.

In most cases, use of the standard SI curve proves satisfactory, but if satisfactory grading cannot be achieved, use of the VI or EI curves may help to resolve the problem. When digital or numeric relays are used, other characteristics may be provided, including the possibility of user-definable curves. More details are provided in the following sections.

Relays for power systems designed to North American practice utilise ANSI/IEEE curves. Table C1.1(b) gives the mathematical description of these characteristics and Figure C1.4(b) shows the curves standardised to a time dial setting of 1.0.

5. Combined I.D.M.T. high set instantaneous overcurrent relays

A high-set instantaneous element can be used where the source impedance is small in comparison with the protected circuit impedance. This makes a reduction in the tripping time at high fault levels possible. It also improves the overall system grading by allowing the 'discriminating curves' behind the high set instantaneous elements to be lowered.

As shown in Figure C1.6, one of the advantages of the high set instantaneous elements is to reduce the operating time of the circuit protection by the shaded area below the 'discriminating curves'.

If the source impedance remains constant, it is then possible to achieve high-speed protection over a large section of the protected circuit. The rapid fault clearance time achieved helps to minimise damage at the fault location. Figure C1.6 also illustrates a further important advantage gained by the use of high set instantaneous elements. Grading with the relay immediately behind the relay that has the instantaneous elements enabled is carried out at the current setting of the instantaneous elements and not at the maximum fault level. For example, in Figure C1.6, relay R_2 is graded with relay R_3 at 500A and not 1100A, allowing relay R_2 to be set with a TMS of 0.15 instead of 0.2 while maintaining a grading margin between relays of 0.4s. Similarly, relay R_1 is graded with R_2 at 1400A and not at 2300A.

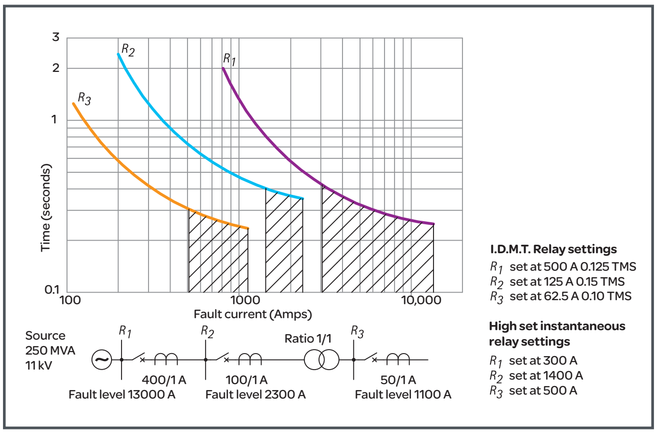


Figure C1.6:
Characteristics of combined IDMT and high-set instantaneous overcurrent relays

6. Very inverse (VI) overcurrent relays

6.1 Transient overreach

The reach of a relay is that part of the system protected by the relay if a fault occurs. A relay that operates for a fault that lies beyond the intended zone of protection is said to overreach.

When using instantaneous overcurrent elements, care must be exercised in choosing the settings to prevent them operating for faults beyond the protected section. The initial current due to a d.c. offset in the current wave may be greater than the relay pick-up value and cause it to operate. This may occur even though the steady state r.m.s. value of the fault current for a fault at a point beyond the required reach point may be less than the relay setting. This phenomenon is called transient overreach, and is defined as:

% transient overreach $\frac{I_1 - I_2}{I_2} \times 100\%$ ...*Equation C1.1*

where:

I_1 = r.m.s steady-state relay pick-up current

I_2 = steady state r.m.s. current which when fully offset just causes relay pick-up

When applied to power transformers, the high set instantaneous overcurrent elements must be set above the maximum through fault current that the power transformer can supply for a fault across its LV terminals, in order to maintain discrimination with the relays on the LV side of the transformer.

Very inverse overcurrent relays are particularly suitable if there is a substantial reduction of fault current as the distance from the power source increases, i.e. there is a substantial increase in fault impedance. The VI operating characteristic is such that the operating time is approximately doubled for reduction in current from 7 to 4 times the relay current setting. This permits the use of the same time multiplier setting for several relays in series.

Figure C1.7 provides a comparison of the SI and VI curves for a relay. The VI curve is much steeper and therefore the operation increases much faster for the same reduction in current compared to the SI curve. This enables the requisite grading margin to be obtained with a lower TMS for the same setting current, and hence the tripping time at source can be minimised. It is noted that the curves become definite minimum time typically at 20-30 x I_S.

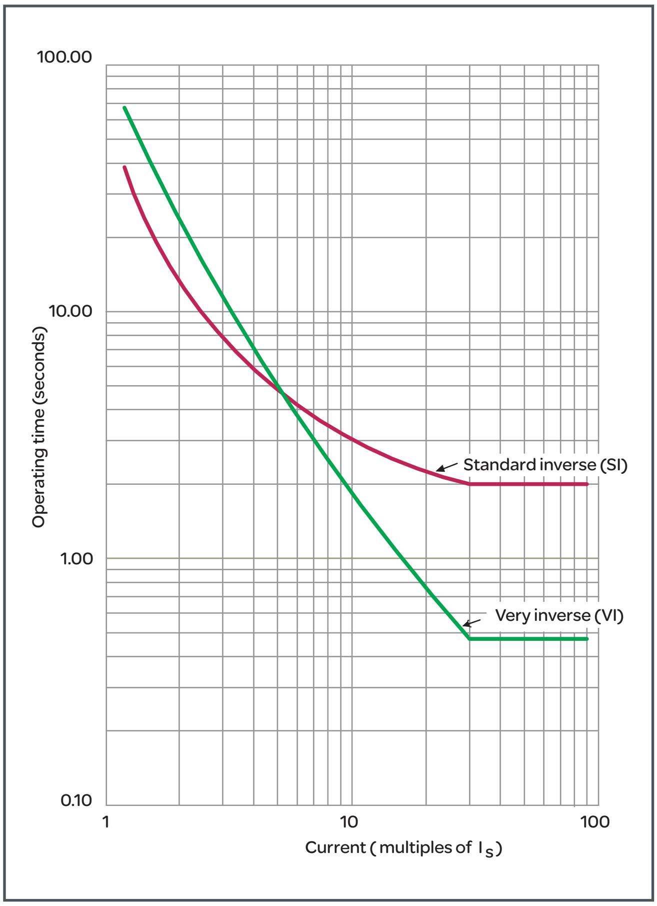


Figure C1.7:
Comparison of SI and VI relay characteristics

7. Extremely inverse (EI) overcurrent relays

With this characteristic, the operation time is approximately inversely proportional to the square of the applied current. This makes it suitable for the protection of distribution feeder circuits in which the feeder is subjected to peak currents on switching in, as would be the case on a power circuit supplying refrigerators, pumps, water heaters and so on, which remain connected even after a prolonged interruption of supply. The long time operating characteristic of the extremely inverse relay at normal peak load values of current also makes this relay particularly suitable for grading with fuses.

Figure C1.8 shows typical curves to illustrate this. It can be seen that use of the EI characteristic gives a satisfactory grading margin, but use of the VI or SI characteristics at the same settings does not. Another application of this relay is in conjunction with auto-reclosers in low voltage distribution circuits. The majority of faults are transient in nature and unnecessary blowing and replacing of the fuses present in final circuits of such a system can be avoided if the auto-reclosers are set to operate before the fuse blows. If the fault persists, the auto-recloser locks itself in the closed position after one opening and the fuse blows to isolate the fault.

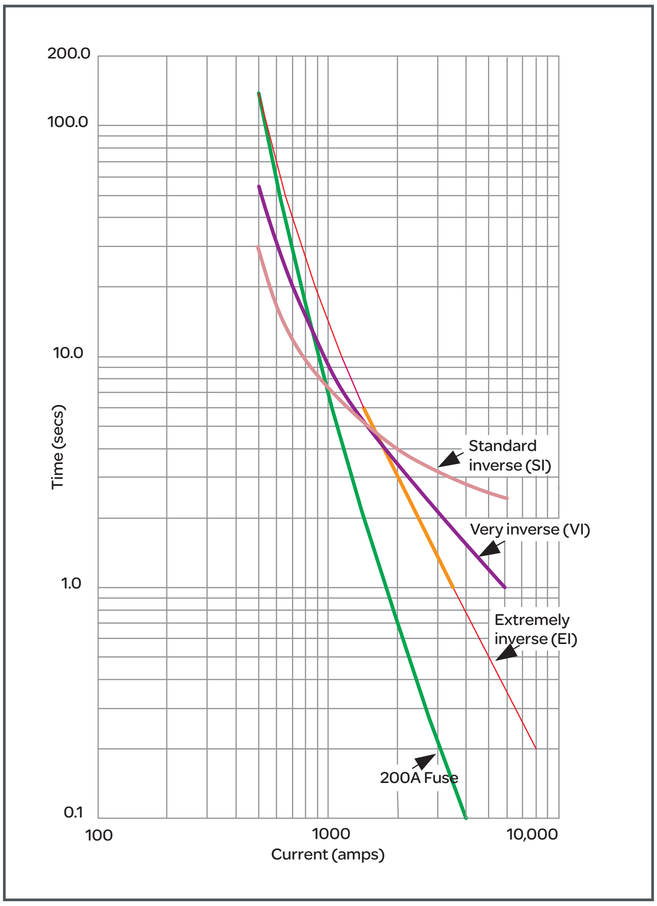


Figure C1.8:
Comparison of relay and fuse characteristics

8. Other relay characteristics

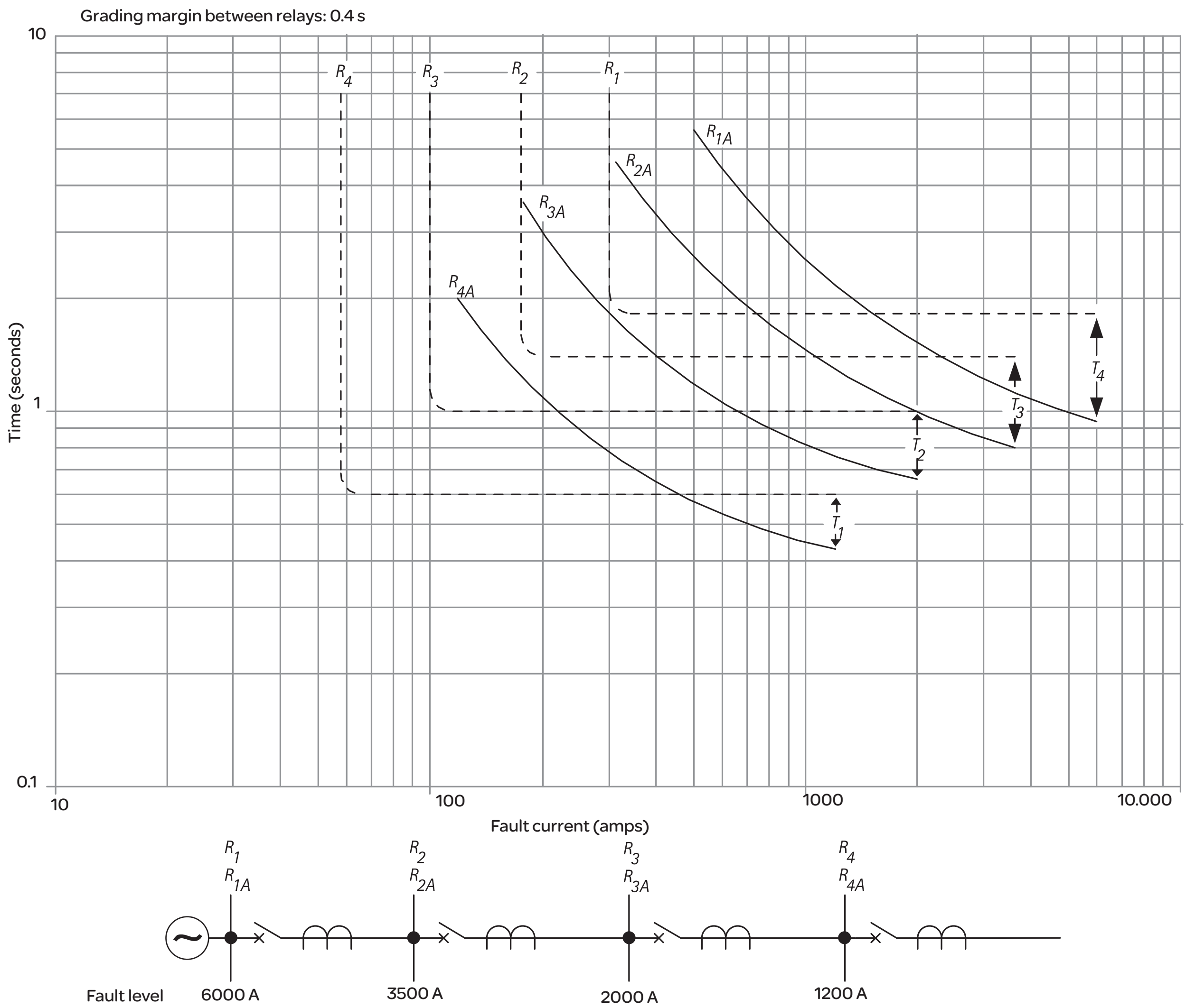
User definable curves may be provided on some types of digital or numerical relays. The general principle is that the user enters a series of current/time co-ordinates that are stored in the memory of the relay. Interpolation between points is used to provide a smooth trip characteristic. Such a feature, if available, may be used in special cases if none of the standard tripping characteristics is suitable. However, grading of upstream protection may become more difficult, and it is necessary to ensure that the curve is properly documented, along with the reasons for use. Since the standard curves provided cover most cases with adequate tripping times, and most equipment is designed with standard protection curves in mind, the need to utilise this form of protection is relatively rare.

Digital and numerical relays may also include pre-defined logic schemes utilising digital (relay) I/O provided in the relay to implement standard schemes such as CB failure and trip circuit supervision. This saves the provision of separate relay or PLC (Programmable Logic Controller) hardware to perform these functions.

9. Independent (definite) time overcurrent relays

Overcurrent relays are normally also provided with elements having independent or definite time characteristics. These characteristics provide a ready means of co-ordinating several relays in series in situations in which the system fault current varies very widely due to changes in source impedance, as there is no change in time with the variation of fault current. The time/current characteristics of this curve are shown in Figure C1.9, together with those of the standard I.D.M.T. characteristic, to indicate that lower operating times are achieved by the inverse relay at the higher values of fault current, whereas the definite time relay has lower operating times at the lower current values.

Vertical lines T_1, T_2, T_3, and T_4 indicate the reduction in operating times achieved by the inverse relay at high fault levels.



Settings of independent (definite) time relay

R_{1A} set at 300 A 1.8 s
R_{2A} set at 175 A 1.4 s
R_{3A} set at 100 A 1.0 s
R_{4A} set at 57.5 A 0.6 s

Settings of I.D.M.T. relay with standard inverse characteristic

R_{1A} set at 300 A 0.2 TMS
R_{2A} set at 175 A 0.3 TMS
R_{3A} set at 100 A 0.37 TMS
R_{4A} set at 57.5 A 0.42 TMS

Figure C1.9:
Comparison of definite time and standard I.D.M.T. relay

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10. Relay current setting

An overcurrent relay has a minimum operating current, known as the current setting of the relay. The current setting must be chosen so that the relay does not operate for the maximum load current in the circuit being protected, but does operate for a current equal or greater to the minimum expected fault current. Although by using a current setting that is only just above the maximum load current in the circuit a certain degree of protection against overloads as well as faults may be provided, the main function of overcurrent protection is to isolate primary system faults and not to provide overload protection. In general, the current setting will be selected to be above the maximum short time rated current of the circuit involved. Since all relays have hysteresis in their current settings, the setting must be sufficiently high to allow the relay to reset when the rated current of the circuit is being carried. The amount of hysteresis in the current setting is denoted by the pick-up/drop-off ratio of a relay – the value for a modern relay is typically 0.95. Thus, a relay minimum current setting of at least 1.05 times the short-time rated current of the circuit is likely to be required.

11. Relay time grading margin

The time interval that must be allowed between the operation of two adjacent relays in order to achieve correct discrimination between them is called the grading margin. If a grading margin is not provided, or is insufficient, more than one relay will operate for a fault, leading to difficulties in determining the location of the fault and unnecessary loss of supply to some consumers.

The grading margin depends on a number of factors:

a. the fault current interrupting time of the circuit breaker

b. relay timing errors

c. the overshoot time of the relay

d. CT errors

e. final margin on completion of operation

Factors **(b)** and **(c)** above depend to a certain extent on the relay technology used – an electromechanical relay, for instance, will have a larger overshoot time than a numerical relay.

Grading is initially carried out for the maximum fault level at the relaying point under consideration, but a check is also made that the required grading margin exists for all current levels between relay pick-up current and maximum fault level.

11.1 Circuit breaker interrupting time

The circuit breaker interrupting the fault must have completely interrupted the current before the discriminating relay ceases to be energised. The time taken is dependent on the type of circuit breaker used and the fault current to be interrupted. Manufacturers normally provide the fault interrupting time at rated interrupting capacity and this value is invariably used in the calculation of grading margin.

11.2 Relay timing error

All relays have errors in their timing compared to the ideal characteristic as defined in IEC 60255. For a relay specified to IEC 60255, a relay error index is quoted that determines the maximum timing error of the relay. The timing error must be taken into account when determining the grading margin.

11.3 Overshoot

When the relay is de-energised, operation may continue for a little longer until any stored energy has been dissipated. For example, an induction disc relay will have stored kinetic energy in the motion of the disc; static relay circuits may have energy stored in capacitors. Relay design is directed to minimising and absorbing these energies, but some allowance is usually necessary.

The overshoot time is defined as the difference between the operating time of a relay at a specified value of input current and the maximum duration of input current, which when suddenly reduced below the relay operating level, is insufficient to cause relay operation.

11.4 CT errors

Current transformers have phase and ratio errors due to the exciting current required to magnetise their cores. The result is that the CT secondary current is not an identical scaled replica of the primary current. This leads to errors in the operation of relays, especially in the time of operation. CT errors are not relevant when independent definite-time delay overcurrent relays are being considered.

11.5 Final margin

After the above allowances have been made, the discriminating relay must just fail to complete its operation. Some extra allowance, or safety margin, is required to ensure that relay operation does not occur.

11. Relay time grading margin

11.6 Overall accuracy

The overall limits of accuracy according to IEC 60255-4 for an IDMT relay with standard inverse characteristic are shown in Figure C1.10.

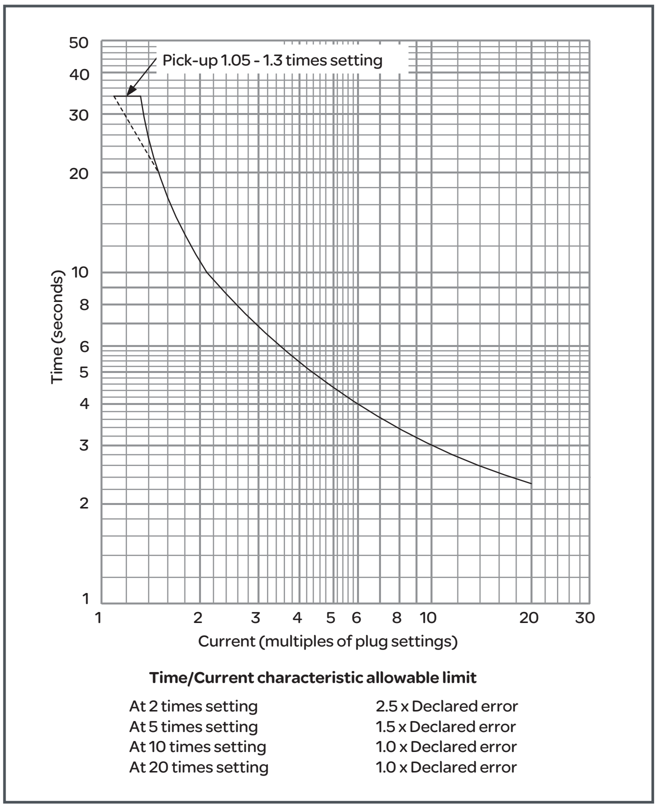

Figure C1.10:
Typical limits of accuracy and miminum setting range from IEC 60255-151 for an inverse definite minimum time overcurrent relay

12. Recommended grading intervals

The following sections give the recommended overall grading margins between different protection devices.

12.1 Grading: Relay to relay

The total interval required to cover the above items depends on the operating speed of the circuit breakers and the relay performance. At one time 0.5 s was a normal grading margin. With faster modern circuit breakers and a lower relay overshoot time, 0.4 s is reasonable, while under the best conditions even lower intervals may be practical.

The use of a fixed grading margin is popular, but it may be better to calculate the required value for each relay location. This more precise margin comprises a fixed time, covering circuit breaker fault interrupting time, relay overshoot time and a safety margin, plus a variable time that allows for relay and CT errors. Table C1.2 gives typical relay errors according to the technology used.

It should be noted that use of a fixed grading margin is only appropriate at high fault levels that lead to short relay operating times. At lower fault current levels, with longer operating times, the permitted error specified in IEC 60255 (7.5% of operating time) may exceed the fixed grading margin, resulting in the possibility that the relay fails to grade correctly while remaining within specification. This requires consideration when considering the grading margin at low fault current levels.

	Relay technology			
	Electro-mechanical	Static	Digital	Numerical
Typical basic timing error (%)	7.5	5	5	5
Overshoot time (s)	0.05	0.03	0.02	0.02
Safety margin (s)	0.1	0.05	0.03	0.03
Typical overall grading margin - relay to relay (s)	0.4	0.35	0.3	0.3

Table C1.2:
Typical relay timing errors - standard IDMT relays

A practical solution for determining the optimum grading margin is to assume that the relay nearer to the fault has a maximum possible timing error of +2E, where E is the basic

C1

12. Recommended grading intervals

timing error. To this total effective error for the relay, a further 10% should be added for the overall current transformer error.

A suitable minimum grading time interval, t', may be calculated as follows:

$$t' = \left[\frac{2E_R + E_{CT}}{100}\right] t + t_{CB} + t_o + t_s \ \ seconds$$

...Equation C1.2

where:

E_R = relay timing error (IEC 60255-4)

E_{CT} = allowance for CT ratio error (%)

t = operating time of relay nearer fault (s)

t_{CB} = CB interrupting time (s)

t_o = relay overshoot time (s)

t_s = safety margin (s)

If, for example $t = 0.5\ s$, the time interval for an electromechanical relay tripping a conventional circuit breaker would be $0.375\ s$, whereas, at the lower extreme, for a static relay tripping a vacuum circuit breaker, the interval could be as low as $0.24\ s$.

When the overcurrent relays have independent definite time delay characteristics, it is not necessary to include the allowance for CT error. Hence:

$$t' = \left[\frac{2E_R}{100}\right] t + t_{CB} + t_o + t_s \ \ seconds$$

...Equation C1.3

Calculation of specific grading times for each relay can often be tedious when performing a protection grading calculation on a power system. Table C1.2 also gives practical grading times at high fault current levels between overcurrent relays for different technologies. Where relays of different technologies are used, the time appropriate to the technology of the downstream relay should be used.

12.2 Grading: Fuse to fuse

The operating time of a fuse is a function of both the pre-arcing and arcing time of the fusing element, which follows an I^2t law. So, to achieve proper co-ordination between two fuses in series, it is necessary to ensure that the total I^2t taken by the smaller fuse is not greater than the pre-arcing I^2t value of the larger fuse. It has been established by tests that satisfactory grading between the two fuses will generally be achieved if the current rating ratio between them is greater than two.

12.3 Grading: Fuse to relay

For grading inverse time relays with fuses, the basic approach is to ensure whenever possible that the relay backs up the fuse and not vice versa. If the fuse is upstream of the relay, it is very difficult to maintain correct discrimination at high values of fault current because of the fast operation of the fuse.

The relay characteristic best suited for this co-ordination with fuses is normally the extremely inverse (EI) characteristic as it follows a similar I^2t characteristic. To ensure satisfactory co-ordination between relay and fuse, the primary current setting of the relay should be approximately three times the current rating of the fuse. The grading margin for proper co-ordination, when expressed as a fixed quantity, should not be less than 0.4s or, when expressed as a variable quantity, should have a minimum value of:

$$t' = 0.4t + 0.15\ seconds$$

...Equation C1.4

where t is the nominal operating time of fuse.

Section 20.1 gives an example of fuse to relay grading.

13. Calculation of phase fault overcurrent relay settings

The correct co-ordination of overcurrent relays in a power system requires the calculation of the estimated relay settings in terms of both current and time.

The resultant settings are then traditionally plotted in suitable log/log format to show pictorially that a suitable grading margin exists between the relays at adjacent substations. Plotting may be done by hand, but nowadays is more commonly achieved using suitable software.

The information required at each relaying point to allow a relay setting calculation to proceed is given in Section 2. The principal relay data may be tabulated in a table similar to that shown in Table C1.3, if only to assist in record keeping.

It is usual to plot all time/current characteristics to a common voltage/MVA base on log/log scales. The plot includes all relays in a single path, starting with the relay nearest the load and finishing with the relay nearest the source of supply.

A separate plot is required for each independent path, and the settings of any relays that lie on multiple paths must be carefully considered to ensure that the final setting is appropriate for all conditions. Earthfaults are considered

13. Calculation of phase fault overcurrent relay settings

Location	Fault current (A)		Maximun load current (A)	CT ratio	Relay current setting		Relay time multiplier setting
	Max.	Min.			Per cent	Primary current (A)	

Table C1.3:
Typical relay data table

separately from phase faults and require separate plots.

After relay settings have been finalised, they are entered in a table. One such table is shown in Table C1.3. This also assists in record keeping and during commissioning of the relays at site.

13.1 Independent (definite) time relays

The selection of settings for independent (definite) time relays presents little difficulty. The overcurrent elements must be given settings that are lower, by a reasonable margin, than the fault current that is likely to flow to a fault at the remote end of the system up to which back-up protection is required, with the minimum plant in service.

The settings must be high enough to avoid relay operation with the maximum probable load, a suitable margin being allowed for large motor starting currents or transformer inrush transients.

Time settings will be chosen to allow suitable grading margins, as discussed in Section 12.

13.2 Inverse time relays

When the power system consists of a series of short sections of cable, so that the total line impedance is low, the value of fault current will be controlled principally by the impedance of transformers or other fixed plant and will not vary greatly with the location of the fault. In such cases, it may be possible to grade the inverse time relays in very much the same way as definite time relays. However, when the prospective fault current varies substantially with the location of the fault, it is possible to make use of this fact by employing both current and time grading to improve the overall performance of the relay.

The procedure begins by selection of the appropriate relay characteristics. Current settings are then chosen, with finally the time multiplier settings to give appropriate grading margins between relays. Otherwise, the procedure is similar to that for definite time delay relays. An example of a relay setting study is given in Section 20.1.

14. Directional phase fault overcurrent relays

When fault current can flow in both directions through the relay location, it may be necessary to make the response of the relay directional by the introduction of a directional control facility. The facility is provided by use of additional voltage inputs to the relay, in order to provide a directional reference quantity.

14.1 Relay connections

There are many possibilities for a suitable connection of voltage and current inputs. The various connections are dependent on the phase angle, at unity system power factor, by which the current and voltage applied to the relay are displaced. Reference [Ref C1.1: Directional Element Connections for Phase Relays] details all of the connections that have been used. However, only very few are used in current practice and these are described below.

In a digital or numerical relay, the phase displacements are realised by the use of software, while electromechanical and static relays generally obtain the required phase displacements by suitable connection of the input quantities to the relay. The history of the topic results in the relay connections being defined as if they were obtained by suitable connection of the input quantities, irrespective of the actual method used.

14.2 90° Relay quadrature connection

This is the standard connection for static, digital or numerical relays. Depending on the angle by which the applied voltage is shifted to produce maximum relay sensitivity (the Relay Characteristic Angle, or RCA) two types are available.

14.2.1 90°-30° characteristic (30° RCA)

The A phase relay element is supplied with current I_a and voltage V_{bc} displaced by 30° in an anti-clockwise direction. In this case, the relay maximum sensitivity is produced when the current lags the system phase to neutral voltage by 60°. This connection gives a correct directional tripping zone over the current range of 30° leading to 150° lagging; see Figure C1.11. The relay sensitivity at unity power factor is 50% of the relay maximum sensitivity and 86.6% at zero power factor lagging. This characteristic is recommended when the relay is used for the protection of plain feeders with the zero sequence source behind the relaying point.

14. Directional phase fault overcurrent relays

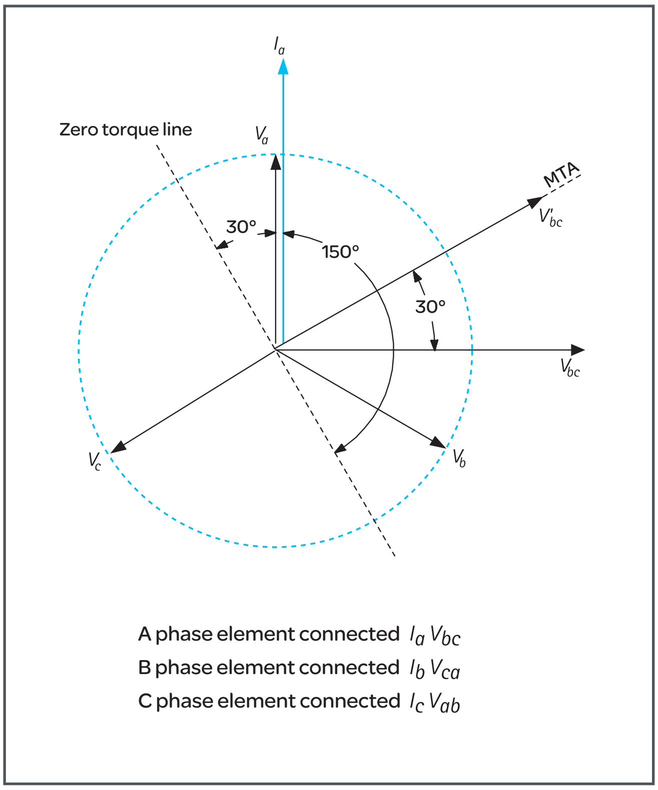

Figure C1.11:
Vector diagram for the 90°-30° connection (phase A element)

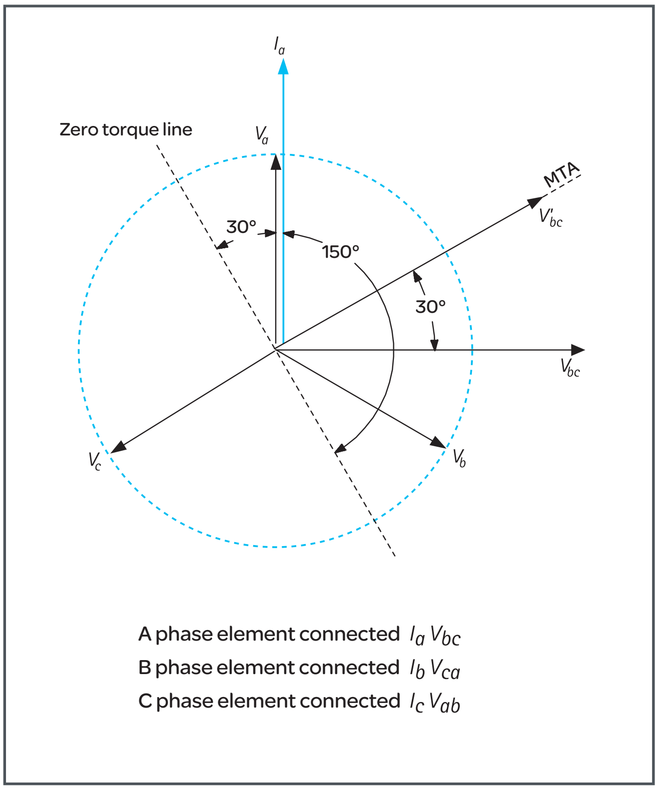

Figure C1.12:
Vector diagram for the 90°-45° connection (phase A element)

14.2.2 90°-45° characteristic (45° RCA)

The A phase relay element is supplied with current I_a and voltage V_{bc} displaced by 45° in an anti-clockwise direction. The relay maximum sensitivity is produced when the current lags the system phase to neutral voltage by 45°. This connection gives a correct directional tripping zone over the current range of 45° leading to 135° lagging. The relay sensitivity at unity power factor is 70.7% of the maximum torque and the same at zero power factor lagging; see Figure C1.12.

This connection is recommended for the protection of transformer feeders or feeders that have a zero sequence source in front of the relay. It is essential in the case of parallel transformers or transformer feeders, in order to ensure correct relay operation for faults beyond the star/delta transformer. This connection should also be used whenever single-phase directional relays are applied to a circuit where a current distribution of the form 2-1-1 may arise. For a digital or numerical relay, it is common to allow user-selection of the RCA angle within a wide range.

Theoretically, three fault conditions can cause maloperation of the directional element:

a. a phase-phase-ground fault on a plain feeder

b. a phase-ground fault on a transformer feeder with the zero sequence source in front of the relay

c. a phase-phase fault on a power transformer with the relay looking into the delta winding of the transformer

It should be remembered, however, that the conditions assumed above to establish the maximum angular displacement between the current and voltage quantities at the relay are such that, in practice, the magnitude of the current input to the relay would be insufficient to cause the overcurrent element to operate. It can be shown analytically that the possibility of maloperation with the 90°-45° connection is, for all practical purposes, non-existent.

14.3 Application of directional relays

If non-unit, non-directional relays are applied to parallel feeders having a single generating source, any faults that might occur on any one line will, regardless of the relay settings used, isolate both lines and completely disconnect the power supply. With this type of system configuration, it is necessary to apply directional relays at the receiving end and to grade them with the non-directional relays at the sending end, to ensure correct discriminative operation of the relays during line faults. This is done by setting the directional relays R'_1 and R'_2 in Figure C1.13 with their directional elements looking into the protected line, and giving them lower time and current settings than relays R_1 and R_2. The usual practice is to set relays R'_1 and R'_1 to 50% of the normal full load of the protected circuit and 0.1 TMS, but care must be taken to

14. Directional phase fault overcurrent relays

ensure that the continuous thermal rating of the relays of twice rated current is not exceeded. An example calculation is given in Section 20.3.

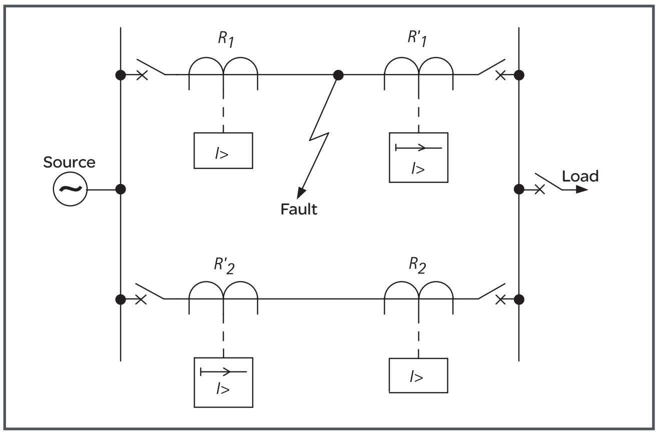

Figure C1.13:
Directional relays applied to parallel feeders

15. Ring mains

A particularly common arrangement within distribution networks is the Ring Main. The primary reason for its use is to maintain supplies to consumers in case of fault conditions occurring on the interconnecting feeders. A typical ring main with associated overcurrent protection is shown in Figure C1.14. Current may flow in either direction through the various relay locations, and therefore directional overcurrent relays are applied.

In the case of a ring main fed at one point only, the settings of the relays at the supply end and at the mid-point substation are identical. They can therefore be made non-directional, if, in the latter case, the relays are located on the same feeder, that is, one at each end of the feeder.

It is interesting to note that when the number of feeders round the ring is an even number, the two relays with the same operating time are at the same substation. They will therefore have to be directional. When the number of feeders is an odd number, the two relays with the same operating time are at different substations and therefore do not need to be directional. It may also be noted that, at intermediate substations, whenever the operating time of the relays at each substation are different, the difference between their operating times is never less than the grading margin, so the relay with the longer operating time can be non-directional. With modern numerical relays, a directional facility is often available for little or no extra cost, so that it may be simpler in practice to apply directional relays at all locations. Also, in the event of an additional feeder being added subsequently, the relays that can be non-directional need to be re-determined and will not necessarily be the same – giving rise to problems of changing a non-directional relay for a directional one. If a VT was not provided originally, this may be very difficult to install at a later date.

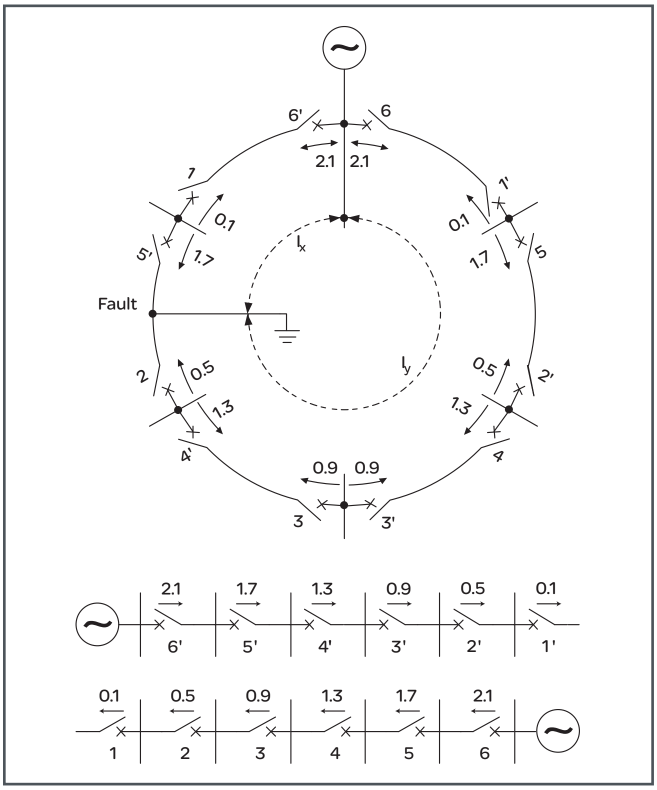

Figure C1.14:
Grading of ring mains

15. Ring mains

15.1 Grading of ring mains

The usual grading procedure for relays in a ring main circuit is to open the ring at the supply point and to grade the relays first clockwise and then anti-clockwise. That is, the relays looking in a clockwise direction around the ring are arranged to operate in the sequence 1-2-3-4-5-6 and the relays looking in the anti-clockwise direction are arranged to operate in the sequence 1'-2'-3'-4'-5'-6', as shown in Figure C1.14.

The arrows associated with the relaying points indicate the direction of current flow that will cause the relay to operate. A double-headed arrow is used to indicate a non-directional relay, such as those at the supply point where the power can flow only in one direction. A single-headed arrow is used to indicate a directional relay, such as those at intermediate substations around the ring where the power can flow in either direction. The directional relays are set in accordance with the invariable rule, applicable to all forms of directional protection, that the current in the system must flow from the substation busbars into the protected line in order that the relays may operate.

Disconnection of the faulted line is carried out according to time and fault current direction. As in any parallel system, the fault current has two parallel paths and divides itself in the inverse ratio of their impedances. Thus, at each substation in the ring, one set of relays will be made inoperative because of the direction of current flow, and the other set operative. It will also be found that the operating times of the relays that are inoperative are faster than those of the operative relays, with the exception of the mid-point substation, where the operating times of relays 3 and 3' happen to be the same.

The relays that are operative are graded downwards towards the fault and the last to be affected by the fault operates first. This applies to both paths to the fault. Consequently, the faulted line is the only one to be disconnected from the ring and the power supply is maintained to all the substations.

When two or more power sources feed into a ring main, time graded overcurrent protection is difficult to apply and full discrimination may not be possible. With two sources of supply, two solutions are possible. The first is to open the ring at one of the supply points, whichever is more convenient, by means of a suitable high set instantaneous overcurrent relay. The ring is then graded as in the case of a single infeed. The second method is to treat the section of the ring between the two supply points as a continuous bus separate from the ring and to protect it with a unit protection system, and then proceed to grade the ring as in the case of a single infeed. Section 20.4 provides a worked example of ring main grading.

16. Earthfault protection

In the foregoing description, attention has been principally directed towards phase fault overcurrent protection. More sensitive protection against earthfaults can be obtained by using a relay that responds only to the residual current of the system, since a residual component exists only when fault current flows to earth. The earthfault relay is therefore completely unaffected by load currents, whether balanced or not, and can be given a setting which is limited only by the design of the equipment and the presence of unbalanced leakage or capacitance currents to earth. This is an important consideration if settings of only a few percent of system rating are considered, since leakage currents may produce a residual quantity of this order.

On the whole, the low settings permissible for earthfault relays are very useful, as earthfaults are not only by far the most frequent of all faults, but may be limited in magnitude by the neutral earthing impedance, or by earth contact resistance.

The residual component is extracted by connecting the line current transformers in parallel as shown in Figure C1.15. The simple connection shown in Figure C1.15(a) can be extended by connecting overcurrent elements in the individual phase leads, as illustrated in Figure C1.15(b), and inserting the earthfault relay between the star points of the relay group and the current transformers.

Phase fault overcurrent relays are often provided on only two phases since these will detect any interphase fault; the connections to the earthfault relay are unaffected by this consideration. The arrangement is illustrated in Figure C1.15(c).

The typical settings for earthfault relays are 30%-40% of the full-load current or minimum earthfault current on the part of the system being protected. However, account may have to be taken of the variation of setting with relay burden as described in Section 16.1 below. If greater sensitivity than this is required, one of the methods described in Section 16.3 for obtaining sensitive earthfault protection must be used.

16.1 Effective setting of earthfault relays

The primary setting of an overcurrent relay can usually be taken as the relay setting multiplied by the CT ratio. The CT can be assumed to maintain a sufficiently accurate ratio so that, expressed as a percentage of rated current, the primary setting will be directly proportional to the relay setting. However, this may not be true for an earthfault relay. The

16. Earthfault protection

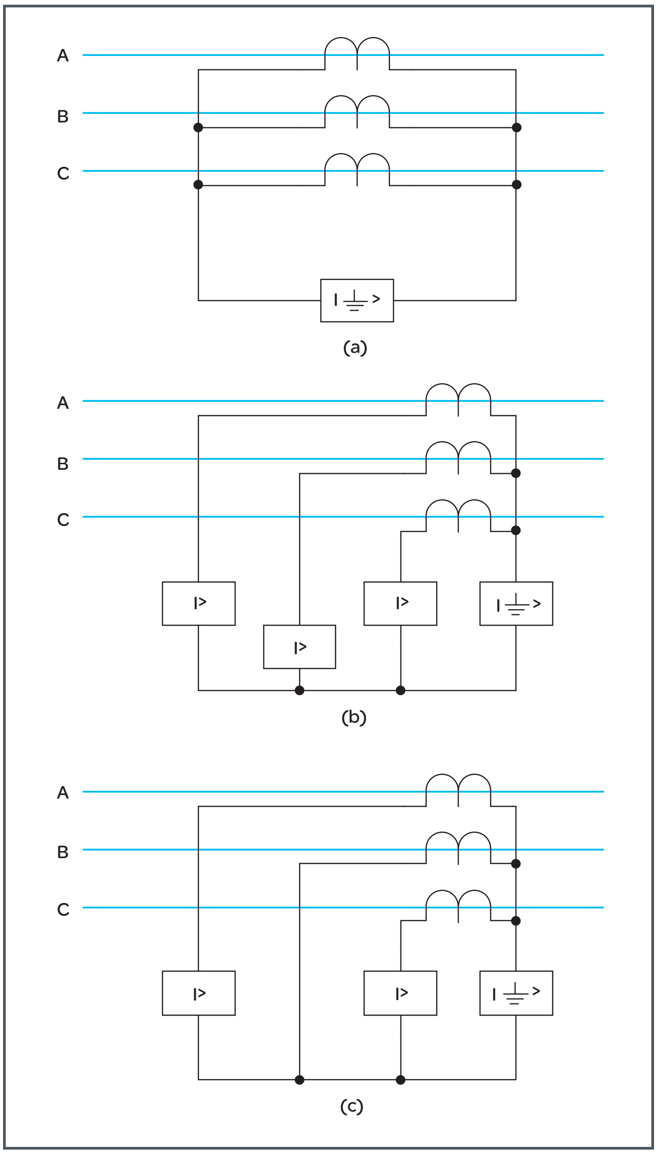

Figure C1.15:
Residual connection of current transformers to earthfault relays

performance varies according to the relay technology used.

16.1.1 Static, digital and numerical relays

When static, digital or numerical relays are used the relatively low value and limited variation of the relay burden over the relay setting range results in the above statement holding true. The variation of input burden with current should be checked to ensure that the variation is sufficiently small. If not, substantial errors may occur, and the setting procedure will have to follow that for electro- mechanical relays.

16.1.2 Electromechanical relays

When using an electromechanical relay, the earthfault element generally will be similar to the phase elements. It will have a similar VA consumption at setting, but will impose a far higher burden at nominal or rated current, because of its lower setting. For example, a relay with a setting of 20% will have an impedance of 25 times that of a similar element with a setting of 100%. Very frequently, this burden will exceed the rated burden of the current transformers. It might be thought that correspondingly larger current transformers should be used, but this is considered to be unnecessary. The current transformers that handle the phase burdens can operate the earthfault relay and the increased errors can easily be allowed for.

Not only is the exciting current of the energising current transformer proportionately high due to the large burden of the earthfault relay, but the voltage drop on this relay is impressed on the other current transformers of the paralleled group, whether they are carrying primary current or not. The total exciting current is therefore the product of the magnetising loss in one CT and the number of current transformers in parallel. The summated magnetising loss can be appreciable in comparison with the operating current of the relay, and in extreme cases where the setting current is low or the current transformers are of low performance, may even exceed the output to the relay. The 'effective setting current' in secondary terms is the sum of the relay setting current and the total excitation loss. Strictly speaking, the effective setting is the vector sum of the relay setting current and the total exciting current, but the arithmetic sum is near enough, because of the similarity of power factors. It is instructive to calculate the effective setting for a range of setting values of a relay, a process that is set out in Table C1.4, with the results illustrated in Figure C1.16.

Relay plug setting		Coil voltage at setting (V)	Exciting current (Ie)	Effective setting	
%	Current (A)			Current (A)	%
5	0.25	12	0.583	2.4	0
10	0.5	6	0.405	1.715	34.3
15	0.75	4	0.3	1.65	33
20	1	3	0.27	1.81	36
40	2	1.5	0.17	2.51	50
60	3	1	0.12	3.36	67
80	4	0.75	0.1	4.3	86
100	5	0.6	0.08	5.24	105

Table C1.4:
Calculation of effective settings

The effect of the relatively high relay impedance and the summation of CT excitation losses in the residual circuit is augmented still further by the fact that, at setting, the flux density in the current transformers corresponds to the bottom bend of the excitation characteristic. The exciting impedance under this condition is relatively low, causing the ratio error to be high. The current transformer actually improves in

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16. Earthfault protection

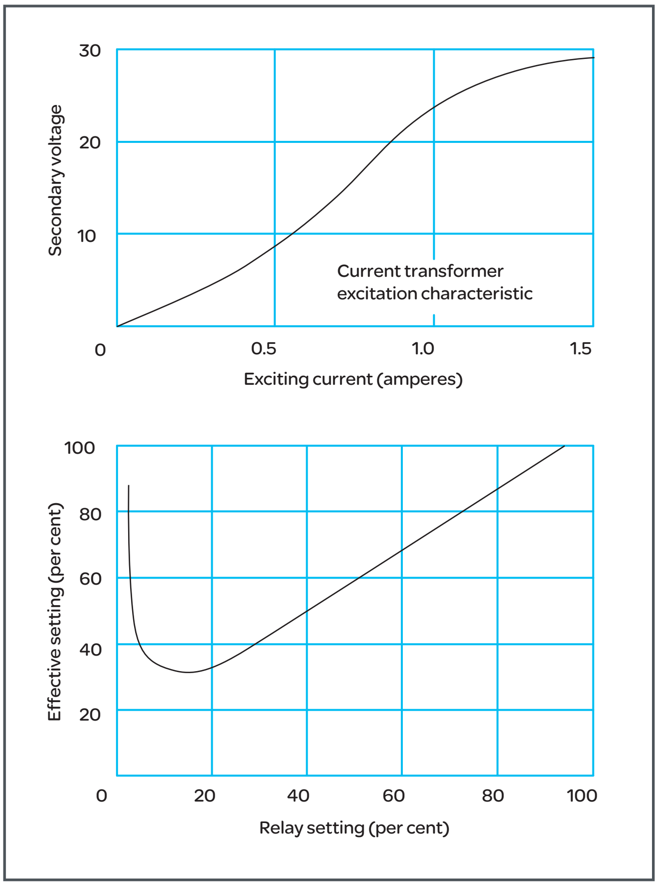

Figure C1.16:
Effective setting of earthfault relay

performance with increased primary current, while the relay impedance decreases until, with an input current several times greater than the primary setting, the multiple of setting current in the relay is appreciably higher than the multiple of primary setting current which is applied to the primary circuit. This causes the relay operating time to be shorter than might be expected.

At still higher input currents, the CT performance falls off until finally the output current ceases to increase substantially. Beyond this value of input current, operation is further complicated by distortion of the output current waveform.

16.2 Time grading of earthfault relays

The time grading of earthfault relays can be arranged in the same manner as for phase fault relays. The time/primary current characteristic for electro-mechanical relays cannot be kept proportionate to the relay characteristic with anything like the accuracy that is possible for phase fault relays. As shown above, the ratio error of the current transformers at relay setting current may be very high. It is clear that time grading of electromechanical earthfault relays is not such a simple matter as the procedure adopted for phase relays in Table C1.3. Either the above factors must be taken into account with the errors calculated for each current level, making the process much more tedious, or longer grading margins must be allowed. However, for other types of relay, the procedure adopted for phase fault relays can be used.

16.3 Sensitive earthfault protection

LV systems are not normally earthed through an impedance, due to the resulting overvoltages that may occur and consequential safety implications. HV systems may be designed to accommodate such overvoltages, but not the majority of LV systems.

However, it is quite common to earth HV systems through an impedance that limits the earthfault current. Further, in some countries, the resistivity of the earth path may be very high due to the nature of the ground itself (e.g. desert or rock). A fault to earth not involving earth conductors may result in the flow of only a small current, insufficient to operate a normal protection system. A similar difficulty also arises in the case of broken line conductors, which, after falling on to hedges or dry metalled roads, remain energised because of the low leakage current, and therefore present a danger to life.

To overcome the problem, it is necessary to provide an earthfault protection system with a setting that is considerably lower than the normal line protection. This presents no difficulty to a modern digital or numerical relay. However, older electromechanical or static relays may present difficulties due to the high effective burden they may present to the CT.

The required sensitivity cannot normally be provided by means of conventional CTs. A core balance current transformer (CBCT) will normally be used. The CBCT is a current transformer mounted around all three phase (and neutral if present) conductors so that the CT secondary current is proportional to the residual (i.e. earth) current. Such a CT can be made to have any convenient ratio suitable for operating a sensitive earthfault relay element. By use of such techniques, earthfault settings down to 10% of the current rating of the circuit to be protected can be obtained.

Care must be taken to position a CBCT correctly in a cable circuit. If the cable sheath is earthed, the earth connection from the cable gland/sheath junction must be taken through the CBCT primary to ensure that phase-sheath faults are detected. Figure C1.17 shows the correct and incorrect methods. With the incorrect method, the fault current in the sheath is not seen as an unbalance current and hence relay operation does not occur.

The normal residual current that may flow during healthy conditions limits the application of non-directional sensitive earthfault protection. Such residual effects can occur due to unbalanced leakage or capacitance in the system.

16. Earthfault protection

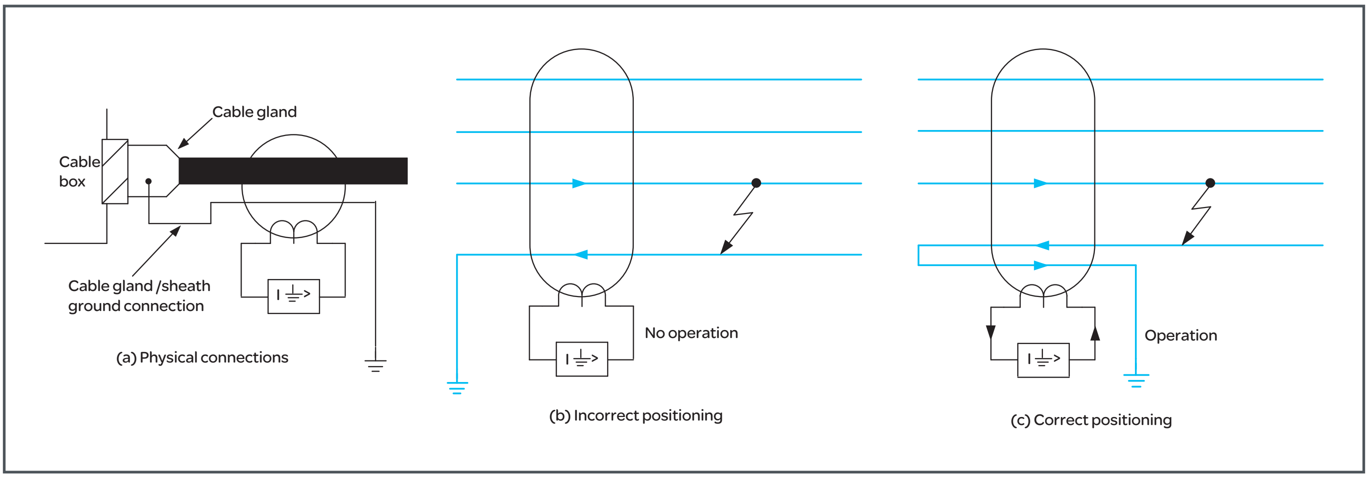

Figure C1.17:
Positioning of core balance current transformers

17. Directional earthfault overcurrent protection

Directional earthfault overcurrent may need to be applied in the following situations:

a. for earthfault protection where the overcurrent protection is by directional relays

b. in insulated-earth networks

c. in Petersen coil earthed networks

d. where the sensitivity of sensitive earthfault protection is insufficient – use of a directional earthfault relay may provide greater sensitivity

The relay elements previously described as phase fault elements respond to the flow of earthfault current, and it is important that their directional response be correct for this condition. If a special earthfault element is provided as described in Section 16 (which will normally be the case), a related directional element is needed.

17.1 Relay connections

The residual current is extracted as shown in Figure C1.15. Since this current may be derived from any phase, in order to obtain a directional response it is necessary to obtain an appropriate quantity to polarise the relay. In digital or numerical relays there are usually two choices provided.

17.1.1 Residual voltage

A suitable quantity is the residual voltage of the system. This is the vector sum of the individual phase voltages. If the secondary windings of a three-phase, five limb voltage

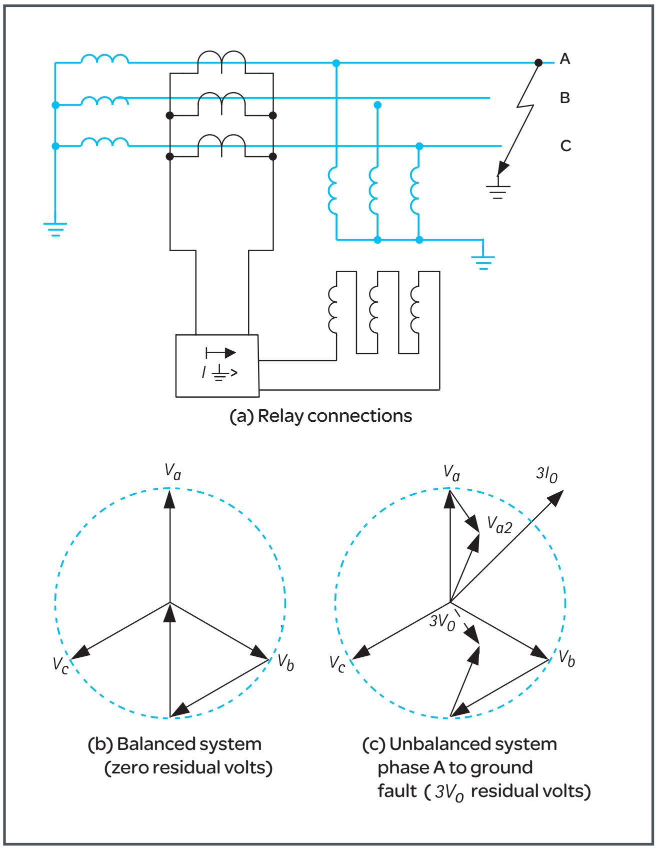

Figure C1.18:
Voltage polarised directional earthfault relay

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17. Directional earthfault overcurrent protection

transformer or three single-phase units are connected in broken delta, the voltage developed across its terminals will be the vector sum of the phase to ground voltages and hence the residual voltage of the system, as illustrated in Figure C1.18.

The primary star point of the VT must be earthed. However, a three-phase, three limb VT is not suitable, as there is no path for the residual magnetic flux. For applications where the main voltage transformer associated with the high voltage system is not provided with a broken delta secondary winding to polarise the directional earthfault relay, it is permissible to use three single-phase interposing voltage transformers. Their primary windings are connected in star and their secondary windings are connected in broken delta. For satisfactory operation, however, it is necessary to ensure that the main voltage transformers are of a suitable construction to reproduce the residual voltage and that the star point of the primary winding is solidly earthed. In addition, the star point of the primary windings of the interposing voltage transformers must be connected to the star point of the secondary windings of the main voltage transformers.

The residual voltage will be zero for balanced phase voltages. For simple earthfault conditions, it will be equal to the depression of the faulted phase voltage. In all cases the residual voltage is equal to three times the zero sequence voltage drop on the source impedance and is therefore displaced from the residual current by the characteristic angle of the source impedance. The residual quantities are applied to the directional element of the earthfault relay.

The residual current is phase offset from the residual voltage and hence angle adjustment is required. Typically, the current will lag the polarising voltage. The method of system earthing also affects the Relay Characteristic Angle (RCA), and the following settings are usual:

a. resistance-earthed system: 0° RCA

b. distribution system, solidly-earthed: -45° RCA

c. transmission system, solidly-earthed: -60° RCA

The different settings for distribution and transmission systems arise from the different X/R ratios found in these systems.

17.1.2 Negative sequence current

The residual voltage at any point in the system may be insufficient to polarise a directional relay, or the voltage transformers available may not satisfy the conditions for providing residual voltage. In these circumstances, negative sequence current can be used as the polarising quantity. The fault direction is determined by comparison of the negative sequence voltage with the negative sequence current. The RCA must be set based on the angle of the negative phase sequence source voltage.

18. Earthfault protection on insulated networks

Occasionally, a power system is run completely insulated from earth. The advantage of this is that a single phase-earthfault on the system does not cause any earthfault current to flow, and so the whole system remains operational. The system must be designed to withstand high transient and steady-state overvoltages however, so its use is generally restricted to low and medium voltage systems.

It is vital that detection of a single phase-earthfault is achieved, so that the fault can be traced and rectified. While system operation is unaffected for this condition, the occurrence of a second earthfault allows substantial currents to flow.

The absence of earthfault current for a single phase-earthfault clearly presents some difficulties in fault detection. Two methods are available using modern relays.

18.1 Residual voltage

When a single phase-earthfault occurs, the healthy phase voltages rise by a factor of √3 and the three phase voltages no longer have a phasor sum of zero. Hence, a residual voltage element can be used to detect the fault. However, the method does not provide any discrimination, as the unbalanced voltage occurs on the whole of the affected section of the system. One advantage of this method is that no CT's are required, as voltage is being measured. However, the requirements for the VT's as given in Section 17.1.1 apply.

Grading is a problem with this method, since all relays in the affected section will see the fault. It may be possible to use definite-time grading, but in general, it is not possible to provide fully discriminative protection using this technique.

18.2 Sensitive earthfault

This method is principally applied to MV systems, as it relies on detection of the imbalance in the per-phase charging currents that occurs.

Figure C1.19 illustrates the situation that occurs when a single phase-earthfault is present. The relays on the healthy feeders see the unbalance in charging currents for their own feeders. The relay in the faulted feeder sees the charging currents in

18. Earthfault protection on insulated networks

the rest of the system, with the current of its own feeders cancelled out. Figure C1.20 shows the phasor diagram.

Use of Core Balance CTs is essential. With reference to Figure C1.20, the unbalance current on the healthy feeders lags the residual voltage by 90°. The charging currents on these feeders will be √3 times the normal value, as the phase-earth voltages have risen by this amount. The magnitude of the residual current is therefore three times the steady-state charging current per phase. As the residual currents on the healthy and faulted feeders are in antiphase, use of a directional earthfault relay can provide the discrimination required. The polarising quantity used is the residual voltage. By shifting this by 90°, the residual current seen by the relay on the faulted feeder lies within the 'operate' region of the directional characteristic, while the residual currents on the healthy feeders lie within the 'restrain' region. Thus, the RCA required is 90°. The relay setting has to lie between one and three times the per-phase charging current.

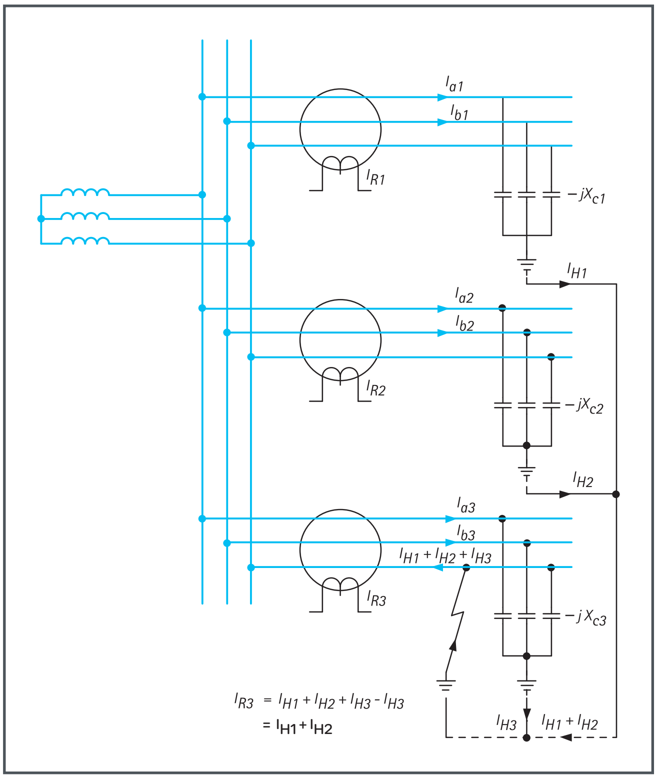

Figure C1.19:
Current distribution in an insulated system with a C phase – earthfault

This may be calculated at the design stage, but confirmation by means of tests on-site is usual. A single phase-earthfault is deliberately applied and the resulting currents noted, a process made easier in a modern digital or numeric relay by the measurement facilities provided. As noted earlier, application of such a fault for a short period does not involve any disruption to the network, or fault currents, but the duration should be as short as possible to guard against a second such fault occurring.

It is also possible to dispense with the directional element if the relay can be set at a current value that lies between the charging current on the feeder to be protected and the charging current of the rest of the system.

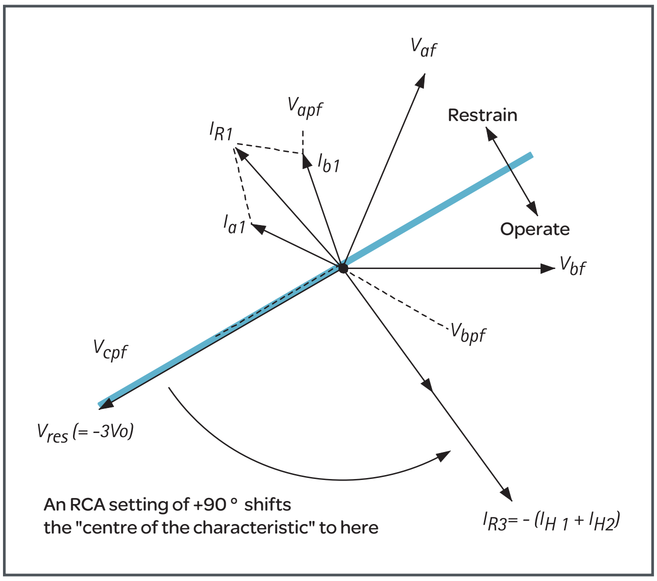

Figure C1.20:
Phasor diagram for insulated system with C phase-earthfault

19. Earthfault protection on Petersen Coil earthed networks

Petersen Coil earthing is a special case of high impedance earthing. The network is earthed via a reactor, whose reactance is made nominally equal to the total system capacitance to earth. Under this condition, a single phase-earthfault does not result in any earthfault current in steady-state conditions. The effect is therefore similar to having an insulated system. The effectiveness of the method is dependent on the accuracy of tuning of the reactance value – changes in system capacitance (due to system configuration changes for instance) require changes to the coil reactance. In practice, perfect matching of the coil reactance to the system capacitance is difficult to achieve, so that a small earthfault current will flow. Petersen Coil earthed systems are commonly found in areas where the system consists mainly of rural overhead lines, and are particularly beneficial in locations subject to a high incidence of transient faults.

To understand how to correctly apply earthfault protection to such systems, system behaviour under earthfault conditions must first be understood.

Figure C1.21 illustrates a simple network earthed through a Petersen Coil. The equations clearly show that, if the reactor is correctly tuned, no earthfault current will flow.

Figure C1.22 shows a radial distribution system earthed using a Petersen Coil. One feeder has a phase-earthfault on phase C.

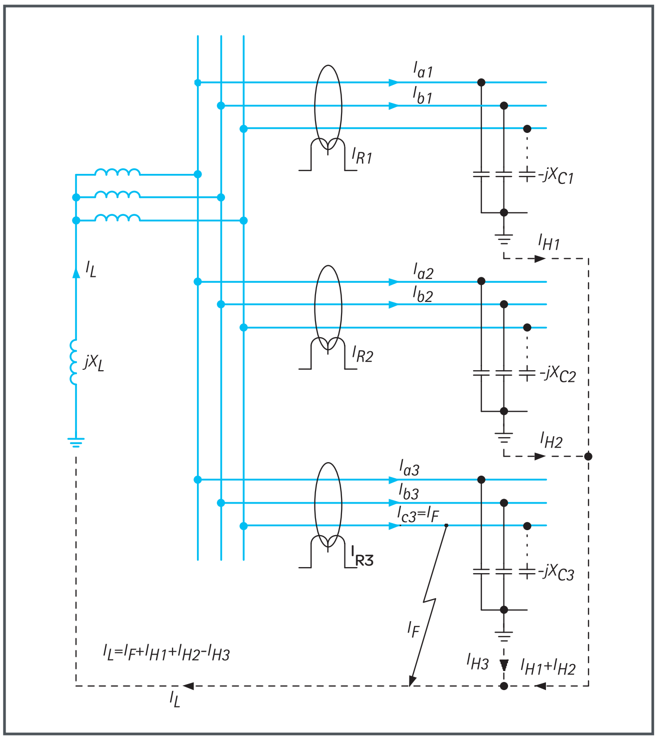

Figure C1.22:
Distribution of currents during a C phase-earthfault – radial distribution system

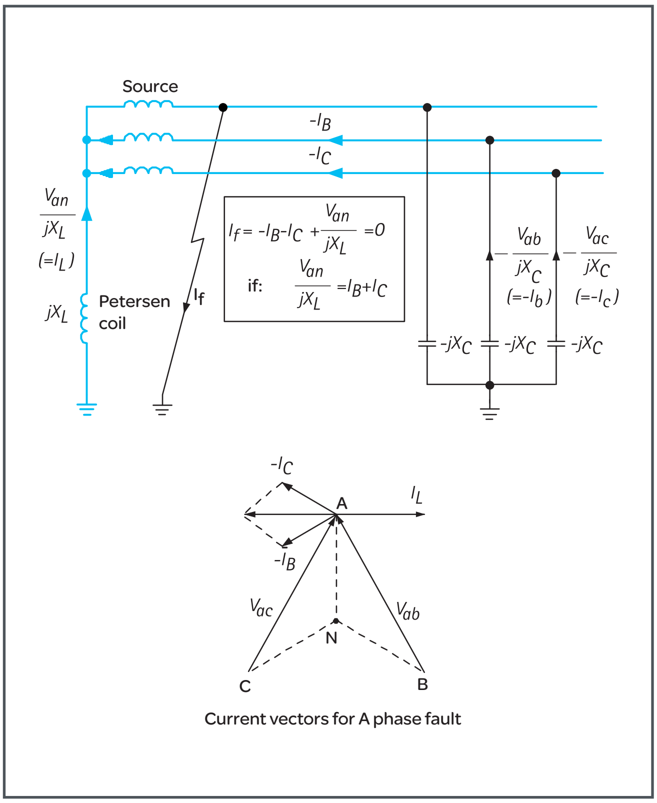

Figure C1.21:
Earthfault in Petersen Coil earthed system

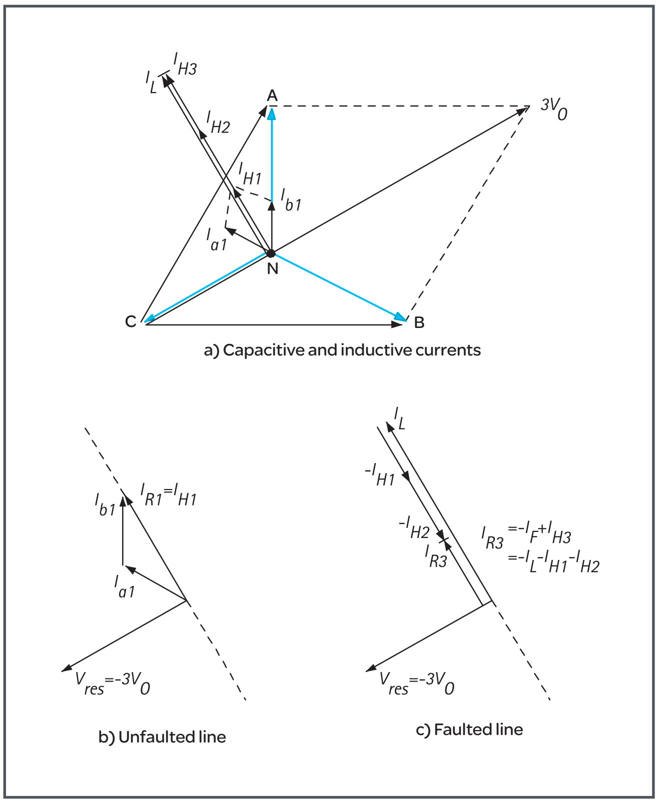

Figure C1.23: C phase-earthfault in Petersen Coil earthed network: theoretical case - no resistance present in X_L or X_C

19. Earthfault protection on Petersen Coil earthed networks

Figure C1.23 shows the resulting phasor diagrams, assuming that no resistance is present. In Figure C1.23(a), it can be seen that the fault causes the healthy phase voltages to rise by a factor of √3 and the charging currents lead the voltages by 90°.

Using a CBCT, the unbalance currents seen on the healthy feeders can be seen to be a simple vector addition of I_{a1} and I_{b1}, and this lies at exactly 90° lagging to the residual voltage (Figure C1.23(b). The magnitude of the residual current I_{R1} is equal to three times the steady-state charging current per phase. On the faulted feeder, the residual current is equal to $I_L - I_{H1} - I_{H2}$, as shown in Figure C1.23(c) and more clearly by the zero sequence network of Figure C1.24.

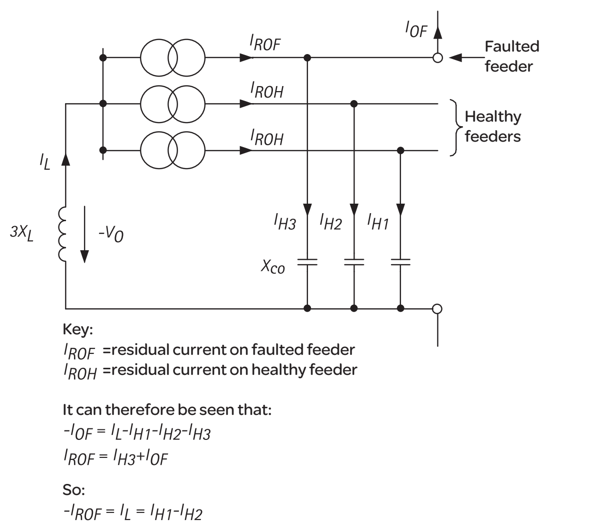

Figure C1.24:
Zero sequence network showing residual currents

However, in practical cases, resistance is present and Figure C1.25 shows the resulting phasor diagrams. If the residual voltage V_{res} is used as the polarising voltage, the residual current is phase shifted by an angle less than 90° on the faulted feeder and greater than 90° on the healthy feeders.

Hence a directional relay can be used, and with an RCA of 0°, the healthy feeder residual current will fall in the 'restrain' area of the relay characteristic while the faulted feeder residual current falls in the 'operate' area.

Often, a resistance is deliberately inserted in parallel with the Petersen Coil to ensure a measurable earthfault current and increase the angular difference between the residual signals to aid relay application.

Having established that a directional relay can be used, two possibilities exist for the type of protection element that can be applied – sensitive earthfault and zero sequence wattmetric.

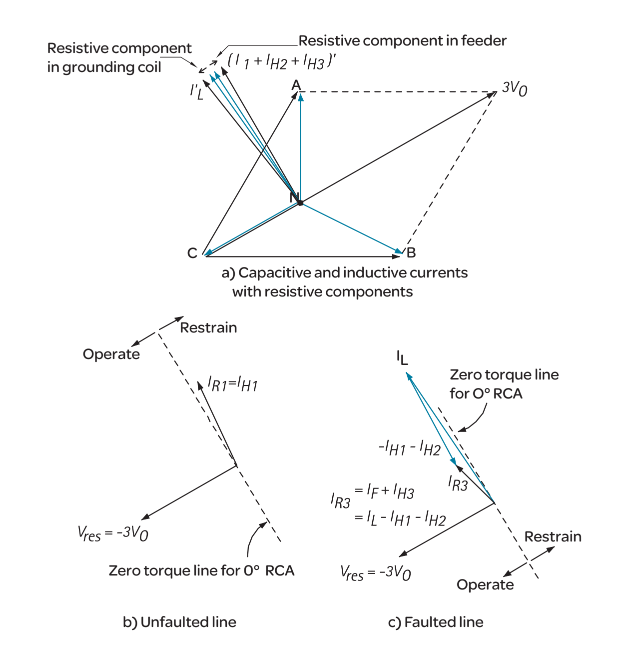

Figure C1.25:
C phase-earthfault in Petersen Coil earthed network: practical case with resistance present in X_L or X_C

19.1 Sensitive earthfault protection

To apply this form of protection, the relay must meet two requirements:

a. current measurement setting capable of being set to very low values

b. an RCA of 0°, and capable of fine adjustment around this value

The sensitive current element is required because of the very low current that may flow – so settings of less than 0.5% of rated current may be required. However, as compensation by the Petersen Coil may not be perfect, low levels of steady-state earthfault current will flow and increase the residual current seen by the relay. An often used setting value is the per phase charging current of the circuit being protected.

Fine tuning of the RCA is also required about the 0° setting, to compensate for coil and feeder resistances and the performance of the CT used. In practice, these adjustments are best carried out on site through deliberate application of faults and recording of the resulting currents.

19.2 Sensitive wattmetric protection

It can be seen in Figure C1.25 that a small angular difference exists between the spill current on the healthy and faulted feeders. Figure C1.26 illustrates how this angular difference gives rise to active components of current which are in antiphase to each other.

19. Earthfault protection on Petersen Coil earthed networks

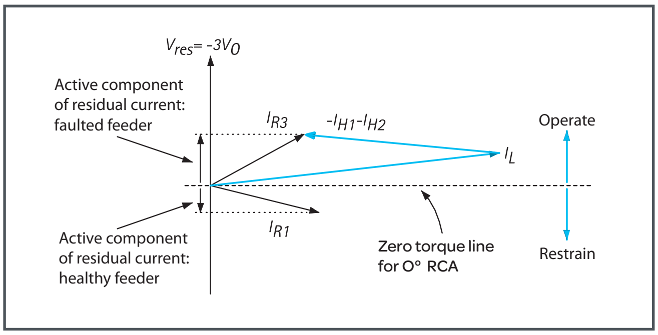

Figure C1.26:
Resistive components of spill current

Consequently, the active components of zero sequence power will also lie in similar planes and a relay capable of detecting active power can make a discriminatory decision. If the wattmetric component of zero sequence power is detected in the forward direction, it indicates a fault on that feeder, while a power in the reverse direction indicates a fault elsewhere on the system. This method of protection is more popular than the sensitive earthfault method, and can provide greater security against false operation due to spurious CBCT output under non-earthfault conditions.

Wattmetric power is calculated in practice using residual quantities instead of zero sequence ones. The resulting values are therefore nine times the zero sequence quantities as the residual values of current and voltage are each three times the corresponding zero sequence values. The equation used is:

$$V_{res} \times I_{res} \times \cos(\varphi - \varphi_c)$$

$$= 9 \times V_o \times I_o \times \cos(\varphi - \varphi_c) \qquad \text{...Equation C1.5}$$

where:

V_{res} = residual voltage

I_{res} = residual current

V_o = zero sequence voltage

I_o = zero sequence current

φ = angle between Vres and Ires

φ_c = relay characteristic angle setting

The current and RCA settings are as for a sensitive earthfault relay.

20. Examples of time and current grading

This section provides details of the time/current grading of some example networks, to illustrate the process of relay setting calculations and relay grading. They are based on the use of a modern numerical overcurrent relay illustrated in Figure C1.27, with setting data taken from this relay.

20.1 Relay phase fault setting example

Consider the system shown in Figure C1.28.

The problem is to calculate appropriate relay settings for relays 1-5 inclusive. Because the example is concerned with grading, considerations such as bus-zone protection, and CT knee-point voltage requirements, etc., are not dealt with. All curves are plotted to an 11kV base. The contactors in series with fuses F_{S1}/F_{S2} have a maximum breaking capacity of 3 kA, and relay F_{S2} has been set to ensure that the fuse operates prior to the contactor for currents in excess of this value. CT's for relays, F_1/F_2 and 5 are existing CTs with 5 A secondaries, while the remaining CTs are new with 1 A secondaries. Relay 5 is the property of the supply utility, and is required to be set using an SI characteristic in order to ensure grading with upstream relays.

Figure C1.27:
MiCOM Px40 in 60 TE

20. Examples of time and current grading

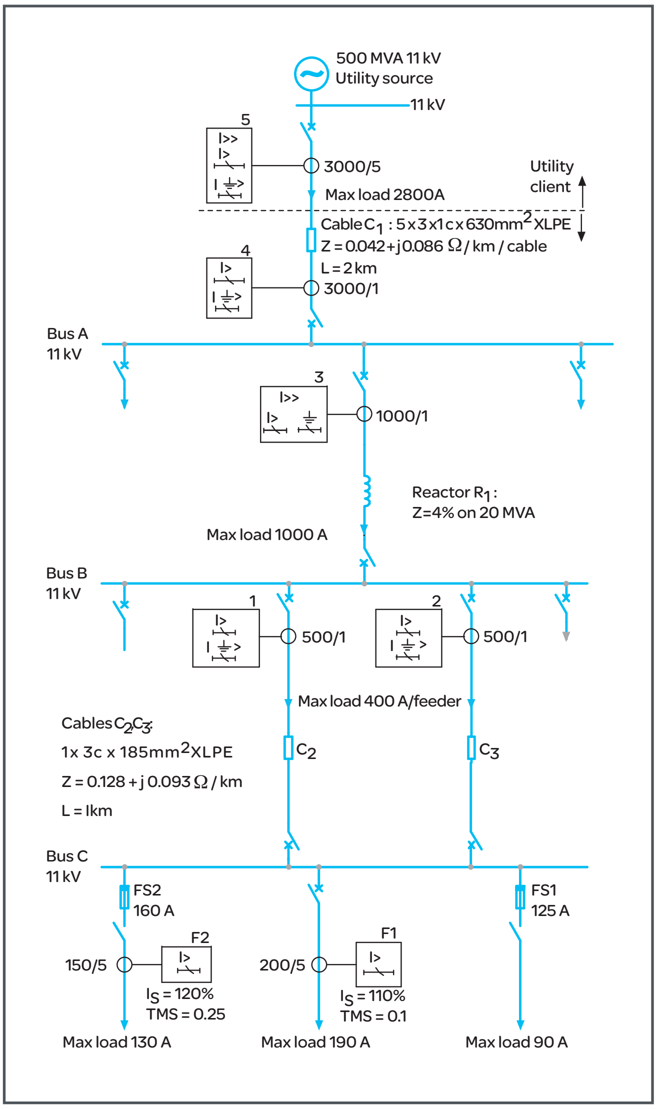

Figure C1.28:
IDMT relay grading example

20.1.1 Impedance Calculations

All impedances must first be referred to a common base, taken as 500 MVA, as follows:

a. Reactor R_1

$$Z_{R1} = \frac{4 \times 500}{20} = 100\ \%$$

b. Cable C_1

$$Z_{C1} = \frac{0.096}{5} \times 2 = 0.038\,\Omega$$

On 500 MVA base,

$$Z_{C1} = \frac{0.038 \times 100 \times 500}{(11)^2} = 15.7\%$$

c. Cables C_2, C_3

$$Z_{C2}\,,\ Z_{C3} = 0.158\ \Omega$$

On 500 MVA base,

$$Z_{C2}\,, Z_{C3} = \frac{0.158 \times 100 \times 500}{(11)^2} = 65.3\%$$

d. Source Impedance (500 MVA base)

$$Z_S = \frac{500}{500} \times 100\,\% = 100\%$$

20.1.2 Fault Levels

The fault levels are calculated as follows:

a. At bus C

For 2 feeders,

$$Fault\ Level = \frac{500 \times 100}{Z_{R1} + Z_S + Z_{C1} + Z_{C2}/2} MVA$$

$$= 10.6\ kA\ on\ 11\ kV\ base$$

For a single feeder, fault level

$$= 178\ MVA$$

$$= 9.33\ kA$$

b. At bus B

$$Fault\ Level = \frac{500 \times 100}{Z_S + Z_{C1} + Z_{R1}} MVA$$

$$= 232\ MVA$$

$$= 12.2\ kA$$

c. At bus A

$$Fault\ Level = \frac{500 \times 100}{Z_S + Z_{C1}} MVA$$

$$= 432 MVA$$

$$= 22.7 kA$$

d. Source

$$Fault\ Level = 500\ MVA$$

$$= 26.3\ kA$$

20.1.3 CT ratio selection

This requires consideration not only of the maximum load current, but also of the maximum secondary current under fault conditions.

CT secondaries are generally rated to carry a short-term current equal to 100 x rated secondary current. Therefore, a check is required that none of the new CT secondaries has a current of more than 100 A when maximum fault current is flowing in the primary. Using the calculated fault currents, this condition is satisfied, so modifications to the CT ratios are not required.

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20. Examples of time and current grading

20.1.4 Relay overcurrent settings – Relays 1/2

These relays perform overcurrent protection of the cable feeders, Busbar C and backup-protection to relays $F1$, $F2$ and their associated fuses $FS1$ and $FS2$. The settings for Relays 1 and 2 will be identical, so calculations will only be performed for Relay 1. Consider first the current setting of the relay.

Relay 1 must be able to reset at a current of 400 A – the rating of the feeder. The relay has a drop-off/pick-up ratio of 0.95, so the relay current setting must not be less than 400/0.95, or 421 A. A suitable setting that is greater than this value is 450 A. However, Section 12.3 also recommends that the current setting should be three times the largest fuse rating (i.e. 3 x 160 A, the rating of the largest fuse on the outgoing circuits from Busbar C), leading to a current setting of 480 A, or 96% of relay rated primary current. Note that in this application of relays to a distribution system, the question of maximum and minimum fault levels are probably not relevant as the difference between maximum and minimum fault levels will be very small. However in other applications where significant differences between maximum and minimum fault levels exist, it is essential to ensure that the selection of a current setting that is greater than full load current does not result in the relay failing to operate under minimum fault current conditions. Such a situation may arise for example in a self-contained power system with its own generation. Minimum generation may be represented by the presence of a single generator and the difference between minimum fault level and maximum load level may make the choice of relay current settings difficult.

The grading margin now has to be considered. For simplicity, a fixed grading margin of 0.3 s between relays is used in the calculations, in accordance with Table C1.2. Between fuse and relay, Equation C1.4 is applied, and with fuse $FS2$ pre-arcing time of 0.01 s (from Figure C1.29), the grading margin is 0.154 s.

Consider first the IDMT overcurrent protection. Select the EI characteristic, as fuses exist downstream, to ensure grading. The relay must discriminate with the longest operating time between relays $FS1$, and fuse $FS2$ (being the largest fuse) at the maximum fault level seen by relays 1 and 2. The maximum fault current seen by relay 1 for a fault at Busbar C occurs when only one of cables C_2, C_3 is in service. This is because the whole of the fault current then flows through the feeder that is in service. With two feeders in service, although the fault level at Busbar C is higher, each relay only sees half of the total fault current, which is less than the fault current with a single feeder in service. With EI characteristics used for relays $F1$ and $F2$, the operating time for relay $F1$ is 0.02 s at $TMS\text{-}0.1$ because the fault current is greater than 20 times relay setting, at which point the EI characteristic becomes definite time (Figure C1.4) and 0.05 s for relay $F2$ ($TMS=0.25$).

Hence select relay 1 operating time = 0.3 + 0.05 = 0.35 s, to ensure grading with relay $F2$ at a fault current of 9.33 kA.

With a primary setting of 480 A, a fault current of 9.33 kA represents 9330/480 = 19.44 times setting.

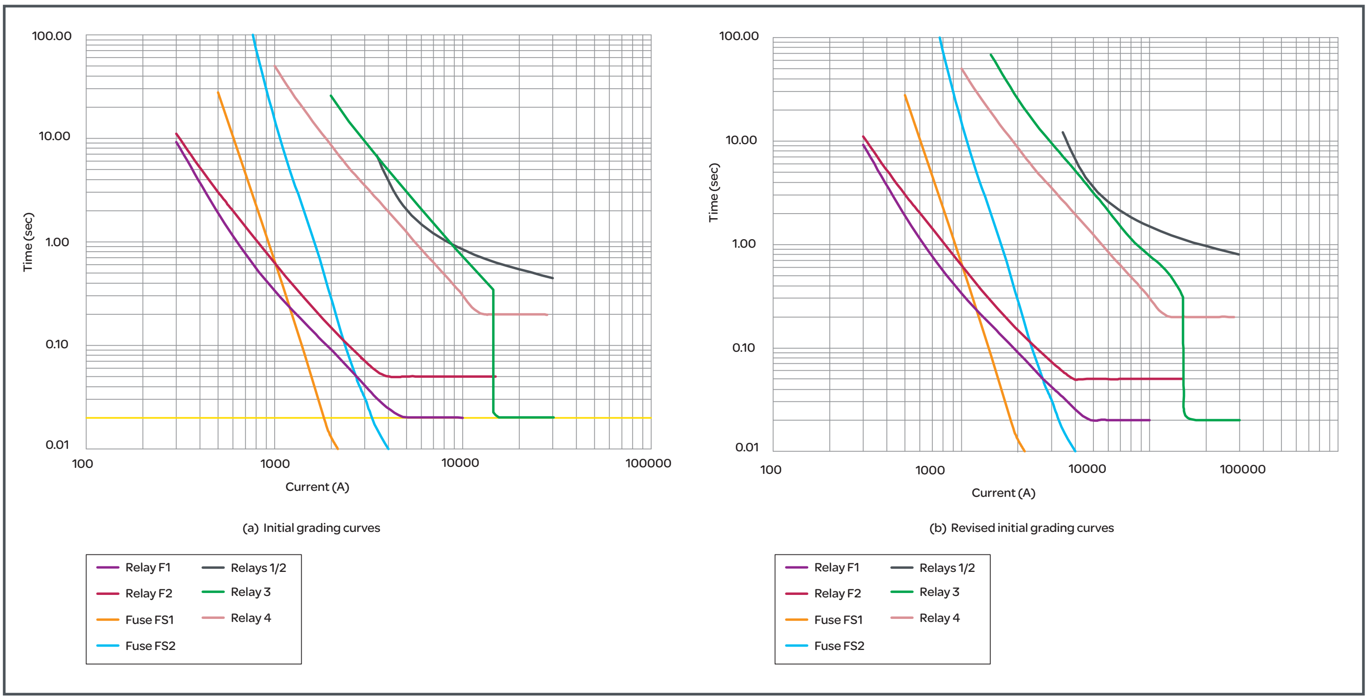

Figure C1.29:
Initial relay grading curves – overcurrent relay example

20. Examples of time and current grading

Thus relay 1 operating time at $TMS=1.0$ is $0.21\ s$. The required TMS Setting is given by the formula:

$$TMS = \frac{operation\ time\ required}{Actual\ op.\ time\ required\ at\ TMS = 1.0}$$

$$TMS = \frac{0.35}{0.21} = 1.66$$

This value of TMS is outside the settable range of the relay (maximum setting 1.2). Therefore, changes must be made to the relay current setting in order to bring the value of TMS required into the range available, provided this does not result in the inability of the relay to operate at the minimum fault level.

By re-arrangement of the formula for the EI characteristic:

$$I_{sr1f} = \sqrt{\frac{80}{t} + 1}$$

where

t is the required operation time (s)

I_{sr1f} = setting of relay at fault current

Hence, with $t = 0.35$,

$I_{sr1f} = 15.16$

or,

$$I_{sr1} = \frac{9330}{15.16} = 615.4\ A$$

$$I_{sr1} = \frac{616}{500} = 1.232$$

Use $1.24 = 620A$ nearest available value

At a TMS of 1.0, operation time at 9330 A

$$= \frac{80}{\left(\frac{9330}{620}\right)^2 - 1} = 0.355\ s$$

Hence, required TMS

$$= \frac{0.35}{0.355} = 0.99$$

for convenience, use a TMS of 1.0, slightly greater than the required value.

From the grading curves of Figure C1.29, it can be seen that there are no grading problems with fuse $FS1$ or relays $F1$ and $F2$.

20.1.5 Relay overcurrent settings - Relay 3

This relay provides overcurrent protection for reactor R_1, and backup overcurrent protection for cables C_2 and C_3.

The overcurrent protection also provides busbar protection for Busbar B.

Again, the EI characteristic is used to ensure grading with relays 1 and 2. The maximum load current is 1000 A. Relay 3 current setting is therefore

$$I_{sr3} > \frac{feeder\ flc}{CT\ primary\ current \times 0.95}$$

Substituting values,

$I_{sr3} > 1052\ A$

Use a setting of 106% or 1060 A, nearest available setting above 1052 A.

Relay 3 has to grade with relays $1/2$ under two conditions:

1. for a fault just beyond relays 1 and 2 where the fault current will be the busbar fault current of 12.2 kA
2. for a fault at Bus C where the fault current seen by either relay 1 or 2 will be half the total Bus C fault current of 10.6 kA, i.e. 5.3 kA

Examining first condition 1. With a current setting of 620 A, a TMS of 1.0 and a fault current of 12.2 kA, relay 1 will operate in 0.21 s. Using a grading interval of 0.3 s, relay 3 must therefore operate in

$0.3 + 0.21 = 0.51\ s$

at a fault current of 12.2 kA.

12.2 kA represents 12200/1060 = 11.51 times setting for relay 3 and thus the time multiplier setting of relay 3 should be 0.84 to give an operating time of 0.51 s at 11.51 times setting.

Consider now condition 2. With settings of 620 A and TMS of 1.0 and a fault current of 5.3 kA, relay 1 will operate in 1.11 s. Using a grading interval of 0.3 s, relay 3 must therefore operate in

$0.3 + 1.11 = 1.41\ s$

at a fault current of 5.3 kA.

5.3 kA represents 5300/1060 = 5 times setting for relay 3, and thus the time multiplier setting of relay 3 should be 0.33 to give an operating time of 1.11 s at 5 times setting. Thus condition 1 represents the worst case and the time multiplier setting of relay 3 should be set at 0.84. In practice, a value of 0.85 is used as the nearest available setting on the relay.

Relay 3 also has an instantaneous element. This is set such that it will not operate for the maximum through-fault current seen by the relay, a setting of 130% of this value being satisfactory. The setting is therefore:

$1.3 \times 12.2\ kA = 15.86\ kA$

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20. Examples of time and current grading

This is equal to a current setting of 14.96 times the setting of relay 3.

20.1.6 Relay 4

This must grade with relay 3 and relay 5. The supply authority requires that relay 5 use an SI characteristic to ensure grading with relays further upstream, so the SI characteristic will be used for relay 4 also. Relay 4 must grade with relay 3 at Bus A maximum fault level of 22.7 kA. However with the use of an instantaneous high set element for relay 3, the actual grading point becomes the point at which the high set setting of relay 3 operates, i.e. 15.86 kA. At this current, the operation time of relay 3 is

$$\frac{80}{(14.96)^2 - 1} \times 0.85\ s = 0.305\ s$$

Thus, relay 4 required operating time is

$$0.305 + 0.3 = 0.605\ s$$

at a fault level of 15.86 kA.

Relay 4 current setting must be at least

$$\frac{2800}{3000 \times 0.95} = 98\%$$

For convenience, use a value of 100% (=3000 A). Thus relay 4 must operate in 0.605 s at 15860/3000 = 5.29 times setting. Thus select a time multiplier setting of 0.15, giving a relay operating time of 0.62 s for a normal inverse type characteristic.

At this stage, it is instructive to review the grading curves, which are shown in Figure C1.29(a). While it can be seen that there are no grading problems between the fuses and relays $1/2$, and between relays $F1/2$ and relays $1/2$, it is clear that relay 3 and relay 4 do not grade over the whole range of fault current. This is a consequence of the change in characteristic for relay 4 to SI from the EI characteristic of relay 3 to ensure grading of relay 4 with relay 5.

The solution is to increase the TMS setting of relay 4 until correct grading is achieved. The alternative is to increase the current setting, but this is undesirable unless the limit of the TMS setting is reached, because the current setting should always be as low as possible to help ensure positive operation of the relay and provide overload protection. Trial and error is often used, but suitable software can speed the task – for instance it is not difficult to construct a spreadsheet with the fuse/relay operation times and grading margins calculated. Satisfactory grading can be found for relay 4 setting values of:

$I_{st4} = 1.0$ or $3000\ A$

$TMS = 0.275$

At 22.7 kA, the operation time of relay 4 is 0.93 s. The revised grading curves are shown in Figure C1.29(b).

20.1.7 Relay 5

Relay 5 must grade with relay 4 at a fault current of 22.7 kA. At this fault current, relay 4 operates in 0.93 s and thus relay 5 must operate in

$$0.3 + 0.93 = 1.23\ s\ at\ 22.7\ kA$$

A current setting of 110% of relay 4 current setting (i.e. 110% or 3300 A) is chosen to ensure relay 4 picks up prior to relay 5. Thus 22.7 kA represents 6.88 times the setting of relay 5. Relay 5 must grade with relay 4 at a fault current of 22.7 kA, where the required operation time is 1.23 s. At a TMS of 1.0, relay 5 operation time is

$$\frac{0.14}{(6.88)^{0.02} - 1} = 3.56\ s$$

Therefore, the required TMS is 1.23/3.56 = 0.345, use 0.35 nearest available value.

The protection grading curves that result are shown in Figure C1.30 and the setting values in Table C1.5. Grading is now satisfactory. In situations where one of the relays to be graded is provided by a third party, it is common for the settings of the relay to be specified and this may lead to a lack of co-ordination between this relay and others (usually those downstream). Negotiation is then required to try and achieve acceptable settings, but it is often the case that no change to the settings of the relay provided by the third party is allowed. A lack of co-ordination between relays then has to be accepted over at least part of the range of fault currents.

20. Examples of time and current grading

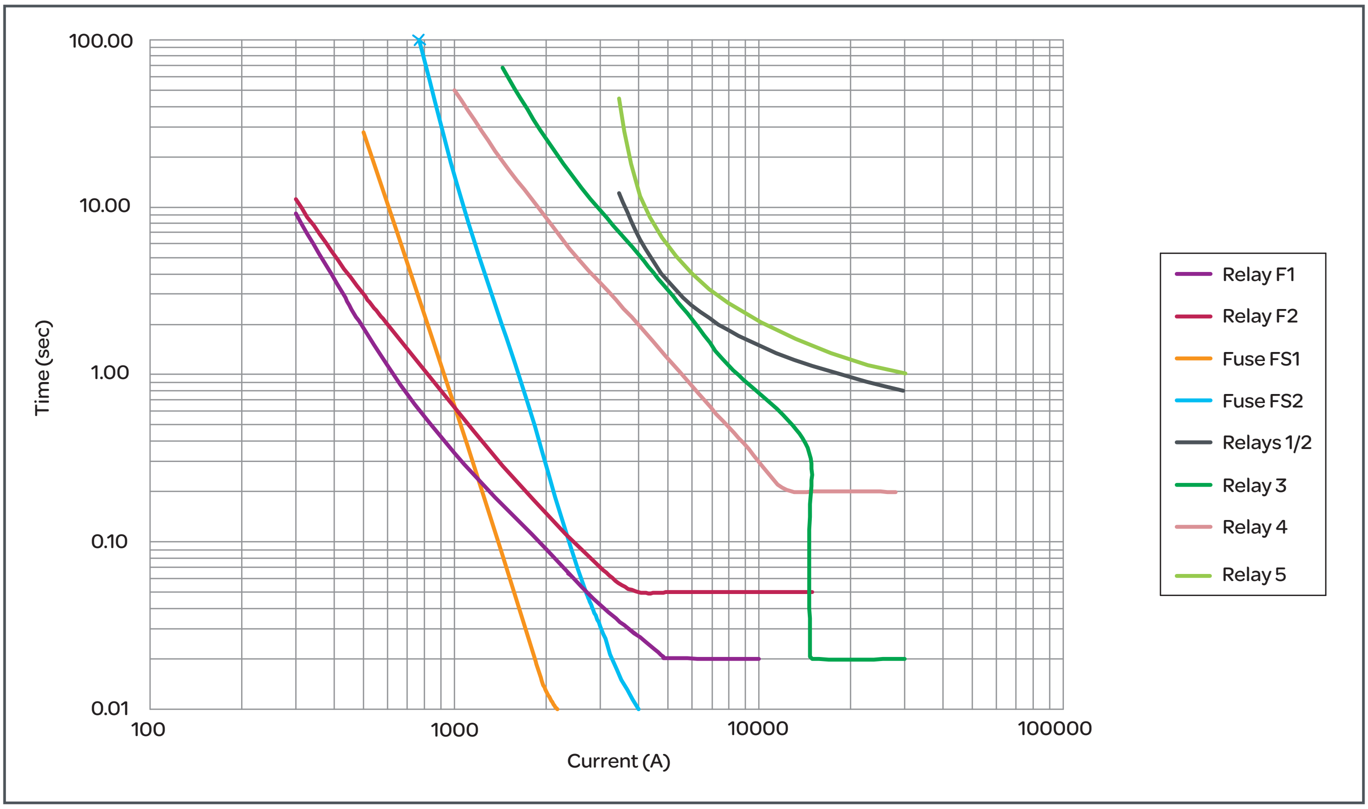

Figure C1.30:
IDMT relay grading example

Relay / fuse	Load current (A)	Max. fault current (A)	Ct ratio	Fuse rating	Relay settings			
					Charac-teristic	Current setting		TMS
						Primary amps	Per cent	
F_1	190	10.6	200/5		EI	100	100	0.1
F_2	130	10.6	150/5		EI	150	120	0.25
F_{S1}	90	10.6	-	125 A				
F_{S2}	130	10.6	-	160 A		-	-	-
1	400	12.2	500/1		EI	620	124	1
2	400	12.2	500/1		EI	620	124	1
3	1000	22.7	1000/1		EI Instant.	1060 15860	106 14.96	0.85
4	3000	22.7	3000/1		EI	3000	100	0.275
5	3000	26.25	3000/5		EI	3300	110	0.35

Table C1.5:
Relay settings for overcurrent relay example

20.2 Relay earthfault settings

The procedure for setting the earthfault elements is identical to that for the overcurrent elements, except that zero sequence impedances must be used if available and different from positive sequence impedances in order to calculate fault levels. However, such impedances are frequently not available, or known only approximately, and the phase fault current levels have to be used. Note that earthfault levels can be higher than phase fault levels if the system contains multiple earth points, or if earthfault levels are considered on the star side of a delta/star transformer when the star winding is solidly earthed.

On the circuit with fuse $F2$, low-level earthfaults may not be of sufficient magnitude to blow the fuse.

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20. Examples of time and current grading

Attempting to grade the earthfault element of the upstream relay with fuse $F2$ will not be possible. Similarly, relays $F1$ and $F2$ have phase fault settings that do not provide effective protection against earthfaults. The remedy would be to modify the downstream protection, but such considerations lie outside the scope of this example. In general therefore, the earthfault elements of relays upstream of circuits with only phase fault protection (i.e. relays with only phase fault elements or fuses) will have to be set with a compromise that they will detect downstream earthfaults but will not provide a discriminative trip. This illustrates the practical point that it is rare in anything other than a very simple network to achieve satisfactory grading for all faults throughout the network.

In the example of Figure C1.27, it is likely that the difference in fault levels between phase to phase and phase to earthfaults will be very small and thus the only function of earthfault elements is to detect and isolate low level earthfaults not seen by the phase fault elements. Following the guidelines of Section 16, relays $1/2$ can use a current setting of 30% (150 A) and a TMS of 0.2, using the EI characteristic. Grading of relays $3/4/5$ follows the same procedure as described for the phase-fault elements of these relays.

20.3 Protection of parallel feeders

Figure C1.31(a) shows two parallel transformer feeders forming part of a supply circuit. Impedances are as given in the diagram.

The example shows that unless relays 2 and 3 are made directional, they will maloperate for a fault at $F3$. Also shown is how to calculate appropriate relay settings for all six relays to ensure satisfactory protection for faults at locations $F1$ - $F4$.

Figure C1.31(b) shows the impedance diagram, to 100 MVA, 110 kV base. The fault currents for faults with various system configurations are shown in Table C1.6.

If relays 2 and 3 are non-directional, then, using SI relay characteristics for all relays, grading of the relays is dictated by the following:

a. fault at location $F1$, with 2 feeders in service

b. fault at location $F4$, with one feeder in service

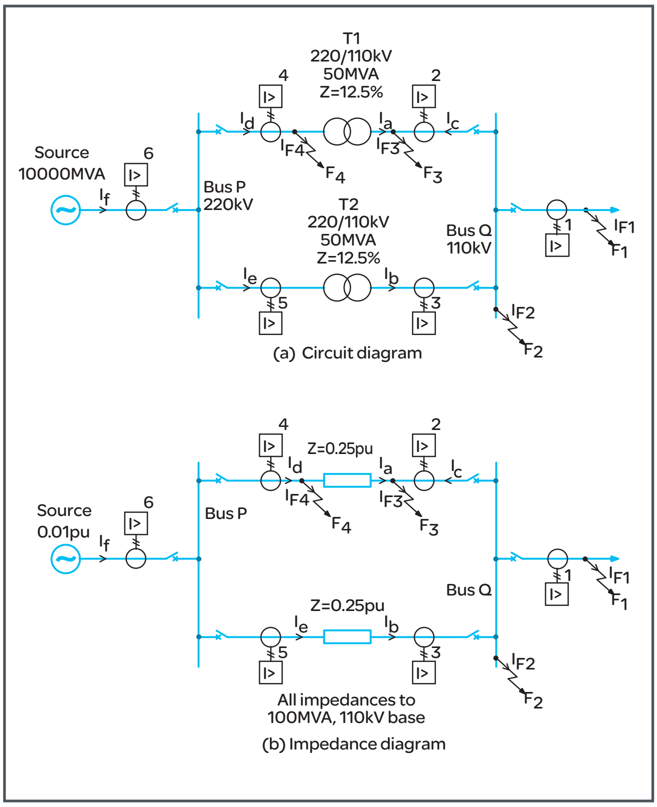


Figure C1.31:
System diagram: parallel feeder example

The settings shown in Figure C1.32(a) can be arrived at, with the relay operation times shown in Figure C1.32(b). It is clear that for a fault at $F3$ with both transformer feeders in service, relay 3 operates at the same time as relay 2 and results in total disconnection of Bus Q and all consumers supplied solely from it. This is undesirable – the advantages of duplicated 100% rated transformers have been lost.

By making relays 2 and 3 directional as shown in Figure C1.33(a), lower settings for these relays can be adopted – they can be set as low as reasonably practical but normally a current setting of about 50% of feeder full load current is

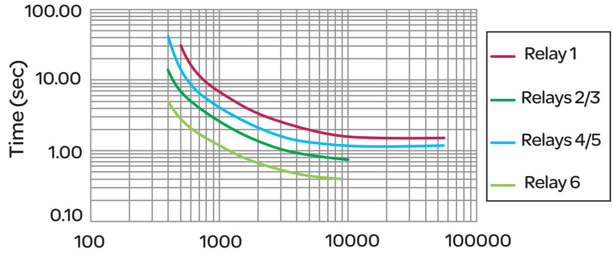
Fault position	System config.	Relay settings						
		Fault	Ia	Ib	Ic	Id	Ie	if
F_1	2 fdrs	3888	1944	1944	0	972	972	1944
F_1/F_2	2 fdr	2019	2019	0	0	1009	0	1009
F_2	2 fdrs 3	888	1944	1944	0	972	972	1944
F_3	2 fdrs	3888	1944	1944	1944	972	972	1944
F_4	1 fdr	26243	0	0	0	26243	0	26243

Table C1.6:
Fault currents for parallel feeder example

20. Examples of time and current grading

Relay	CT primary	Current setting	TMS	Characteristic
1	300	1	0.2	SI
2	300	1.1	0.3	SI
3	300	1.1	0.3	SI
4	300	0.61	0.425	SI
5	300	0.61	0.425	SI
6	300	0.7	0.7	SI

(a) Relay settings - non-directional relays



(b) Relay grading curves - non-directional relays

Figure C1.32:
Relay grading for parallel feeder example – non-directional relays

used, with a TMS of 0.1. Grading rules can be established as follows:

a. relay *4* is graded with relay *1* for faults at location *F1* with one transformer feeder in service

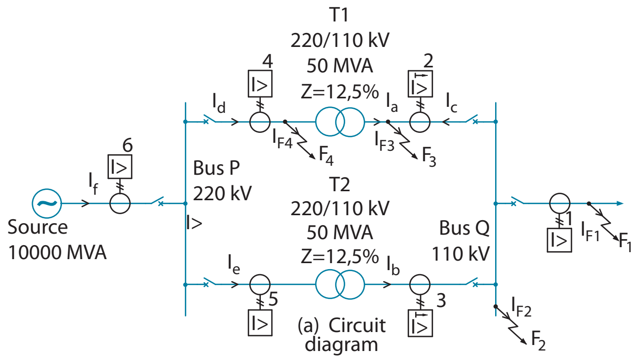
b. relay *4* is graded with relay *3* for faults at location *F3* with two transformer feeders in service

c. relay *6* grades with relay *4* for faults at *F4*.

d. relay *6* also has to grade with relay *4* for faults at *F1* with both transformer feeders in service – relay *6* sees the total fault current but relay *4* only 50% of this current.

Normal rules about calculating current setting values of relays in series apply. The settings and resulting operation times are given in Figure C1.33(b) and (c) respectively.

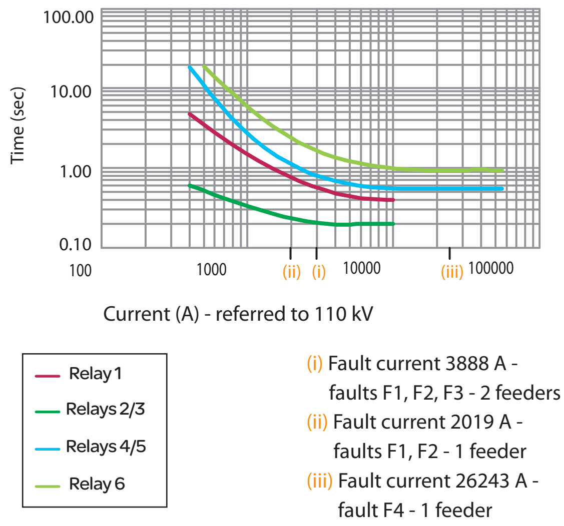
In practice, a complete protection study would include instantaneous elements on the primary side of the transformers and analysis of the situation with only one transformer in service. These have been omitted from this example, as the purpose is to illustrate the principles of parallel feeder protection in a simple fashion.



(a) Circuit diagram

Relay	CT primary	Current setting	TMS	Characteristic
1	300	1	0.2	SI
2	300	0.42	0.1	SI
3	300	0.42	0.1	SI
4	300	0.6	0.275	SI
5	300	0.6	0.275	SI
6	300	0.7	0.475	SI

(b) Relay settings



(c) Relay characteristics

Figures C1.33:
Relay grading for parallel feeder example – directional relays

20.4 Grading of a ring main

Figure C1.34 shows a simple ring main, with a single infeed at Bus *A* and three load busbars. Settings for the directional relays *R2*-*R7* and non-directional relays *R1*-*R8* are required. Maximum load current in the ring is 785 A (maximum continuous current with one transformer out of service), so 1000/1 A CTs are chosen. The relay considered is a MiCOM P140 series.

C1

20. Examples of time and current grading

The first step is to establish the maximum fault current at each relay location. Assuming a fault at Bus B (the actual location is not important), two possible configurations of the ring have to be considered, firstly a closed ring and secondly an open ring. For convenience, the ring will be considered to be open at CB1 (CB8 is the other possibility to be considered, but the conclusion will be the same).

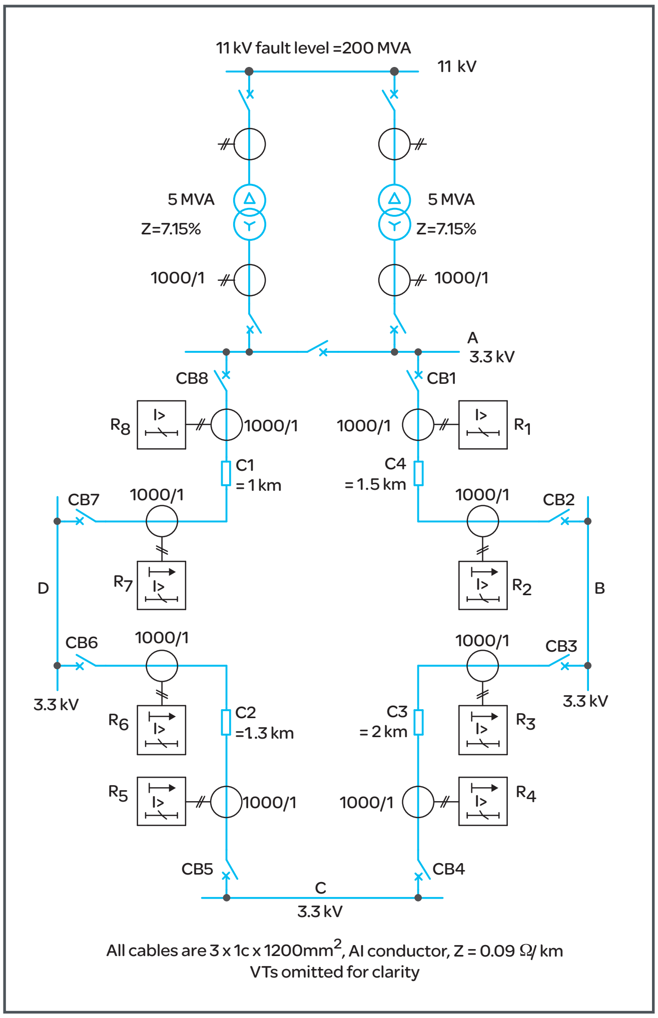


Figure C1.34:
Ring main grading example – circuit diagram

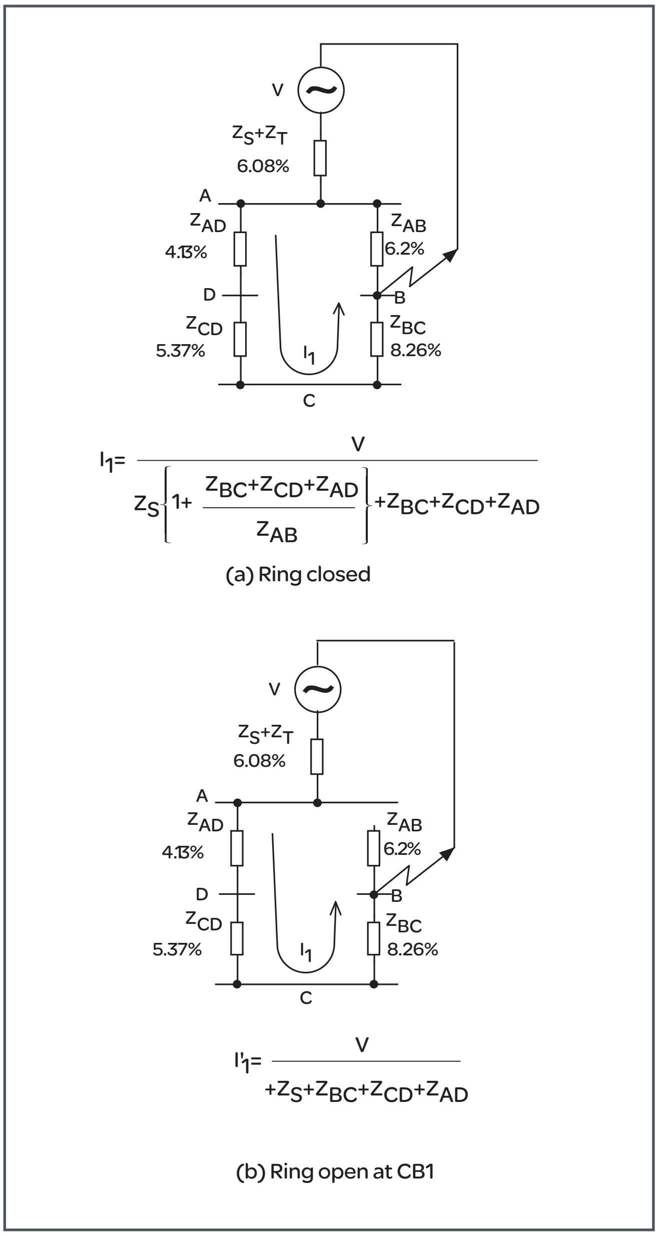


Figure C1.35:
Impedance diagrams with ring open

Figure C1.35 shows the impedance diagram for these two cases.

Three-phase fault currents I_1 and I'_1 can be calculated as 2.13 kA and 3.67 kA respectively, so that the worst case is with the ring open (this can also be seen from consideration of the impedance relationships, without the necessity of performing the calculation).

Table C1.7 shows the fault currents at each bus for open points at *CB1* and *CB8*.

Clockwise		Clockwise	
Open point CB8		Open point CB1	
Bus	Fault current kA	Bus	Fault current kA
D	7.124	B	3.665
C	4.259	C	5.615
B	3.376	D	8.568

Table C1.7:
Fault current tabulation with ring open

20. Examples of time and current grading

For grading of the relays, consider relays looking in a clockwise direction round the ring, i.e. relays $R1/R3/R5/R7$.

20.4.1 Relay R7

Load current cannot flow from Bus D to Bus A since Bus A is the only source. Hence low relay current and TMS settings can be chosen to ensure a rapid fault clearance time. These can be chosen arbitrarily, so long as they are above the cable charging current and within the relay setting characteristics. Select a relay current setting of 0.8 (i.e. 800A CT primary current) and TMS of 0.05. This ensures that the other relays will not pick up under conditions of normal load current. At a fault current of 3376 A, relay operating time on the SI characteristic is

$$0.05 \times \left[\frac{0.14}{(4.22)^{0.02} - 1} \right] s = 0.24\ s$$

20.4.2 Relay R5

This relay must grade with relay $R7$ at 3376 A and have a minimum operation time of 0.54 s. Relay $R5$ current setting must be at least 110% of relay $R7$ to prevent unwanted pickup, so select relay $R5$ current setting of 0.88 (i.e. 880 A CT primary current).

Relay $R5$ operating time at $TMS = 1.0$

$$= \left[\frac{0.14}{(3.84)^{0.02} - 1} \right] s = 5.14\ s$$

Hence, relay $R5\ TMS = \frac{0.54}{5.14} = 0.105\ s$

Use nearest settable value of TMS of 0.125.

Table C1.8 summarises the relay settings, while Figure C1.36 illustrates the relay grading curves.

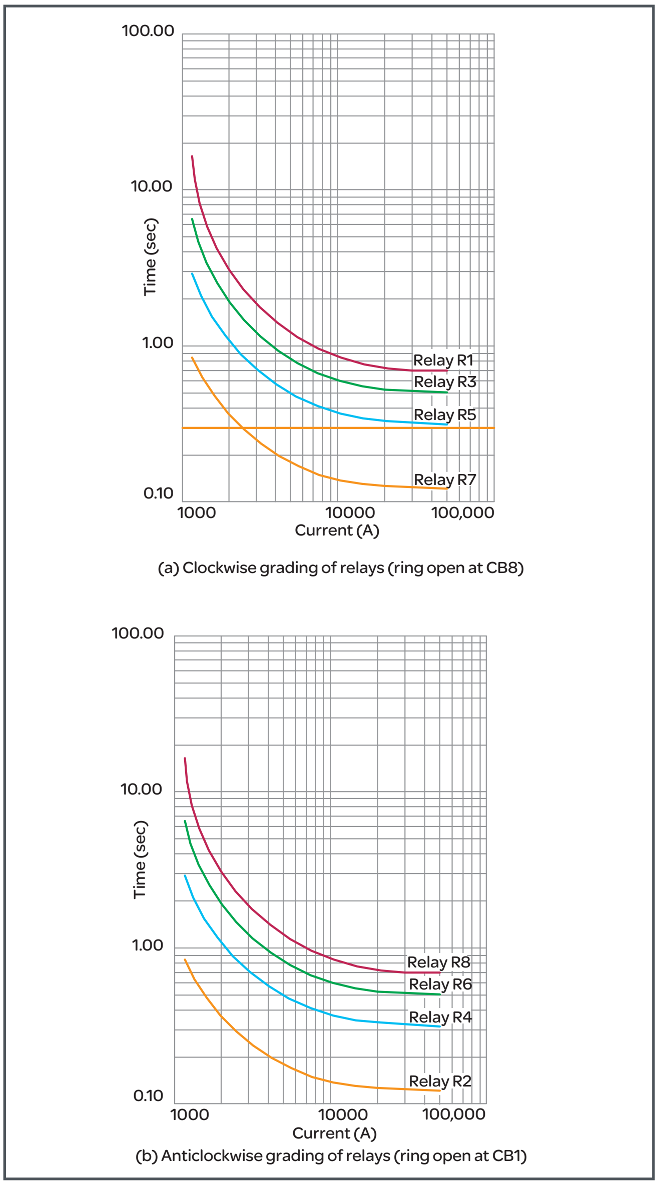


Figure C1.36:
Ring main example – relay grading curves

Bus	Relay	Relay charact.	CT radio	Max. load current (A)	Max. fault current (A) (3.3kV base)	Current setting p.u.	TMS
D	R7	SI	1000/1	874	3376	0.8	0.05
C	R5	SI	1000/1	874	4259	0.88	0.125
B	R3	SI	1000/1	874	7124	0.97	0.2
A	R1	SI	1000/1	874	14387	1.07	0.275
A	R8	SI	1000/1	874	14387	1.07	0.3
D	R6	SI	1000/1	874	8568	0.97	0.2
C	R4	SI	1000/1	874	5615	0.88	0.125
B	R2	SI	1000/1	874	3665	0.8	0.05

Table C1.8:
Ring main example relay settings

C1

21. References

[C1.1] Directional Element Connections for Phase Relays.
W.K Sonnemann,
Transactions A.I.E.E. 1950.

C2

Line Differential Protection

Network Protection & Automation Guide

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Chapter C2

Line Differential Protection

C2

1. Introduction

The graded overcurrent systems described in Chapter [C1: Overcurrent Protection for Phase and Earth Faults], though attractively simple in principle, do not meet all the protection requirements of a power system. Application difficulties are encountered for two reasons: firstly, satisfactory grading cannot always be arranged for a complex network, and secondly, the settings may lead to maximum tripping times at points in the system that are too long to prevent excessive disturbances occurring.

These problems led to the concept of 'Unit Protection', whereby sections of the power system are protected individually as a complete unit without reference to other sections. One form of 'Unit Protection' is also known as 'Differential Protection', as the principle is to sense the difference in currents between the incoming and outgoing terminals of the unit being protected.

Other forms can be based on directional comparison, or distance teleprotection schemes, which are covered in Chapter [C4: Distance Protection Schemes], or phase comparison protection, which is discussed later in this chapter. The configuration of the power system may lend itself to unit protection; for instance, a simple earth fault relay applied at the source end of a transformer-feeder can be regarded as unit protection provided that the transformer winding associated with the feeder is not earthed. In this case the protection coverage is restricted to the feeder and transformer winding because the transformer cannot transmit zero sequence current to an out-of-zone fault.

In most cases, however, a unit protection system involves the measurement of fault currents (and possibly voltages) at each end of the zone, and the transmission of information between the equipment at zone boundaries. It should be noted that a stand-alone distance relay, although nominally responding only to faults within its setting zone, does not satisfy the conditions for a unit system because the zone is not clearly defined; it is defined only within the accuracy limits of the measurement. Also, to cater for some conditions, the setting of a stand-alone distance relay may also extend outside of the protected zone to cater for some conditions.

Merz and Price [Ref C2.1: Protective Gear] first established the principle of current differential unit systems; their fundamental differential systems have formed the basis of many highly developed protection arrangements for feeders and numerous other items of plant. In one arrangement, an auxiliary 'pilot' circuit interconnects similar current transformers at each end of the protected zone, as shown in Figure C2.1. Current transmitted through the zone causes secondary current to circulate round the pilot circuit without producing any current in the relay.

For a fault within the protected zone the CT secondary currents will not balance, compared with the through-fault condition, and the difference between the currents will flow in the relay.

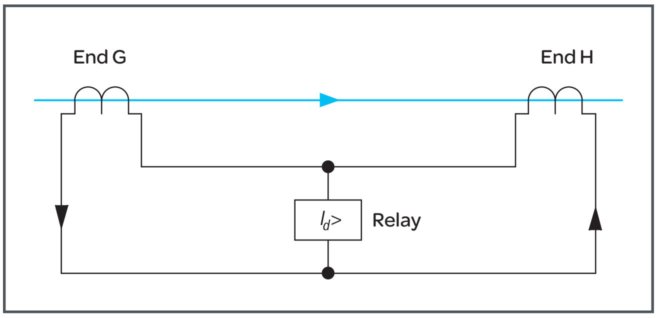

Figure C2.1:
Circulating current system

An alternative arrangement is shown in Figure C2.2, in which the CT secondary windings are opposed for through-fault conditions so that no current flows in the series connected relays. The former system is known as a 'Circulating Current' system, while the latter is known as a 'Balanced Voltage' system.

Most systems of unit protection function through the determination of the relative direction of the fault current. This direction can only be expressed on a comparative basis, and such a comparative measurement is the common factor of many systems, including directional comparison protection and distance teleprotection schemes with directional impedance measurement.

A major factor in consideration of unit protection is the method of communication between the relays. This is covered in detail in Chapter [D2: Signalling and Intertripping in Protection Schemes] in respect of the latest fibre-optic based digital techniques. For older 'pilot wire' systems, only brief mention is made.

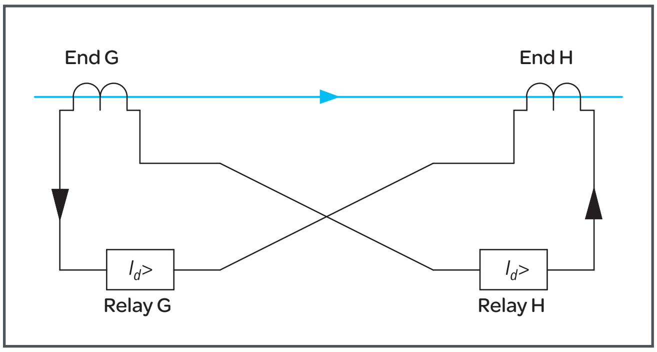

Figure C2.2:
Balanced voltage system

2. Convention of direction

It is useful to establish a convention of direction of current flow; for this purpose, the direction measured from a busbar outwards along a feeder is taken as positive. Hence the notation of current flow shown in Figure C2.3; the section GH carries a through current which is counted positive at G but negative at H, while the infeeds to the faulted section HJ are both positive.

Neglect of this rule has often led to anomalous arrangements of equipment or difficulty in describing the action of a complex system. When applied, the rule will normally lead to the use of identical equipments at the zone boundaries, and is equally suitable for extension to multi-ended systems. It also conforms to the standard methods of network analysis.

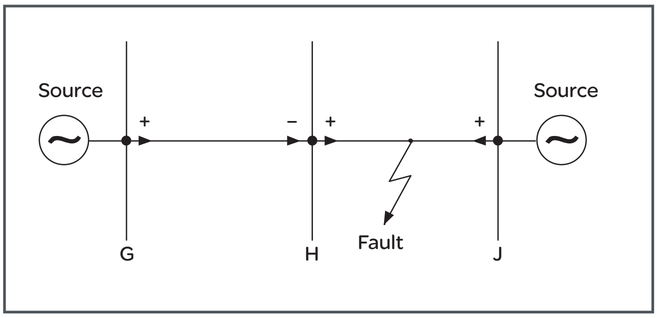

Figure C2.3:
Convention of current direction

3. Conditions for direction comparison

The circulating current and balanced voltage systems of Figures C2.1 and C2.2 perform full vectorial comparison of the zone boundary currents. Such systems can be treated as analogues of the protected zone of the power system, in which CT secondary quantities represent primary currents and the relay operating current corresponds to an in-zone fault current.

These systems are simple in concept; they are nevertheless applicable to zones having any number of boundary connections and for any pattern of terminal currents.

To define a current requires that both magnitude and phase be stated. Comparison in terms of both of these quantities is performed in the Merz-Price systems, but it is not always easy to transmit all this information over some pilot channels. Chapter [D2: Signalling and Intertripping in Protection Schemes] provides a detailed description of modern methods that may be used.

4. Circulating current system

The principle of this system is shown in outline in Figure C2.1. If the current transformers are ideal, the functioning of the system is straightforward. The transformers will, however, have errors arising from both Wattmetric and magnetising current losses that cause deviation from the ideal, and the interconnections between them may have unequal impedances. This can give rise to a 'spill' current through the relay even without a fault being present, thus limiting the sensitivity that can be obtained. Figure C2.4 illustrates the equivalent circuit of the circulating current scheme. If a high impedance relay is used, then unless the relay is located at point J in the circuit, a current will flow through the relay even with currents I_{Pg} and I_{Ph} being identical. If a low impedance relay is used, voltage FF' will be very small, but the CT exciting currents will be unequal due to the unequal burdens and relay current I_R will still be non-zero.

4.1 Transient instability

It is shown in Chapter [B2: Current and Voltage Transformers, Section 4.10], that an asymmetrical current applied to a current transformer will induce a flux that is greater than the peak flux corresponding to the steady state alternating component of the current. It may take the CT into saturation, with the result that the dynamic exciting impedance is reduced and the exciting current greatly increased.

C2

4. Circulating current system

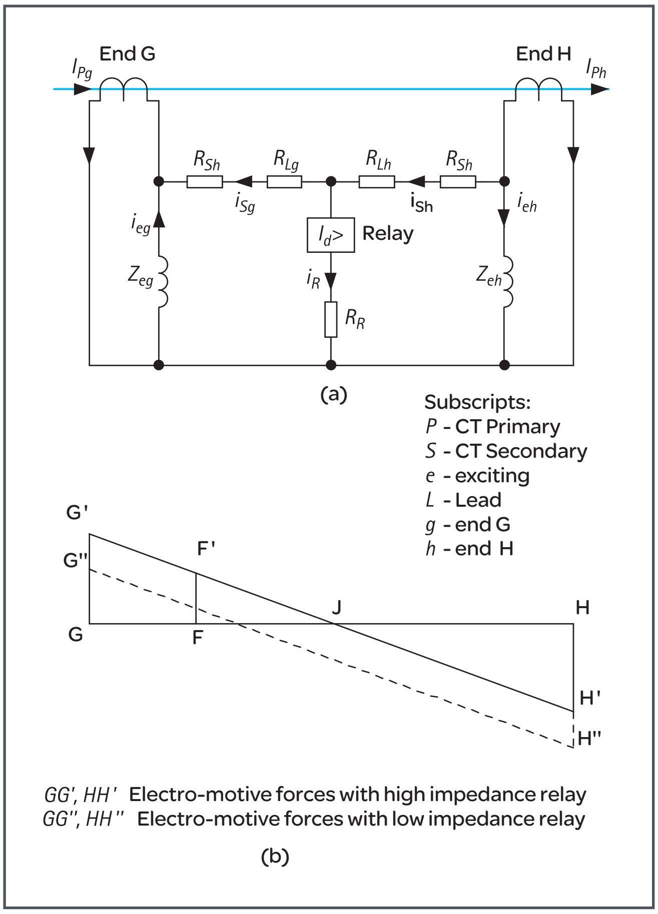

Figure C2.4:
Equivalent circuit of circulating current scheme

When the balancing current transformers of a unit protection system differ in excitation characteristics, or have unequal burdens, the transient flux build-ups will differ and an increased 'spill' current will result. There is a consequent risk of relay operation on a healthy circuit under transient conditions, which is clearly unacceptable. One solution is to include a stabilising resistance in series with the relay. Details of how to calculate the value of the stabilising resistor are usually included in the instruction manuals of all relays that require one.

When a stabilising resistor is used, the relay current setting can be reduced to any practical value, the relay now being a voltage- measuring device. There is obviously a lower limit, below which the relay element does not have the sensitivity to pick up. Relay calibration can in fact be in terms of voltage.

4.2 Bias

The 'spill' current in the relay arising from these various sources of error is dependent on the magnitude of the through current, being negligible at low values of through-fault current but sometimes reaching a disproportionately large value for more severe faults. Setting the operating threshold of the protection above the maximum level of spill current produces poor sensitivity. By making the differential setting approximately proportional to the fault current, the low-level fault sensitivity is greatly improved. Figure C2.5 illustrates a typical bias characteristic for a modern relay that overcomes the problem. At low currents, the bias is small, thus enabling the relay to be made sensitive. At higher currents, such as would be obtained from inrush or through fault conditions, the bias used is higher, and thus the spill current required to cause operation is higher. The relay is therefore more tolerant of spill current at higher fault currents and therefore less likely to maloperate, while still being sensitive at lower current levels.

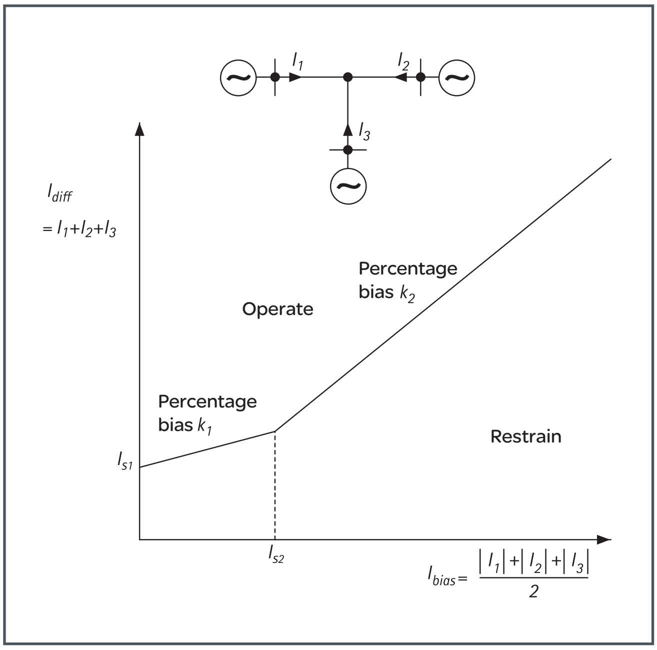

Figure C2.5:
Typical bias characteristic of relay

5. Balanced voltage system

This section is included for historical reasons, mainly because of the number of such schemes still to be found in service – for new installations it has been almost completely superseded by circulating current schemes. It is the dual of the circulating current protection, and is summarised in Figure C2.2 as used in the 'Translay H04' scheme.

With primary through current, the secondary e.m.f.s of the current transformers are opposed, and provide no current in the interconnecting pilot leads or the series connected relays. An in-zone fault leads to a circulating current condition in the CT secondaries and hence to relay operation.

An immediate consequence of the arrangement is that the current transformers are in effect open-circuited, as no secondary current flows for any primary through-current conditions. To avoid excessive saturation of the core and secondary waveform distortion, the core is provided with non-magnetic gaps sufficient to absorb the whole primary m.m.f. at the maximum current level, the flux density remaining within the linear range. The secondary winding therefore develops an e.m.f. and can be regarded as a voltage source. The shunt reactance of the transformer is relatively low, so the device acts as a transformer loaded with a reactive shunt; hence the American name of transactor. The equivalent circuit of the system is as shown in Figure C2.6.

The series connected relays are of relatively high impedance; because of this the CT secondary winding resistances are not of great significance and the pilot resistance can be moderately large without significantly affecting the operation of the system. This is why the scheme was developed for feeder protection.

5.1 Stability Limit of the Voltage Balance System

Unlike normal current transformers, transactors are not subject to errors caused by the progressive build-up of exciting current, because the whole of the primary current is expended as exciting current. In consequence, the secondary e.m.f. is an accurate measure of the primary current within the linear range of the transformer. Provided the transformers are designed to be linear up to the maximum value of fault current, balance is limited only by the inherent limit of accuracy of the transformers, and as a result of capacitance between the pilot cores. A broken line in the equivalent circuit shown in Figure C2.6 indicates such capacitance. Under through-fault conditions the pilots are energised to a proportionate voltage, the charging current flowing through the relays. The stability ratio that can be achieved with this system is only moderate and a bias technique is used to overcome the problem.

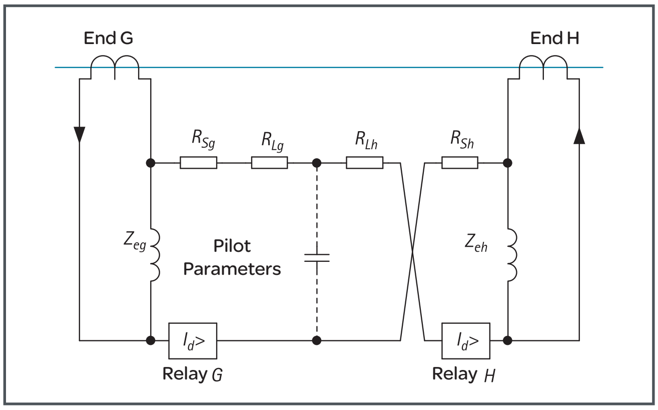

Figure C2.6:
Equivalent circuit for balanced voltage system

6. Summation arrangements

Schemes have so far been discussed as though they were applied to single-phase systems. A polyphase system could be provided with independent protection for each phase. Modern digital or numerical relays communicating via fibre-optic links operate on this basis, since the amount of data to be communicated is not a major constraint. For older relays, use of this technique over pilot wires may be possible for relatively short distances, such as would be found with industrial and urban power distribution systems. Clearly, each phase would require a separate set of pilot wires if the protection was applied on a per phase basis. The cost of providing separate pilot-pairs and also separate relay elements per phase is generally prohibitive. Summation techniques can be used to combine the separate phase currents into a single relaying quantity for comparison over a single pair of pilot wires.

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7. Examples of electromechanical and static unit protection systems

As mentioned above, the basic balanced voltage principle of protection evolved to biased protection systems. Several of these have been designed, some of which appear to be quite different from others. These dissimilarities are, however, superficial.

A number of these systems that are still in common use are described below.

7.1 Balanced voltage electromechanical system

A typical biased, electromechanical balanced voltage system, still giving useful service on distribution systems is shown in Figure C2.7.

The electromechanical design derives its balancing voltages from the transactor incorporated in the measuring relay at each line end. The latter are based on the induction-type meter electromagnet as shown in Figure C2.7.

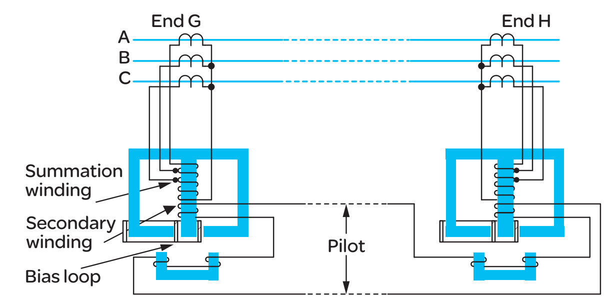

Figure C2.7:
Typical biased electromechanical differential protection system.

The upper magnet carries a summation winding to receive the output of the current transformers, and a secondary winding which delivers the reference e.m.f. The secondary windings of the conjugate relays are interconnected as a balanced voltage system over the pilot channel, the lower electromagnets of both relays being included in this circuit.

Through current in the power circuit produces a state of balance in the pilot circuit and zero current in the lower electromagnet coils. In this condition, no operating torque is produced.

An in-zone fault causing an inflow of current from each end of the line produces circulating current in the pilot circuit and the energisation of the lower electromagnets. These co-operate with the flux of the upper electromagnets to produce an operating torque in the discs of both relays. An infeed from one end only will result in relay operation at the feeding end, but no operation at the other, because of the absence of upper magnet flux.

Bias is produced by a copper shading loop fitted to the pole of the upper magnet, thereby establishing a Ferraris motor action that gives a reverse or restraining torque proportional to the square of the upper magnet flux value.

Typical settings achievable with such a relay are:

a. Least sensitive earth fault - 40% of rating

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

c. Three-phase fault - 52% of rating

7.2 Static circulating current unit protection system

A typical static modular pilot wire unit protection system operating on the circulating current principle is shown in Figure C2.8. This uses summation transformers with a neutral section that is tapped, to provide alternative earth fault sensitivities. Phase comparators tuned to the power frequency are used for measurement and a restraint circuit gives a high level of stability for through-faults and transient charging currents. High-speed operation is obtained with moderately sized current transformers and where space for current transformers is limited and where the lowest possible operating time is not essential, smaller current transformers may be used. This is made possible by a special adjustment (K_t) by which the operating time of the differential protection can be selectively increased if necessary, thereby enabling the use of current transformers having a correspondingly decreased knee-point voltage, whilst ensuring that through-fault stability is maintained to greater than 50 times the rated current.

Internal faults give simultaneous tripping of relays at both ends of the line, providing rapid fault clearance irrespective of whether the fault current is fed from both line ends or from only one line end.

7. Examples of electromechanical and static unit protection systems

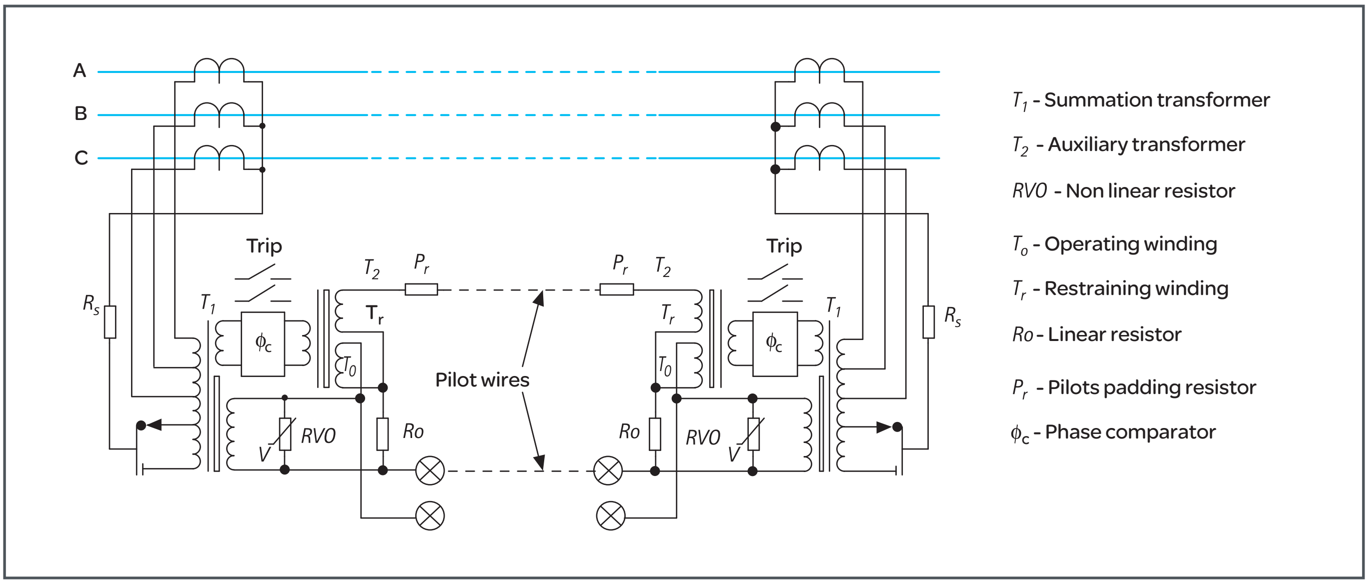

Figure C2.8:
Typical static circulating current feeder unit protection circuit diagram

8. Digital / numerical current differential protection systems

A digital or numerical unit protection relay may typically provide phase-segregated current differential protection. This means that the comparison of the currents at each relay is done on a per phase basis. For digital data communication between relays, it is usual that a direct optical connection is used (for short distances) or a multiplexed link. Link speeds of up to 64kbit/s (56kbit/s in North America) are normal. Through current bias is typically applied to provide through fault stability in the event of CT saturation. A dual slope bias technique (Figure C2.5) is used to enhance stability for through faults. A typical trip criterion is as follows:

For $|I_{bias}| < I_{s2}$

$$|I_{diff}| < k_1 |I_{bias}| + I_{s1}$$

For $|I_{bias}| < I_{s2}$

$$|I_{diff}| < k_2 |I_{bias}| - (k_2 - k_1) I_{s2} + I_{s1}$$

Once the relay at one end of the protected section has determined that a trip condition exists, an intertrip signal is transmitted to the relay at the other end. Relays that are supplied with information on line currents at all ends of the line may not need to implement intertripping facilities. However, it is usual to provide intertripping in any case to ensure the protection operates in the event of any of the relays detecting a fault.

A facility for vector/ratio compensation of the measured currents, so that transformer feeders can be included in the unit protection scheme without the use of interposing CTs or defining the transformer as a separate zone, increases versatility. Any interposing CTs required are implemented in software. Maloperation on transformer inrush is prevented by second harmonic detection. Care must be taken if the transformer has a wide-ratio on-load tap changer, as this results in the current ratio departing from nominal and may cause maloperation, depending on the sensitivity of the relays. The initial bias slope should be set taking this into consideration.

Tuned measurement of power frequency currents provides 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 made available and the susceptance of the protected zone is known.

Where an earthed transformer winding or earthing transformer is included within the zone of protection, some form of zero sequence current filtering is required. This is because there will be an in-zone source of zero sequence current for an external earth fault. The differential protection will see zero sequence differential current for an external fault and it could incorrectly operate as a result.

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8. Digital / numerical current differential protection systems

In older protection schemes, the problem was eliminated by delta connection of the CT secondary windings. For a digital or numerical relay, a selectable software zero sequence filter is typically employed.

The problem remains of compensating for the time difference between the current measurements made at the ends of the feeder, since small differences can upset the stability of the scheme, even when using fast direct fibre-optic links. The problem is overcome by either time synchronisation of the measurements taken by the relays, or continuous calculation of the propagation delay of the link.

8.1 Time synchronisation of relays

Fibre-optic media allow direct transmission of the signals between relays for distances of up to several km without the need for repeaters. For longer distances repeaters will be required. Where a dedicated fibre pair is not available, multiplexing techniques can be used. As phase comparison techniques are used on a per phase basis, time synchronisation of the measurements is vitally important. This requires knowledge of the transmission delay between the relays. Four techniques are possible for this:

a. assume a value

b. measurement during commissioning only

c. continuous online measurement

d. GPS time signal

Method (a)

is not used, as the error between the assumed and actual value will be too great.

Method (b)

provides reliable data if direct communication between relays is used. As signal propagation delays may change over a period of years, repeat measurements may be required at intervals and relays re-programmed accordingly. There is some risk of maloperation due to changes in signal propagation time causing incorrect time synchronisation between measurement intervals. The technique is less suitable if rented fibre-optic pilots are used, since the owner may perform circuit re-routing for operational reasons without warning, resulting in the propagation delay being outside of limits and leading to scheme maloperation. Where re-routing is limited to a few routes, it may be possible to measure the delay on all routes and pre-program the relays accordingly, with the relay digital inputs and ladder logic being used to detect changes in route and select the appropriate delay accordingly.

Method (c)

is a robust technique, employing continuous sensing of the signal propagation delay. One method of achieving this is shown in Figure C2.9.

Relays A and B sample signals at time are T_{A1}, T_{A2} … and T_{B1}, T_{B2} … respectively. The times will not be coincident, even if they start coincidentally, due to slight differences in sampling

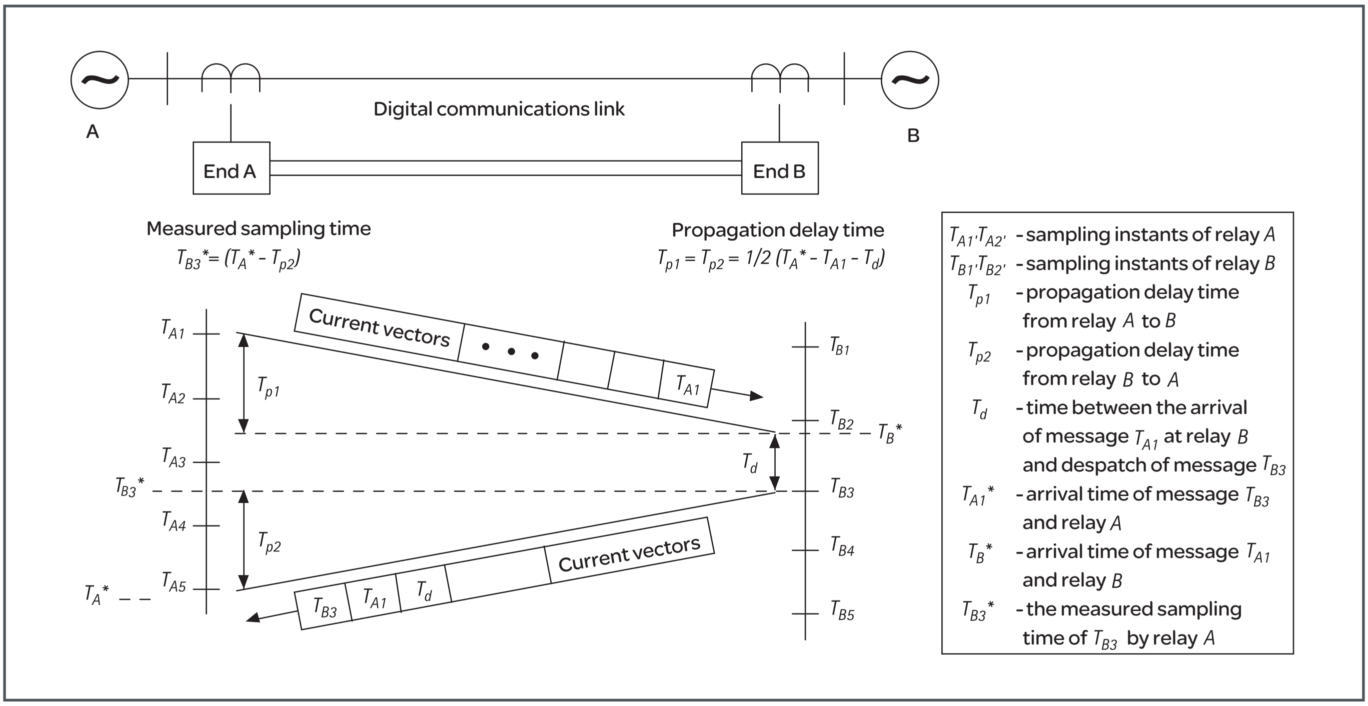

Figure C2.9:
Signal propagation delay measurement

8. Digital / numerical current differential protection systems

frequencies. At time T_{A1} relay A transmits its data to relay B, containing a time tag and other data. Relay B receives it at time $T_{A1} + T_{p1}$ where T_{p1} is the propagation time from relay A to relay B. Relay B records this time as time T_B*. Relay B also sends messages of identical format to relay A. It transmits such a message at time T_{B3}, received by relay A at time T_{B3}+ T_{p2} (say time T_A*), where T_{p2} is the propagation time from relay B to relay A. The message from relay B to relay A includes the time T_{B3}, the last received time tag from relay A (T_{A1}) and the delay time between the arrival time of the message from A (T_B*) and T_{B3} – call this the delay time T_d. The total elapsed time is therefore:

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

If it is assumed that $T_{p1} = T_{p2}$, then the value of T_{p1} and T_{p2} can be calculated, and hence also T_{B3}. The relay B measured data as received at relay A can then be adjusted to enable data comparison to be performed. Relay B performs similar computations in respect of the data received from relay A (which also contains similar time information). Therefore, continuous measurement of the propagation delay is made, thus reducing the possibility of maloperation due to this cause to a minimum. Comparison is carried out on a per-phase basis, so signal transmission and the calculations are required for each phase.

A variation of this technique is available that can cope with unequal propagation delays in the two communication channels under well-defined conditions.

The technique can also be used with all types of pilots, subject to provision of appropriate interfacing devices.

Method (d)

is also a robust technique. It involves both relays being capable of receiving a time signal from a GPS satellite. The propagation delay on each communication channel is no longer required to be known or calculated as both relays are synchronised to a common time signal. For the protection scheme to meet the required performance in respect of availability and maloperation, the GPS signal must be capable of reliable receipt under all atmospheric conditions. There is extra satellite signal receiving equipment required at both ends of the line, which implies extra cost.

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

8.2 Application to mesh corner and 1 1/2 breaker switched substations

These substation arrangements are quite common, and the arrangement for the latter is shown in Figure C2.10. Problems exist in protecting the feeders due to the location of the line CT's, as either Bus 1 or Bus 2 or both can supply the feeder. Two alternatives are used to overcome the problem, and they are illustrated in the figure. The first is to common the line CT inputs (as shown for Feeder A) and the alternative is to use a second set of CT inputs to the relay (as shown for Feeder B).

In the case of a through fault as shown, the relay connected to Feeder A theoretically sees no unbalance current, and hence will be stable. However, with the line disconnect switch open, no bias is produced in the relay, so CT's need to be well matched and equally loaded if maloperation is to be avoided.

For Feeder B, the relay also theoretically sees no differential current, but it will see a large bias current even with the line disconnect switch open. This provides a high degree of stability, in the event of transient asymmetric CT saturation. Therefore, this technique is preferred.

Sensing of the state of the line isolator through auxiliary contacts enables the current values transmitted to and received from remote relays to be set to zero when the isolator is open. Hence, stub-bus protection for the energised part of the bus is then possible, with any fault resulting in tripping of the relevant CB.

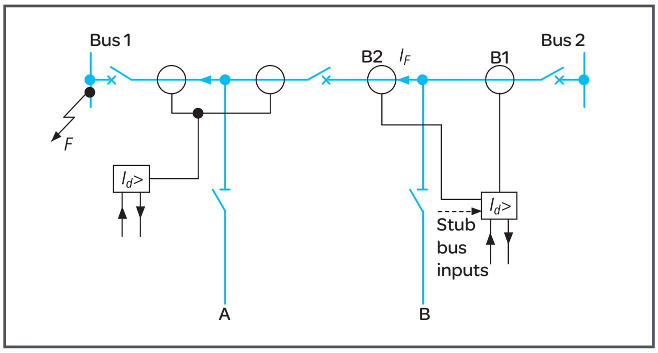

Figure C2.10:
Breaker and a half switched substation

9. Carrier unit protection schemes

In earlier sections, the pilot links between relays have been treated as an auxiliary wire circuit that interconnects relays at the boundaries of the protected zone. In many circumstances, such as the protection of longer line sections or where the route involves installation difficulties, it is too expensive to provide an auxiliary cable circuit for this purpose, and other means are sought.

In all cases (apart from private pilots and some short rented pilots) power system frequencies cannot be transmitted directly on the communication medium. Instead a relaying quantity may be used to vary the higher frequency associated with each medium (or the light intensity for fibre-optic systems), and this process is normally referred to as modulation of a carrier wave. Demodulation or detection of the variation at a remote receiver permits the relaying quantity to be reconstituted for use in conjunction with the relaying quantities derived locally, and forms the basis for all carrier systems of unit protection.

Carrier systems are generally insensitive to induced power system currents since the systems are designed to operate at much higher frequencies, but each medium may be subjected to noise at the carrier frequencies that may interfere with its correct operation.

Variations of signal level, restrictions of the bandwidth available for relaying and other characteristics unique to each medium influence the choice of the most appropriate type of scheme. Methods and media for communication are discussed in Chapter [D2: Signalling and Intertripping in Protection Schemes].

10. Current differential scheme - analogue techniques

The carrier channel is used in this type of scheme to convey both the phase and magnitude of the current at one relaying point to another for comparison with the phase and magnitude of the current at that point. Transmission techniques may use either voice frequency channels using FM modulation or A/D converters and digital transmission. Signal propagation delays still need to be taken into consideration by introducing a deliberate delay in the locally derived signal before a comparison with the remote signal is made.

A further problem that may occur concerns the dynamic range of the scheme. As the fault current may be up to 30 times the rated current, a scheme with linear characteristics requires a wide dynamic range, which implies a wide signal transmission bandwidth. In practice, bandwidth is limited, so either a non-linear modulation characteristic must be used or detection of fault currents close to the setpoint will be difficult.

10.1 Phase comparison scheme

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 principles of phase comparison are illustrated in Figure C2.11. The carrier channel transfers a 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 provides the basis for the measurement of phase shift between power system currents at the two ends and hence discrimination between internal and through-faults.

Current flowing above the set threshold results in turn-off of the carrier signal. The protection operates if gaps in the carrier signal are greater than a set duration – the phase angle setting of the protection.

Load or through-fault currents at the two ends of a protected feeder are in antiphase (using the normal relay convention for direction), whilst during an internal fault the (conventional) currents tend towards the in-phase condition. Hence, if the phase relationship of through-fault currents is taken as a reference condition, internal faults cause a phase shift of approximately 180° with respect to the reference condition.

10. Current differential scheme - analogue techniques

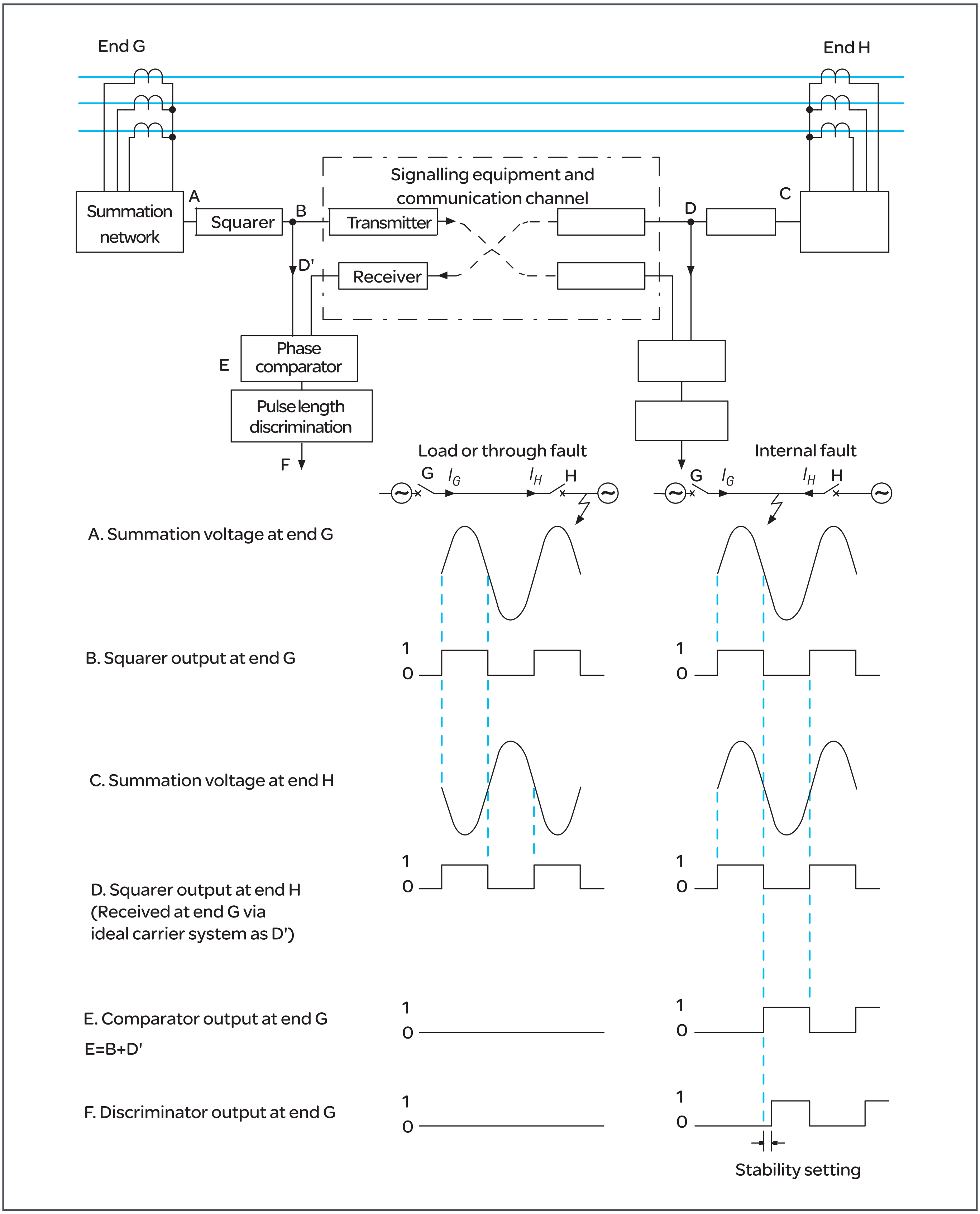

Figure C2.11
Principles of phase comparison protection

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10. Current differential scheme - analogue techniques

Phase comparison schemes respond to any phase shift from the reference conditions, but tripping is usually permitted only when the phase shift exceeds an angle of typically 30 to 90 degrees, determined by the time delay setting of the measurement circuit, and this angle is usually referred to as the Stability Angle. Figure C2.12 is a polar diagram that illustrates the discrimination characteristics that result from the measurement techniques used in phase comparison schemes.

Since the carrier channel is required to transfer only binary information, the techniques are associated with sending teleprotection commands. Blocking or permissive trip modes of operation are possible, however Figure C2.11 illustrates the more usual blocking mode, since the comparator provides an output when neither squarer is at logic '*1*'. A permissive trip scheme can be realised if the comparator is arranged to give an output when both squarers are at logic '*1*'. Performance of the scheme during failure or disturbance of the carrier channel and its ability to clear single-end-fed faults depends on the mode of operation, the type and function of fault detectors or starting units, and the use of any additional signals or codes for channel monitoring and transfer tripping.

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

Voice frequency channels involving FSK use two discrete frequencies either side of the middle of the voice band. This arrangement is less sensitive to variations in delay or frequency response than if the full bandwidth was used. Blocking or permissive trip modes of operation may be implemented. In addition to the two frequencies used for conveying the squarer information, a third tone is often used, either for channel monitoring or transfer tripping dependent on the scheme.

For a sensitive phase comparison scheme, accurate compensation for channel delay is required. However, since both the local and remote signals are logic pulses, simple time delay circuits can be used, in contrast to the analogue delay circuitry usually required for current differential schemes.

The principles of the Power Line Carrier channel technique are illustrated in Figure C2.13. The scheme operates in the blocking mode. The 'squarer' logic is used directly to turn a transmitter 'on' or 'off' at one end, and the resultant burst (or block) of carrier is coupled to and propagates along the power line which is being protected to a receiver at the other end. Carrier signals above a threshold are detected by the receiver, and hence produce a logic signal corresponding to the block of carrier. In contrast to Figure C2.11, the signalling system is a 2-wire rather than 4-wire arrangement, in which the local transmission is fed directly to the local receiver along with any received signal. The transmitter frequencies at both ends are nominally equal, so the receiver responds equally to blocks of carrier from either end. Through-fault current results in transmission of blocks of carrier from both ends, each lasting for half a cycle, but with a phase displacement

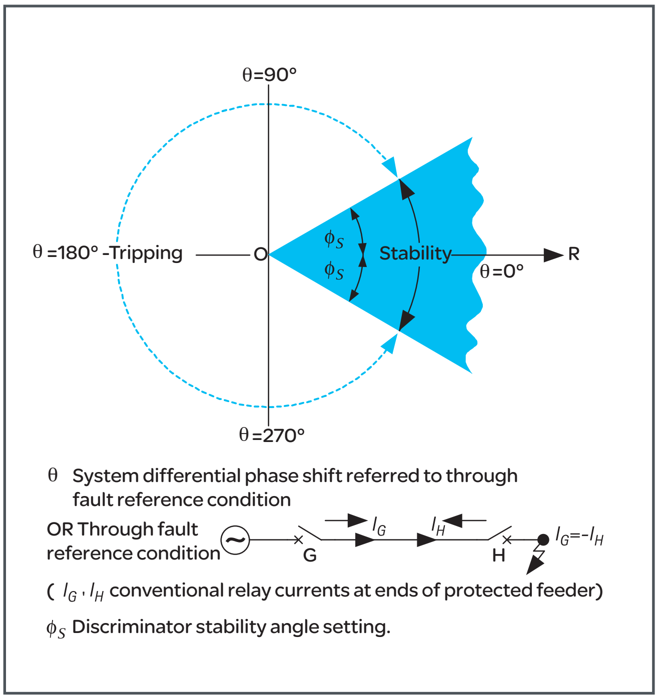

Figure C2.12
Polar diagram for phase comparison scheme

of half a cycle, so that the composite signal is continuously above the threshold level and the detector output logic is continuously '*1*'. Any phase shift relative to the through-fault condition produces a gap in the composite carrier signal and hence a corresponding '0' logic level from the detector. The duration of the logic '0' provides the basis for discrimination between internal and external faults, tripping being permitted only when a time delay setting is exceeded. This delay is usually expressed in terms of the corresponding phase shift in degrees at system frequency ϕ_S in Figure C2.12.

The advantages generally associated with the use of the power line as the communication medium apply, namely that a power line provides a robust, reliable, and low-loss interconnection between the relaying points. In addition, dedicated 'on/off' signalling is particularly suited for use in phase comparison blocking mode schemes, as signal attenuation is not a problem. This is in contrast to permissive or direct tripping schemes, where high power output or boosting is required to overcome the extra attenuation due to the fault.

The noise immunity is also very good, making the scheme very reliable. Signal propagation delay is easily allowed for in the stability angle setting, making the scheme very sensitive as well.

10. Current differential scheme - analogue techniques

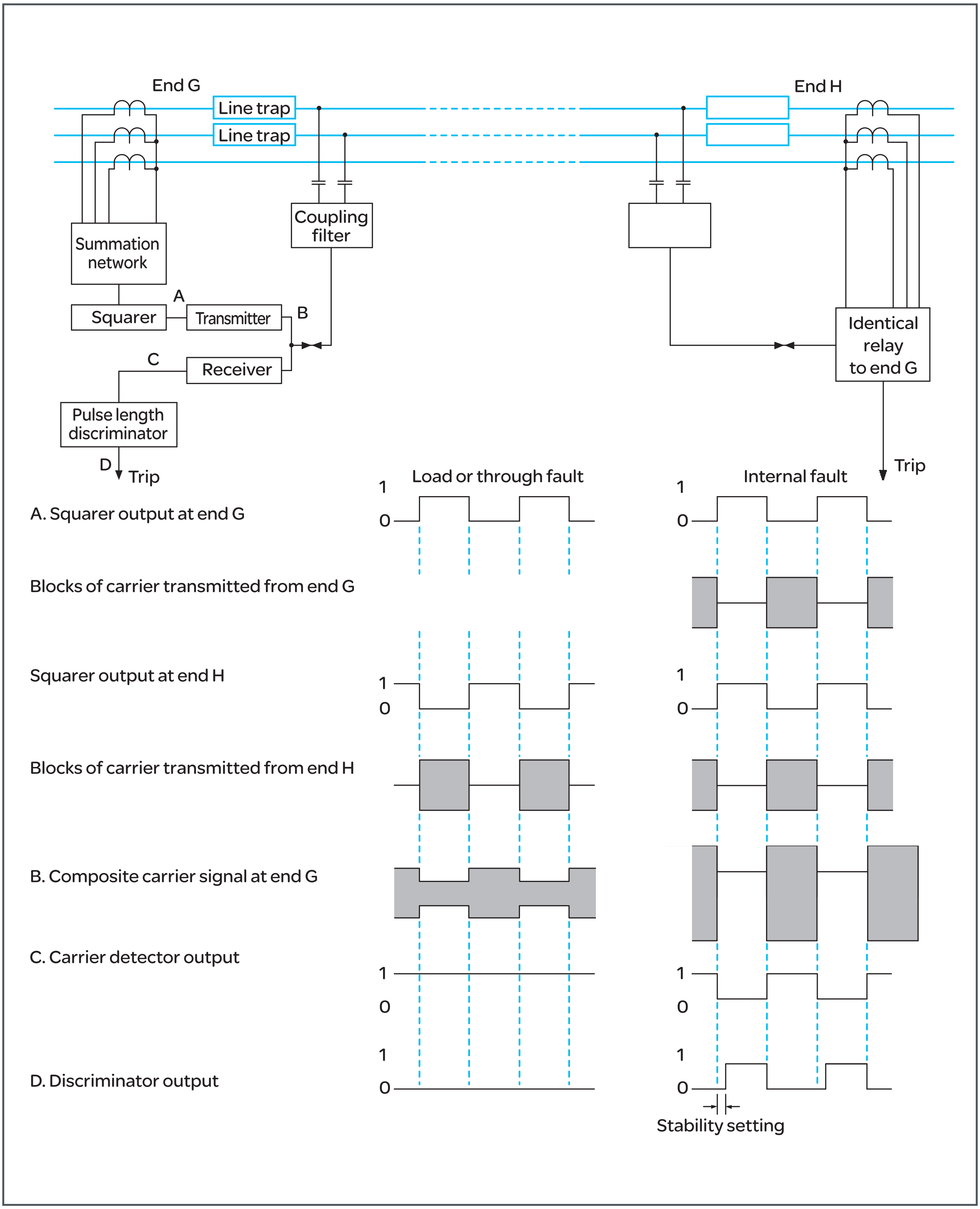

Figure C2.13
Principles of power line carrier phase comparison

C2

11. Phase comparison protection scheme considerations

One type of unit protection that uses carrier techniques for communication between relays is phase comparison protection. Communication between relays commonly uses PLCC or frequency modulated carrier modem techniques. There are a number of considerations that apply only to phase comparison protection systems, which are discussed in this section.

11.1 Lines with shunt capacitance

A problem can occur with the shunt capacitance current that flows from an energising source. Since this current is in addition to the load current that flows out of the line, and typically leads it by more than 90°, significant differential phase shifts between the currents at the ends of the line can occur, particularly when load current is low.

The system differential phase shift may encroach into the tripping region of the simple discriminator characteristic, regardless of how large the stability angle setting may be. Figure C2.14 illustrates the effect and indicates techniques that are commonly used to ensure stability.

Operation of the discriminator can be permitted only when current is above some threshold, so that measurement of the large differential phase shifts which occur near the origin of the polar diagram is avoided. By choice of a suitable threshold and stability angle, a 'keyhole' characteristic can be provided such that the capacitive current characteristic falls within the resultant stability region. Fast resetting of the fault detector is required to ensure stability following the clearance of a through-fault when 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 amplitude. Any decrease in the mark-space ratio will permit a corresponding differential phase shift to occur between the currents before any output is given from the comparator for measurement in the discriminator. A squarer circuit with an offset or bias can provide a decreasing mark-space ratio at low currents, and with a suitable 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 falls towards zero and the resultant stability region on the polar diagram is usually smaller than on the keyhole characteristic, giving improvements in sensitivity and/or dependability of the scheme. Since the stability region encompasses all through-fault currents, the resetting speed of any fault detectors or starter (which may still be required for other purposes, such as the control of a normally quiescent scheme) is much less critical than with the keyhole characteristic.

11.2 System tripping angles

For the protection scheme to trip correctly on internal faults the change in differential phase shift, θ_o, from the through-fault condition taken as reference, must exceed the effective

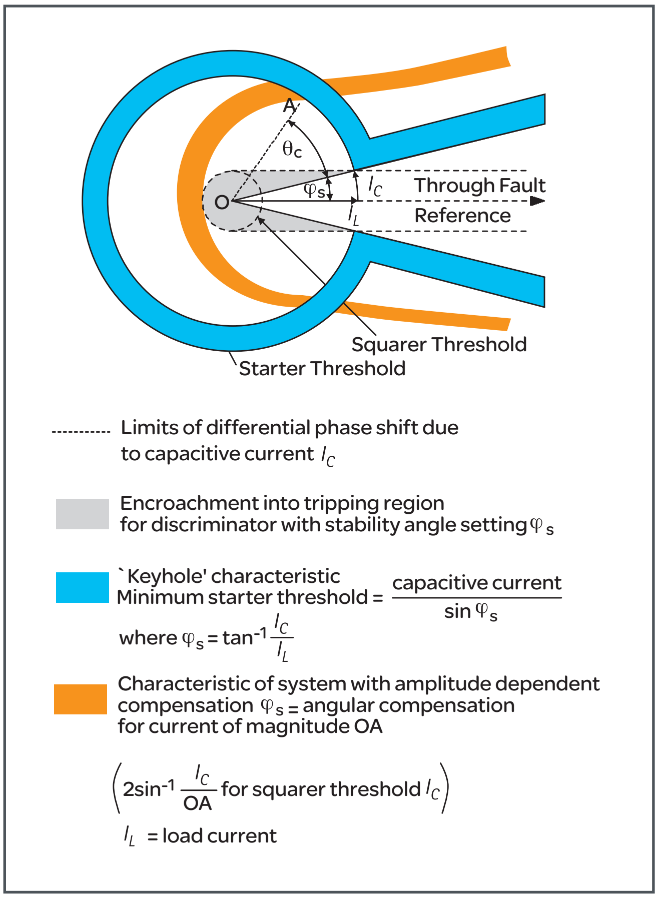

Figure C2.14:
Capacitive current in phase comparison schemes and techniques used to avoid instability

stability angle of the scheme. Hence:

$$\theta_o = \varphi_s + \theta_c \qquad \textit{...Equation C2.1}$$

where

φ_s = stability angle setting

θ_c = capacitive current compensation (when applicable)

The currents at the ends of a transmission line I_G and I_H may be expressed in terms of magnitude and phase shift θ with respect a common system voltage.

$$I_G = |I_G| < \theta_G$$

$$I_H = |I_H| < \theta_H$$

Using the relay convention described in Section 2, the reference through-fault condition is

$$I_G = I_H$$

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

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

11. Phase comparison protection scheme considerations

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

$$\therefore\ \theta_G = 180^\circ - |\theta_G - \theta_H|$$

Substituting θ_0 in Equation C2.1, the conditions for tripping are:

$$180^\circ - |\theta_G - \theta_H| \geq \varphi_S + \theta_c$$

$$\therefore\ |\theta_G - \theta_H| \leq 180^\circ - (\varphi_S + \theta_c) \quad \text{...Equation C2.2}$$

The term ($\varphi_S + \theta_c$) is the effective stability angle setting of the scheme. Substituting a typical value of 60° in Equation C2.2. gives the tripping condition as

$$|\theta_G - \theta_H| \leq 120^\circ \quad \text{...Equation C2.3}$$

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

Hence $|\theta_G - \theta_H| \leq 20^\circ$ and the requirements of Equation C2.3 are very easily satisfied. The addition of arc or fault resistance makes no difference to the reasoning above, so the scheme is inherently capable of clearing such faults.

11.3 Effect of load current

When a line is heavily loaded prior to a fault the e.m.f.s of the sources which cause the fault current to flow 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° mentioned above need to be added.

So $|\theta_G - \theta_H| \leq 70^\circ$ and the requirements of Equation C2.3 are still easily satisfied.

For three phase faults, or solid earth faults on phase-by-phase comparison schemes, through load current falls to zero during the fault and so need not be considered. For all other faults, load current continues to flow in the healthy phases and may therefore tend to increase towards the through-fault reference value. For low resistance faults the fault current usually far exceeds the load current and so has little effect. High resistance faults or the presence of a weak source at one end can prove more difficult, but high performance is still possible if the modulating quantity is chosen with care and/or fault detectors are added.

11.4 Modulating quantity

Phase-by-phase comparison schemes usually use phase current for modulation of the carrier. Load and fault currents are almost in antiphase at an end with a weak source. Correct performance is possible only when fault current exceeds load current, or:

for $I_F < I_L'\ |\theta_G - \theta_H| \approx 180^\circ$

for $I_F > I_L'\ |\theta_G - \theta_H| \approx 180^\circ$ ...Equation C2.4

where

I_F = fault current contribution from weak source

I_L = load current flowing towards weak source

To avoid any risk of failure to operate, fault detectors with a setting greater than the maximum load current may be applied, but they may limit the sensitivity of scheme. When the fault detector is not operated at one end, fault clearance invariably involves sequential tripping of the circuit breakers.

Most phase comparison schemes use summation techniques to produce a single modulating quantity, responsive to faults on any of the three phases. Phase sequence components are often used and a typical modulating quantity is:

$$I_M = MI_2 + NI_1 \quad \text{...Equation C2.5}$$

where

I_1 = Positive phase sequence component

I_2 = Negative phase sequence component

M,I = constants

With the exception of three phase faults all internal faults give rise to negative phase sequence (NPS) currents, I_2, which are approximately in phase at the ends of the line and therefore could form an ideal modulating quantity. In order to provide a modulating signal during three phase faults, which give rise to positive phase sequence (PPS) currents, I_1, only, a practical modulating quantity must include some response to I_1 in addition to I_2.

Typical values of the ratio M/N exceed 5:1, so that the modulating quantity is weighted heavily in favour of NPS, and any PPS associated with load current tends to be swamped out on all but the highest resistance faults.

For a high resistance phase-earth fault, the system remains well balanced so that load current I_L is entirely positive sequence. The fault contribution I_F provides equal parts of positive, negative and zero sequence components $I_F/3$. Assuming the fault is on 'A' phase and the load is resistive, all sequence components are in phase at the infeed end G:

$$\therefore\ I_{mG} = NI_L + \frac{MI_{FG}}{3} + \frac{NI_{FG}}{3}$$

and

$$\theta_G \approx 0$$

At the outfeed end load current is negative,

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

Now, for

$I_{mH} > 0,\ \theta_H = 0,$ and $|\theta_G - \theta_H| = 0^\circ$

11. Phase comparison protection scheme considerations

and for

$I_{mH} < 0,\ \theta_H = 180°,$ and $|\ \theta_G - \theta_H\ | = 180°$

Hence for correct operation $I_{mH} \geq 0$

Let $I_{mH} = 0$

Then

$$I_{FH} = \frac{3I_L}{\left(\frac{M}{N} + 1\right)} = I_E \qquad \text{...Equation C2.6}$$

The fault current in Equation C2.6 is the effective earth fault sensitivity of the scheme. For the typical values of

$M = 6$ and $N = -1$

$M/N = -6$

Comparing this with Equation C2.4, a scheme using summation is potentially 1.667 times more sensitive than one using phase current for modulation.

Even though the use of a negative value of M gives a lower value of I_E than if it were positive, it is usually 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 occurs there, even with the lowest fault levels. For operation of the scheme it is sufficient therefore that the fault current contribution from the load infeed end exceeds the effective setting.

For faults on phase B or C, the NPS components are displaced by 120° or 240° with respect to the PPS components. No simple cancellation can occur, but instead a phase displacement is introduced. For tripping to occur, Equation C2.2 must be satisfied, and to achieve high dependability under these marginal conditions, a small effective stability angle is essential. Figure C2.15 illustrates operation near to the limits of earth fault sensitivity.

Very sensitive schemes may be implemented by using high values of M/N but the scheme then becomes more sensitive to differential errors in NPS currents, such as the unbalanced components of capacitive current or spill from partially saturated CT's.

Techniques such as capacitive current compensation and reduction of M/N at high fault levels may be required to ensure stability of the scheme.

11.5 Fault detection and starting

For a scheme using a carrier system that continuously transmits the modulating quantity, protecting an ideal line (capacitive current is zero) in an interconnected transmission system, measurement of current magnitude might be unnecessary. In practice, fault detector or starting elements are invariably provided and the scheme then becomes a permissive tripping scheme in which both the fault detector and the discriminator

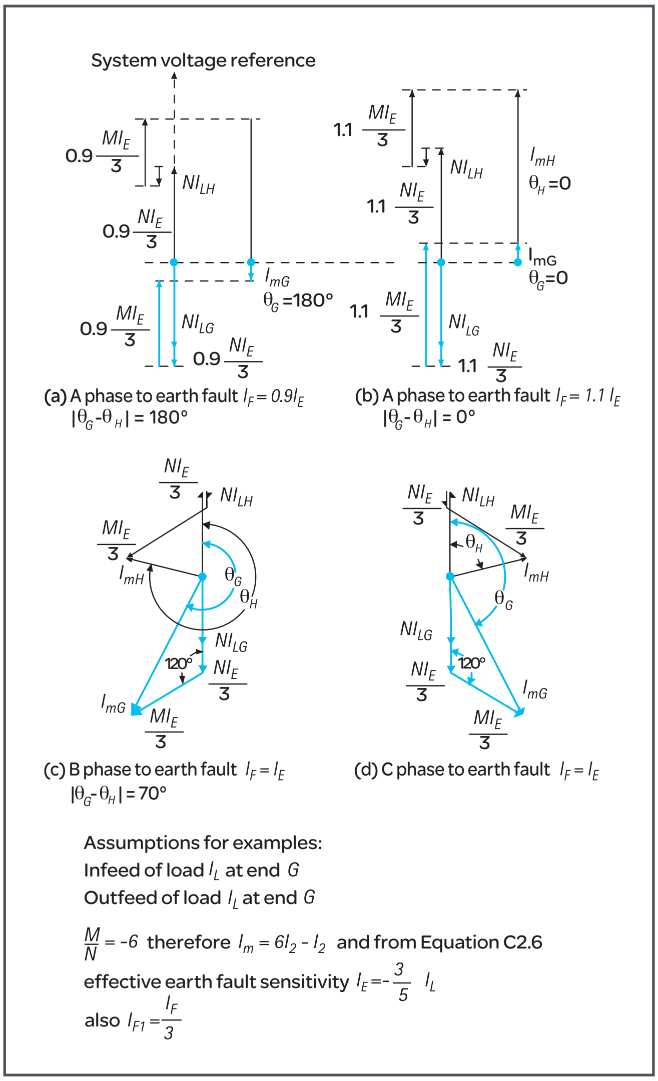

Figure C2.15:
Effect of load current on differential phase shift $|\theta_G - \theta_H|$ for resistive earth faults at the effective earth fault sensitivity I_E

must operate to provide a trip output, and the fault detector may limit the sensitivity of the scheme. Requirements for the fault detectors vary according to the type of carrier channel used, mode of operation used in the phase angle measurement, that is, blocking or permissive, and the features used to provide tolerance to capacitive current.

11.6 Normally quiescent power line carrier (blocking mode)

To ensure stability of through-faults, it is essential that carrier transmission starts before any measurement of the width of the gap is permitted. To allow for equipment tolerances and the difference in magnitude of the two currents due to capacitive current, two starting elements are used, usually referred to as 'Low Set' and 'High Set' respectively. Low Set controls the start-up of transmission whilst High Set, having

11. Phase comparison protection scheme considerations

a setting typically 1.5 to 2 times that of the Low Set element, permits the phase angle measurement to proceed.

The use of impulse starters that respond to the change in current level enables sensitivities of less than rated current to be achieved. Resetting of the starters occurs naturally after a swell time or at the clearance of the fault. 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 often avoided by the transmitting of an unmodulated (and therefore blocking) carrier for a short time following the reset of low set; this feature is often referred to as 'Marginal Guard.'

11.7 Scheme without capacitive current compensation

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

11.8 Scheme with capacitive current compensation (blocking mode)

When the magnitude of the modulating quantity is less than the threshold of the squarer, transmission if it occurred, would be a continuous blocking signal. This might occur at an end with a weak source, remote from a fault close to a strong source. A fault detector is required to permit transmission only when the current exceeds the modulator threshold by some multiple (typically about 2 times) so that the effective stability angle is not excessive. For PLCC schemes, the low set element referred to in Section 11.6 is usually used for this purpose. If the fault current is insufficient to operate the fault detector, circuit breaker tripping will normally occur sequentially.

11.9 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. However, 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, which would lead to failure of such fault detection, resulting in sequential tripping (for blocking mode schemes) or no tripping (for permissive schemes). Although fault detectors can be designed to respond to any disturbance (increase or decrease of current), it is more usual to use phase sequence components. All unbalanced faults produce a rise in the NPS components from the zero level associated with balanced load current, whilst balanced faults produce an increase in the PPS components from the load level (except at ends with very low fault level) so that the use of NPS and PPS fault detectors make the scheme sensitive to all faults. For schemes using summation of NPS and PPS components for the modulating quantity, the use of NPS and PPS fault detectors is particularly appropriate since, in addition to any reductions in hardware, the scheme may be characterized 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 follows:

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

b. Phase-phase fault $I_F = \sqrt{3I_{2S}}$

c. Phase-earth fault $I_F = 3I_{2S}$

12. Examples

This section gives examples of setting calculations for simple unit protection schemes. It cannot and is not intended to replace a proper setting calculation for a particular application. It is intended to illustrate the principles of the calculations required. The examples use the Schneider Electric Industries MiCOM P541 Current Differential relay, which has the setting ranges given in Table C2.1 for differential protection. The relay also has backup distance, high-set instantaneous, and earth-fault protection included in the basic model to provide a complete 'one-box' solution of main and backup protection.

12.1 Unit protection of a plain feeder

The circuit to be protected is shown in Figure C2.16. It consists of a plain feeder circuit formed of an overhead line 25km long. The relevant properties of the line are:

a. Line voltage $V = 33kV$

b. Line impedance $Z = 0.157 + j0.337\Omega/km$

c. Shunt charging current $I_c = 0.065A/km$

C2

12. Examples

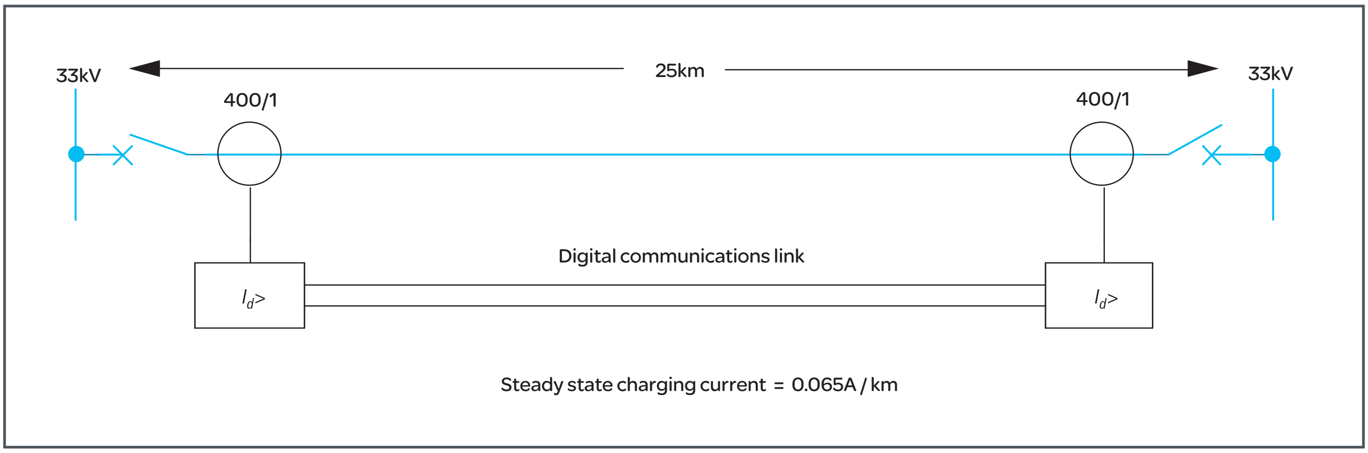

Figure C2.16:
Typical plain feeder circuit

To arrive at the correct settings, the characteristics of the relays to be applied must be considered.

The recommended settings for three of the adjustable values (taken from the relay manual) are:

Parameter	Setting Range
Differential Current Setting, I_{s1}	0.2 -2.0 I_n
Bias Current Threshold Setting, I_{s2}	1-30 I_n
Lower Percentage Bias Setting, k_1	0.3-1.5
Higher Precentage Bias Setting, k_2	0.3-1.5
I_n - CT rated secondary current	
I_{s2} = 2.0 p.u. , k_1 = 30% , k_2 = 150%	

Table C2.1:
Relay setting ranges

To provide immunity from the effects of line charging current, the setting of I_{s1} must be at least 2.5 times the steady-state charging current, i.e. 4.1A or 0.01 p.u., after taking into consideration the CT ratio of 400/1. The nearest available setting above this is 0.20 p.u. This gives the points on the relay characteristic as shown in Figure C2.17.

The minimum operating current I_{dmin} is related to the value of I_{s1} by the formula

$$I_{dmin} = (k_1 I_L + I_{s1}) / (1 - 0.5 k_1)$$

for $I_{bias} < I_{s2}$

and

$$I_{dmin} = (k_2 I_L - (k_2 - k_1) I_{s2} + I_{s1})/(1 - 0.5 k_2)$$

for $I_{bias} > I_{s2}$

where

I_L = load current, and hence the minimum operating current at no load is 0.235 p.u. or 94A.

In cases where the capacitive charging current is very large and hence the minimum tripping current needs to be set to an unacceptably high value, some relays offer the facility of subtracting the charging current from the measured value. Use of this facility depends on having a suitable VT input and knowledge of the shunt capacitance of the circuit.

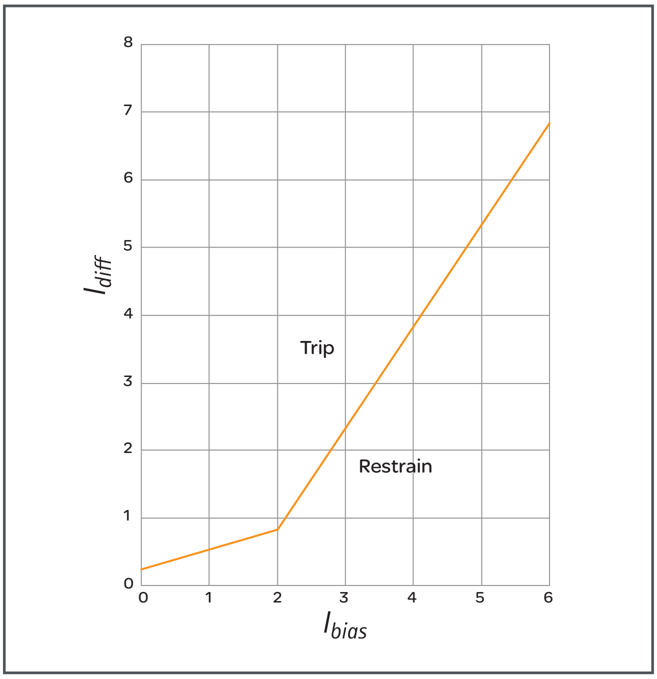

Figure C2.17:
Relay characteristic; plain feeder example

12.2 Unit protection of a transformer feeder

Figure C2.18 shows unit protection applied to a transformer feeder. The feeder is assumed to be a 100m length of cable, such as might be found in some industrial plants or where a short distance separates the 33kV and 11kV substations. While 11kV cable capacitance will exist, it can be regarded as negligible for the purposes of this example.

The delta/star transformer connection requires phase shift correction of CT secondary currents across the transformer, and in this case software equivalents of interposing CT's are used.

Since the LV side quantities lag the HV side quantities by 30°, it is necessary to correct this phase shift by using software CT settings that produce a 30° phase shift. There are two obvious possibilities:

a. HV side: $Yd1$

LV side: $Yy0$

b. HV side: $Yy0$

LV side: $Yd11$

Only the second combination is satisfactory, since only this one provides the necessary zero-sequence current trap to avoid maloperation of the protection scheme for earth faults on the LV side of the transformer outside of the protected zone.

Ratio correction must also be applied, in order to ensure that the relays see currents from the primary and secondary sides of the transformer feeder that are well balanced under full load conditions. This is not always inherently the case, due to selection of the main CT ratios.

For the example of Figure C2.18, transformer turns ratio at nominal tap:

$$V_p / V_s = 11\ kV/33\ kV = 0.3333$$

Required turns ratio, according to the CT ratios used

$$= \frac{400/1}{1250/1} = 0.32$$

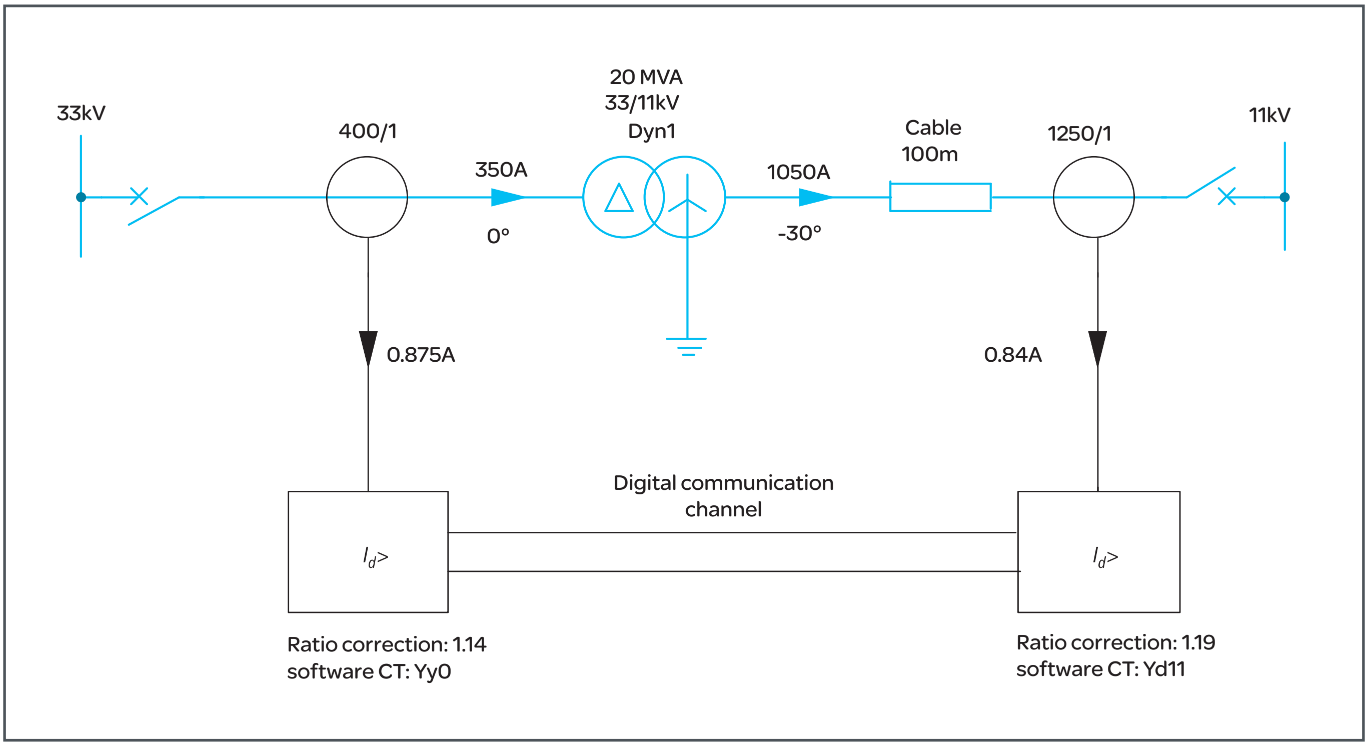

Figure C2.18:
Unit protection of a transformer feeder

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12. Examples

Spill current that will arise due to the incompatibility of the CT ratios used with the power transformer turns ratio may cause relay maloperation. This has to be eliminated by using the facility in the relay for CT ratio correction factors. For this particular relay, the correction factors are chosen such that the full load current seen by the relay software is equal to 1A.

The appropriate correction factors are:

- HV: 400 / 350 = 1.14
- LV: 1250/1050 = 1.19 where:

transformer rated primary current = 350A

transformer rated secondary current = 1050A

With the line charging current being negligible, the following relay settings are then suitable, and allow for transformer efficiency and mismatch due to tap-changing:

I_{S1} = 20% (minimum possible)

I_{S1} = 20%

k_1 = 30%

k_2 = 150%

13. References

[C2.1] Merz-Price Protective Gear.

K. Faye-Hansen and G. Harlow.

IEE Proceedings, 1911.

C3

Distance Protection

Network Protection & Automation Guide

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Chapter C3

Distance Protection

C3

1. Introduction

The problem of combining fast fault clearance with selective tripping of plant is a key aim for the protection of power systems. To meet these requirements, high-speed protection systems for transmission and primary distribution circuits that are suitable for use with the automatic reclosure of circuit breakers are under continuous development and are very widely applied.

Distance protection, in its basic form, is a non-unit system of protection offering considerable economic and technical advantages. Unlike phase and neutral overcurrent protection, the key advantage of distance protection is that its fault coverage of the protected circuit is virtually independent of source impedance variations.

This is illustrated in Figure C3.1, where it can be seen that overcurrent protection cannot be applied satisfactorily. Distance protection is comparatively simple to apply and it can be fast in operation for faults located along most of a protected circuit. It can also provide both primary and remote back-up functions in a single scheme. It can easily be adapted to create a unit protection scheme when applied with a signalling channel. In this form it is eminently suitable for application with high-speed auto-reclosing, for the protection of critical transmission lines.

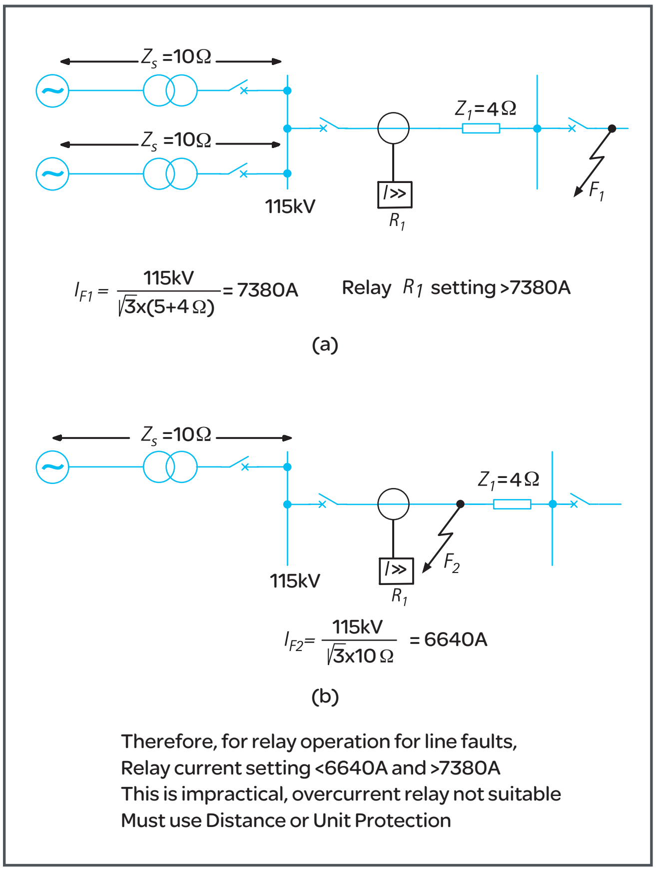


Figure C3.1:
Advantages of distance over overcurrent protection

2. Principles of distance relays

Since the impedance of a transmission line is proportional to its length, for distance measurement it is appropriate to use a relay capable of measuring the impedance of a line up to a predetermined point (the reach point). Such a relay is described as a distance relay and is designed to operate only for faults occurring between the relay location and the selected reach point, thus giving discrimination for faults that may occur in different line sections.

The basic principle of distance protection involves the division of the voltage at the relaying point by the measured current. The apparent impedance so calculated is compared with the reach point impedance. If the measured impedance is less than the reach point impedance, it is assumed that a fault exists on the line between the relay and the reach point.

The reach point of a relay is the point along the line impedance locus that is intersected by the boundary characteristic of the relay. Since this is dependent on the ratio of voltage and current and the phase angle between them, it may be plotted on an R/X diagram. The loci of power system impedances as seen by the relay during faults, power swings and load variations may be plotted on the same diagram and in this manner the performance of the relay in the presence of system faults and disturbances may be studied.

3. Relay performance

Distance relay performance is defined in terms of reach accuracy and operating time. Reach accuracy is a comparison of the actual ohmic reach of the relay under practical conditions with the relay setting value in ohms. Reach accuracy particularly depends on the level of voltage presented to the relay under fault conditions. The impedance measuring techniques employed in particular relay designs also have an impact.

Operating times can vary with fault current, with fault position relative to the relay setting, and with the point on the voltage wave at which the fault occurs. Depending on the measuring techniques employed in a particular relay design, measuring signal transient errors, such as those produced by Capacitor Voltage Transformers or saturating CT's, can also adversely delay relay operation for faults close to the reach point. It is usual for electromechanical and static distance relays to claim both maximum and minimum operating times. However, for modern digital or numerical distance relays, the variation between these is small over a wide range of system operating conditions and fault positions.

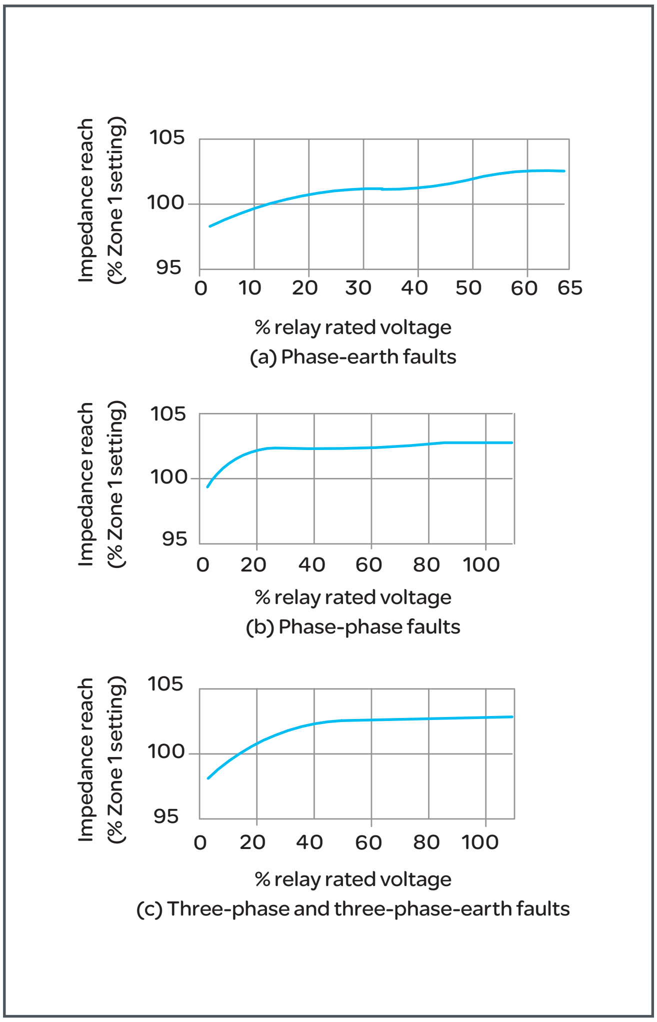


Figure C3.2:
Typical impedance reach accuracy characteristics for Zone 1

3.1 Electromechanical/static distance relays

With electromechanical and earlier static relay designs, the magnitude of input quantities particularly influenced both reach accuracy and operating time. It was customary to present information on relay performance by voltage/reach curves, as shown in Figure C3.2, and operating time/fault position curves for various values of source impedance ratios (SIRs) as shown in Figure C3.3, where:

$$SIR = Z_S / Z_L$$

and

Z_S = power system source impedance behind the relay location

Z_L = line impedance equivalent to relay reach setting

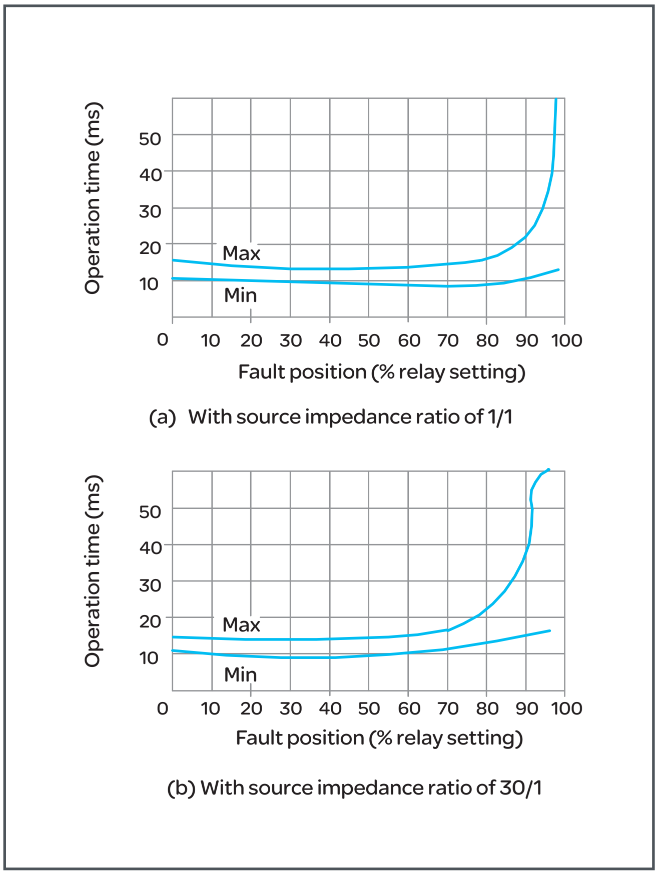


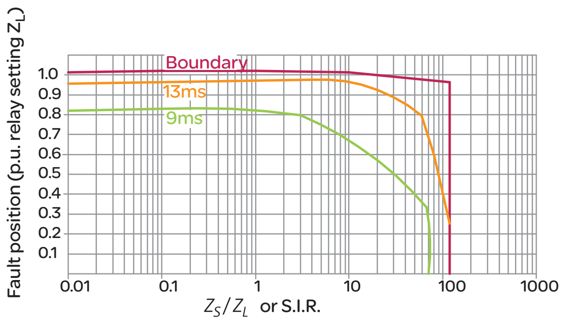
Figure C3.3:
Typical operation time characteristics for Zone 1 phase-phase faults

Alternatively, the above information was combined in a family of contour curves, where the fault position expressed as a percentage of the relay setting is plotted against the source to line impedance ratio, as illustrated in Figure C3.4(a) and C3.4(b).

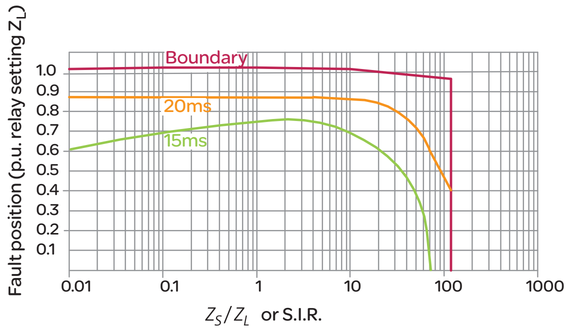
3. Relay performance

3.2 Digital/numerical distance relays

Digital/Numerical distance relays tend to have more consistent operating times. They are usually slightly slower than some of the older relay designs when operating under the best conditions, but their maximum operating times are also less under adverse waveform conditions or for boundary fault conditions.



(a) Zone 1 phase-phase fault: minimum operation times



(b) Zone 1 phase-phase fault: maximum operation times

Figure C3.4a:
Typical minimum operation-time contours

Figure C3.4b:
Typical maximum operation-time contours

4. Relationship between relay voltage and Z_S / Z_L ratio

A single, generic, equivalent circuit, as shown in Figure C3.5(a), may represent any fault condition in a three-phase power system. The voltage V applied to the impedance loop is the open circuit voltage of the power system. Point R represents the relay location; I_R and V_R are the current and voltage measured by the relay, respectively.

The impedances Z_S and Z_L are described as source and line impedances because of their position with respect to the relay location. Source impedance Z_S is a measure of the fault level at the relaying point. For faults involving earth it is dependent on the method of system earthing behind the relaying point.

Line impedance Z_L is a measure of the impedance of the protected section. The voltage V_R applied to the relay is, therefore, $I_R\ Z_L$. For a fault at the reach point, this may be alternatively expressed in terms of source to line impedance ratio Z_S/Z_L by means of the following expressions:

$$V_R = I_R Z_L$$

where:

$$I_R = \frac{V}{Z_S + Z_L}$$

Therefore :

$$V_R = \frac{Z_L}{Z_S + Z_L} V$$

or

$$V_R = \frac{1}{\left(Z_S / Z_L\right) + 1} V$$

...Equation C3.1

The above generic relationship between V_R and Z_S/Z_L, illustrated in Figure C3.5(b), is valid for all types of short circuits provided a few simple rules are observed. These are:

a. for phase faults, V is the phase-phase source voltage and Z_S/Z_L is the positive sequence source to line impedance ratio. V_R is the phase-phase relay voltage and I_R is the phase-phase relay current, for the faulted phases

$$V_R = \frac{1}{\left(Z_S / Z_L\right) + 1} V_{p-p}$$

...Equation C3.2

b. for earth faults, V is the phase-neutral source voltage and Z_S/Z_L is a composite ratio involving the positive and zero sequence impedances. V_R is the phase-neutral relay voltage and I_R is the relay current for the faulted phase

4. Relationship between relay voltage and Z_S / Z_L ratio

$$V_R = \frac{1}{\left(Z_S / Z_L\right)\left(\dfrac{2+p}{2+q}\right)+1} V_{l-n} \qquad \text{...Equation C3.3}$$

where

$$Z_S = 2Z_{S1} + Z_{S0} = Z_{S1}(2+p)$$

$$Z_L = 2Z_{L1} + Z_{L0} = Z_{L1}(2+q)$$

and

$$p = \frac{Z_{S0}}{Z_{S1}}$$

$$q = \frac{Z_{L0}}{Z_{L1}}$$

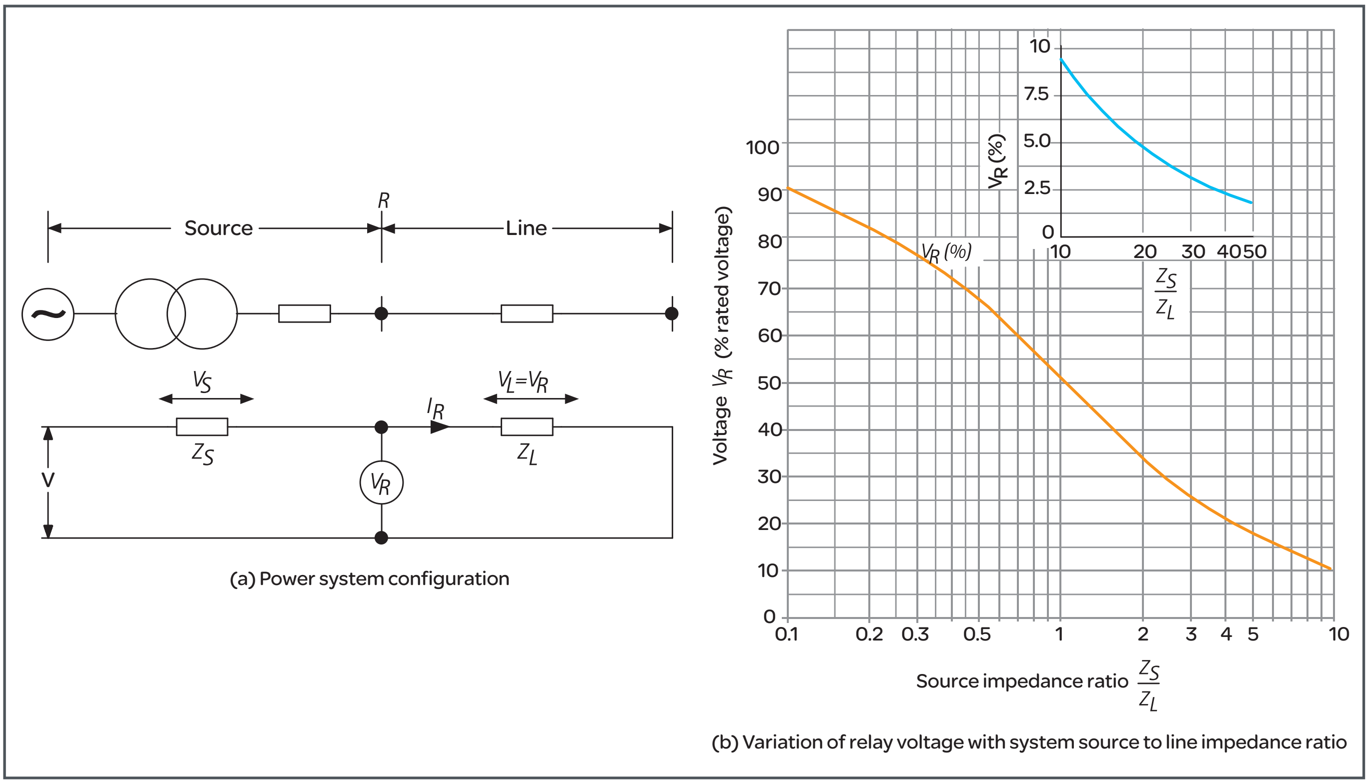


Figure C3.5:
Relationship between source to line ratio and relay voltage

5. Voltage limit for accurate reach point measurement

The ability of a distance relay to measure accurately for a reach point fault depends on the minimum voltage at the relay location under this condition being above a declared value. This voltage, which depends on the relay design, can also be quoted in terms of an equivalent maximum Z_S/Z_L or SIR.

Distance relays are designed so that, provided the reach point voltage criterion is met, any increased measuring errors for faults closer to the relay will not prevent relay operation. Most modern relays are provided with healthy phase voltage polarisation and/or memory voltage polarisation. The prime purpose of the relay polarising voltage is to ensure correct relay directional response for close-up faults, in the forward or reverse direction, where the fault-loop voltage measured by the relay may be very small.

6. Zones of protection

Careful selection of the reach settings and tripping times for the various zones of measurement enables correct co-ordination between distance relays on a power system. Basic distance protection will comprise instantaneous directional Zone 1 protection and one or more time-delayed zones. Typical reach and time settings for a 3-zone distance protection are shown in Figure C3.6. Digital and numerical distance relays may have more than three zones (e.g. MiCOM P44x up to five, MiCOM P43x up to eight), some set to measure in the reverse direction. Typical settings for three forward-looking zones of basic distance protection are given in the following sub- sections. To determine the settings for a particular relay design or for a particular distance teleprotection scheme, involving end-to- end signalling, the relay manufacturer's instructions should be referred to.

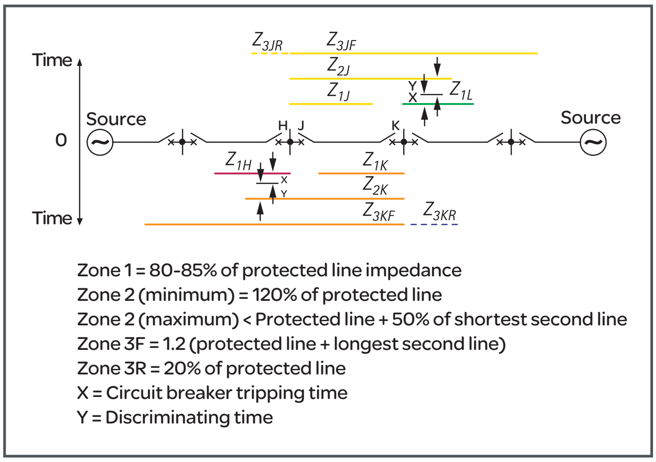


Figure C3.6:
Typical time/distance characteristics for three zone distance protection

6.1 Zone 1 setting

Electromechanical/static relays usually have a reach setting of up to 80% of the protected line impedance for instantaneous Zone 1 protection. For digital/numerical distance relays, settings of up to 85% may be safe. The resulting 15-20% safety margin ensures that there is no risk of the Zone 1 protection over-reaching the protected line due to errors in the current and voltage transformers, inaccuracies in line impedance data provided for setting purposes and errors of relay setting and measurement. Otherwise, there would be a loss of discrimination with fast operating protection on the following line section. Zone 2 of the distance protection must cover the remaining 15-20% of the line.

6.2 Zone 2 setting

To ensure full cover of the line with allowance for the sources of error already listed in the previous section, the reach setting of the Zone 2 protection should be at least 120% of the protected line impedance. In many applications it is common practice to set the Zone 2 reach to be equal to the protected line section +50% of the shortest adjacent line. Where possible, this ensures that the resulting maximum effective Zone 2 reach does not extend beyond the minimum effective Zone 1 reach of the adjacent line protection.

This avoids the need to grade the Zone 2 time settings between upstream and downstream relays. In electromechanical and static relays, Zone 2 protection is provided either by separate elements or by extending the reach of the Zone 1 elements after a time delay that is initiated by a fault detector. In most digital and numerical relays, the Zone 2 elements are implemented in software.

Zone 2 tripping must be time-delayed to ensure grading with the primary relaying applied to adjacent circuits that fall within the Zone 2 reach. Thus complete coverage of a line section is obtained, with fast clearance of faults in the first 80-85% of the line and somewhat slower clearance of faults in the remaining section of the line.

6.3 Zone 3 setting

Remote back-up protection for all faults on adjacent lines can be provided by a third zone of protection that is time delayed to discriminate with Zone 2 protection plus circuit breaker trip time for the adjacent line. Zone 3 reach should be set to at least 1.2 times the impedance presented to the relay for a fault at the remote end of the second line section.

On interconnected power systems, the effect of fault current infeed at the remote busbars will cause the impedance presented to the relay to be much greater than the actual impedance to the fault and this needs to be taken into account when setting Zone 3. In some systems, variations in the remote busbar infeed can prevent the application of remote back-up Zone 3 protection, but on radial distribution systems with single end infeed, no difficulties should arise.

6.4 Settings for reverse reach and other zones

Modern digital or numerical relays may have additional impedance zones that can be utilised to provide additional protection functions. For example, where the first three zones are set as above, Zone 4 might be used to provide back-up protection for the local busbar, by applying a reverse reach setting of the order of 25% of the Zone 1 reach. Alternatively, one of the forward-looking zones (typically Zone 3) could be set with a small reverse offset reach from the origin of the R/X diagram, in addition to its forward reach setting.

An offset impedance measurement characteristic is non-directional. One advantage of a non-directional zone of impedance measurement is that it is able to operate for a close-up, zero- impedance fault, in situations where there may be no healthy phase voltage signal or memory voltage signal available to allow operation of a directional impedance zone. With the offset-zone time delay bypassed, there can be provision of 'Switch-on-to-Fault' (SOTF) protection. This is required where there are line voltage transformers, to provide fast tripping in the event of accidental line energisation with maintenance earthing clamps left in position. Additional impedance zones may be deployed as part of a distance protection scheme used in conjunction with a teleprotection signalling channel.

7. Distance relay characteristics

Some numerical relays measure the absolute fault impedance and then determine whether operation is required according to impedance boundaries defined on the R/X diagram. Traditional distance relays and numerical relays that emulate the impedance elements of traditional relays do not measure absolute impedance. They compare the measured fault voltage with a replica voltage derived from the fault current and the zone impedance setting to determine whether the fault is within zone or out-of-zone. Distance relay impedance comparators or algorithms which emulate traditional comparators are classified according to their polar characteristics, the number of signal inputs they have, and the method by which signal comparisons are made. The common types compare either the relative amplitude or phase of two input quantities to obtain operating characteristics that are either straight lines or circles when plotted on an R/X diagram. At each stage of distance relay design evolution, the development of impedance operating characteristic shapes and sophistication has been governed by the technology available and the acceptable cost. Since many traditional relays are still in service and since some numerical relays emulate the techniques of the traditional relays, a brief review of impedance comparators is justified.

7.1 Amplitude and phase comparison

Relay measuring elements whose functionality is based on the comparison of two independent quantities are essentially either amplitude or phase comparators. For the impedance elements of a distance relay, the quantities being compared are the voltage and current measured by the relay. There are numerous techniques available for performing the comparison, depending on the technology used. They vary from balanced-beam (amplitude comparison) and induction cup (phase comparison) electromagnetic relays, through diode and operational amplifier comparators in static-type distance relays, to digital sequence comparators in digital relays and to algorithms used in numerical relays.

Any type of impedance characteristic obtainable with one comparator is also obtainable with the other. The addition and subtraction of the signals for one type of comparator produces the required signals to obtain a similar characteristic using the other type. For example, comparing V and I in an amplitude comparator results in a circular impedance characteristic centred at the origin of the R/X diagram. If the sum and difference of V and I are applied to the phase comparator the result is a similar characteristic.

7.2 Plain impedance characteristic

This characteristic takes no account of the phase angle between the current and the voltage applied to it; for this reason its impedance characteristic when plotted on an R/X diagram is a circle with its centre at the origin of the co-ordinates and of radius equal to its setting in ohms. Operation occurs for all impedance values less than the setting, that is, for all points within the circle. The relay characteristic, shown in Figure C3.7, is therefore non-directional, and in this form would operate for all faults along the vector AL and also for all faults behind the busbars up to an impedance AM. It is to be noted that A is the relaying point and RAB is the angle by which the fault current lags the relay voltage for a fault on the line AB and RAC is the equivalent leading angle for a fault on line AC. Vector AB represents the impedance in front of the relay between the relaying point A and the end of line AB. Vector AC represents the impedance of line AC behind the relaying point. AL represents the reach of instantaneous Zone 1 protection, set to cover 80% to 85% of the protected line.

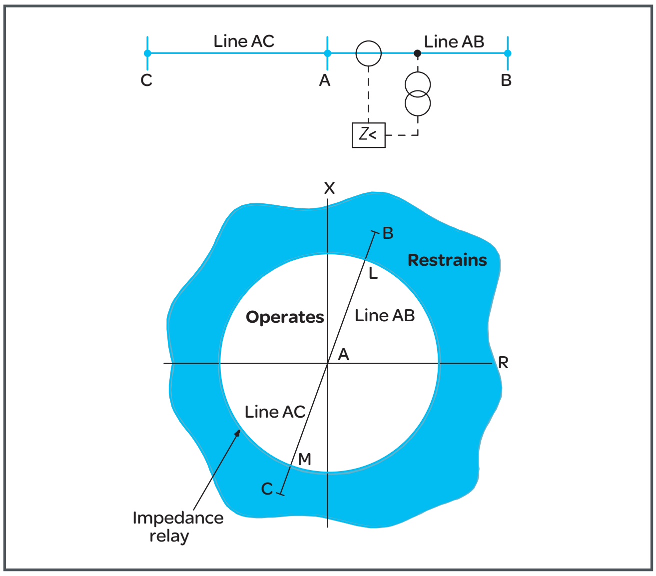


Figure C3.7: Plain impedance relay characteristic

A relay using this characteristic has three important disadvantages:

a. it is non-directional; it will see faults both in front of and behind the relaying point, and therefore requires a directional element to give it correct discrimination

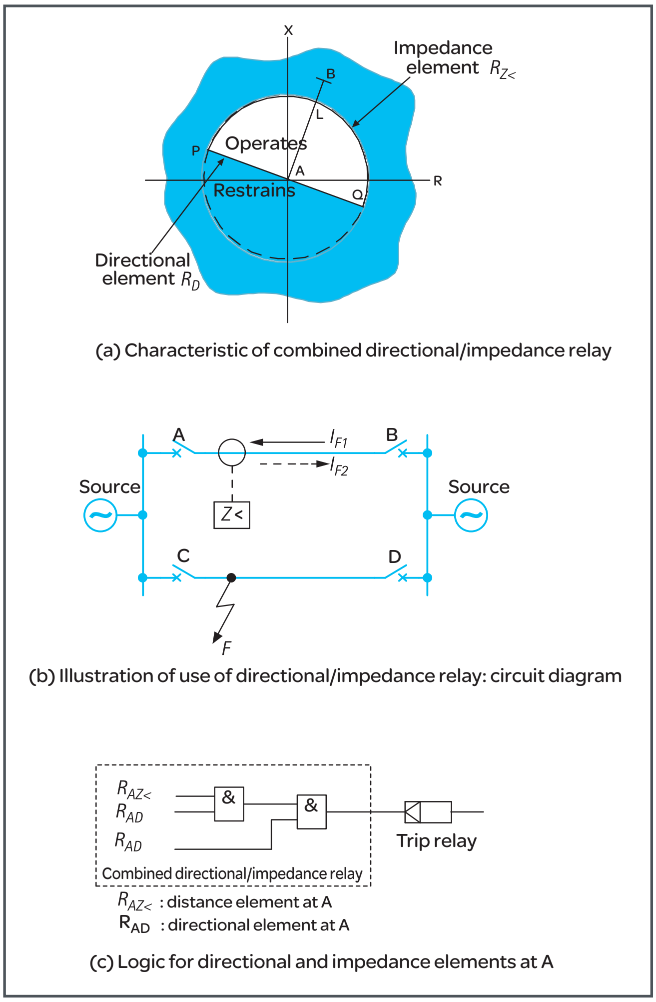
b. it has non-uniform fault resistance coverage

c. it is susceptible to power swings and heavy loading of a long line, because of the large area covered by the impedance circle

Directional control is an essential discrimination quality for a distance relay, to make the relay non-responsive to faults outside the protected line. This can be obtained by the addition of a separate directional control element. The impedance characteristic of a directional control element is a straight line on the R/X diagram, so the combined characteristic of the directional and impedance relays is the semi-circle $APLQ$ shown in Figure C3.8.

7. Distance relay characteristics

If a fault occurs at F close to C on the parallel line CD, the directional unit R_D at A will restrain due to current I_{F1}. At the same time, the impedance unit is prevented from operating by the inhibiting output of unit R_D. If this control is not provided, the under impedance element could operate prior to circuit breaker C opening. Reversal of current through the relay from I_{F1} to I_{F2} when C opens could then result in incorrect tripping of the healthy line if the directional unit R_D operates before the impedance unit resets. This is an example of the need to consider the proper co-ordination of multiple relay elements to attain reliable relay performance during evolving fault conditions. In older relay designs, the type of problem to be addressed was commonly referred to as one of 'contact race'.



(a) Characteristic of combined directional/impedance relay

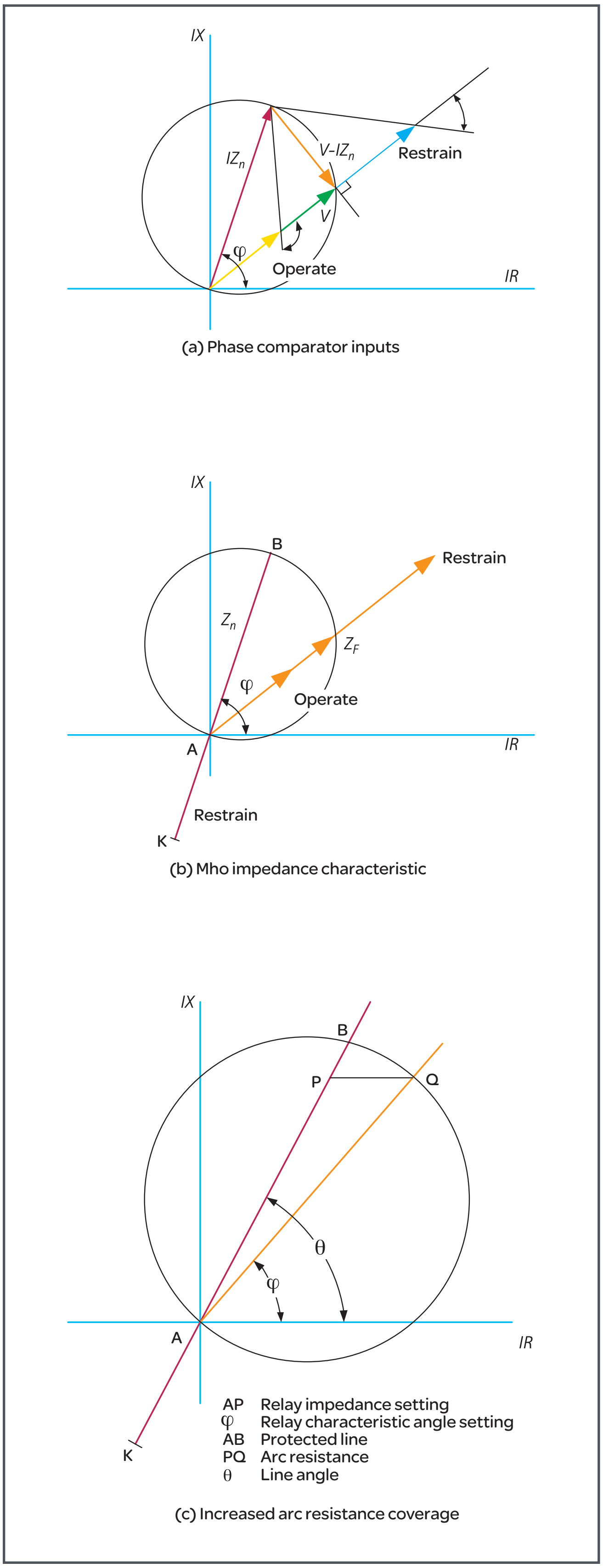
(b) Illustration of use of directional/impedance relay: circuit diagram

(c) Logic for directional and impedance elements at A

Figure C3.8:
Combined directional and impedance relays

7.3 Self-polarised mho relay

The mho impedance element is generally known as such because its characteristic is a straight line on an admittance diagram. It cleverly combines the discriminating qualities of



(a) Phase comparator inputs

(b) Mho impedance characteristic

(c) Increased arc resistance coverage

Figure C3.9:
Mho relay characteristic

7. Distance relay characteristics

both reach control and directional control, thereby eliminating the 'contact race' problems that may be encountered with separate reach and directional control elements. This is achieved by the addition of a polarising signal. Mho impedance elements were particularly attractive for economic reasons where electromechanical relay elements were employed. As a result, they have been widely deployed worldwide for many years and their advantages and limitations are now well understood. For this reason they are still emulated in the algorithms of some modern numerical relays.

The characteristic of a mho impedance element, when plotted on an R/X diagram, is a circle whose circumference passes through the origin, as illustrated in Figure C3.9(a). This demonstrates that the impedance element is inherently directional and such that it will operate only for faults in the forward direction along line AB as shown in Figure C3.9(b).

The impedance characteristic is adjusted by setting Z_n, the impedance reach, along the diameter and φ, the angle of displacement of the diameter from the R axis. Angle φ is known as the Relay Characteristic Angle (RCA). The relay operates for values of fault impedance Z_F within its characteristic.

It will be noted that the impedance reach varies with fault angle. As the line to be protected is made up of resistance and inductance, its fault angle will be dependent upon the relative values of R and X at the system operating frequency. Under an arcing fault condition, or an earth fault involving additional resistance, such as tower footing resistance or fault through vegetation, the value of the resistive component of fault impedance will increase to change the impedance angle. Thus a relay having a characteristic angle equivalent to the line angle will under-reach under resistive fault conditions.

It is usual, therefore, to set the RCA less than the line angle, so that it is possible to accept a small amount of fault resistance without causing under-reach. However, when setting the relay, the difference between the line angle θ and the relay characteristic angle φ must be known. The resulting characteristic is shown in Figure C3.9(c) where AB corresponds to the length of the line to be protected. With φ set less than θ, the actual amount of line protected, AB, would be equal to the relay setting value AQ multiplied by cosine (θ-φ). Therefore the required relay setting AQ is given by:

$$AQ = \frac{AB}{\cos(\theta - \varphi)}$$

Due to the physical nature of an arc, there is a non-linear relationship between arc voltage and arc current, which results in a non-linear resistance. Using the empirical formula derived by A.R. van C. Warrington [Ref C3.1: Protective Relays – their Theory and Practice] the approximate value of arc resistance can be assessed as:

$$R_a = \frac{28710}{I^{1.4}} L \qquad \text{...Equation C3.4}$$

where:

R_a = arc resistance (Ω)

L = length of arc (m)

I = arc current (A)

On long overhead lines carried on steel towers with overhead earth wires the effect of arc resistance can usually be neglected. The effect is most significant on short overhead lines and with fault currents below 2000A (i.e. minimum plant condition), or if the protected line is of wood-pole construction without earth wires. In the latter case, the earth fault resistance reduces the effective earth-fault reach of a mho Zone 1 element to such an extent that the majority of faults are detected in Zone 2 time. This problem can usually be overcome by using a relay with a cross-polarised mho or a polygonal characteristic.

Where a power system is resistance-earthed, it should be appreciated that this does not need to be considered with regard to the relay settings other than the effect that reduced fault current may have on the value of arc resistance seen. The earthing resistance is in the source behind the relay and only modifies the source angle and source to line impedance ratio for earth faults. It would therefore be taken into account only when assessing relay performance in terms of system impedance ratio.

7.4 Offset mho/lenticular characteristics

Under close up fault conditions, when the relay voltage falls to zero or near-zero, a relay using a self-polarised mho characteristic or any other form of self-polarised directional impedance characteristic may fail to operate when it is required to do so. Methods of covering this condition include the use of non-directional impedance characteristics, such as offset mho, offset lenticular, or cross-polarised and memory polarised directional impedance characteristics.

If current bias is employed, the mho characteristic is shifted to embrace the origin, so that the measuring element can operate for close-up faults in both the forward and the reverse directions. The offset mho relay has two main applications:

7.4.1 Third zone and busbar back-up zone

In this application it is used in conjunction with mho measuring units as a fault detector and/or Zone 3 measuring unit. So, with the reverse reach arranged to extend into the busbar zone, as shown in Figure C3.10(a), it will provide back-up protection for busbar faults. This facility can also be provided with quadrilateral characteristics. A further benefit of the Zone 3 application is for Switch-on-to-Fault (SOTF) protection, where the Zone 3 time delay would be bypassed for a short period immediately following line energisation to allow rapid clearance of a fault anywhere along the protected line.

7. Distance relay characteristics

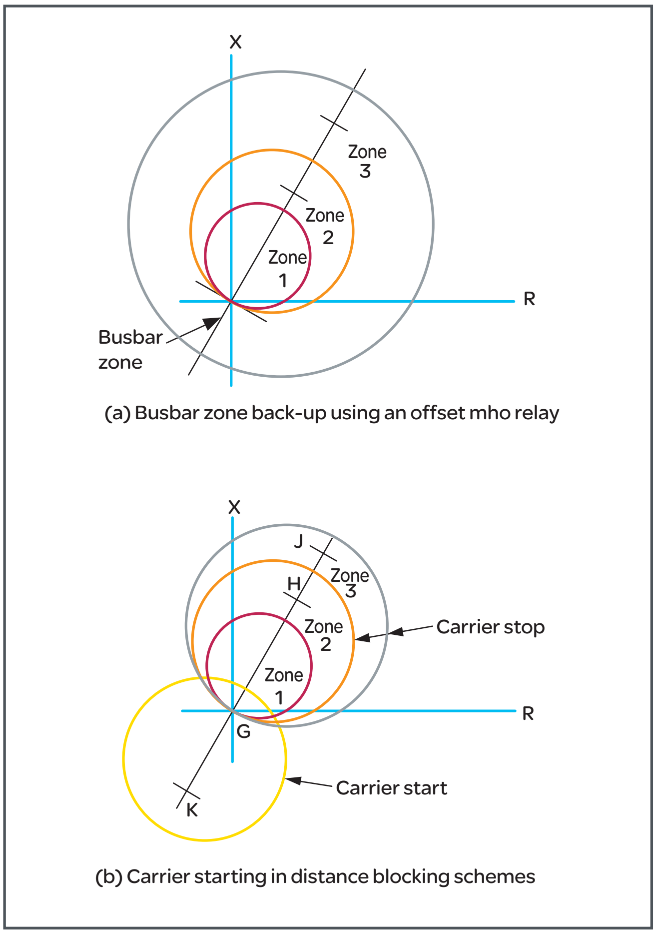


Figure C3.10:
Typical applications for the offset mho relay

7.4.2 Carrier starting unit in distance schemes with carrier blocking

If the offset mho unit is used for starting carrier signalling, it is arranged as shown in Figure C3.10(b). Carrier is transmitted if the fault is external to the protected line but inside the reach of the offset mho relay, in order to prevent accelerated tripping of the second or third zone relay at the remote station. Transmission is prevented for internal faults by operation of the local mho measuring units, which allows high-speed fault clearance by the local and remote end circuit breakers.

7.4.3 Application of lenticular characteristic

There is a danger that the offset mho relay shown in Figure C3.10(a) may operate under maximum load transfer conditions if Zone 3 of the relay has a large reach setting. A large Zone 3 reach may be required to provide remote back-up protection for faults on the adjacent feeder. To avoid this, a shaped type of characteristic may be used, where the resistive coverage is restricted.

With a 'lenticular' characteristic, the aspect ratio of the lens is (a/b) adjustable, enabling it to be set to provide the maximum fault resistance coverage consistent with non-operation under maximum load transfer conditions.

Figure C3.11 shows how the lenticular characteristic can tolerate much higher degrees of line loading than offset mho and plain impedance characteristics.

Reduction of load impedance from Z_{D3} to Z_{D1} will correspond to an equivalent increase in load current.

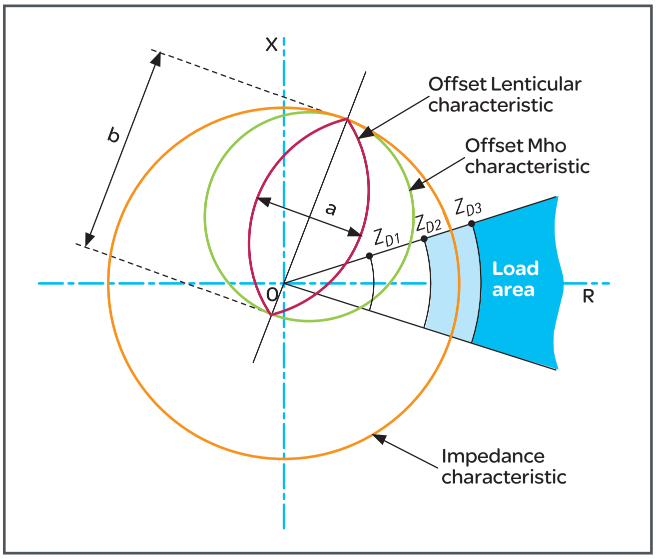


Figure C3.11:
Minimum load impedance permitted with lenticular, offset mho and impedance relays

7.5 Fully cross-polarised mho characteristic

The previous section showed how the non-directional offset mho characteristic is inherently able to operate for close-up zero voltage faults, where there would be no polarising voltage to allow operation of a plain mho directional element. One way of ensuring correct mho element response for zero-voltage faults is to add a percentage of voltage from the healthy phase(s) to the main polarising voltage as a substitute phase reference. This technique is called cross-polarising, and it has the advantage of preserving and indeed enhancing the directional properties of the mho characteristic. By the use of a phase voltage memory system, that provides several cycles of pre-fault voltage reference during a fault, the cross-polarisation technique is also effective for close-up three-phase faults. For this type of fault, no healthy phase voltage reference is available.

Early memory systems were based on tuned, resonant, analogue circuits, but problems occurred when applied to networks where the power system operating frequency could vary. More modern digital or numerical systems can offer a synchronous phase reference for variations in power system frequency before or even during a fault.

7. Distance relay characteristics

As described in Section 7.3, a disadvantage of the self-polarised, plain mho impedance characteristic, when applied to overhead line circuits with high impedance angles, is that it has limited coverage of arc or fault resistance. The problem is aggravated in the case of short lines, since the required Zone 1 ohmic setting is low. The amount of the resistive coverage offered by the mho circle is directly related to the forward reach setting.

Hence, the resulting resistive coverage may be too small in relation to the expected values of fault resistance.

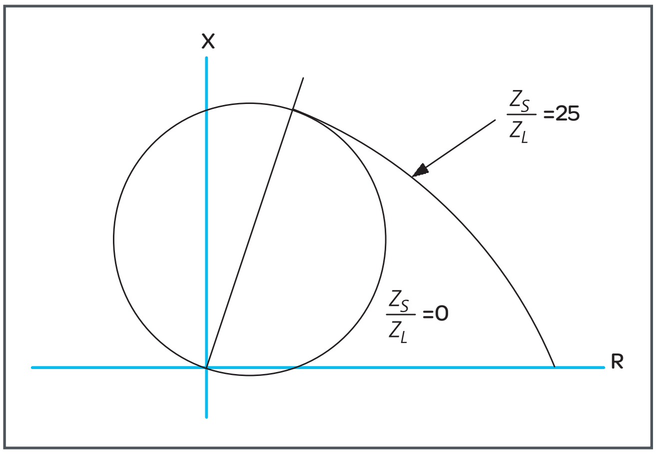


Figure C3.12:
Fully cross-polarised mho relay characteristic with variations of Z_S/Z_L ratio

One additional benefit of applying cross-polarisation to a mho impedance element is that its resistive coverage will be enhanced. This effect is illustrated in Figure C3.12, for the case where a mho element has 100% cross-polarisation. With cross-polarisation from the healthy phase(s) or from a memory system, the mho resistive expansion will occur during a balanced three-phase fault as well as for unbalanced faults. The expansion will not occur under load conditions, when there is no phase shift between the measured voltage and the polarising voltage. The degree of resistive reach enhancement depends on the ratio of source impedance to relay reach (impedance) setting as can be deduced by reference to Figure C3.13. It must be emphasised that the apparent extension of a fully cross-polarised impedance characteristic into the negative reactance quadrants of Figure C3.13 does not imply that there would be operation for reverse faults. With cross-polarisation, the relay characteristic expands to encompass the origin of the impedance diagram for forward faults only. For reverse faults, the effect is to exclude the origin of the impedance diagram, thereby ensuring proper directional responses for close-up forward or reverse faults.

Fully cross-polarised characteristics have now largely been superseded, due to the tendency of comparators connected to healthy phases to operate under heavy fault conditions on another phase. This is of no consequence in a switched distance relay, where a single comparator is connected to the correct fault loop impedance by starting units before measurement begins. However, modern relays offer independent impedance measurement for each of the three earth-fault and three phase-fault loops. For these types of relay, maloperation of healthy phases is undesirable, especially when single-pole tripping is required for single-phase faults.

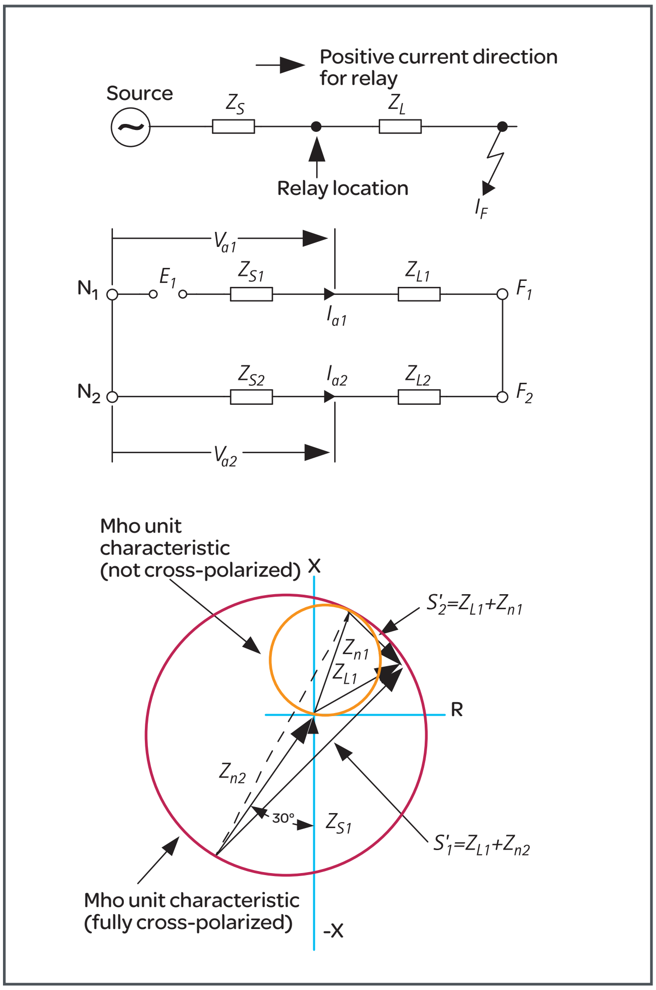


Figure C3.13:
Illustration of improvement in relay resistive coverage for fully crosspolarised characteristic

7.6 Partially cross-polarised mho characteristic

Where a reliable, independent method of faulted phase selection is not provided, a modern non-switched distance relay may only employ a relatively small percentage of cross polarisation. The level selected must be sufficient to provide reliable directional control in the presence of CVT transients for close-up faults, and also attain reliable faulted phase selection. By employing only partial cross- polarisation, the disadvantages of the fully cross-polarised characteristic are avoided, while still retaining the advantages. Figure C3.14 shows a typical characteristic that can be obtained using this technique.

7. Distance relay characteristics

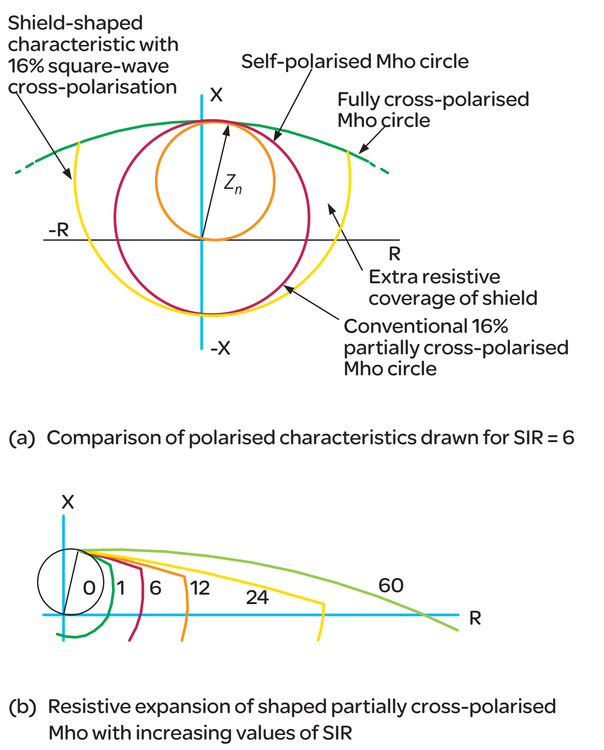


Figure C3.14: Partially cross-polarised characteristic with 'shield' shape

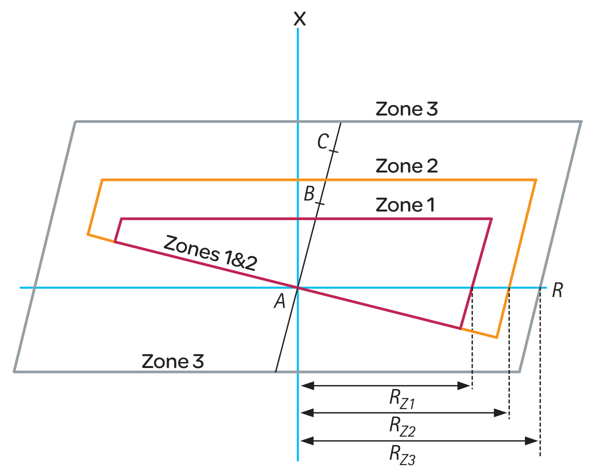


Figure C3.15: Quadrilateral characteristic

7.7 Quadrilateral characteristic

This form of polygonal impedance characteristic is shown in Figure C3.15. The characteristic is provided with forward reach and resistive reach settings that are independently adjustable. It therefore provides better resistive coverage than any mho-type characteristic for short lines. This is especially true for earth fault impedance measurement, where the arc resistances and fault resistance to earth contribute to the highest values of fault resistance. To avoid excessive errors in the zone reach accuracy, it is common to impose a maximum resistive reach in terms of the zone impedance reach. Recommendations in this respect can usually be found in the appropriate relay manuals.

Quadrilateral elements with plain reactance reach lines can introduce reach error problems for resistive earth faults where the angle of total fault current differs from the angle of the current measured by the relay. This will be the case where the local and remote source voltage vectors are phase shifted with respect to each other due to pre-fault power flow. This can be overcome by selecting an alternative to use of a phase current for polarisation of the reactance reach line. Polygonal impedance characteristics are highly flexible in terms of fault impedance coverage for both phase and earth faults. For this reason, most digital and numerical distance relays now offer this form of characteristic. A further factor is that the additional cost implications of implementing this characteristic using discrete component electromechanical or early static relay technology do not arise.

7.8 Protection against power swings – Use of the ohm characteristic

During severe power swing conditions from which a system is unlikely to recover, stability might only be regained if the swinging sources are separated. Where such scenarios are identified, power swing, or out-of-step, tripping protection can be deployed, to strategically split a power system at a preferred location. Ideally, the split should be made so that the plant capacity and connected loads on either side of the split are matched.

This type of disturbance cannot normally be correctly identified by an ordinary distance protection. As previously mentioned, it is often necessary to prevent distance protection schemes from operating during stable or unstable power swings, in order to avoid cascade tripping. To initiate system separation for a prospective unstable power swing, an out-of-step tripping scheme employing ohm impedance measuring elements can be deployed.

Ohm impedance characteristics are applied along the forward and reverse resistance axes of the R/X diagram and their operating boundaries are set to be parallel to the protected line impedance vector, as shown in Figure C3.16.

The ohm impedance elements divide the R/X impedance diagram into three zones, A, B and C. As the impedance changes during a power swing, the point representing the impedance moves along the swing locus, entering the three zones in turn and causing the ohm units to operate in sequence. When the impedance enters the third zone the trip sequence is completed and the circuit breaker trip coil can be energised at a favourable angle between system sources for arc interruption

7. Distance relay characteristics

with little risk of restriking. Only an unstable power swing condition can cause the impedance vector to move successively through the three zones. Therefore, other types of system disturbance, such as power system fault conditions, will not result in relay element operation.

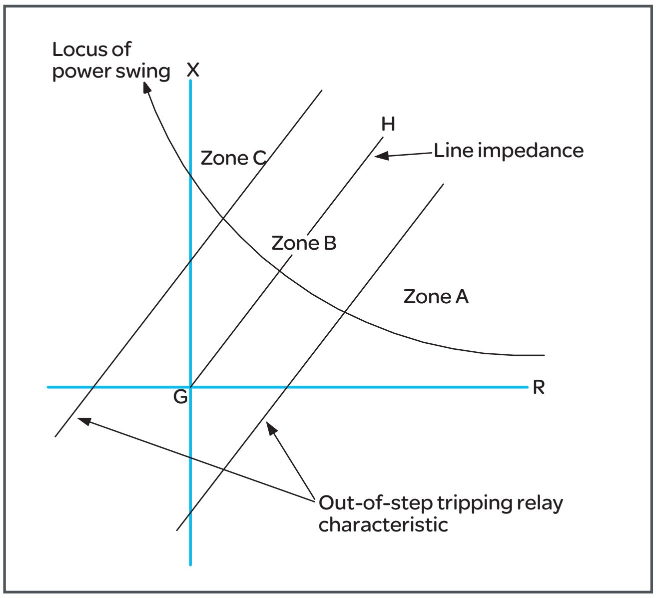


Figure C3.16:
Application of out-of-step tripping relay characteristic

7.9 Other characteristics

The execution time for the algorithm for traditional distance protection using quadrilateral or similar characteristics may result in a relatively long operation time, possibly up to 40ms in some relay designs based on Fourier filtering. To overcome this, some numerical distance relays also use alternative algorithms that can be executed significantly faster. These algorithms are based generally on detecting changes in current and voltage that are in excess of what is expected, often known as the 'Delta' algorithm.

This algorithm detects a fault by comparing the measured values of current and voltage with the values sampled previously. If the change between these samples exceeds a predefined amount (the 'delta'), it is assumed a fault has occurred. In parallel, the distance to fault is also computed. Provided the computed distance to fault lies within the Zone reach of the relay, a trip command is issued. This algorithm can be executed significantly faster than the conventional distance algorithm, resulting in faster overall tripping times. Faulted phase selection can be carried out by comparing the signs of the changes in voltage and current.

Relays that use the 'Delta' algorithm generally run both this and conventional distance protection algorithms in parallel, as some types of fault (e.g. high-resistance faults) may not fall within the fault detection criteria of the Delta algorithm.

C3

8. Distance relay implementation

Discriminating zones of protection can be achieved using distance relays, provided that fault distance is a simple function of impedance. While this is true in principle for transmission circuits, the impedances actually measured by a distance relay also depend on the following factors:

a. the magnitudes of current and voltage (the relay may not see all the current that produces the fault voltage)

b. the fault impedance loop being measured

c. the type of fault

d. the fault resistance

e. the symmetry of line impedance

f. the circuit configuration (single, double or multi-terminal circuit)

It is impossible to eliminate all of the above factors for all possible operating conditions. However, considerable success can be achieved with a suitable distance relay. This may comprise relay elements or algorithms for starting, distance measuring and for scheme logic.

The distance measurement elements may produce impedance characteristics selected from those described in Section 7. Various distance relay formats exist, depending on the operating speed required and cost considerations related to the relaying hardware, software or numerical relay processing capacity required. The most common formats are:

a. a single measuring element for each phase is provided, which covers all phase faults

b. a more economical arrangement is for 'starter' elements to detect which phase or phases have suffered a fault. The starter elements switch a single measuring element or algorithm to measure the most appropriate fault impedance loop. This is commonly referred to as a switched distance relay

c. a single set of impedance measuring elements for each impedance loop may have their reach settings progressively increased from one zone reach setting to another. The increase occurs after zone time delays that are initiated by operation of starter elements. This type of relay is commonly referred to as a reach-stepped distance relay

d. each zone may be provided with independent sets of impedance measuring elements for each impedance loop. This is known as a full distance scheme, capable of offering the highest performance in terms of speed and application flexibility

Furthermore, protection against earth faults may require different characteristics and/or settings to those required for phase faults, resulting in additional units being required. A total of 18 impedance - measuring elements or algorithms would be required in a full distance relay for three-zone protection for all types of fault.

With electromechanical technology, each of the measuring elements would have been a separate relay housed in its own case, so that the distance relay comprised a panel-mounted assembly of the required relays with suitable inter-unit wiring. Figure C3.17(a) shows an example of such a relay scheme. Digital/numerical distance relays (Figure C3.17(b)) are likely to have all of the above functions implemented in software. Starter units may not be necessary. The complete distance relay is housed in a single unit, making for significant economies in space, wiring and increased dependability, through the increased availability that stems from the provision of continuous self-supervision. When the additional features detailed in Section 11 are taken into consideration, such equipment offers substantial user benefits.

Figure C3.17a:
First generation of static distance relay

Figure C3.17b:
MiCOM P440 series numerical distance relay

8. Distance relay implementation

8.1 Starters for switched distance protection

Electromechanical and static distance relays do not normally use an individual impedance-measuring element per phase. The cost and the resulting physical scheme size made this arrangement impractical, except for the most demanding EHV transmission applications. To achieve economy for other applications, only one measuring element was provided, together with 'starter' units that detected which phases were faulted, in order to switch the appropriate signals to the single measuring function. A distance relay using this technique is known as a switched distance relay. A number of different types of starters have been used, the most common being based on overcurrent, undervoltage or under-impedance measurement.

Numerical distance relays permit direct detection of the phases involved in a fault. This is called faulted phase selection, often abbreviated to phase selection. Several techniques are available for faulted phase selection, which then permits the appropriate distance-measuring zone to trip. Without phase selection, the relay risks having over- or under-reach problems, or tripping three-phase when single-pole fault clearance is required. Several techniques are available for faulted phase selection, such as:

a. superimposed current comparisons, comparing the step change of level between pre-fault load, and fault current (the 'Delta' algorithm). This enables very fast detection of the faulted phases, within only a few samples of the analogue current inputs

b. change in voltage magnitude

c. change in current magnitude

Numerical phase selection is much faster than traditional starter techniques used in electromechanical or static distance relays. It does not impose a time penalty as the phase selection and measuring zone algorithms run in parallel. It is possible to build a full-scheme relay with these numerical techniques. The phase selection algorithm provides faulted phase selection, together with a segregated measuring algorithm for each phase-ground and phase to phase fault loop (AN, BN, CN, AB, BC, CA), thus ensuring full-scheme operation.

However, there may be occasions where a numerical relay that mimics earlier switched distance protection techniques is desired. The reasons may be economic (less software required – thus cheaper than a relay that contains a full-scheme implementation) and/or technical.

Some applications may require the numerical relay characteristics to match those of earlier generations already installed on a network, to aid selectivity. Such relays are available, often with refinements such as multi-sided polygonal impedance characteristics that assist in avoiding tripping due to heavy load conditions.

With electromechanical or static switched distance relays, a selection of available starters often had to be made. The choice of starter was dependent on power system parameters such as maximum load transfer in relation to maximum reach required and power system earthing arrangements.

Where overcurrent starters are used, care must be taken to ensure that, with minimum generating plant in service, the setting of the overcurrent starters is sensitive enough to detect faults beyond the third zone. Furthermore, these starters require a high drop-off to pick-up ratio, to ensure that they will drop off under maximum load conditions after a second or third zone fault has been cleared by the first zone relay in the faulty section. Without this feature, indiscriminate tripping may result for subsequent faults in the second or third zone. For satisfactory operation of the overcurrent starters in a switched distance scheme, the following conditions must be fulfilled:

a. the current setting of the overcurrent starters must be not less than 1.2 times the maximum full load current of the protected line

b. the power system minimum fault current for a fault at the Zone 3 reach of the distance relay must not be less than 1.5 times the setting of the overcurrent starters

On multiple-earthed systems where the neutrals of all the power transformers are solidly earthed, or in power systems where the fault current is less than the full load current of the protected line, it is not possible to use overcurrent starters. In these circumstances under-impedance starters are typically used.

The type of under-impedance starter used is mainly dependent on the maximum expected load current and equivalent minimum load impedance in relation to the required relay setting to cover faults in Zone 3. This is illustrated in Figure C3.11 where Z_{D1}, Z_{D2}, and Z_{D3} are respectively the minimum load impedances permitted when lenticular, offset mho and impedance relays are used.

9. Effect of source impedance and earthing methods

For correct operation, distance relays must be capable of measuring the distance to the fault accurately. To ensure this, it is necessary to provide the correct measured quantities to the measurement elements. It is not always the case that use of the voltage and current for a particular phase will give the correct result, or that additional compensation is required.

9.1 Phase fault impedance measurement

Figure C3.18 shows the current and voltage relations for the different types of fault. If Z_{S1} and Z_L are the source and line positive sequence impedances, viewed from the relaying point, the currents and voltages at this point for double phase faults are dependent on the source impedance as well as the line impedance. The relationships are given in Figure C3.19.

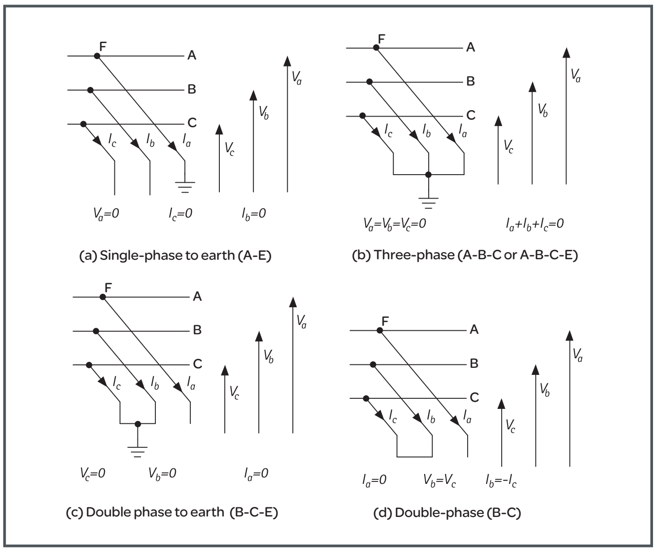


Figure C3.18:
Current and voltage relationships for some shunt faults

Fault quantity	Three-phase (A-B-C)	Double-phase (B-C)
I'_a	I'_1	0
I'_b	$a^2I'_1$	$(a^2-a)I'_1$
I'_c	aI'_1	$(a-a^2)I'_1$
V'_a	$Z_{L1}I'_1$	$2(Z_{S1}+Z_{L1})I'_1$
V'_b	$a^2Z_{L1}I'_1$	$(2a^2Z_{L1}-Z_{S1})I'_1$
V'_c	$aZ_{L1}I'_1$	$(2aZ_{L1}-Z_{S1})I'_1$

Note 1: $a = -\frac{1}{2} + j \times \sqrt{3/2}$ I' and V' are at relay location

Note 2: $I'_1 = \frac{1}{3}(I'_a + aI'_b + a^2I'_c)$

Figure C3.19:
Phase currents and voltages at relaying point for 3-phase and double-phase faults

Applying the difference of the phase voltages to the relay eliminates the dependence on Z_{S1}.

For example:

$$V'_{bc} = \left(a^2 - a\right) Z_{L1} I'_1 \quad \text{(for 3-phase faults)}$$

$$V'_{bc} = 2\left(a^2 - a\right) Z_{L1} I'_1 \quad \text{(for double-phase faults)}$$

Distance measuring elements are usually calibrated in terms of the positive sequence impedance. Correct measurement for both phase-phase and three-phase faults is achieved by supplying each phase-phase measuring element with its corresponding phase - phase voltage and difference of phase currents. Thus, for the B-C element, the current measured will be:

$$I'_b - I'_c = \left(a^2 - a\right) I'_1 \quad \text{(for 3-phase faults)}$$

$$I'_b - I'_c = 2\left(a^2 - a\right) I'_1 \quad \text{(for double-phase faults)}$$

and the relay will measure Z_{L1} in each case.

9.2 Earth fault impedance measurement

When a phase-earth fault occurs, the phase-earth voltage at the fault location is zero. It would appear that the voltage drop to the fault is simply the product of the phase current and line impedance. However, the current in the fault loop depends on the number of earthing points, the method of earthing and sequence impedances of the fault loop. Unless these factors are taken into account, the impedance measurement will be incorrect.

The voltage drop to the fault is the sum of the sequence voltage drops between the relaying point and the fault. The voltage drop to the fault and current in the fault loop are:

$$V'_a = I'_1 Z_{L1} + I'_2 Z_{L1} + I'_0 Z_{L0}$$

$$I'_a = I'_1 + I'_2 + I'_0$$

and the residual current $I'N$ at the relaying point is given by:

$$I'_n = I'_a + I'_b + I'_c = 3I'_0$$

where I'_a, I'_b, I'_c are the phase currents at the relaying point.

From the above expressions, the voltage at the relaying point can be expressed in terms of:

a. the phase currents at the relaying point

b. the ratio of the transmission line zero sequence to positive sequence impedance $K(=Z_{L0}/Z_{L1})$

c. the transmission line positive sequence impedance Z_{L1}:

$$V'_a = Z_{L1}\left\{I'_a + \left(I'_a + I'_b + I'_c\right)\frac{K-1}{3}\right\} \quad \text{...Equation C3.5}$$

The voltage appearing at the relaying point, as previously mentioned, varies with the number of infeeds, the method of system earthing and the position of the relay relative to the infeed and earthing points in the system. Figure C3.20 illustrates the three possible arrangements that can occur in practice with a single infeed.

9. Effect of source impedance and earthing methods

In Figure C3.20(a), the healthy phase currents are zero, so that the phase currents I_a, I_b and I_c have a 1-0-0 pattern. The impedance seen by a relay comparing I_a and V_a is:

$$Z = \left\{1 + \frac{(K-1)}{3}\right\} Z_{L1} \quad \text{...Equation C3.6}$$

In Figure C3.20(b), the currents entering the fault from the relay branch have a 2-1-1 distribution, so:

$$Z = Z_{L1}$$

In Figure C3.20(c), the phase currents have a 1-1-1 distribution, and hence:

$$Z = KZ_{L1}$$

If there were infeeds at both ends of the line, the impedance measured would be a superposition of any two of the above examples, with the relative magnitudes of the infeeds taken into account.

This analysis shows that the relay can only measure an impedance which is independent of infeed and earthing arrangements if a proportion

$$K_N = \frac{(K-1)}{3}$$

of the residual current $I_n = I_a + I_b + I_c$ is added to the phase current I_a.

This technique is known as 'residual compensation'.

Most distance relays compensate for the earth fault conditions by using an additional replica impedance Z_N within the measuring circuits. Whereas the phase replica impedance Z_1 is fed with the phase current at the relaying point, Z_N is fed with the full residual current. The value of Z_N is adjusted so that for a fault at the reach point, the sum of the voltages developed across Z_1 and Z_N equals the measured phase to neutral voltage in the faulted phase.

The required setting for Z_N can be determined by considering an earth fault at the reach point of the relay. This is illustrated with reference to the A-N fault with a single earthing point behind the relay as in Figure C3.20(a).

Voltage supplied from the VT's:

$$= I_1(Z_1 + Z_2 + Z_0) = I_1(2Z_1 + Z_0)$$

Voltage across the replica impedances:

$$= I_a Z_1 + I_N Z_N$$

$$= I_a(Z_1 + Z_N)$$

$$= 3I_1(Z_1 + Z_N)$$

Hence, the required setting of Z_N for balance at the reach point is given by equating the above two expressions:

$$3I_1(Z_1 + Z_N) = I_1(2Z_1 + Z_N)$$

$$Z_N = \frac{Z_0 - Z_1}{3} \quad \text{...Equation C3.7}$$

$$= \frac{(Z_0 - Z_1)}{3Z_1} Z_1$$

With the replica impedance set to $\frac{Z_0 - Z_1}{3}$, earth fault measuring elements will measure the fault impedance correctly, irrespective of the number of infeeds and earthing points on the system.

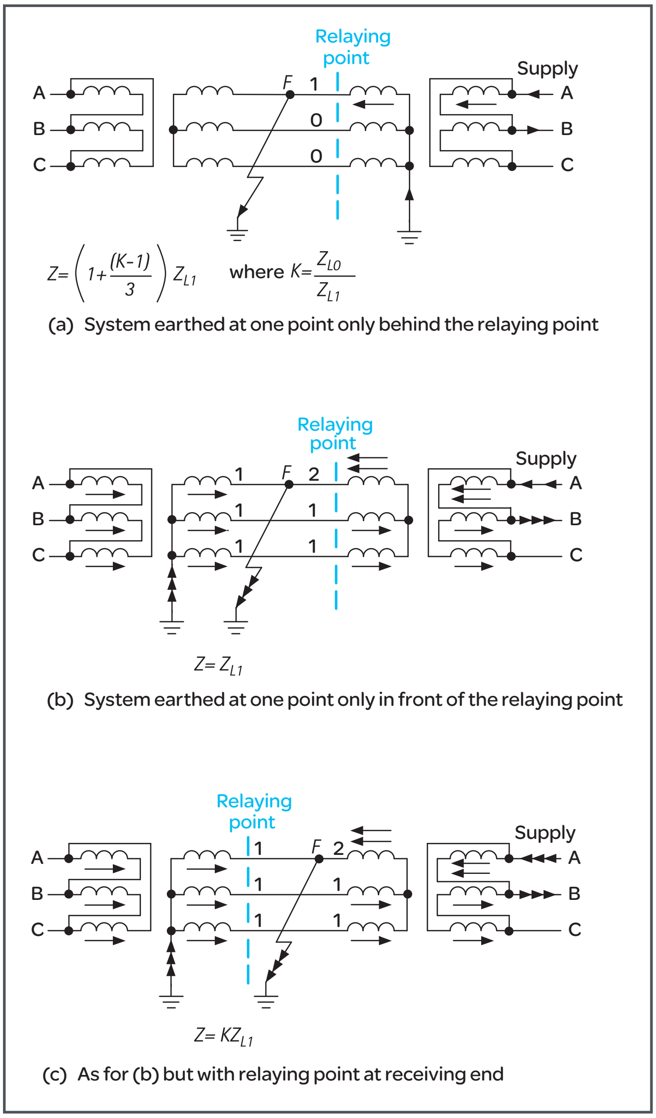


Figure C3.20:
Effect of infeed and earthing arrangements on earth fault distance measurement

C3

10. Distance relay application problems

Distance relays may suffer from a number of difficulties in their application. Many of them have been overcome in the latest numerical relays. Nevertheless, an awareness of the problems is useful where a protection engineer has to deal with older relays that are already installed and not due for replacement.

10.1 Minimum voltage at relay terminals

To attain their claimed accuracy, distance relays that do not employ voltage memory techniques require a minimum voltage at the relay terminals under fault conditions. This voltage should be declared in the data sheet for the relay. With knowledge of the sequence impedances involved in the fault, or alternatively the fault MVA, the system voltage and the earthing arrangements, it is possible to calculate the minimum voltage at the relay terminals for a fault at the reach point of the relay. It is then only necessary to check that the minimum voltage for accurate reach measurement can be attained for a given application. Care should be taken that both phase and earth faults are considered.

10.2 Minimum length of line

To determine the minimum length of line that can be protected by a distance relay, it is necessary to check first that any minimum voltage requirement of the relay for a fault at the Zone 1 reach is within the declared sensitivity for the relay. Secondly, the ohmic impedance of the line (referred if necessary to VT/CT secondary side quantities) must fall within the ohmic setting range for Zone 1 reach of the relay. For very short lines and especially for cable circuits, it may be found that the circuit impedance is less than the minimum setting range of the relay. In such cases, an alternative method of protection will be required.

A suitable alternative might be current differential protection, as the line length will probably be short enough for the cost-effective provision of a high bandwidth communication link between the relays fitted at the ends of the protected circuit. However, the latest numerical distance relays have a very wide range of impedance setting ranges and good sensitivity with low levels of relaying voltage, so such problems are now rarely encountered. Application checks are still essential, though. When considering earth faults, particular care must be taken to ensure that the appropriate earth fault loop impedance is used in the calculation.

10.3 Under-reach - Effect of remote infeed

A distance relay is said to under-reach when the impedance presented to it is apparently greater than the impedance to the fault.

Percentage under-reach is defined as:

$$\frac{Z_R - Z_F}{Z_R} \times 100\%$$

where:

Z_R = intended relay reach (relay reach setting)

Z_F = effective reach

The main cause of underreaching is the effect of fault current infeed at remote busbars. This is best illustrated by an example.

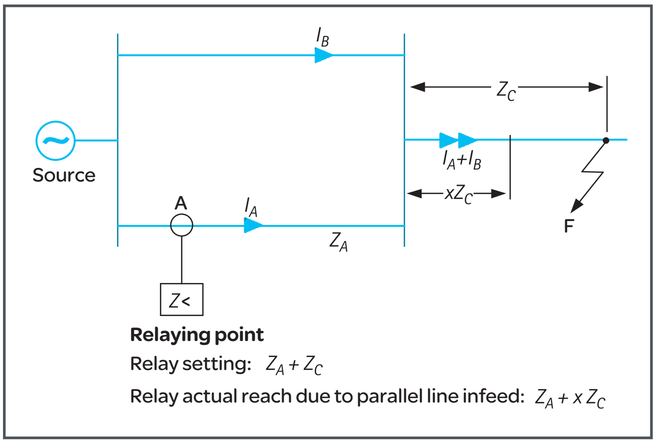


Figure C3.21: Effect on distance relays of infeed at the remote busbart

In Figure C3.21, the relay at A will not measure the correct impedance for a fault on line section Z_c due to current infeed I_B. Consider a relay setting of $Z_A + Z_C$.

For a fault at point F, the relay is presented with an impedance:

$$Z_A + \frac{I_A + I_B}{I_A} \times x \times Z_C$$

So, for relay balance:

$$Z_A + Z_C = Z_A + \frac{(I_A + I_B)}{I_A} \times x \times Z_C$$

Therefore the effective reach is

$$Z_A + \left(\frac{I_A}{I_A + I_B}\right) Z_C \qquad \text{...Equation C3.8}$$

It is clear from Equation C3.8 that the relay will under-reach. It is relatively easy to compensate for this by increasing the reach setting of the relay, but care has to be taken. Should there be a possibility of the remote infeed being reduced or zero, the relay will then reach further than intended. For example, setting Zone 2 to reach a specific distance into an adjacent line section under parallel circuit conditions may mean that Zone 2 reaches beyond the Zone 1 reach of the adjacent line protection under single circuit operation. If $I_B=9I_A$ and the relay reach is set to see faults at F, then in the absence of the remote infeed, the relay effective setting becomes Z_A+10Z_C.

Care should also be taken that large forward reach settings will not result in operation of healthy phase relays for reverse earth faults, see Section 10.5.

10. Distance relay application problems

10.4 Over-reach

A distance relay is said to over-reach when the apparent impedance presented to it is less than the impedance to the fault.

Percentage over-reach is defined by the equation:

$$\frac{Z_F - Z_R}{Z_R} \times 100\% \qquad \text{...Equation C3.9}$$

where:

Z_R = relay reach setting

Z_F = effective reach

An example of the over-reaching effect is when distance relays are applied on parallel lines and one line is taken out of service and earthed at each end. This is covered in Chapter [C5: Protection of Complex Transmission Circuits, Section 2.3].

10.5 Forward reach limitations

There are limitations on the maximum forward reach setting that can be applied to a distance relay. For example, with reference to Figure C3.6, Zone 2 of one line section should not reach beyond the Zone 1 coverage of the next line section relay. Where there is a link between the forward reach setting and the relay resistive coverage (e.g. a Mho Zone 3 element), a relay must not operate under maximum load conditions. Also, if the relay reach is excessive, the healthy phase-earth fault units of some relay designs may be prone to operation for heavy reverse faults. This problem only affected older relays applied to three-terminal lines that have significant line section length asymmetry. A number of the features offered with modern relays can eliminate this problem.

10.6 Power swing blocking

Power swings are variations in power flow that occur when the internal voltages of generators at different points of the power system slip relative to each other. The changes in load flows that occur as a result of faults and their subsequent clearance are one cause of power swings.

A power swing may cause the impedance presented to a distance relay to move away from the normal load area and into the relay characteristic. In the case of a stable power swing it is especially important that the distance relay should not trip in order to allow the power system to return to a stable conditions. For this reason, most distance protection schemes applied to transmission systems have a power swing blocking facility available. Different relays may use different principles for detection of a power swing, but all involve recognising that the movement of the measured impedance in relation to the relay measurement characteristics is at a rate that is significantly less than the rate of change that occurs during fault conditions. When the relay detects such a condition, operation of the relay elements can be blocked. Power swing blocking may be applied individually to each of the relay zones, or on an, all zones applied/inhibited, basis, depending on the particular relay used.

Various techniques are used in different relay designs to inhibit power swing blocking in the event of a fault occurring while a power swing is in progress. This is particularly important, for example, to allow the relay to respond to a fault that develops on a line during the dead time of a single pole autoreclose cycle.

Some Utilities may designate certain points on the network as split points, where the network should be split in the event of an unstable power swing or pole-slipping occurring. A dedicated power swing tripping relay may be employed for this purpose (see Section 7.8). Alternatively, it may be possible to achieve splitting by strategically limiting the duration for which the operation a specific distance relay is blocked during power swing conditions.

10.7 Voltage transformer supervision

Fuses or sensitive miniature circuit breakers normally protect the secondary wiring between the voltage transformer secondary windings and the relay terminals.

Distance relays having:

a. self-polarised offset characteristics encompassing the zero impedance point of the R/X diagram

b. sound phase polarisation

c. voltage memory polarisation

may maloperate if one or more voltage inputs are removed due to operation of these devices.

For these types of distance relay, supervision of the voltage inputs is recommended. The supervision may be provided by external means, e.g. separate voltage supervision circuits, or it may be incorporated into the distance relay itself. On detection of VT failure, tripping of the distance relay can be inhibited and/or an alarm is given. Modern distance protection relays employ voltage supervision that operates from sequence voltages and currents. Zero or negative sequence voltages and corresponding zero or negative sequence currents are derived. Discrimination between primary power system faults and wiring faults or loss of supply due to individual fuses blowing or MCB's being opened is obtained by blocking the distance protection only when zero or negative sequence voltage is detected without the presence of zero or negative sequence current. This arrangement will not detect the simultaneous loss of all three voltages and additional detection is required that operates for loss of voltage with no change in current, or a current less than that corresponding to the three phase fault current under minimum fault infeed conditions. If fast-acting miniature circuit breakers are used to protect the VT secondary circuits, contacts from these may be used to inhibit operation of the distance protection elements and prevent tripping.

11. Other distance relay features

Numerical distance relays will often incorporate additional features that assist the protection engineer in providing a comprehensive solution to the protection requirements of a particular part of a network.

Fault Location (Distance to fault)
Instantaneous Overcurrent Protection
Tee'd feeder protection
Alternative setting groups
CT supervision
Check synchroniser
Auto-reclose
CB state monitoring
CB condition monitoring
CB control
Measurement of voltages, currents, etc.
Event Recorder
Disturbance Recorder
CB failure detection/logic
Directional/Non-directional phase fault overcurrent protection
(backup to distance protection)
Directional/Non-directional earth fault overcurrent protection
(backup to distance protection)
Negative sequence protection
Under/Overvoltage protection
Stub-bus protection
Broken conductor detection
User-programmable scheme logic

Table C3.1:
Additional features in a distance relay

Table C3.1 provides an indication of the additional features that may be provided in such a relay. The combination of features that are actually provided is manufacturer and relay model dependent, but it can be seen from the Table that steady progression is being made towards a 'one-box' solution that incorporates all the protection and control requirements for a line or cable. However, at the highest transmission voltages, the level of dependability required for rapid clearance of any protected circuit fault will still demand the use of two independent protection systems.

Relay parameter	Parameter description	Parameter value	Units
Z_{L1} (mag)	Line positive sequence impedance (magnitude)	48.42	Ω
Z_{L1} (ang)	Line positive sequence impedance (phase angle)	79.41	deg
Z_{L0} (mag)	Line zero sequence impedance (magnitude)	163.26	Ω
Z_{L0} (ang)	Line zero sequence impedance (phase angle)	74.87	deg
K_{Z0} (mag)	Default residual compensation factor (magnitude)	0.79	–
K_{Z0} (ang)	Default residual compensation factor (phase angle)	-6.5	deg
Z_1 (mag)	Zone 1 reach impedance setting (magnitude)	38.74	Ω
Z_1 (ang)	Zone 1 reach impedance setting (phase angle)	80	deg
Z_2 (mag)	Zone 2 reach impedance setting (magnitude)	62.95	Ω
Z_2 (ang)	Zone 2 reach impedance setting (phase angle)	80	deg
Z_3 (mag)	Zone 3 reach impedance setting (magnitude)	83.27	Ω
Z3 (ang)	Zone 3 reach impedance setting (phase angle)	80	deg
R_{1ph}	Phase fault resistive reach value - Zone 1	78	Ω
R_{2ph}	Phase fault resistive reach value - Zone 2	78	Ω
R_{3ph}	Phase fault resistive reach value - Zone 3	78	Ω
T_{Z1}	Time delay - Zone 1	0	s
T_{Z2}	Time delay - Zone 2	0.35	s
T_{Z3}	Time delay - Zone 3	0.8	s
R_{1G}	Ground fault resistive reach value - Zone 1	104	Ω
R_{2G}	Ground fault resistive reach value - Zone 2	104	Ω
R_{3G}	Ground fault resistive reach value - Zone 3	104	Ω

Table C3.2:
Distance relay parameters for example

12. Distance relay application example

The system diagram shown in Figure C3.22 shows a simple 230kV network. The following example shows the calculations necessary to apply three-zone distance protection to the line interconnecting substations ABC and XYZ. All relevant data for this exercise are given in the diagram. The MiCOM P441 relay with quadrilateral characteristics is considered in this example. Relay parameters used in the example are listed in Table C3.2.

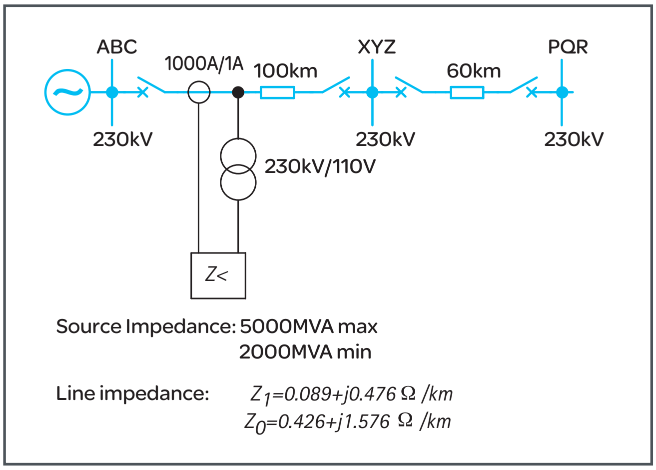


Figure C3.22:
Example network for distance relay setting calculation

Calculations are carried out in terms of primary system impedances in ohms, rather than the traditional practice of using secondary impedances. With numerical relays, where the CT and VT ratios may be entered as parameters, the scaling between primary and secondary ohms can be performed by the relay. This simplifies the example by allowing calculations to be carried out in primary quantities and eliminates considerations of VT/CT ratios.

For simplicity, it is assumed that only a conventional 3-zone distance protection is to be set and that there is no teleprotection scheme to be considered. In practice, a teleprotection scheme would normally be applied to a line at this voltage level.

12.1 Line impedance

The line impedance is:

$$Z_L = (0.089 + j0.476)\Omega/km \ x \ 100km$$

$$= 8.9 + j\,47.6\Omega$$

$$= 48.42 \angle 79.41^\circ\Omega$$

Use values of 48.42 Ω (magnitude) and 80° (angle) as nearest settable values.

12.2 Residual compensation

The relays used are calibrated in terms of the positive sequence impedance of the protected line. Since the zero sequence impedance of the line between substations ABC and XYZ is different from the positive sequence impedance, the impedance seen by the relay in the case of an earth fault, involving the passage of zero sequence current, will be different to that seen for a phase fault.

Hence, the earth fault reach of the relay requires zero sequence compensation (see Section 9.2).

For the relay used, this adjustment is provided by the residual (or neutral) compensation factor K_{Z0}, set equal to:

$$|K_{Z0}| = \left|\frac{(Z_0 - Z_1)}{3Z_1}\right|$$

$$\angle K_{Z0} = \angle\frac{(Z_0 - Z_1)}{3Z_1}$$

For each of the transmission lines:

$$Z_{L1} = 0.089 + j0.476\Omega \ \left(0.484 \angle 79.41^o\,\Omega\right)$$

$$Z_{L0} = 0.426 + j1.576\Omega \ \left(1.632 \angle 74.87^o\,\Omega\right)$$

Hence,

$$|K_{Z0}| = 0.792$$

$$\angle K_{Z0} = -6.5^o$$

12.3 Zone 1 phase reach

The required Zone 1 reach is 80% of the line impedance. Therefore,

$$0.8 \times \left(48.42\angle 79.41^o\Omega\right) = 38.74 \angle 79.41^o\Omega$$

Use $38.74\angle 80^\circ\,\Omega$ nearest settable value.

12.4 Zone 2 phase reach

Ideally, the requirements for setting Zone 2 reach are:

1. at least 120% of the protected line
2. less than the protected line + 50% of the next line

Sometimes, the two requirements are in conflict. In this case, both requirements can be met. A setting of the whole of the line between substations ABC and XYZ, plus 50% of the adjacent line section to substation PQR is used.

Hence, Zone 2 reach:

$$= \begin{pmatrix} 48.42 \angle 79.41^o \ + \\ 0.5 \ x \ 60 \ km \ x \ 0.089 \dfrac{1}{km} + j0.476 \end{pmatrix} \Omega$$

$$= 62.95 \angle 79.41^o\,\Omega$$

Use $62.95\angle 80^\circ\,\Omega$ nearest available setting.

C3

12. Distance relay application example

12.5 Zone 3 phase reach

Zone 3 is set to cover 120% of the sum of the lines between substations ABC and PQR, provided this does not result in any transformers at substation XYZ being included. It is assumed that this constraint is met.

Hence, Zone 3 reach:

$$= \begin{pmatrix} 48.42 \angle 79.41^o + \\ 1.2 \times 60 \times 0.484 \angle 79.41^o \end{pmatrix} \Omega$$

$$= 83.27 \angle 79.41^o \ \Omega$$

Use a setting of $83.27\angle 80^\circ \ \Omega$ nearest available setting.

12.6 Zone time delay settings

Proper co-ordination of the distance relay settings with those of other relays is required. Independent timers are available for the three zones to ensure this.

For Zone 1, instantaneous tripping is normal. A time delay is used only in cases where large d.c. offsets occur and old circuit breakers, incapable of breaking the instantaneous d.c. component, are involved.

The Zone 2 element has to grade with the relays protecting the line between substations XYZ and PQR since the Zone 2 element covers part of these lines. Assuming that this line has distance, unit or instantaneous high-set overcurrent protection applied, the time delay required is that to cover the total clearance time of the downstream relays. To this must be added the reset time for the Zone 2 element following clearance of a fault on the adjacent line, and a suitable safety margin. A typical time delay is 350ms, and the normal range is 200-500ms.

The considerations for the Zone 3 element are the same as for the Zone 2 element, except that the downstream fault clearance time is that for the Zone 2 element of a distance relay or IDMT overcurrent protection. Assuming distance relays are used, a typical time is 800ms. In summary:

T_{Z1} = 0ms (instantaneous)

T_{Z2} = 350ms

T_{Z3} = 800ms

12.7 Phase fault resistive reach settings

With the use of a quadrilateral characteristic, the resistive reach settings for each zone can be set independently of the impedance reach settings. The resistive reach setting represents the maximum amount of additional fault resistance (in excess of the line impedance) for which a zone will trip, regardless of the fault within the zone.

Two constraints are imposed upon the settings, as follows:

a. it must be greater than the maximum expected phase-phase fault resistance (principally that of the fault arc)

b. it must be less than the apparent resistance measured due to the heaviest load on the line

The minimum fault current at Substation ABC is of the order of 1.8kA, leading to a typical arc resistance R_{arc} using the van Warrington formula (Equation C3.4) of 8 Ω. Using the current transformer ratio as a guide to the maximum expected load current, the minimum load impedance Z_{lmin} will be 130 Ω. Typically, the resistive reaches will be set to avoid the minimum load impedance by a 40% margin for the phase elements, leading to a maximum resistive reach setting of 78 Ω.

Therefore, the resistive reach setting lies between 8 Ω and 78 Ω. Allowance should be made for the effects of any remote fault infeed, by using the maximum resistive reach possible. While each zone can have its own resistive reach setting, for this simple example they can all be set equal. This need not always be the case, it depends on the particular distance protection scheme used and the need to include Power Swing Blocking.

Suitable settings are chosen to be 80% of the load resistance:

R_{3ph} = 78 Ω

R_{2ph} = 78 Ω

R_{1ph} = 78 Ω

12.8 Earth fault impedance reach settings

By default, the residual compensation factor as calculated in Section 12.2 is used to adjust the phase fault reach setting in the case of earth faults, and is applied to all zones.

12.9 Earth fault resistive reach settings

The margin for avoiding the minimum load impedance need only be 20%. Hence the settings are:

R_{3G} = 104 Ω

R_{2G} = 104 Ω

R_{1G} = 104 Ω

This completes the setting of the relay. Table C3.2 also shows the settings calculated.

13. References

[C3.1] Protective Relays – their Theory and Practice.
A. R. van C. Warrington, Chapman and Hall, 1962.

C4

Distance Protection Schemes

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Chapter C4

Distance Protection Schemes

C4

1. Introduction

Conventional time-stepped distance protection is illustrated in Figure C4.1. One of the main disadvantages of this scheme is that the instantaneous Zone 1 protection at each end of the protected line cannot be set to cover the whole of the feeder length and is usually set to about 80%. This leaves two 'end zones', each being about 20% of the protected feeder length. Faults in these zones are cleared in Zone 1 time by the protection at one end of the feeder and in Zone 2 time (typically 0.25 to 0.4 seconds) by the protection at the other end of the feeder.

This situation cannot be tolerated in some applications, for two main reasons:

a. faults remaining on the feeder for Zone 2 time may cause the system to become unstable

b. where high-speed auto-reclosing is used, the non-simultaneous opening of the circuit breakers at both ends of the faulted section results in no 'dead time' during the auto-reclose cycle for the fault to be extinguished and for ionised gases to clear. This results in the possibility that a transient fault will cause permanent lockout of the circuit breakers at each end of the line section

Even where instability does not occur, the increased duration of the disturbance may give rise to power quality problems, and may result in increased plant damage.

Unit schemes of protection that compare the conditions at the two ends of the feeder simultaneously (e.g., line differential protection) positively identify whether the fault is internal or external to the protected section and provide high-speed protection for the whole feeder length. This advantage is balanced by the fact that the unit scheme does not provide the back up protection for adjacent feeders given by a distance scheme.

The most desirable scheme is obviously a combination of the best features of both arrangements, that is, instantaneous tripping over the whole feeder length plus back-up protection to adjacent feeders. This can be achieved by interconnecting the distance protection relays at each end of the protected feeder by a communications channel. Communication techniques are described in detail in Chapter [D2: Signalling and Intertripping in Protection Schemes].

The purpose of the communications channel is to transmit information about the system conditions from one end of the protected line to the other, including requests to initiate or prevent tripping of the remote circuit breaker. The former arrangement is generally known as a 'transfer tripping scheme' while the latter is generally known as a 'blocking scheme'. However, the terminology of the various schemes varies widely, according to local custom and practice.

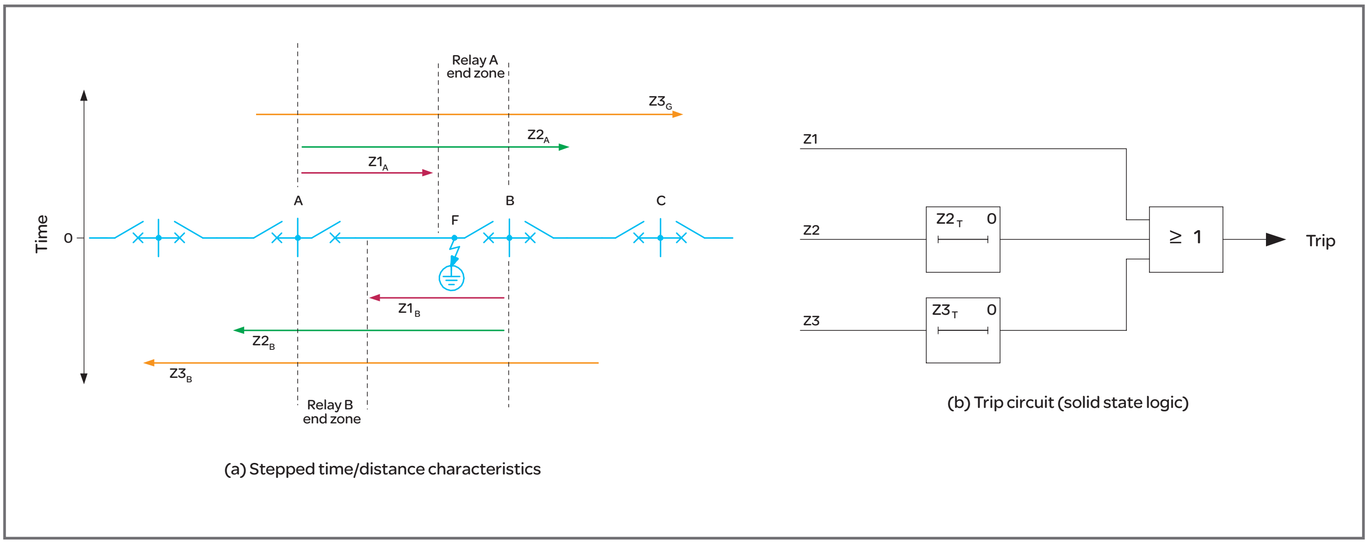

Figure C4.1:
Conventional distance scheme

This scheme is intended for use with an auto-reclose facility, or where no communications channel is available, or the channel has failed. Thus it may be used on radial distribution feeders, or on interconnected lines as a fallback when no communications channel is available, e.g. due to maintenance or temporary fault. The scheme is shown in Figure C4.2.

The Zone 1 elements of the distance relay have two settings. One is set to cover 80% of the protected line length as in the basic distance scheme. The other, known as 'Extended Zone 1'or 'Z1X', is set to overreach the protected line, a setting of 120% of the protected line being common. The Zone 1 reach is normally controlled by the Z1X setting and is reset to the basic Zone 1 setting when a command from the auto-reclose relay is received.

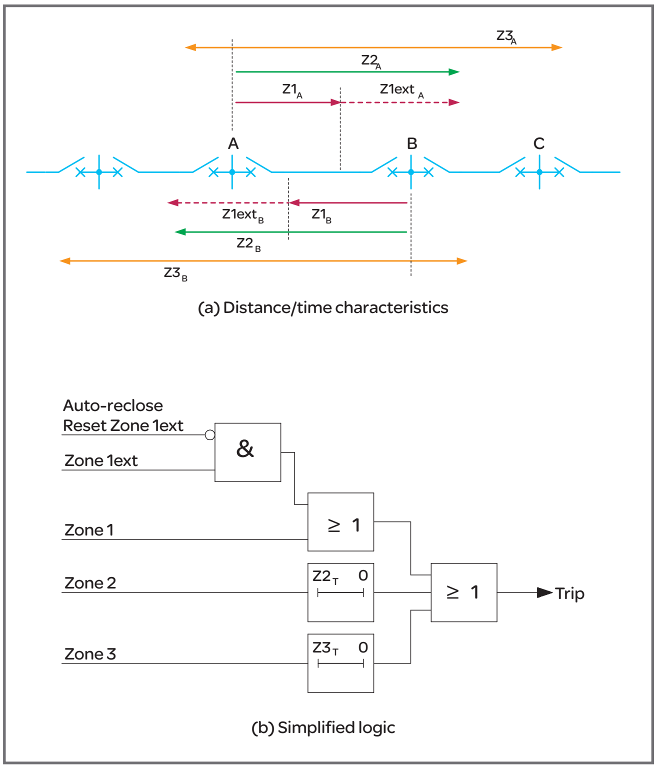

Figure C4.2:
Zone 1 extension scheme

On occurrence of a fault at any point within the Z1X reach, the relay operates in Zone 1 time, trips the circuit breaker and initiates auto-reclosure. The Zone 1 reach of the distance relay is also reset to the basic value of 80%, prior to the auto-reclose closing pulse being applied to the breaker. This should also occur when the auto-reclose facility is out of service. Reversion to the Z1X reach setting occurs only at the end of the reclaim time. For interconnected lines, the Z1X scheme is established (automatically or manually) upon loss of the communications channel by selection of the appropriate relay setting (setting group in a numerical relay).

If the fault is transient, the tripped circuit breakers will reclose successfully, but otherwise further tripping during the reclaim time is subject to the discrimination obtained with normal Zone 1 and Zone 2 settings.

The disadvantage of the Zone 1 extension scheme is that external faults within the Z1X reach of the relay result in tripping of circuit breakers external to the faulted section, increasing the amount of breaker maintenance needed and needless transient loss of supply to some consumers. This is illustrated in Figure C4.3(a) for a single circuit line where three circuit breakers operate and in Figure C4.3(b) for a double circuit line, where five circuit breakers operate.

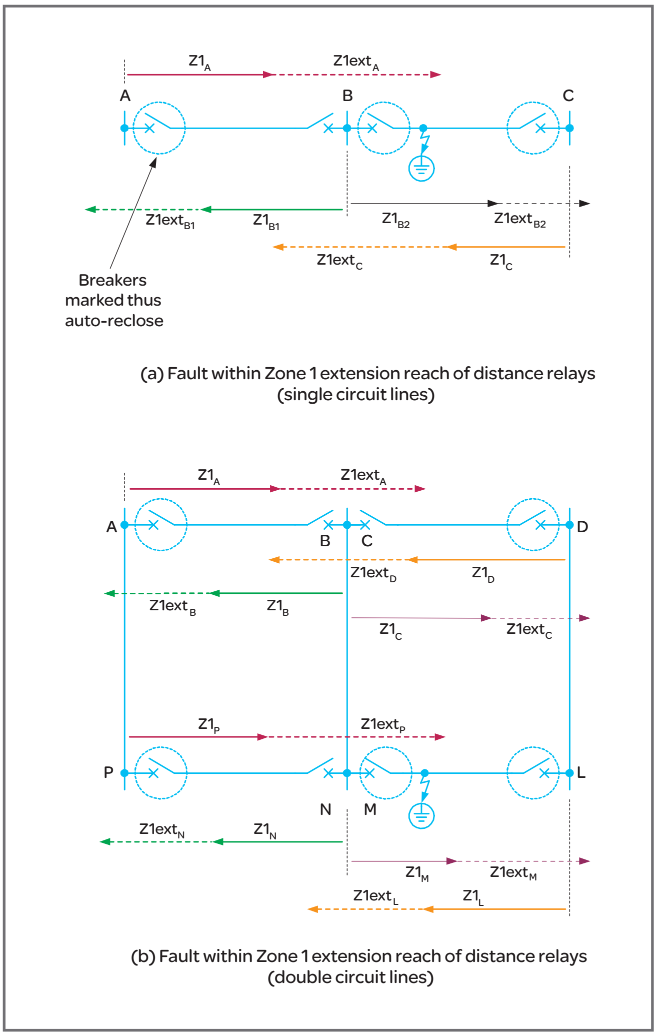

Figure C4.3:
Performance of Zone 1 extension scheme in conjunction with auto-reclose relays

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3. Transfer tripping schemes

A number of these schemes are available, as described below. Selection of an appropriate scheme depends on the requirements of the system being protected.

3.1 Direct under-reach transfer tripping scheme

The simplest way of reducing the fault clearance time at the terminal that clears an end zone fault in Zone 2 time is to adopt a direct transfer trip or intertrip technique, the logic of which is shown in Figure C4.4.

A contact operated by the Zone 1 relay element is arranged to send a signal to the remote relay requesting a trip. The scheme may be called a 'direct under-reach transfer tripping scheme', 'transfer trip under-reaching scheme', or 'intertripping under-reach distance protection scheme', as the Zone 1 relay elements do not cover the whole of the line.

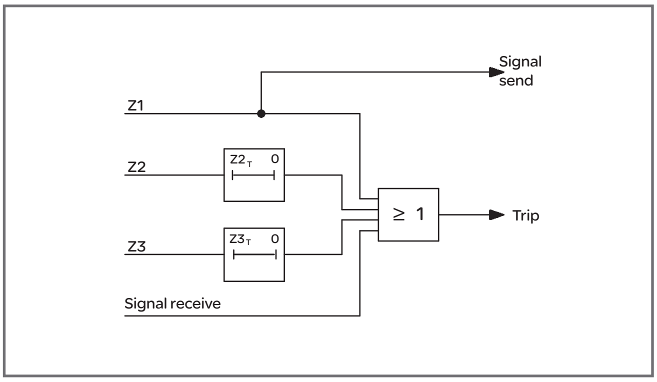

Figure C4.4:
Logic for direct under-reach transfer tripping scheme

A fault F in the end zone at end B in Figure C4.1(a) results in operation of the Zone 1 relay and tripping of the circuit breaker at end B. A request to trip is also sent to the relay at end A. The receipt of a signal at A initiates tripping immediately because the receive relay contact is connected directly to the trip relay. The disadvantage of this scheme is the possibility of undesired tripping by accidental operation or maloperation of signalling equipment, or interference on the communications channel. As a result, it is not commonly used.

3.2 Permissive under-reach transfer tripping (PUP) scheme

The direct under-reach transfer tripping scheme described above is made more secure by supervising the received signal with the operation of the Zone 2 relay element before allowing an instantaneous trip, as shown in Figure C4.5. The scheme is then known as a 'permissive under-reach transfer tripping scheme' (sometimes abbreviated as PUP Z2 scheme) or 'permissive under-reach distance protection', as both relays must detect a fault before the remote end relay is permitted to trip in Zone 1 time.

A variant of this scheme, found on some relays, allows tripping by Zone 3 element operation as well as Zone 2, provided the fault is in the forward direction. This is sometimes called the PUP-Fwd scheme.

Time delayed resetting of the 'signal received' element is required to ensure that the relays at both ends of a single-end fed faulted line of a parallel feeder circuit have time to trip when the fault is close to one end. Consider a fault F in a double circuit line, as shown in Figure C4.6.

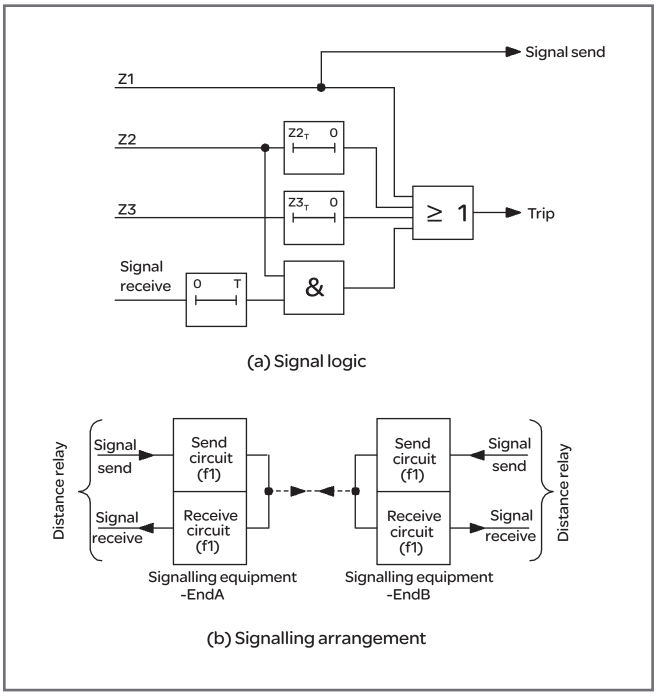

Figure C4.5:
Permissive under-reach transfer tripping scheme

The fault is close to end A, so there is negligible infeed from end B when the fault at F occurs. The protection at B detects a Zone 2 fault only after the breaker at end A has tripped. It is possible for the Zone 1 element at B to reset, thus removing the permissive signal to and causing the 'signal received' element at B to reset before the Zone 2 unit at end B operates. It is therefore necessary to delay the resetting of the 'signal received' element to ensure high speed tripping at end B.

The PUP schemes require only a single communications channel for two-way signalling between the line ends, as the channel is keyed by the under-reaching Zone 1 elements.

When the circuit breaker at one end is open, or there is a weak infeed such that the relevant relay element does not operate, instantaneous clearance cannot be achieved for end-zone faults near the 'breaker open' terminal unless special features are included, as detailed in section 3.5.

3. Transfer tripping schemes

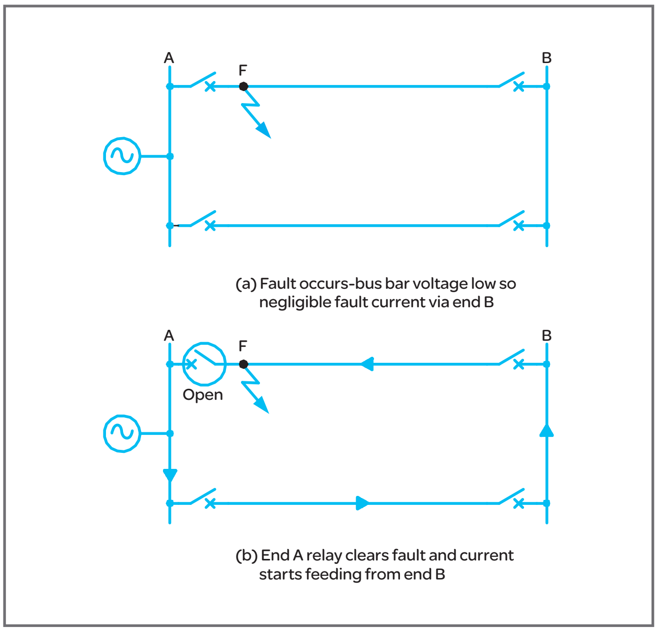

Figure C4.6:
PUP scheme: Single-end fed close-up fault on double circuit line

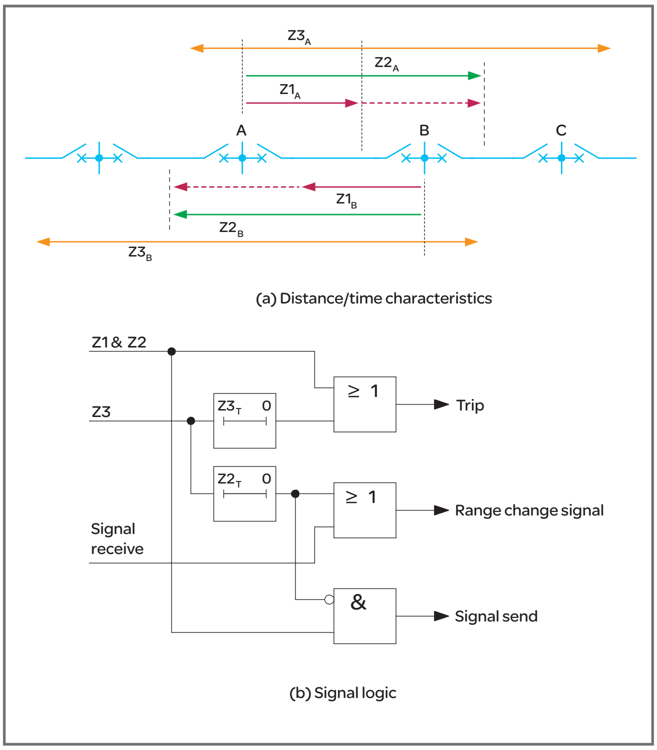

Figure C4.7:
Permissive under-reaching acceleration scheme

3.3 Permissive under-reaching acceleration scheme

This scheme is applicable only to zone switched distance relays that share the same measuring elements for both Zone 1 and Zone 2. In these relays, the reach of the measuring elements is extended from Zone 1 to Zone 2 by means of a range change signal immediately, instead of after Zone 2 time. It is also called an 'accelerated underreach distance protection scheme'.

The under-reaching Zone 1 unit is arranged to send a signal to the remote end of the feeder in addition to tripping the local circuit breaker. The receive relay contact is arranged to extend the reach of the measuring element from Zone 1 to Zone 2. This accelerates the fault clearance at the remote end for faults that lie in the region between the Zone 1 and Zone 2 reaches. The scheme is shown in Figure C4.7. Modern distance relays do not employ switched measuring elements, so the scheme is likely to fall into disuse.

3.4 Permissive over-reach transfer tripping (POP) scheme

In this scheme, a distance relay element set to reach beyond the remote end of the protected line is used to send an intertripping signal to the remote end. However, it is essential that the receive relay contact is monitored by a directional relay contact to ensure that tripping does not take place unless the fault is within the protected section; see Figure C4.8. The instantaneous contacts of the Zone 2 unit are arranged to send the signal, and the received signal, supervised by Zone 2 operation, is used to energise the trip circuit. The scheme is then known as a 'permissive over-reach transfer tripping scheme' (sometimes abbreviated to 'POP'), 'directional comparison scheme', or 'permissive overreach distance protection scheme'.

Since the signalling channel is keyed by over-reaching Zone 2 elements, the scheme requires duplex communication channels - one frequency for each direction of signalling.

If distance relays with mho characteristics are used, the scheme may be more advantageous than the permissive under-reaching scheme for protecting short lines, because the resistive coverage of the Zone 2 unit may be greater than that of Zone 1.

To prevent operation under current reversal conditions in a parallel feeder circuit, it is necessary to use a current reversal guard timer to inhibit the tripping of the forward Zone 2 elements. Otherwise maloperation of the scheme may occur under current reversal conditions, see Chapter [C3: Distance Protection, Section 9] for more details. It is necessary only when the Zone 2 reach is set greater than 150% of the protected line impedance.

The timer is used to block the permissive trip and signal send circuits as shown in Figure C4.9. The timer is energised if a signal is received and there is no operation of Zone 2 elements. An adjustable time delay on pick-up (tp) is usually set to allow instantaneous tripping to take place for any internal faults, taking into account a possible slower operation of Zone 2. The timer will have operated and blocked the 'permissive trip' and 'signal send' circuits by the time the current reversal takes place.

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3. Transfer tripping schemes

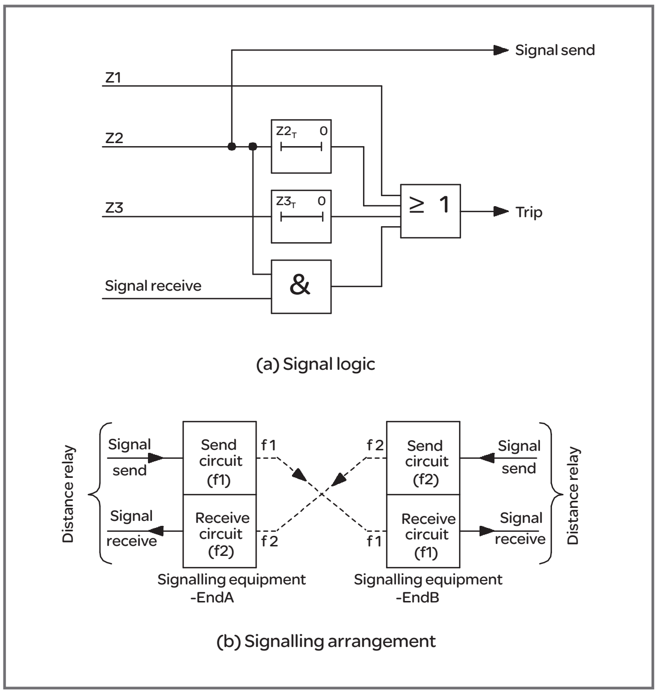

Figure C4.8:
Permissive over-reach transfer tripping scheme

The timer is de-energised if the Zone 2 elements operate or the 'signal received' element resets. The reset time delay (td) of the timer is set to cover any overlap in time caused by Zone 2 elements operating and the signal resetting at the remote end, when the current in the healthy feeder reverses. Using a timer in this manner means that no extra time delay is added in the permissive trip circuit for an internal fault.

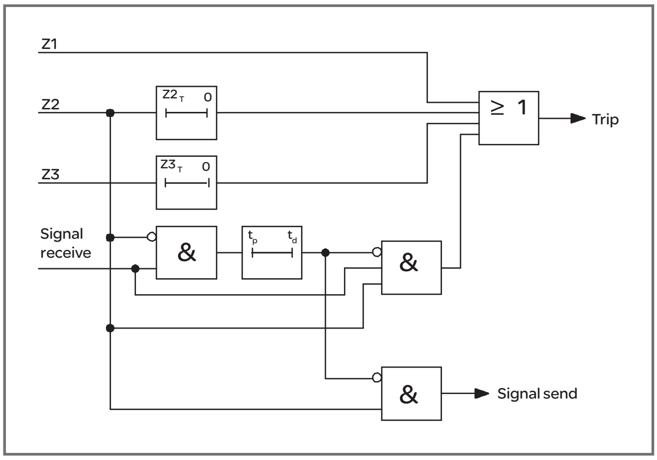

Figure C4.9:
Current reversal guard logic – permissive over-reach scheme

The above scheme using Zone 2 relay elements is often referred to as a POP Z2 scheme. An alternative exists that uses Zone 1 elements instead of Zone 2, and this is referred to as the POP Z1 scheme.

3.5 Weak infeed conditions

In the standard permissive over-reach scheme, as with the permissive under-reach scheme, instantaneous clearance cannot be achieved for end-zone faults under weak infeed or breaker open conditions. To overcome this disadvantage, two possibilities exist.

The Weak Infeed Echo feature available in some protection relays allows the remote relay to echo the trip signal back to the sending relay even if the appropriate remote relay element has not operated. This caters for conditions of the remote end having a weak infeed or circuit breaker open condition, so that the relevant remote relay element does not operate. Fast clearance for these faults is now obtained at both ends of the line. The logic is shown in Figure C4.10. A time delay (T_1) is required in the echo circuit to prevent tripping of the remote end breaker when the local breaker is tripped by the busbar protection or breaker fail protection associated with other feeders connected to the busbar. The time delay ensures that the remote end Zone 2 element will reset by the time the echoed signal is received at that end. Signal transmission can take place even after the remote end breaker has tripped. This gives rise to the possibility of continuous signal transmission due to lock-up of both signals. Timer T_1 is used to prevent this. After this time delay, 'signal send' is blocked.

A variation on the Weak Infeed Echo feature is to allow tripping of the remote relay under the circumstances described above, providing that an undervoltage condition exists, due to the fault. This is known as the Weak Infeed Trip feature and ensures that both ends are tripped if the conditions are satisfied.

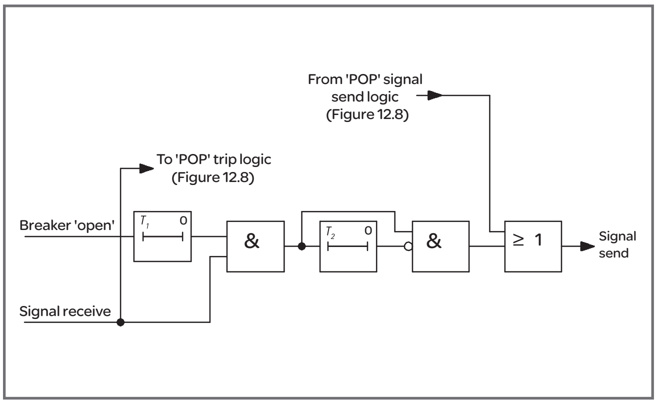

Figure C4.10:
Weak Infeed Echo logic circuit

4. Blocking over-reaching schemes

The arrangements described so far have used the signalling channel(s) to transmit a tripping instruction. If the signalling channel fails or there is no Weak Infeed feature provided, end-zone faults may take longer to be cleared.

Blocking over-reaching schemes use an over-reaching distance scheme and inverse logic. Signalling is initiated only for external faults and signalling transmission takes place over healthy line sections. Fast fault clearance occurs when no signal is received and the over-reaching Zone 2 distance measuring elements looking into the line operate. The signalling channel is keyed by reverse-looking distance elements (Z3 in the diagram, though which zone is used depends on the particular relay used). An ideal blocking scheme is shown in Figure C4.11. The single frequency signalling channel operates both local and remote receive relays when a block signal is initiated at any end of the protected section.

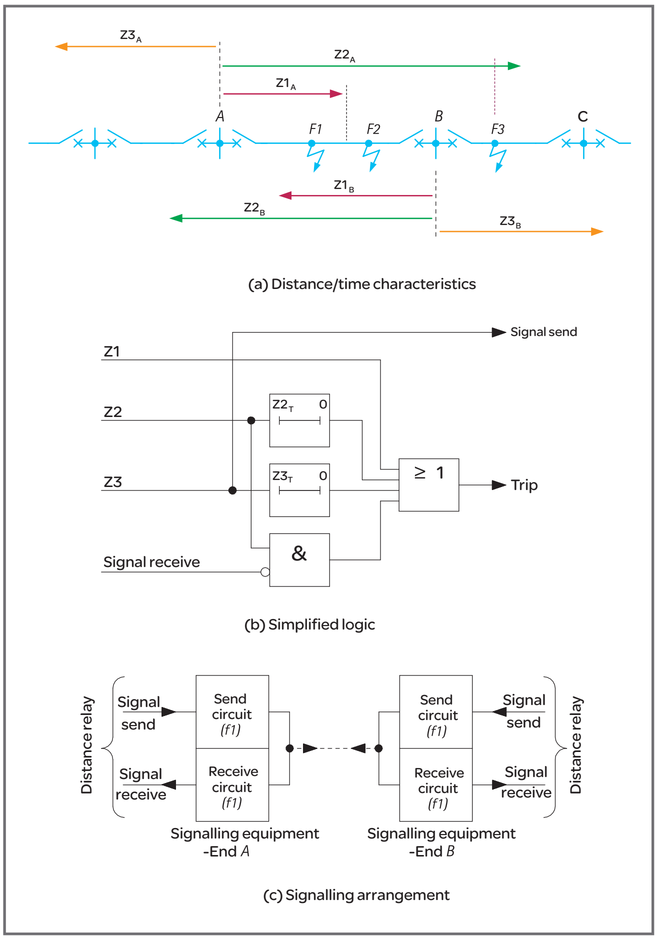

Figure C4.11:
Ideal distance protection blocking scheme

4.1 Practical blocking schemes

A blocking instruction has to be sent by the reverse-looking relay elements to prevent instantaneous tripping of the remote relay for Zone 2 faults external to the protected section. To achieve this, the reverse-looking elements and the signalling channel must operate faster than the forward-looking elements. In practice, this is seldom the case and to ensure discrimination, a short time delay is generally introduced into the blocking mode trip circuit. Either the Zone 2 or Zone 1 element can be used as the forward-looking element, giving rise to two variants of the scheme.

4.1.1 Blocking over-reaching protection scheme using zone 2 element

This scheme (sometimes abbreviated to BOP Z2) is based on the ideal blocking scheme of Figure C4.11, but has the signal logic illustrated in Figure C4.12. It is also known as a ‘directional comparison blocking scheme’ or a ‘blocking over-reach distance protection scheme’.

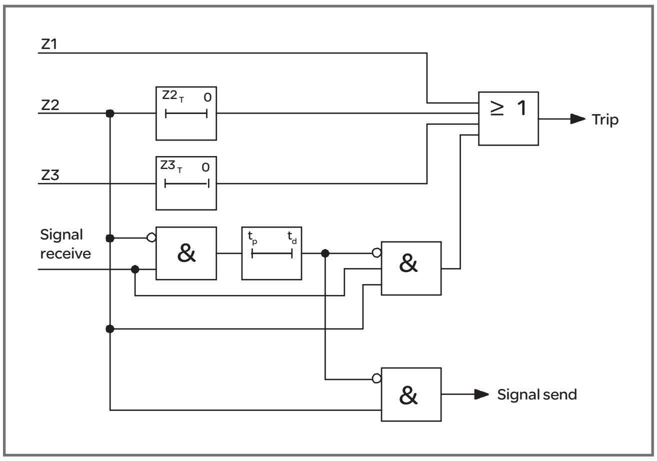

Figure C4.12:
Signal logic for BOP Z2 scheme

Operation of the scheme can be understood by considering the faults shown at $F1$, $F2$ and $F3$ in Figure C4.11 along with the signal logic of Figure C4.12.

A fault at $F1$ is seen by the Zone 1 relay elements at both ends A and B; as a result, the fault is cleared instantaneously at both ends of the protected line. Signalling is controlled by the Z3 elements looking away from the protected section, so no transmission takes place, thus giving fast tripping via the forward-looking Zone 1 elements.

A fault at $F2$ is seen by the forward-looking Zone 2 elements at ends A and B and by the Zone 1 elements at end B. No signal transmission takes place, since the fault is internal and the fault is cleared in Zone 1 time at end B and after the short time lag (STL) at end A.

A fault at $F3$ is seen by the reverse-looking Z3 elements at end B and the forward looking Zone 2 elements at end A. The Zone 1 relay elements at end B associated with line section B-C would normally clear the fault at $F3$. To prevent

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4. Blocking over-reaching schemes

the Z2 elements at end A from tripping, the reverse-looking Zone 3 elements at end B send a blocking signal to end A. If the fault is not cleared instantaneously by the protection on line section B-C, the trip signal will be given at end B for section A-B after the Z3 time delay.

The setting of the reverse-looking Zone 3 elements must be greater than that of the Zone 2 elements at the remote end of the feeder, otherwise there is the possibility of Zone 2 elements initiating tripping and the reverse looking Zone 3 elements failing to see an external fault. This would result in instantaneous tripping for an external fault. When the signalling channel is used for a stabilising signal, as in the above case, transmission takes place over a healthy line section if power line carrier is used. The signalling channel should then be more reliable when used in the blocking mode than in tripping mode.

It is essential that the operating times of the various relays be skilfully co-ordinated for all system conditions, so that sufficient time is always allowed for the receipt of a blocking signal from the remote end of the feeder. If this is not done accurately, the scheme may trip for an external fault or alternatively, the end zone tripping times may be delayed longer than is necessary.

If the signalling channel fails, the scheme must be arranged to revert to conventional basic distance protection. Normally, the blocking mode trip circuit is supervised by a 'channel-in-service' contact so that the blocking mode trip circuit is isolated when the channel is out of service, as shown in Figure C4.12. In a practical application, the reverse-looking relay elements may be set with a forward offset characteristic to provide back-up protection for busbar faults after the zone time delay. It is then necessary to stop the blocking signal being sent for internal faults. This is achieved by making the 'signal send' circuit conditional upon non-operation of the forward-looking Zone 2 elements, as shown in Figure C4.13.

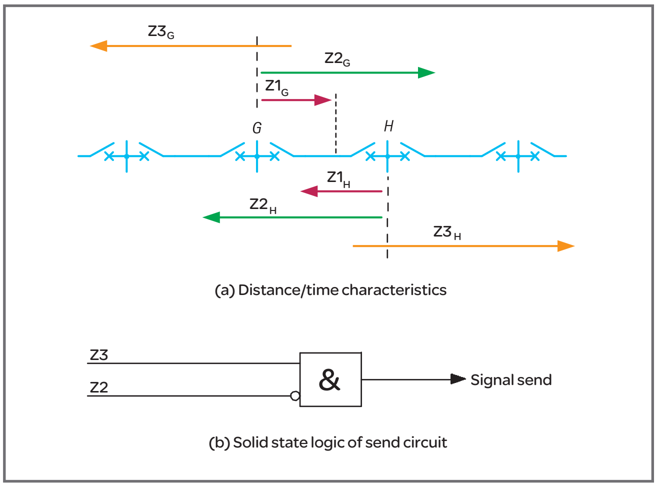

Figure C4.13:
Blocking scheme using reverselooking relays with offset

Blocking schemes, like the permissive over-reach scheme, are also affected by the current reversal in the healthy feeder due to a fault in a double circuit line. If current reversal conditions occur, as described in section 9.9, it may be possible for the maloperation of a breaker on the healthy line to occur. To avoid this, the resetting of the 'signal received' element provided in the blocking scheme is time delayed.

The timer with delayed resetting (td) is set to cover the time difference between the maximum resetting time of reverse-looking Zone 3 elements and the signalling channel. So, if there is a momentary loss of the blocking signal during the current reversal, the timer does not have time to reset in the blocking mode trip circuit and no false tripping takes place.

4.1.2 Blocking over-reaching protection scheme using zone 1 element

This is similar to the BOP Z2 scheme described above, except that an over-reaching Zone 1 element is used in the logic, instead of the Zone 2 element. It may also be known as the BOP Z1 scheme.

4.2 Weak infeed conditions

The protection at the strong infeed terminal will operate for all internal faults, since a blocking signal is not received from the weak infeed terminal end. In the case of external faults behind the weak infeed terminal, the reverse-looking elements at that end will see the fault current fed from the strong infeed terminal and operate, initiating a block signal to the remote end. The relay at the strong infeed end operates correctly without the need for any additional circuits. The relay at the weak infeed end cannot operate for internal faults, and so tripping of that breaker is possible only by means of direct intertripping from the strong source end.

5. Directional comparison unblocking scheme

The permissive over-reach scheme described in Section 3.4 can be arranged to operate on a directional comparison unblocking principle by providing additional circuitry in the signalling equipment. In this scheme (also called a 'deblocking over-reach distance protection scheme'), a continuous block (or guard) signal is transmitted. When the over-reaching distance elements operate, the frequency of the signal transmitted is shifted to an 'unblock' (trip) frequency. The receipt of the unblock frequency signal and the operation of over-reaching distance elements allow fast tripping to occur for faults within the protected zone. In principle, the scheme is similar to the permissive over-reach scheme.

The scheme is made more dependable than the standard permissive over-reach scheme by providing additional circuits in the receiver equipment. These allow tripping to take place for internal faults even if the transmitted unblock signal is short-circuited by the fault. This is achieved by allowing aided tripping for a short time interval, typically 100 to 150 milliseconds, after the loss of both the block and the unblock frequency signals. After this time interval, aided tripping is permitted only if the unblock frequency signal is received.

This arrangement gives the scheme improved security over a blocking scheme, since tripping for external faults is possible only if the fault occurs within the above time interval of channel failure. Weak Infeed terminal conditions can be catered for by the techniques detailed in Section 3.5.

In this way, the scheme has the dependability of a blocking scheme and the security of a permissive over-reach scheme. This scheme is generally preferred when power line carrier is used, except when continuous transmission of signal is not acceptable.

6. Comparison of transfer trip and blocking relaying schemes

On normal two-terminal lines the main deciding factors in the choice of the type of scheme, apart from the reliability of the signalling channel previously discussed, are operating speed and the method of operation of the system. Table C4.1 compares the important characteristics of the various types of scheme.

Modern digital or numerical distance relays are provided with a choice of several schemes in the same relay. Thus, scheme selection is now largely independent of relay selection, and the user is assured that a relay is available with all the required features to cope with changing system conditions.

Criterion	Transfer tripping scheme	Blocking scheme
Speed of operation	Fast	Not as fast
Speed with in-service testing	Slower	As fast
Suitable for auto-reclose	Yes	Yes
Security against maloperation due to:		
Current reversal	Special features required	Special features required
Loss of communications	Poor	Good
Weak Infeed/Open CB	Special features required	Special features required

Table C4.1:
Comparison of different distance protection schemes

C5

Protection of Complex Transmission Circuits

Network Protection & Automation Guide

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Chapter C5

Protection of Complex Transmission Circuits

1. Introduction

Chapters [C2: Line Differential Protection], [C3: Distance Protection] and [C4: Distance Protection Schemes] have covered the basic principles of protection for two terminal, single circuit lines whose circuit impedance is due solely to the conductors used. However parallel transmission circuits are often installed, either as duplicate circuits on a common structure, or as separate lines connecting the same two terminal points via different routes. Also, circuits may be multi-ended, a three-ended circuit being the most common.

For economic reasons, transmission and distribution lines can be much more complicated, maybe having three or more terminals (multi-ended feeder), or with more than one circuit carried on a common structure (parallel feeders), as shown in Figure C5.1. Other possibilities are the use of series capacitors or direct-connected shunt reactors. The protection of such lines is more complicated and requires the basic schemes described in the above chapters to be modified.

The purpose of this chapter is to explain the special requirements of some of these situations in respect of protection and identify which protection schemes are particularly appropriate for use in these situations.

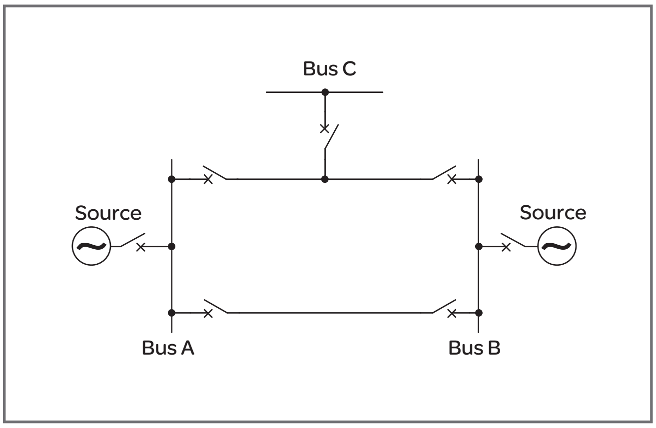

Figure C5.1:
Parallel and multi-ended feeders

2. Parallel feeders

If two overhead lines are supported on the same structures or are otherwise in close proximity over part or whole of their length, there is a mutual coupling between the two circuits. The positive and negative sequence coupling between the two circuits is small and is usually neglected. The zero sequence coupling can be strong and its effect cannot be ignored.

The other situation that requires mutual effects to be taken into account is when there is an earth fault on a feeder when the parallel feeder is out of service and earthed at both ends. An earth fault in the feeder that is in service can induce current in the earth loop of the earthed feeder, causing a misleading mutual compensation signal.

2.1 Unit protection systems

Types of protection that use current only, for example unit protection systems, are not affected by the coupling between the feeders. Therefore, compensation for the effects of mutual coupling is not required for the relay tripping elements.

If the relay has a distance-to-fault feature, mutual compensation is required for an accurate measurement. Refer to Section 2.2.3 for how this is achieved.

2.2 Distance protection

There are a number of problems applicable to distance relays, as described in the following sections.

2.2.1 Current reversal on double circuit lines

When a fault is cleared sequentially on one circuit of a double circuit line with generation sources at both ends of the circuit, the current in the healthy line can reverse for a short time. Unwanted tripping of CBs on the healthy line can then occur if a Permissive Over- reach or Blocking distance scheme, see Chapter [C4: Distance Protection Schemes] is used. Figure C5.2 shows how the situation can arise. The CB at D clears the fault at F faster than the CB at C. Before CB D opens, the Zone 2 elements at A may see the fault and operate, sending a trip signal to the relay for CB B. The reverse looking element of the relay at CB B also sees the fault and inhibits tripping of CBs A and B. However, once CB D opens, the relay element at A starts to reset, while the forward looking elements at B pick up (due to current reversal) and initiate tripping. If the reset time of the forward-looking elements of the relay at A is longer than the operating time of the forward-looking elements at B, the relays will trip the healthy line. The solution is to incorporate a blocking time delay that prevents the tripping of the forward-looking elements of the relays and is initiated by the reverse-looking element. The time delay must be longer than the reset time of the relay elements at A.

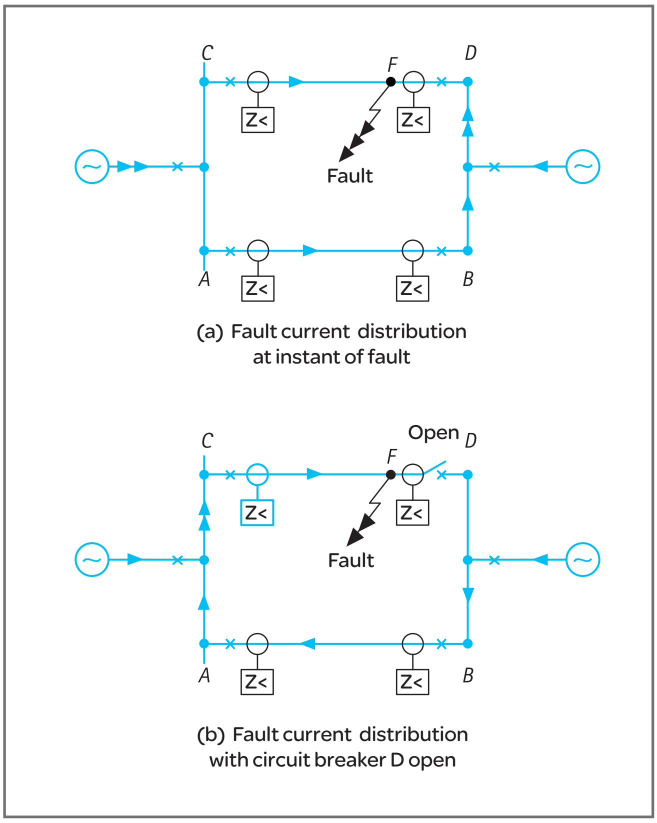

Figure C5.2:
Fault current distribution in a double-circuit line

2.2.2 Under-reach on parallel lines

If a fault occurs on a line beyond the remote terminal end of a parallel line circuit, the distance relay will under-reach for those zones set to reach into the affected line.

Analysis shows that under these conditions, because the relay sees only 50% (for two parallel circuits) of the total fault current for a fault in the adjacent line section, the relay sees the impedance of the affected section as twice the correct value. This may have to be allowed for in the settings of Zones 2 and 3 of conventionally set distance relays.

Since the requirement for the minimum reach of Zone 2 is to the end of the protected line section and the under-reach effect only occurs for faults in the following line section(s), it is not usually necessary to adjust Zone 2 impedance settings to compensate.

However, Zone 3 elements are intended to provide backup protection to adjacent line sections and hence the under-reaching effect must be allowed for in the impedance calculations.

2.2.3 Behaviour of distance relays with earth faults on the protected feeder

When an earth fault occurs in the system, the voltage applied to the earth fault element of the relay in one circuit includes an induced voltage proportional to the zero sequence current in the other circuit.

As the current distribution in the two circuits is unaffected by the presence of mutual coupling, no similar variation in the current applied to the relay element takes place and, consequently, the relay measures the impedance to the fault incorrectly. Whether the apparent impedance to the fault is greater or less than the actual impedance depends on the direction of the current flow in the healthy circuit. For the common case of two circuits, A and B, connected at the local and remote busbars, as shown in Figure C5.3, the impedance of Line A measured by a distance relay, with the normal zero sequence current compensation from its own feeder, is given by:

$$Z_A = nZ_{L1}\left\{1+\frac{\left(I_{B0}/I_{A0}\right)M}{2\left(I_{A1}/I_{A0}\right)+K}\right\}$$ *...Equation C5.1*

where:

$$M = {Z_{M0}}/{Z_{L1}}$$

The true impedance to the fault is nZ_{L1} where n is the per unit fault position measured from R and Z_{L1} is the positive sequence impedance of a single circuit.

The 'error'in measurement is determined from the fraction inside the bracket; this varies with the positive and zero sequence currents in circuit A and the zero sequence currents in circuit B.

These currents are expressed below in terms of the line and source parameters :

$$\frac{I_{B0}}{I_{A0}} = \frac{nZ''_{S0}-(1-n)\,Z'_{S0}}{(2-n)\,Z''_{S0}+(1-n)\,(Z'_{S0}+Z_{L0}+Z_{M0})}$$

$$I_{A1} = \frac{(2-n)\,Z''_{S1}+(1-n)\,(Z'_{S1}+Z_{L1})}{2\,(Z'_{S1}+Z''_{S1})+Z_{L1}}\,I_1$$

$$I_{A0} = \frac{(2-n)\,Z''_{S0}+(1-n)\,(Z'_{S0}+Z_{L0}+Z_{M0})}{2\,(Z'_{S0}+Z''_{S0})+Z_{L0}+Z_{M0}}\,I_0$$

and Z_{M0} = zero sequence mutual impedance between the two circuits

Note: For earth faults $I_1 = I_0$

All symbols in the above expressions are either self-explanatory from Figure C5.3 or have been introduced in Chapter [C3: Distance Protection]. Using the above formulae, families of reach curves may be constructed, of which Figure C5.4 is typical. In this figure, n' is the effective per unit reach of a relay set to protect 80% of the line. It has been assumed that an infinite busbar is located at each line end, that is, Z'_{S1} and Z''_{S1} are both zero. A family of curves of constant n' has been plotted for variations in the source zero sequence impedances Z'_{S0} and Z''_{S0}.

2. Parallel feeders

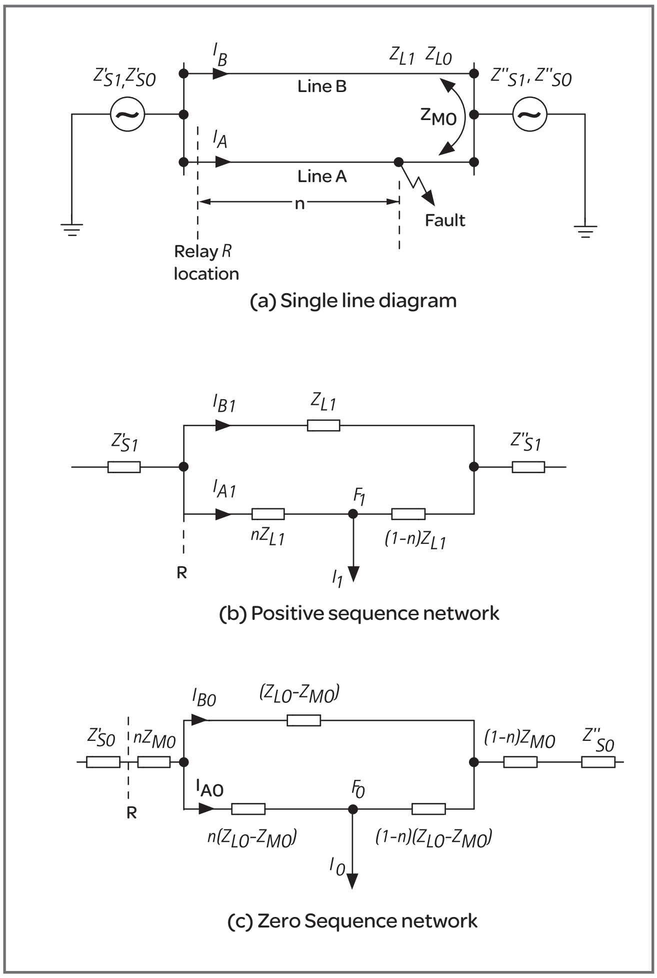

Figure C5.3:
General parallel circuit fed from both ends

It can be seen from Figure C5.4 that relay R can under-reach or over-reach, according to the relative values of the zero sequence source to line impedance ratios; the extreme effective per unit reaches for the relay are 0.67 and 1. Relay over-reach is not a problem, as the condition being examined is a fault in the protected feeder, for which relay operation is desirable. It can also be seen from Figure C5.4 that relay R is more likely to under-reach. However the relay located at the opposite line end will tend to over-reach. As a result, the Zone 1 characteristic of the relays at both ends of the feeder will overlap for an earth fault anywhere in the feeder.

Satisfactory protection can be obtained with a transfer trip, under- reach type distance scheme. Further, compensation for the effect of zero sequence mutual impedance is not necessary unless a distance-to-fault facility is provided. Some relays compensate for the effect of mutual impedance in the distance relay elements, usually as a setting option.

Compensation is achieved by injecting a proportion of the zero sequence current flowing in the parallel feeder into the relay. However, some Utilities will not permit this due to the potential

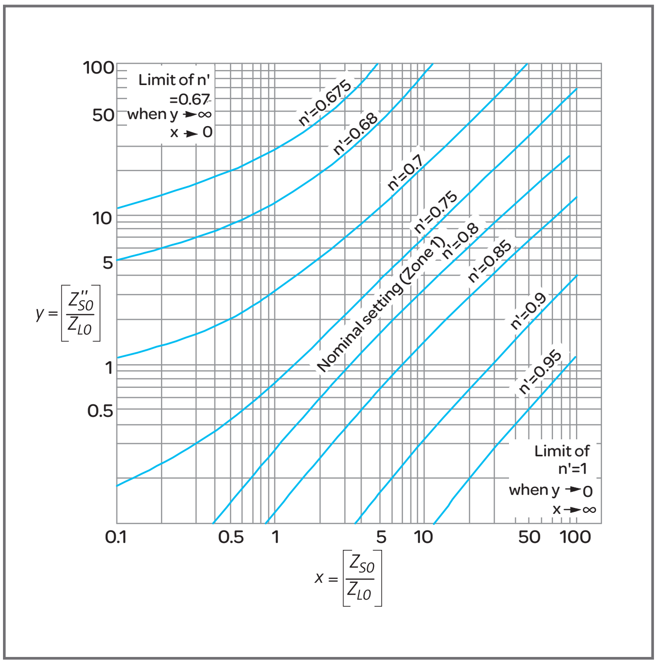

Figure C5.4:
Typical reach curves illustrating the effect of mutual coupling with infinite sources at both ends

hazards associated with feeding a relay protecting one circuit from a CT located in a different circuit.

For a solid phase to earth fault at the theoretical reach of the relay, the voltage and current in the faulty phase at the relaying point are given by:

$$\left.\begin{aligned} V_A &= I_{A1}Z_{L1} + I_{A2}Z_{L2} + I_{A0}Z_{L0} + I_{B0}Z_{M0} \\ I_A &= I_{A1} + I_{A2} + I_{A0} \end{aligned}\right\} \quad \text{...Equation C5.2}$$

The voltage and current fed into the relay are given by:

$$\left.\begin{aligned} V_R &= V_A \\ I_R &= I_A + K_R I_{A0} + K_M I_{B0} \end{aligned}\right\} \quad \text{...Equation C5.3}$$

where:

K_R is the residual compensation factor

K_M is the mutual compensation factor:

For the relay to measure the line impedance accurately, the following condition must be met:

$$\frac{V_R}{I_R} = Z_{L1}$$

Thus:

$$K_R = \frac{Z_{L0} - Z_{L1}}{Z_{L1}} \qquad K_M = \frac{Z_{M0}}{Z_{L1}}$$

2. Parallel feeders

2.2.4 Distance relay behaviour with earth faults on the parallel feeder

Although distance relays with mutual compensation measure the correct distance to the fault, they may not operate correctly if the fault occurs in the adjacent feeder. Davison and Wright [Ref C5.1: Some factors affecting the accuracy of distance type protective equipment under earth fault conditions] have shown that, while distance relays without mutual compensation will not over-reach for faults outside the protected feeder, the relays may see faults in the adjacent feeder if mutual compensation is provided. With reference to Figure C5.3, the amount of over-reach is highest when $Z''_{S1} = Z''_{S2} = Z''_{S0} = \infty$. Under these conditions, faults occurring in the first 43% of feeder A will appear to the distance relay in feeder B to be within its Zone 1 reach. The solution is to compare the parallel line residual current to the protected line residual current and disable the mutual compensation when the ratio is high.

2.2.5 Distance relay behaviour with single-circuit operation

If only one of the parallel feeders is in service, the protection in the remaining feeder measures the fault impedance correctly, except when the feeder that is not in service is earthed at both ends. In this case, the zero sequence impedance network is as shown in Figure C5.5.

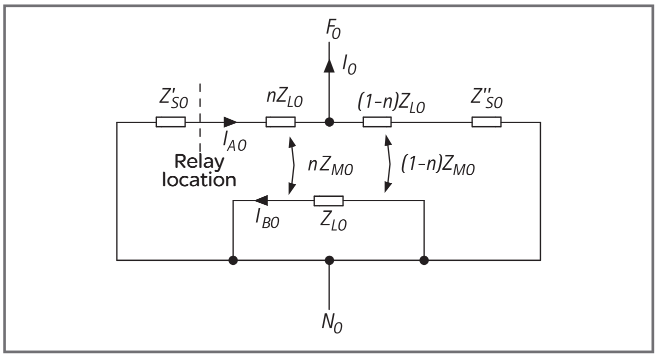

Figure C5.5:
Zero sequence impedance network during single circuit operation

Humpage and Kandil [Ref C5.2: Distance protection performance under conditions of single-circuit working in double-circuit transmission lines] have shown that the apparent impedance presented to the relay under these conditions is given by:

$$Z_R = Z_{L1} - \frac{I_{A0} Z_{M0}^2}{I_R Z_{L0}} \quad \text{...Equation C5.4}$$

where:

I_R is the current fed into the relay = $I_A + K_R I_{A0}$

The ratio I_{A0} / I_R varies with the system conditions, reaching a maximum when the system is earthed behind the relay with no generation at that end. In this case, the ratio I_{A0} / I_R is equal to Z_{L1} / Z_{L0}, and the apparent impedance presented to the relay is:

$$Z_R = Z_{L1}\left(1 - \frac{Z_{M0}^2}{Z_{L0}^2}\right)$$

It is apparent from the above formulae that the relay has a tendency to over-reach. Care should be taken when Zone 1 settings are selected for the distance protection of lines in which this condition may be encountered. In order to overcome this possible over-reaching effect, some Utilities reduce the reach of earth fault relays to around 0.65 Z_{L1} (80% of normal reach) when lines are taken out of service. However, the probability of having a fault on the first section of the following line while one line is out of service is very small, and many Utilities do not reduce the setting under this condition. It should be noted that the use of mutual compensation would not overcome the over-reaching effect since earthing clamps are normally placed on the line side of the current transformers.

Typical values of zero sequence line impedances for HV lines are given in Table C5.1, where the maximum per unit over-reach error $(Z_{M0}/Z_{L0})^2$ is also given. It should be noted that the over-reach values quoted in this table are maxima, and will be found only in rare cases. In most cases, there will be generation at both ends of the feeder and the amount of over-reach will therefore be reduced. In the calculations carried out by Humpage and Kandil, with more realistic conditions, the maximum error found in a 400kV double circuit line was 18.6%.

Line voltage	Conductor size		Zero sequence mutual impedance Z_{MO}		Zero sequence line impedance Z_{LO}		Per unit over-reach error $(ZMO/ZLO)^2$
	(sq.in)	Metric (sq.mm) equiv.	ohms/mile	ohms/km	ohms/mile	ohms/km	
132kV	0.4	258	0.3 + j0.81	0.19 + j0.5	0.41+j1.61	0.25+j1.0	0.264
275kV	2 x 0.4	516	0.18 + j0.69	0.11 + j0.43	0.24+j1.3	0.15+j0.81	0.292
400kV	4 x 0.4	1032	0.135 + j0.6	0.80 + j0.37	0.16+j1.18	0.1+j0.73	0.266

Table C5.1:
Maximum over-reach errors found during single circuit working

C5

3. Multi-ended feeders – unit protection schemes

A multi-ended feeder is defined as one having three or more terminals, with either load or generation, or both, at any terminal. Those terminals with load only are usually known as 'taps'.

The simplest multi-terminal feeders are three-ended, and are generally known as tee'd feeders. This is the type most commonly found in practice.

The protection schemes described previously for the protection of two-ended feeders can also be used for multi-ended feeders. However, the problems involved in the application of these schemes to multi-ended feeders are much more complex and require special attention.

The protection schemes that can be used with multi-ended feeders are unit protection and distance schemes. Each uses some form of signalling channel, such as fibre-optic cable, power line carrier or pilot wires. The specific problems that may be met when applying these protections to multi-ended feeders are discussed in the following sections.

3.1 A.C. pilot wire protection

A.C. pilot wire relays provide a low-cost fast protection; they are insensitive to power swings and, owing to their relative simplicity, their reliability is excellent.

The limitations of pilot wire relays for plain feeder protection also apply. The length of feeder that can be protected is limited by the characteristics of the pilot wires. The protection sees increasing pilot wire resistance as tending to an open circuit and shunt capacitance as an a.c. short circuit across the pilots. The protection will have limiting values for each of these quantities, and when these are exceeded, loss of sensitivity for internal faults and maloperation for external faults may occur. For tee'd feeders, the currents for an external earth fault will not usually be the same. The protection must be linear for any current up to the maximum through-fault value. As a result, the voltage in the pilots during fault conditions cannot be kept to low values, and pilot wires with 250V insulation grade are required.

Two types of older balanced voltage schemes still found in many locations are described below.

3.1.1 'Translay' balanced voltage protection

This is a modification of the balanced voltage scheme described in Chapter [C2: Line Differential Protection, Section 7.1]. Since it is necessary to maintain linearity in the balancing circuit, though not in the sensing element, the voltage reference is derived from separate quadrature transformers, as shown in Figure C5.6. These are auxiliary units with summation windings energized by the main current transformers in series with the upper electromagnets of the sensing elements. The secondary windings of the quadrature current transformers at all ends are interconnected by the pilots in a series circuit that also includes the lower electromagnets of the relays. Secondary windings on the relay elements are not used, but these elements are fitted with bias loops in the usual way.

The plain feeder settings are increased in the tee'd scheme by 50% for one tee and 75% for two.

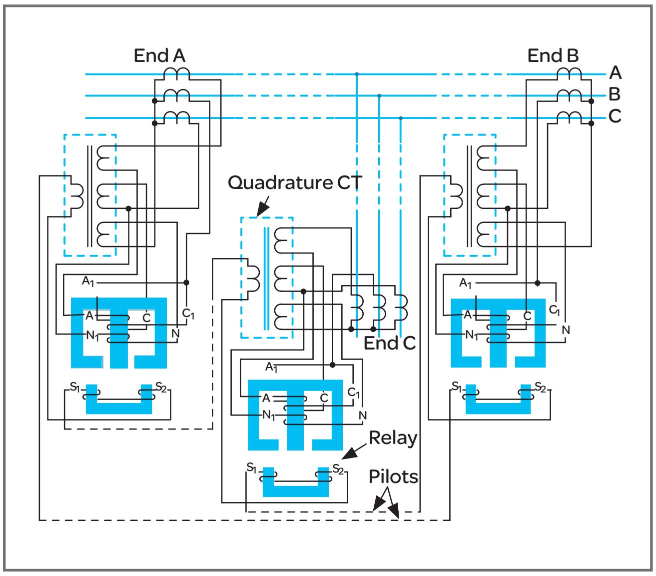

Figure C5.6:
Balanced voltage Tee'd feeder scheme

3.1.2 Dual pilot schemes

It is possible to avoid reducing sensitivity by providing an additional pilot for the bias value. This type is shown in Figure C5.7. Summation quadrature transformers are used to provide the analogue quantity, which is balanced in a series loop through a pilot circuit. Separate secondary windings on the quadrature current transformers are connected to full-wave rectifiers, the outputs of which are connected in series in a second pilot loop, so that the electromotive forces summate arithmetically.

The measuring relay is a double-wound moving coil type, one coil being energized from the vectorial summation loop; the other receives bias from the scalar summation in the second loop proportional to the sum of the currents in the several line terminals, the value being adjusted by the inclusion of an appropriate value of resistance. Since the operating and biasing quantities are both derived by summation, the relays at the different terminals all behave alike, either to operate or to restrain as appropriate.

Special features are included to ensure stability, both in the presence of transformer inrush current flowing through the feeder zone and also with a 2-1-1 distribution of fault current caused by a short circuit on the secondary side of a star-delta transformer.

3. Multi-ended feeders – unit protection schemes

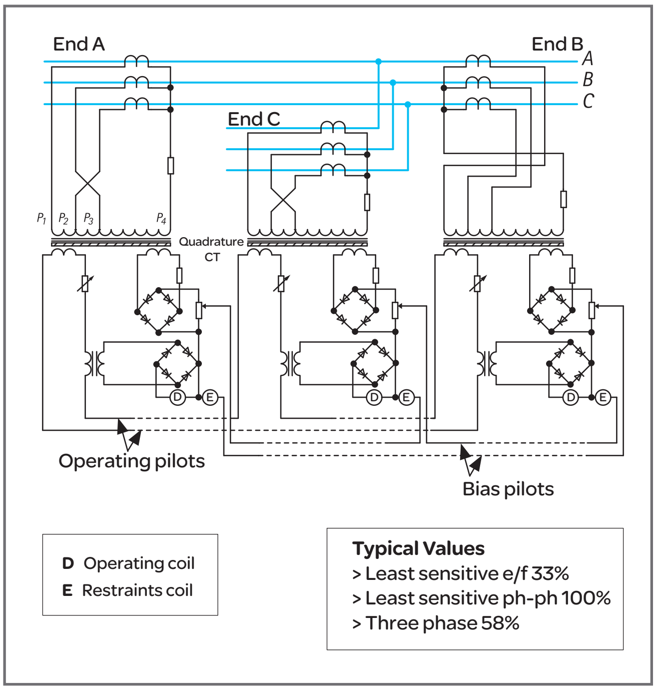

Figure C5.7:
Dual pilot tee'd feeder protection

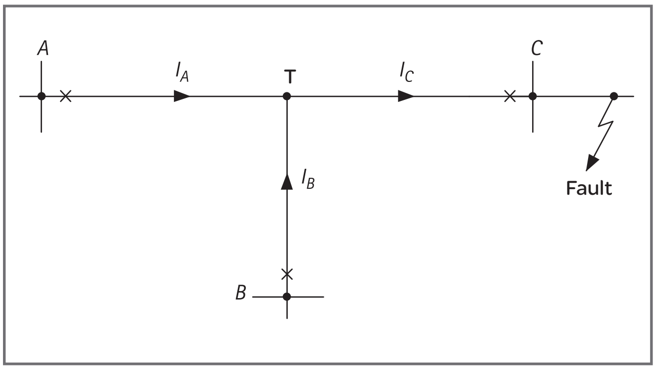

Figure C5.8:
External fault conditions

A further unfavourable condition is that illustrated in Figure C5.9. If an internal fault occurs near one of the ends of the feeder (end B in Figure C5.9) and there is little or no generation at end C, the current at this end may be flowing outwards. The protection is then prevented from operating, since the fault current distribution is similar to that for an external fault; see Figure C5.8. The fault can be cleared only by the back-up protection and, if high speed of operation is required, an alternative type of primary protection must be used.

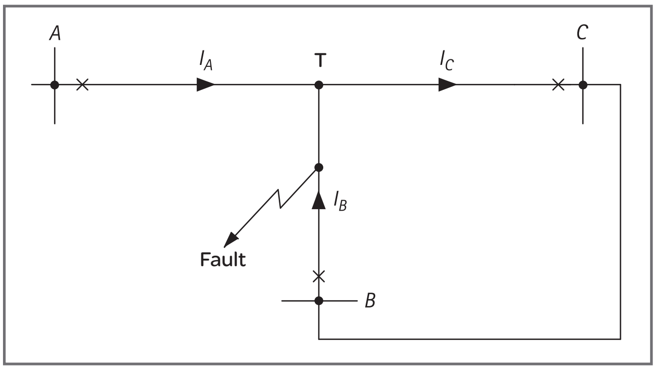

Figure C5.9:
Internal fault with current flowing out at one line end

3.2 Power line carrier phase comparison schemes

The operating principle of these protection schemes has already been covered in detail in Chapter "Distance Protection" (Section 9). It involves comparing the phase angles of signals derived from a combination of the sequence currents at each end of the feeder. When the phase angle difference exceeds a pre-set value, the 'trip angle', a trip signal is sent to the corresponding circuit breakers. In order to prevent incorrect operation for external faults, two different detectors, set at different levels, are used. The low-set detector starts the transmission of carrier signal, while the high-set detector is used to control the trip output. Without this safeguard, the scheme could operate incorrectly for external faults because of operating tolerances of the equipment and the capacitive current of the protected feeder. This condition is worse with multi-terminal feeders, since the currents at the feeder terminals can be very dissimilar for an external fault. In the case of the three-terminal feeder in Figure C5.8, if incorrect operation is to be avoided, it is necessary to make certain that the low-set detector at end A or end B is energised when the current at end C is high enough to operate the high-set detector at that end.

As only one low-set starter, at end A or end B, needs to be energised for correct operation, the most unfavourable condition will be when currents I_A and I_B are equal. To maintain stability under this condition, the high-set to low-set setting ratio of the fault detectors needs to be twice as large as that required when the scheme is applied to a plain feeder. This results in a loss of sensitivity, which may make the equipment unsuitable if the minimum fault level of the power system is low.

A point that should also be considered when applying this scheme is the attenuation of carrier signal at the 'tee' junctions. This attenuation is a function of the relative impedances of the branches of the feeder at the carrier frequency, including the impedance of the receiving equipment. When the impedances of the second and third terminals are equal, a power loss of 50% takes place. In other words, the carrier signal sent from terminal A to terminal B is attenuated by 3dB by the existence of the third terminal C. If the impedances of the two branches corresponding to terminal B to C are not equal, the attenuation may be either greater or less than 3dB.

C5

3. Multi-ended feeders – unit protection schemes

3.3 Differential relay using optical fibre signalling

Current differential relays can provide unit protection for multi- ended circuits without the restrictions associated with other forms of protection. In Chapter [D2: Signalling and Intertripping in Protection Schemes, Section 6.5], the characteristics of optical fibre cables and their use in protection signalling are outlined.

Their use in a three-ended system is shown in Figure C5.10, where the relays at each line end are digital/numerical relays interconnected by optical fibre links so that each can send information to the others. In practice the optical fibre links can be dedicated to the protection system or multiplexed, in which case multiplexing equipment, not shown in Figure C5.10, will be used to terminate the fibres.

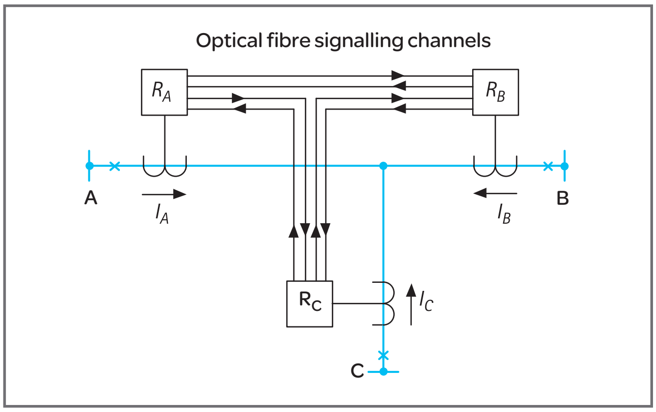

Figure C5.10:
Current differential protection for tee'd feeders using optical fibre signalling

If I_A, I_B, I_C are the current vector signals at line ends A, B, C, then for a healthy circuit: $I_A + I_B + I_C = 0$

The basic principles of operation of the system are that each relay measures its local three phase currents and sends its values to the other relays. Each relay then calculates, for each phase, a resultant differential current and also a bias current, which is used to restrain the relay in the manner conventional for biased differential unit protection.

The bias feature is necessary in this scheme because it is designed to operate from conventional current transformers that are subject to transient transformation errors.

The two quantities are:

$$|I_{diff}| > |I_A + I_B + I_C|$$

$$|I_{bias}| = \frac{1}{2}\left(|I_A| + |I_B| + |I_C|\right)$$

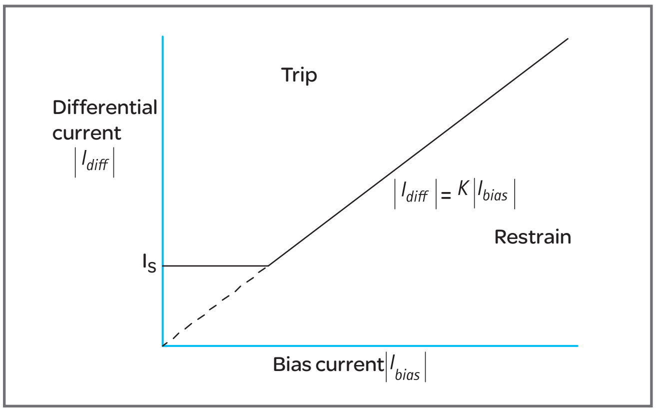

Figure C5.11:
Percentage biased differential protection characteristic

Figure C5.11 shows the percentage biased differential characteristic used, the tripping criteria being:

$|I_{diff}| > K|I_{bias}|$ and $|I_{diff}| > I_s$

where:

K = percentage bias setting

I_S = minimum differential current setting

If the magnitudes of the differential currents indicate that a fault has occurred, the relays trip their local circuit breaker. The relays also continuously monitor the communication channel performance and carry out self-testing and diagnostic operations. The system measures individual phase currents and so single phase tripping can be used when required. Relays are provided with software to re-configure the protection between two and three terminal lines, so that modification of the system from two terminals to three terminals does not require relay replacement. Further, loss of a single communications link only degrades scheme performance slightly. The relays can recognise this and use alternate communications paths. Only if all communication paths from a relay fail does the scheme have to revert to backup protection.

4. Multi-ended feeders – distance relays

Distance protection is widely used at present for tee'd feeder protection. However, its application is not straightforward, requiring careful consideration and systematic checking of all the conditions described later in this section.

Most of the problems found when applying distance protection to tee'd feeders are common to all schemes. A preliminary discussion of these problems will assist in the assessment of the performance of the different types of distance schemes.

4.1 Apparent impedance seen by distance relays

The impedance seen by the distance relays is affected by the current infeeds in the branches of the feeders.

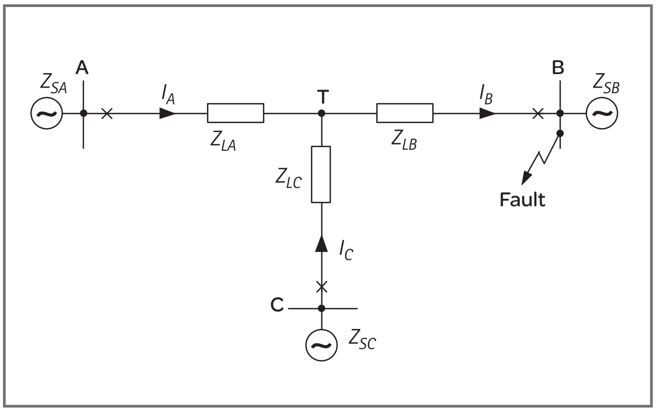

Figure C5.12:
Fault at substation B busbars

Referring to Figure C5.12, for a fault at the busbars of the substation B, the voltage V_A at busbar A is given by:

$$V_A = I_A Z_{LA} + I_B Z_{LB}$$

so the impedance ZA seen by the distance relay at terminal A is given by:

$$Z_A = \frac{V_A}{I_A} = Z_{LA} + \frac{I_B}{I_A} Z_{LB}$$

or

$$Z_A = Z_{LA} + \frac{I_B}{I_A} Z_{LB} \qquad \text{...Equation C5.5}$$

or

$$Z_A = Z_{LA} + Z_{LB} + \frac{I_C}{I_A} Z_{LB}$$

The apparent impedance presented to the relay has been modified by the term $(I_C/I_A)Z_{LB}$. If the pre-fault load is zero, the currents I_A and I_C are in phase and their ratio is a real number. The apparent impedance presented to the relay in this case can be expressed in terms of the source impedances as follows:

$$Z_A = Z_{LA} + Z_{LB} + \frac{(Z_{SB} + Z_{LB})}{(Z_{SC} + Z_{LC})} Z_{LB}$$

The magnitude of the third term in this expression is a function of the total impedances of the branches A and B and can reach a relatively high value when the fault current contribution of branch C is much larger than that of branch A. Figure C5.13 illustrates how a distance relay with a mho characteristic located at A with a Zone 2 element set to 120% of the protected feeder AB, fails to see a fault at the remote busbar B. The 'tee' point T in this example is halfway between substations A and $B (Z_{LA}=Z_{LB})$ and the fault currents I_A and I_C have been assumed to be identical in magnitude and phase angle. With these conditions, the fault appears to the relay to be located at B' instead of at B - i.e. the relay appears to under-reach.

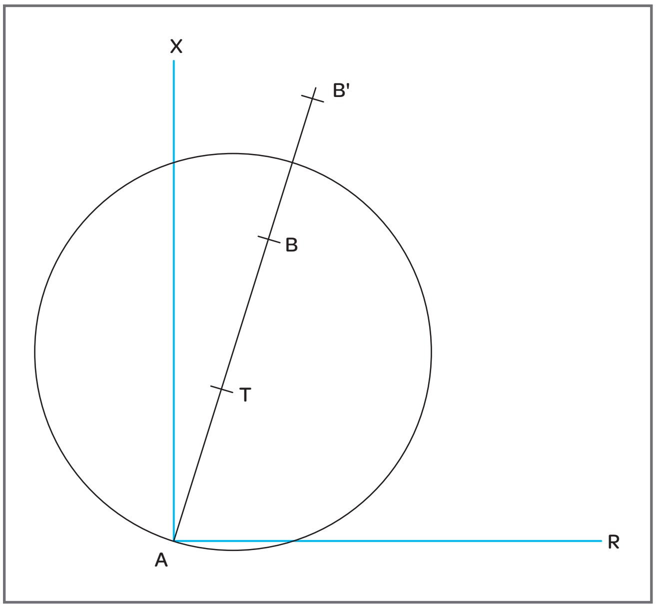

Figure C5.13:
Apparent impedance presented to the relay at substation A for a fault at substation B busbars

The under-reaching effect in tee'd feeders can be found for any kind of fault. For the sake of simplicity, the equations and examples mentioned so far have been for balanced faults only. For unbalanced faults, especially those involving earth, the equations become somewhat more complicated, as the ratios of the sequence fault current contributions at terminals A and C may not be the same. An extreme example of this condition is found when the third terminal is a tap with no generation but with the star point of the primary winding of the transformer connected directly to earth, as shown in Figure C5.14. The corresponding sequence networks are illustrated in Figure C5.15.

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4. Multi-ended feeders – distance relays

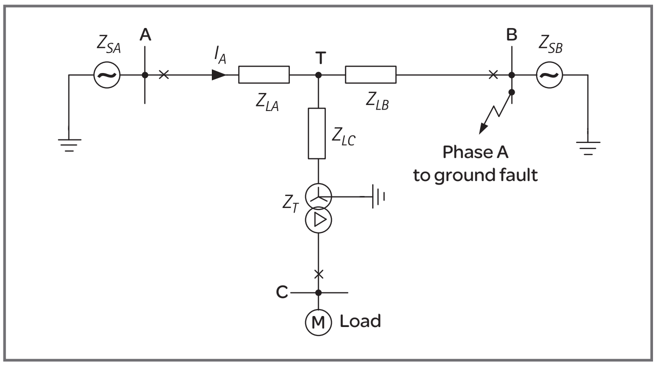

Figure C5.14:
Transformer tap with primary winding solidly earthed

It can be seen from Figure C5.15 that the presence of the tap has little effect in the positive and negative sequence networks. However, the zero sequence impedance of the branch actually shunts the zero sequence current in branch A. As a result, the distance relay located at terminal A tends to under-reach. One solution to the problem is to increase the residual current compensating factor in the distance relay, to compensate for the reduction in zero sequence current. However, the solution has two possible limitations:

a. over-reach will occur when the transformer is not connected, and hence operation for faults outside the protected zone may occur

b. the inherent possibility of maloperation of the earth fault elements for earth faults behind the relay location is increased

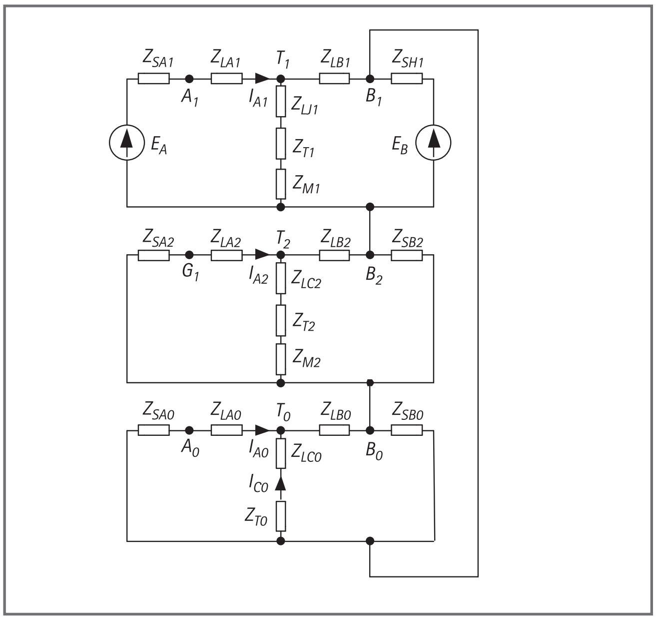

Figure C5.15:
Sequence networks for a phase A to ground fault at busbar B in the system shown in Figure C5.14

4.2 Effect of pre-fault load

In all the previous discussions it has been assumed that the power transfer between terminals of the feeder immediately before the fault occurred was zero. If this is not the case, the fault currents I_A and I_C in Figure C5.12 may not be in phase, and the factor I_C / I_A in the equation for the impedance seen by the relay at A, will be a complex quantity with a positive or a negative phase angle according to whether the current I_C leads or lags the current I_A.

For the fault condition previously considered in Figures C5.12 and C5.13, the pre-fault load current may displace the impedance seen by the distance relay to points such as B'_1 or B'_2, shown in Figure C5.16, according to the phase angle and the magnitude of the pre-fault load current. Humpage and Lewis [Ref C5.3: Distance protection of tee'd circuits] have analysed the effect of pre-fault load on the impedances seen by distance relays for typical cases. Their results and conclusions point out some of the limitations of certain relay characteristics and schemes.

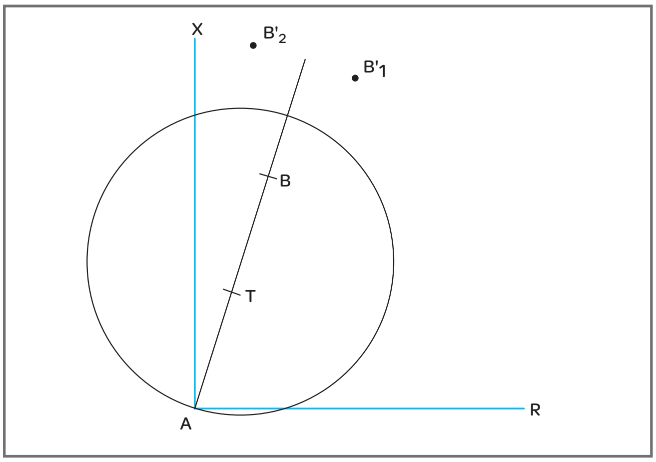

Figure C5.16:
Effects of the pre-fault load on the apparent impedance presented to the relay

4.3 Effect of the fault current flowing outwards at one terminal

Up to this point it has been assumed that the fault currents at terminals A and C flow into the feeder for a fault at the busbar B. Under some conditions, however, the current at one of these terminals may flow outwards instead of inwards. A typical case is illustrated in Figure C5.17; that of a parallel tapped feeder with one of the ends of the parallel circuit open at terminal A.

As the currents I_A and I_C now have different signs, the factor I_C/I_A becomes negative. Consequently, the distance relay at terminal A sees an impedance smaller than that of the protected feeder, (Z_A+Z_B), and therefore has a tendency to over-reach. In some cases the apparent impedance presented to the relay may be as low as 50% of the impedance of the

4. Multi-ended feeders – distance relays

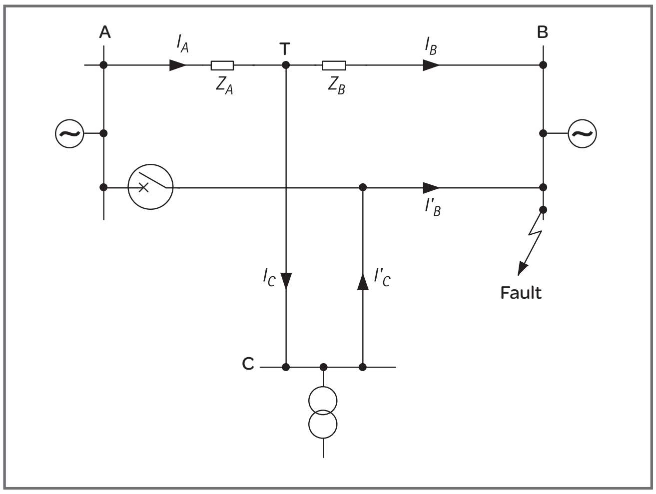

Figure C5.17:
Internal Fault at busbar B with current flowing out at terminal

protected feeder, and even lower if other lines exist between terminals B and C.

If the fault is internal to the feeder and close to the busbars B, as shown in Figure C5.18, the current at terminal C may still flow outwards. As a result, the fault appears as an external fault to the distance relay at terminal C, which fails to operate.

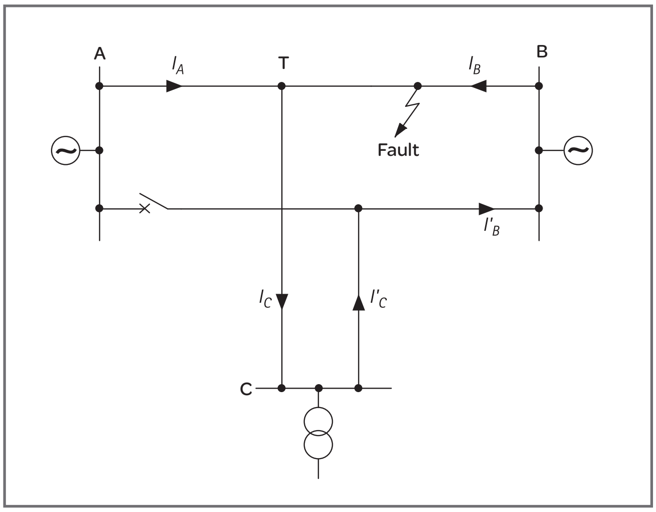

Figure C5.18:
Internal fault near busbar B with current flowing out at terminal C

4.4 Maloperation with reverse faults

Earth fault distance relays with a directional characteristic tend to lose their directional properties under reverse unbalanced fault conditions if the current flowing through the relay is high and the relay setting relatively large. These conditions arise principally from earth faults. The relay setting and the reverse fault current are now related, the first being a function of the maximum line length and the second depending mainly on the impedance of the shortest feeder and the fault level at that terminal.

For instance, referring to Figure C5.19, the setting of the relay at terminal A will depend on the impedance (Z_A+Z_B) and the fault current infeed I_C, for a fault at B, while the fault current I_A for a reverse fault may be quite large if the T point is near the terminals A and C.

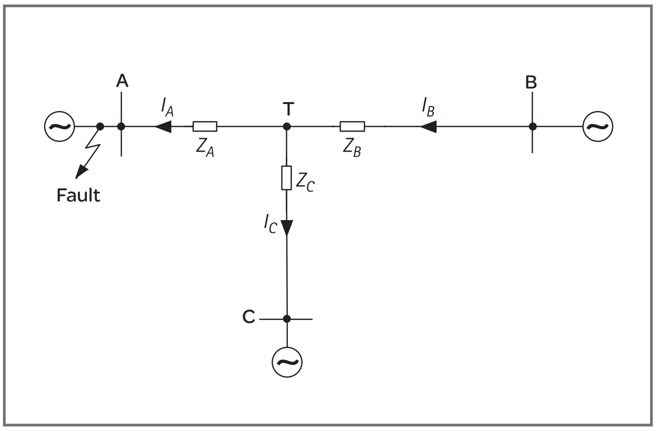

Figure C5.19:
External fault behind the relay at terminal A

A summary of the main problems met in the application of distance protection to tee'd feeders is given in Table C5.2.

Case	Description	Relevant figure number
1	Under-reaching effect for internal faults due to current infeed at the T point	C5.12 to C5.15
2	Effect of pre-fault load on the impedance 'seen' by the relay	C5.16
3	Over-reaching effect for external faults, due to current flowing outwards at one terminal	C5.17
4	Failure to operate for an internal fault, due to current flowing out at one terminal	C5.18
5	Incorrect operation for an external fault, due to high current fed from nearest terminal 1	C5.19

Table C5.2:
Main problems met in the application of distance protection to tee'd feeders

C5

5. Multi-ended feeders - application of distance protection schemes

The schemes that have been described in Chapter [C4: Distance Protection Schemes] for the protection of plain feeders may also be used for tee'd feeder protection. However, the applications of some of these schemes are much more limited in this case.

Distance schemes can be subdivided into two main groups; transfer trip schemes and blocking schemes. The usual considerations when comparing these schemes are security, that is, no operation for external faults, and dependability, that is, assured operation for internal faults.

In addition, it should be borne in mind that transfer trip schemes require fault current infeed at all the terminals to achieve high- speed protection for any fault in the feeder. This is not the case with blocking schemes. While it is rare to find a plain feeder in high voltage systems where there is current infeed at one end only, it is not difficult to envisage a tee'd feeder with no current infeed at one end, for example when the tee'd feeder is operating as a plain feeder with the circuit breaker at one of the terminals open. Nevertheless, transfer trip schemes are also used for tee'd feeder protection, as they offer some advantages under certain conditions.

5.1 Transfer trip under-reach schemes

The main requirement for transfer trip under-reach schemes is that the Zone 1 of the protection, at one end at least, shall see a fault in the feeder. In order to meet this requirement, the Zone 1 characteristics of the relays at different ends must overlap, either the three of them or in pairs. Cases 1, 2 and 3 in Table C5.2 should be checked when the settings for the Zone 1 characteristics are selected. If the conditions mentioned in case 4 are found, direct transfer trip may be used to clear the fault; the alternative is sequentially at end C when the fault current I_C reverses after the circuit breaker at terminal B has opened; see Figure C5.18.

Transfer trip schemes may be applied to feeders that have branches of similar length. If one or two of the branches are very short, and this is often the case in tee'd feeders, it may be difficult or impossible to make the Zone 1 characteristics overlap. Alternative schemes are then required.

Another case for which under-reach schemes may be advantageous is the protection of tapped feeders, mainly when the tap is short and is not near one of the main terminals. Overlap of the Zone 1 characteristics is then easily achieved, and the tap does not require protection applied to the terminal.

5.2 Transfer trip over-reach schemes

For correct operation when internal faults occur, the relays at the three ends should see a fault at any point in the feeder. This condition is often difficult to meet, since the impedance seen by the relays for faults at one of the remote ends of the feeder may be too large, as in case 1 in Table C5.2, increasing the possibility of maloperation for reverse faults, case 5 in Table C5.2. In addition, the relay characteristic might encroach on the load impedance.

These considerations, in addition to the signalling channel requirements mentioned later on, make transfer trip over-reach schemes unattractive for multi-ended feeder protection.

5.3 Blocking schemes

Blocking schemes are particularly suited to the protection of multi-ended feeders, since high-speed operation can be obtained with no fault current infeed at one or more terminals. The only disadvantage is when there is fault current outfeed from a terminal, as shown in Figure C5.18. This is case 4 in Table C5.2. The protection units at that terminal may see the fault as an external fault and send a blocking signal to the remote terminals. Depending on the scheme logic either relay operation will be blocked, or clearance will be in Zone 2 time.

The setting of the directional unit should be such that no maloperation can occur for faults in the reverse direction; case 5 in Table C5.2.

5.4 Signalling channel considerations

The minimum number of signalling channels required depends on the type of scheme used. With under-reach and blocking schemes, only one channel is required, whereas a permissive over-reach scheme requires as many channels as there are feeder ends. The signalling channel equipment at each terminal should include one transmitter and (N-1) receivers, where N is the total number of feeder ends. This may not be a problem if fibre-optic cables are used, but could lead to problems otherwise.

If frequency shift channels are used to improve the reliability of the protection schemes, mainly with transfer trip schemes, N additional frequencies are required for the purpose. Problems of signal attenuation and impedance matching should also be carefully considered when power line carrier frequency channels are used.

5.5 Directional comparison blocking schemes

The principle of operation of these schemes is the same as that of the distance blocking schemes described in the previous section. The main advantage of directional comparison schemes over distance schemes is their greater capability to detect high- resistance earth faults. The reliability of these schemes, in terms of stability for through faults, is lower than that of distance blocking schemes. However, with the increasing reliability of modern signalling channels, directional comparison blocking schemes seem to offer good solutions to the many and difficult problems encountered in the protection of multi-ended feeders. Modern relays implement the required features in different ways – for further information see Chapter [C4: Distance Protection Schemes] and specific relay manuals.

6. Protection of series compensated lines

Figure C5.20 depicts the basic power transfer equation. It can be seen from this equation that transmitted power is proportional to the system voltage level and load angle whilst being inversely proportional to system impedance. Series compensated lines are used in transmission networks where the required level of transmitted power cannot be met, either from a load requirement or system stability requirement. Series compensated transmission lines introduce a series connected capacitor, which has the net result of reducing the overall inductive impedance of the line, hence increasing the prospective, power flow. Typical levels of compensation are 35%, 50% and 70%, where the percentage level dictates the capacitor impedance compared to the transmission line it is associated with. New schemes with >100% compensation are also being discussed.

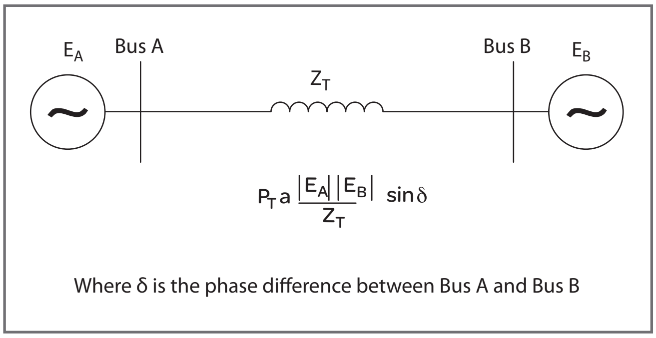

Figure C5.20:
Power transfer in a transmission line

The introduction of a capacitive impedance to a network can give rise to several relaying problems. The most common of these is the situation of voltage inversion, which is shown in Figure C5.21. In this case a fault occurs on the protected line. The overall fault impedance is inductive and hence the fault current is inductive (shown lagging the system e.m.f. by 90 degrees in this case). However, the voltage measured by the relay is that across the capacitor and will therefore lag the fault current by 90 degrees.

The net result is that the voltage measured by the relay is in anti- phase to the system e.m.f.. Whilst this view is highly simplistic, it adequately demonstrates potential relay problems, in that any protection reliant upon making a directional decision bases its decision on an inductive system i.e. one where a forward fault is indicated by fault current lagging the measured voltage. A good example of this is a distance relay, which assumes the transmission line is an evenly distributed inductive impedance. Presenting the relay with a capacitive voltage (impedance) can lead the relay to make an incorrect directional decision.

A second problem is that of current inversion which is demonstrated in Figure C5.22. In this case, the overall fault impedance is taken to be capacitive. The fault current therefore

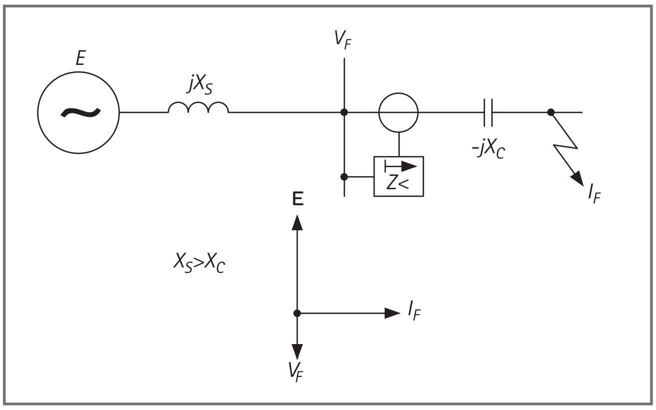

Figure C5.21:
Voltage inversion on a transmission line

leads the system e.m.f. by 90° whilst the measured fault voltage remains in phase with system e.m.f.. Again this condition can give rise to directional stability problems for a variety of protection devices. Practically, the case of current inversion is difficult to obtain. In order to protect capacitors from high over-voltages during fault conditions some form of voltage limiting device (usually in the form of MOVs) is installed to bypass the capacitor at a set current level. In the case of current inversion, the overall fault impedance has to be capacitive and will generally be small. This leads to high levels of fault current, which will trigger the MOVs and bypass the capacitors, hence leaving an inductive fault impedance and preventing the current inversion.

In general, the application of protective relays to a series compensated power system needs careful evaluation. The problems associated with the introduction of a series capacitor can be overcome by a variety of relaying techniques so it is important to ensure the suitability of the chosen protection. Each particular application requires careful investigation to determine the most appropriate solution in respect of protection – there are no general guidelines that can be given.

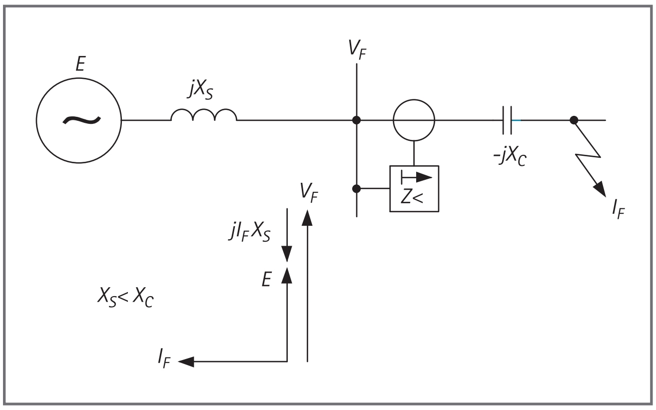

Figure C5.22:
Current inversion in a transmission line

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7. Examples

In this section, an example calculation illustrating the solution to a problem mentioned in this Chapter is given.

7.1 Distance relay applied to parallel circuits

The system diagram shown in Figure C5.23 indicates a simple 110kV network supplied from a 220kV grid through two auto-transformers. The following example shows the calculations necessary to check the suitability of three zone distance protection to the two parallel feeders interconnecting substations A and B, Line 1 being selected for this purpose. All relevant data for this exercise are given in the diagram. The MiCOM P441 relay with quadrilateral characteristics is used to provide the relay data for the example. Relay quantities used in the example are listed in Table C5.3, and calculations are carried out in terms of actual system impedances in ohms, rather than CT secondary quantities. This simplifies the calculations, and enables the example to be simplified by excluding considerations of CT ratios. Most modern distance relays permit settings to be specified in system quantities rather than CT secondary quantities, but older relays may require the system quantities to be converted to impedances as seen by the relay.

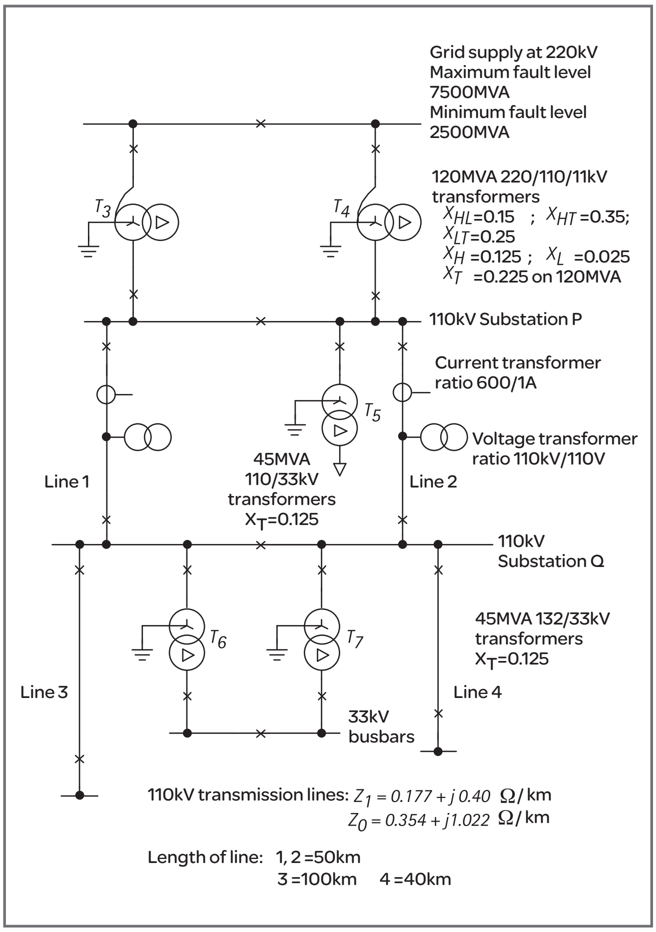

Figure C5.23:
Example network for distance relay setting calculation

7.1.1 Residual compensation

The relays used are calibrated in terms of the positive sequence impedance of the protected line. Since the earth fault impedance of Line 1 is different from the positive sequence impedance, the impedance seen by the relay in the case of a fault involving earth will be different to that seen for a phase fault. Hence, the reach of the earth fault elements of the relay needs to be different.

For the relay used, this adjustment is provided by the residual (or neutral) compensation factor Z_{Z0}, set equal to:

$$|K_{Z0}| = \left|\frac{(Z_o - Z_1)}{3Z_1}\right|$$

$$\angle K_{Z0} = \angle\frac{(Z_o - Z_1)}{3Z_1}$$

For Lines 1 and 2,

$$Z_{L1} = 0.177 + j0.402\Omega$$

$$(0.439\angle 66.236^\circ\Omega)$$

$$Z_{L0} = 0.354 + j1.022\Omega$$

$$(1.082\angle +70.895^\circ\Omega)$$

Hence,

$$|K_{Z0}| = 0.490$$

$$\angle K_{Z0} = 7.8^\circ$$

7.1.2 Zone impedance reach settings – phase faults

Firstly, the impedance reaches for the three relay zones are calculated.

7.1.3 Zone 1 reach

Zone 1 impedance is set to 80% of the impedance of the protected line. Hence,

$$Z_1 = 0.8 \times 50 \times (0.439\angle 66.236^\circ)\ \Omega$$

$$= 0.8 \times 21.95\angle 66.236^\circ\Omega$$

$$= 17.56\angle 66.236^\circ\Omega$$

Use a value of $17.56\angle 66.2^\circ\Omega$

7.1.4 Zone 2 reach

Zone 2 impedance reach is set to cover the maximum of:

a. 120% of Line 1 length

b. Line 1 + 50% of shortest line from Substation B i.e. 50% of Line 4

From the line impedances given,

a. $1.2 \times 21.95\angle 66.236^\circ = 26.34\angle 66.236^\circ\Omega$

b. $21.95\angle 66.236^\circ +$

$0.5 \times 40 \times\ 0.439\angle 66.236^\circ\Omega = 30.73\angle 66.2^\circ\Omega$

It is clear that condition (**b.**) governs the setting, and therefore the initial Zone 2 reach setting is:

$$Z_2 = 30.73\angle 66.2^\circ \Omega$$

The effect of parallel Line 2 is to make relay 1 under-reach for faults on adjacent line sections, as discussed in Section 2.2 of this chapter. This is not a problem for the phase fault elements because Line 1 will always be protected.

7.1.5 Zone 3 reach

The function of Zone 3 is to provide backup protection for uncleared faults in adjacent line sections. The criterion used is that the relay should be set to cover 120% of the impedance between the relay location and the end of the longest adjacent line, taking account of any possible fault infeed from other circuits or parallel paths. In this case, faults in Line 3 will result in the relay under-reaching due to the parallel Lines 1 and 2, so the impedance of Line 3 should be doubled to take this effect into account.

Therefore,

$$Z_3 = 1.2 \times \begin{pmatrix} 21.95\angle 66.2^o \\ +100 \times 2 \times 0.439\angle 66.2^o \end{pmatrix} \Omega$$

$$= 131.8\angle 66.2^o \Omega$$

7.1.6 Zone time delay settings

Proper co-ordination of the distance relay settings with those of other relays is required. Independent timers are available for the three zones to ensure this.

For Zone 1, instantaneous tripping is normal. A time delay is used only in cases where large d.c. offsets occur and old circuit breakers, incapable of breaking the instantaneous d.c. component, are involved.

The Zone 2 element has to grade with the relays protecting Lines 3 and 4 since the Zone 2 element covers part of these lines. Assuming that Lines 3/4 have distance, unit or instantaneous high-set overcurrent protection applied, the time delay required is that to cover the total clearance time of the downstream relays. To this must be added the reset time for the Zone 2 elements following clearance of a fault on an adjacent line, and a suitable safety margin. A typical time delay is 250ms, and the normal range is 200-400ms.

The considerations for the Zone 3 element are the same as for the Zone 2 element, except that the downstream fault clearance time is that for the Zone 2 element of a distance relay or IDMT overcurrent protection. Assuming distance relays are used, a typical time is 1s.

In summary:

T_{Z1} = 0ms (instantaneous)

T_{Z2} = 250ms

T_{Z3} = 1s

7.1.7 Phase fault resistive reach settings

With the use of a quadrilateral characteristic, the resistive reach settings for each zone can be set independently of the impedance reach settings. The resistive reach setting represents the maximum amount of additional fault resistance (in excess of the line impedance) for which a zone will trip, regardless of the fault within the zone.

Two constraints are imposed upon the settings, as follows:

a. it must be greater than the maximum expected phase-phase fault resistance (principally that of the fault arc)

b. it must be less than the apparent resistance measured due to the heaviest load on the line

The minimum fault current at Substation B is of the order of 1.5kA, leading to a typical arc resistance R_{arc} using the van Warrington formula [C3: Distance Protection, Equation C3.4] of 9Ω. Using the current transformer ratio on Line 1 as a guide to the maximum expected load current, the minimum load impedance Z_{lmin} will be 106Ω. Typically, the resistive reaches will be set to avoid the minimum load impedance by a 40% margin for the phase elements, leading to a maximum resistive reach setting of 63.6Ω.

Therefore, the resistive reach setting lies between 9Ω and 63.6Ω. While each zone can have its own resistive reach setting, for this simple example, all of the resistive reach settings can be set equal (depending on the particular distance protection scheme used and the need to include Power Swing Blocking, this need not always be the case).

Suitable settings are chosen to be 60% of the load resistance:

$$R_{3\ ph} = 63.6\ \Omega$$

$$R_{2\ ph} = 63.6\ \Omega$$

$$R_{1\ ph} = 63.6\ \Omega$$

7.1.8 Earth fault reach settings

By default, the residual compensation factor as calculated in section 7.1.1 is used to adjust the phase fault reach setting in the case of earth faults, and is applied to all zones. However, it is also possible to apply this compensation to zones individually. Two cases in particular require consideration, and are covered in this example.

7.1.9 Zone 1 earth fault reach

Where distance protection is applied to parallel lines (as in this example), the Zone 1 earth fault elements may sometimes over-reach and therefore operate when one line is out of service and earthed at both ends.

The solution is to reduce the earth fault reach of the Zone 1 element to typically 80% of the default setting. Hence:

$$\begin{aligned} K_{Z1} &= 0.8 \times K_{Z0} \\ &= 0.8 \times 0.532 \\ &= 0.426 \end{aligned}$$

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7. Examples

In practice, the setting is selected by using an alternative setting group, selected when the parallel line is out of service and earthed.

7.1.10 Zone 2 earth fault reach

With parallel circuits, the Zone 2 element will tend to under-reach due to the zero sequence mutual coupling between the lines.

Maloperation may occur, particularly for earth faults occurring on the remote busbar. The effect can be countered by increasing the Zone 2 earth fault reach setting, but first it is necessary to calculate the amount of under-reach that occurs.

$$Under\text{-}reach = Z_{adj} \times \frac{I_{fltp}}{I_{flt}}$$

where:

Z_{adj} = impedance of adjacent line covered by Zone 2

I_{fltp} = fault current in parallel line

I_{flt} = total fault current

since the two parallel lines are identical, and hence, for Lines 1 and 2,

$$\begin{aligned} Under\text{-}reach &= 8.78\angle 66.2^\circ \times 0.5 \\ &= 4.39\angle 66.2^\circ \Omega \end{aligned}$$

$$\%\ Under\text{-}reach = \frac{Under\text{-}reach}{Reach\ of\ protected\ zone}$$

and hence

% Under-reach = 14.3%

This amount of under-reach is not significant and no adjustment need be made. If adjustment is required, this can be achieved by using the K_{Z2} relay setting, increasing it over the K_{Z0} setting by the percentage under-reach. When this is done, care must also be taken that the percentage over-reach during single circuit operation is not excessive – if it is then use can be made of the alternative setting groups provided in most modern distance relays to change the relay settings according to the number of circuits in operation.

7.1 11 Ground fault resistive reach settings

The same settings can be used as for the phase fault resistive reaches. Hence,

$R_{3G} = 63.6\ \Omega$

$R_{2G} = 63.6\ \Omega$

$R_{1G} = 63.6\ \Omega$

This completes the setting of the relay. Table C5.3 also shows the settings calculated.

Relay parameter	Parameter description	Parameter value	Units
Z_{L1} (mag)	Line positive sequence impedance (magnitude)	21.95	Ω
Z_{L1} (ang)	Line positive sequence impedance (phase angle)	66.2	deg
Z_{L0} (mag)	Line zero sequence impedance (magnitude)	54.1	Ω
Z_{L0} (ang)	Line zero sequence impedance (phase angle)	70.895	deg
K_{Z0} (mag)	Default residual compensation factor (magnitude)	0.49	-
K_{Z0} (ang)	Default residual compensation factor (phase angle)	7.8	deg
Z_1 (mag)	Zone 1 reach impedance setting (magnitude)	17.56	Ω
Z_1 (ang)	Zone 1 reach impedance setting (phase angle)	66.2	deg
Z_2 (mag)	Zone 2 reach impedance setting (magnitude)	30.73	Ω
Z_2 (ang)	Zone 2 reach impedance setting (phase angle)	66.2	deg
Z_3 (mag)	Zone 3 reach impedance setting (magnitude)	131.8	Ω
Z_3 (ang)	Zone 3 reach impedance setting (phase angle)	66.2	deg

Table C5.3: Distance relay settings

7. Examples

Relay parameter	Parameter description	Parameter value	Units
R_{1ph}	Phase fault resistive reach value - Zone 1	63.6	Ω
R_{2ph}	Phase fault resistive reach value - Zone 2	63.6	Ω
R_{3ph}	Phase fault resistive reach value - Zone 3	63.6	Ω
K_{Z1} (mag)	Zone 1 residual compensation factor (magnitude)	0.426	-
K_{Z1} (ang)	Zone 1 residual compensation factor (phase angle)	9.2	deg
K_{Z2} (mag)	Zone 2 residual compensation factor (magnitude)	0.49	-
K_{Z2} (ang)	Zone 2 residual compensation factor (phase angle)	7.8	deg
T_{Z1}	Time delay - Zone 1	0	s
T_{Z2}	Time delay - Zone 2	0.25	s
T_{Z3}	Time delay - Zone 3	1	s
R_{1G}	Ground fault resistive reach value - Zone 1	63.6	Ω
R_{2G}	Ground fault resistive reach value - Zone 2	63.6	Ω
R_{3G}	Ground fault resistive reach value - Zone 3	63.6	Ω

Table C5.3 (cont.): Distance relay settings

8. References

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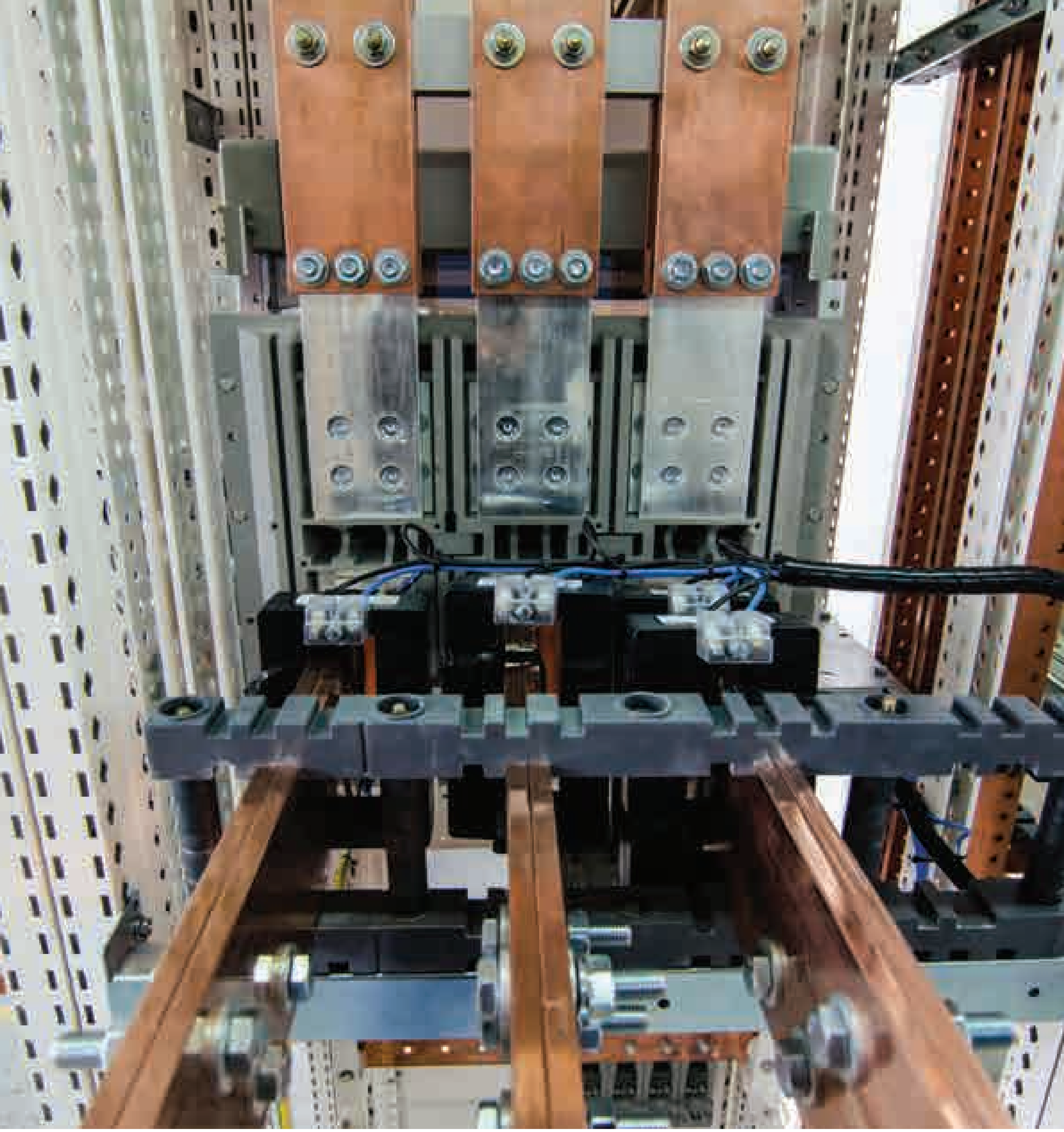

C6

Busbar Protection

Network Protection & Automation Guide

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Chapter

C6

Busbar Protection

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1. Introduction

The protection scheme for a power system should cover the whole system against all probable types of fault. Unrestricted forms of line protection, such as overcurrent and distance systems, meet this requirement, although faults in the busbar zone are cleared only after some time delay. But if unit protection is applied to feeders and plant, the busbars are not inherently protected.

Busbars have often been left without specific protection, for one or more of the following reasons:

a. the busbars and switchgear have a high degree of reliability, to the point of being regarded as intrinsically safe

b. it was feared that accidental operation of busbar protection might cause widespread dislocation of the power system, which, if not quickly cleared, would cause more loss than would the very infrequent actual bus faults

c. it was hoped that system protection or back-up protection would provide sufficient bus protection if needed

It is true that the risk of a fault occurring on modern metal-clad gear is very small, but it cannot be entirely ignored. However, the damage resulting from one uncleared fault, because of the concentration of fault MVA, may be very extensive indeed, up to the complete loss of the station by fire. Serious damage to or destruction of the installation would probably result in widespread and prolonged supply interruption.

Finally, system protection will frequently not provide the cover required. Such protection may be good enough for small distribution substations, but not for important stations. Even if distance protection is applied to all feeders, the busbar will lie in the second zone of all the distance protections, so a bus fault will be cleared relatively slowly, and the resultant duration of the voltage dip imposed on the rest of the system may not be tolerable.

With outdoor switchgear the case is less clear since, although the likelihood of a fault is higher, the risk of widespread damage resulting is much less. In general then, busbar protection is required when the system protection does not cover the busbars, or when, in order to maintain power system stability, high-speed fault clearance is necessary. Unit busbar protection provides this, with the further advantage that if the busbars are sectionalised, one section only need be isolated to clear a fault. The case for unit busbar protection is in fact strongest when there is sectionalisation.

2. Busbar faults

The majority of bus faults involve one phase and earth, but faults arise from many causes and a significant number are interphase clear of earth. In fact, a large proportion of busbar faults result from human error rather than the failure of switchgear components.

With fully phase-segregated metalclad gear, only earth faults are possible, and a protection scheme need have earth fault sensitivity only. In other cases, an ability to respond to phase faults clear of earth is an advantage, although the phase fault sensitivity need not be very high.

3. Protection requirements

Although not basically different from other circuit protection, the key position of the busbar intensifies the emphasis put on the essential requirements of speed and stability. The special features of busbar protection are discussed below.

3.1 Speed

Busbar protection is primarily concerned with:

a. limitation of consequential damage

b. removal of busbar faults in less time than could be achieved by back-up line protection, with the object of maintaining system stability

Some early busbar protection schemes used a low impedance differential system having a relatively long operation time, of up to 0.5 seconds. The basis of most modern schemes is a differential system using either low impedance biased or high impedance unbiased relays capable of operating in a time of the order of one cycle at a very moderate multiple of fault setting. To this must be added the operating time of the tripping relays, but an overall tripping time of less than two cycles can be achieved. With high- speed circuit breakers, complete fault clearance may be obtained in approximately 0.1 seconds. When a frame-earth system is used, the operating speed is comparable.

3.2 Stability

The stability of bus protection is of paramount importance. Bearing in mind the low rate of fault incidence, amounting to no more than an average of one fault per busbar in twenty years, it is clear that unless the stability of the protection is absolute, the degree of disturbance to which the power system is likely to be subjected may be increased by the installation of bus protection. The possibility of incorrect operation has, in the past, led to hesitation in applying bus protection and has also resulted in application of some very complex systems. Increased understanding of the response of differential systems to transient currents enables such systems to be applied with confidence in their fundamental stability. The theory of differential protection is given later in Section 7.

Notwithstanding the complete stability of a correctly applied protection system, dangers exist in practice for a number of reasons. These are:

a. interruption of the secondary circuit of a current transformer will produce an unbalance, which might cause tripping on load depending on the relative values of circuit load and effective setting. It would certainly do so during a through-fault, producing substantial fault current in the circuit in question

b. a mechanical shock of sufficient severity may cause operation, although the likelihood of this occurring with modern numerical schemes is reduced

c. accidental interference with the relay, arising from a mistake during maintenance testing, may lead to operation

In order to maintain the high order of integrity needed for busbar protection, it is an almost invariable practice to make tripping depend on two independent measurements of fault quantities. Moreover, if the tripping of all the breakers within a zone is derived from common measuring relays, two separate elements must be operated at each stage to complete a tripping operation. Although not current practice, in many cases the relays are separated by about 2 metres so that no reasonable accidental mechanical interference to both relays simultaneously is possible.

The two measurements may be made by two similar differential systems, or one differential system may be checked by a frame-earth system, by earth fault relays energised by current transformers in the transformer neutral-earth conductors or by overcurrent relays. Alternatively, a frame-earth system may be checked by earth fault relays.

If two systems of the unit or other similar type are used, they should be energised by separate current transformers in the case of high impedance unbiased differential schemes. The duplicate ring CT cores may be mounted on a common primary conductor but independence must be maintained throughout the secondary circuit.

In the case of low impedance, biased differential schemes that cater for unequal ratio CTs, the scheme can be energised from either one or two separate sets of main current transformers.

The criteria of double feature operation before tripping can be maintained by the provision of two sets of ratio matching interposing CTs per circuit. When multi-contact tripping relays are used, these are also duplicated, one being energised from each discriminating relay; the contacts of the tripping relay are then series-connected in pairs to provide tripping outputs.

Separate tripping relays, each controlling one breaker only, are usually preferred. The importance of such relays is then no more than that of normal circuit protection, so no duplication is required at this stage. Not least among the advantages of using individual tripping relays is the simplification of trip circuit wiring, compared with taking all trip circuits associated with a given bus section through a common multi-contact tripping relay.

In double busbar installations, a separate protection system is applied to each section of each busbar; an overall check system is provided, covering all sections of both busbars. The separate zones are arranged to overlap the busbar section switches, so that a fault on the section switch trips both the adjacent zones. This is sometimes avoided by giving the section switch a time advantage; the section switch is tripped first and the remaining breakers delayed.

Only the zone on the faulty side of the section switch will remain operated and trip, the other zone resetting and retaining that section in service. This gain, applicable only to very infrequent section switch faults, is obtained at the expense of seriously delaying the bus protection for all other faults. This practice is therefore not generally favoured. Some variations are dealt with

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3. Protection requirements

later under the more detailed scheme descriptions. There are many combinations possible, but the essential principle is that no single accidental incident of a secondary nature shall be capable of causing an unnecessary trip of a bus section.

Security against maloperation is only achieved by increasing the amount of equipment that is required to function to complete an operation; and this inevitably increases the statistical risk that a tripping operation due to a fault may fail. Such a failure, leaving aside the question of consequential damage, may result in disruption of the power system to an extent as great, or greater, than would be caused by an unwanted trip. The relative risk of failure of this kind may be slight, but it has been thought worthwhile in some instances to provide a guard in this respect as well.

Security of both stability and operation is obtained by providing three independent channels (say X, Y and Z) whose outputs are arranged in a 'two-out-of three' voting arrangement, as shown in Figure C6.1.

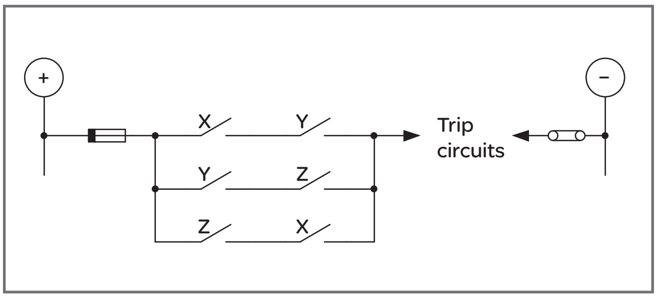

Figure C6.1:
Two-out-of-three principle

4. Types of protection system

A number of busbar protection systems have been devised:

a. system protection used to cover busbars

b. frame-earth protection

c. differential protection

d. phase comparison protection

e. directional blocking protection

Of these, (a) is suitable for small substations only. Detailed discussion of types (b) and (c) occupies most of this chapter.

Early forms of biased differential protection for busbars, such as versions of 'Translay' protection and also a scheme using harmonic restraint, were superseded by unbiased high impedance differential protection.

The relative simplicity of the latter, and more importantly the relative ease with which its performance can be calculated, have ensured its success up to the present day.

But more recently the advances in semiconductor technology, coupled with a more pressing need to be able to accommodate CTs of unequal ratio, have led to the re-introduction of biased schemes, generally using static relay designs, particularly for the most extensive and onerous applications.

Frame-earth protection systems have been in use for many years, mainly associated with smaller busbar protection schemes at distribution voltages and for metalclad busbars (e.g. SF6 insulated busbars). However, it has often been quite common for a unit protection scheme to be used in addition, to provide two separate means of fault detection.

The different types of protection are described in the following sections.

5. System protection schemes

System protection that includes overcurrent or distance systems will inherently give protection cover to the busbars. Overcurrent protection will only be applied to relatively simple distribution systems, or as a back-up protection, set to give a considerable time delay. Distance protection will provide cover for busbar faults with its second and possibly subsequent zones. In both cases the busbar protection obtained is slow and suitable only for limiting the consequential damage.

The only exception is the case of a mesh-connected substation, in which the current transformers are located at the circuit breakers. Here, the busbars are included, in sections, in the individual zones of the main circuit protection, whether this is of unit type or not. In the special case when the current transformers are located on the line side of the mesh, the circuit protection will not cover the busbars in the instantaneous zone and separate busbar protection, known as mesh-corner protection, is generally used – see Section 7.2.1 for details.

6. Frame-earth protection (Howard protection)

Frame leakage protection has been extensively used in the past in many different situations. There are several variations of frame leakage schemes available, providing busbar protection schemes with different capabilities. The schemes in the following sections have been retained for historical and general reference purposes. A considerable number of schemes are still in service and frame leakage may provide an acceptable solution in particular circumstances. However, the need to insulate the switchboard frame and provide cable gland insulation and the availability of alternative schemes using numerical relays, has contributed to a decline in use of frame leakage systems.

6.1 Single-busbar frame-earth protection

This is purely an earth fault system and, in principle, involves simply measuring the fault current flowing from the switchgear frame to earth. A current transformer is mounted on the earthing conductor and is used to energise a simple instantaneous relay as shown in Figure C6.2.

No other earth connections of any type, including incidental connections to structural steelwork are allowed. This requirement is so that:

a. the principal earth connection and current transformer are not shunted, thereby raising the effective setting. An increased effective setting gives rise to the possibility of relay maloperation. This risk is small in practice

b. earth current flowing to a fault elsewhere on the system cannot flow into or out of the switchgear frame via two earth connections, as this might lead to a spurious operation

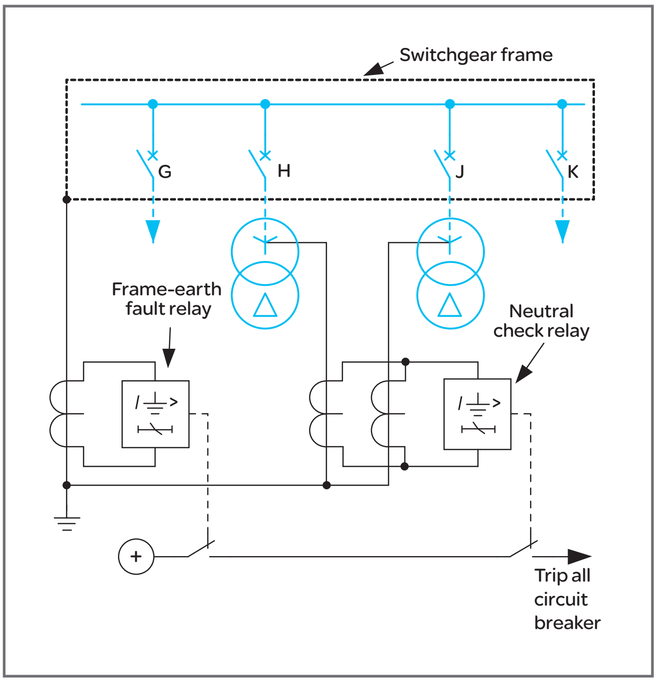

Figure C6.2:
Single zone frame-earth protection

The switchgear must be insulated as a whole, usually by standing it on concrete. Care must be taken that the foundation bolts do not touch the steel reinforcement; sufficient concrete

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6. Frame-earth protection (Howard protection)

must be cut away at each hole to permit grouting-in with no risk of touching metalwork. The insulation to earth finally achieved will not be high, a value of 10 ohms being satisfactory.

When planning the earthing arrangements of a frame-leakage scheme, the use of one common electrode for both the switchgear frame and the power system neutral point is preferred, because the fault path would otherwise include the two earthing electrodes in series. If either or both of these are of high resistance or have inadequate current carrying capacity, the fault current may be limited to such an extent that the protection equipment becomes inoperative. In addition, if the electrode earthing the switchgear frame is the offender, the potential of the frame may be raised to a dangerous value. The use of a common earthing electrode of adequate rating and low resistance ensures sufficient current for scheme operation and limits the rise in frame potential. When the system is resistance earthed, the earthing connection from the switchgear frame is made between the bottom of the earthing resistor and the earthing electrode.

Figure C6.3 illustrates why a lower limit of 10 ohms insulation resistance between frame and earth is necessary.

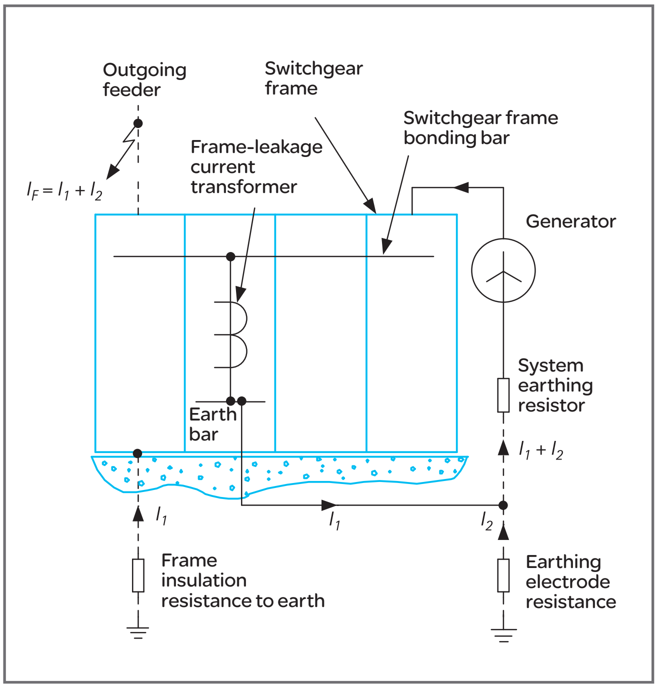

Figure C6.3:
Current distribution for external fault

Under external fault conditions, the current I_1 flows through the frame-leakage current transformer. If the insulation resistance is too low, sufficient current may flow to operate the frame-leakage relay, and, as the check feature is unrestricted, this will also operate to complete the trip circuit. The earth resistance between the earthing electrode and true earth is seldom greater than 1Ω, so with 10Ω insulation resistance the current I_1 is limited to 10% of the total earth fault current I_1 and I_2.

For this reason, the recommended minimum setting for the scheme is about 30% of the minimum earth fault current.

All cable glands must be insulated, to prevent the circulation of spurious current through the frame and earthing system by any voltages induced in the cable sheath. Preferably, the gland insulation should be provided in two layers or stages, with an interposing layer of metal, to facilitate the testing of the gland insulation. A test level of 5kV from each side is suitable.

6.2 Frame-earth protection - sectioned busbars

Section 6.1 covered the basic requirements for a system to protect switchgear as a whole. When the busbar is divided into sections, these can be protected separately, provided the frame is also sub-divided, the sections mutually insulated, and each provided with a separate earth conductor, current transformer and relay.

Ideally, the section switch should be treated as a separate zone, as shown in Figure C6.4, and provided with either a separate relay or two secondaries on the frame-leakage current transformer, with an arrangement to trip both adjacent zones. The individual zone relays trip their respective zone and the section switch.

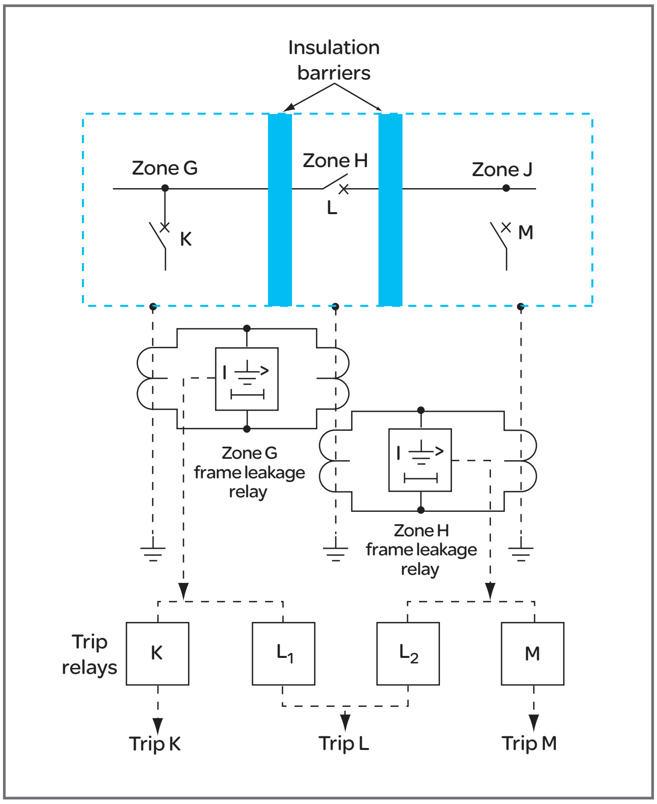

Figure C6.4:
Three zone frame earth scheme

6. Frame-earth protection (Howard protection)

If it is inconvenient to insulate the section switch frame on one side, this switch may be included in that zone. It is then necessary to intertrip the other zone after approximately 0.5 seconds if fault persists after the zone including the section switch has been tripped. This is illustrated in Figure C6.5. For the above schemes to function it is necessary to have a least one infeed or earthed source of supply, and in the latter case it is essential that this source of supply be connected to the side of the switchboard not containing the section switch. Further, if possible, it is preferable that an earthed source of supply be provided on both sides of the switchboard, in order to ensure that any faults that may develop between the insulating barrier and the section switch will continue to be fed with fault current after the isolation of the first half of the switchboard, and thus allow the fault to be removed. Of the two arrangements, the first is the one normally recommended, since it provides instantaneous clearance of busbar faults on all sections of the switchboard.

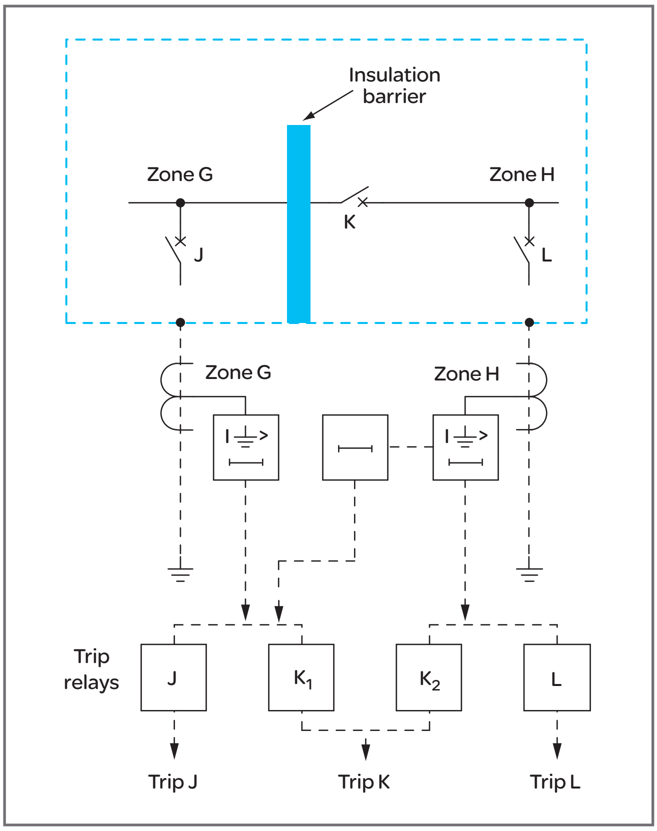

Figure C6.5:
Frame-earth scheme: bus section breaker insulated on one side only

6.3 Frame-earth scheme - double bus substation

It is not generally feasible to separately insulate the metal enclosures of the main and auxiliary busbars. Protection is therefore generally provided as for single bus installations, but with the additional feature that circuits connected to the auxiliary bus are tripped for all faults, as shown in Figure C6.6.

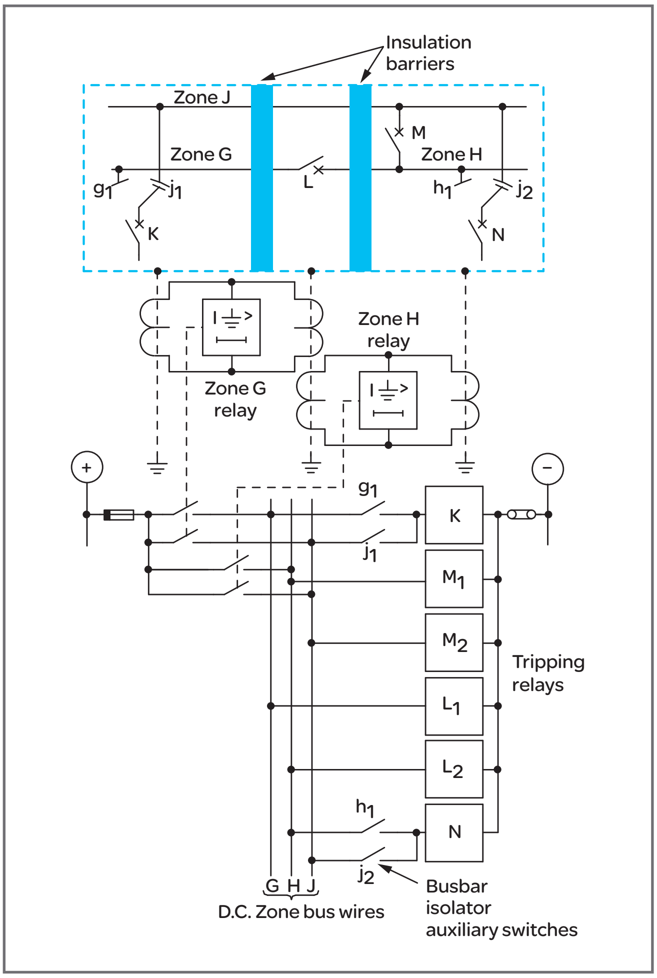

Figure C6.6:
Frame-earth scheme for double busbar substation

6.4 Frame-earth protection - check system

On all but the smallest equipments, a check system should be provided to guard against such contingencies as operation due to mechanical shock or mistakes made by personnel. Faults in the low voltage auxiliary wiring must also be prevented from causing operation by passing current to earth through the switchgear frame. A useful check is provided by a relay energised by the system neutral current, or residual current. If the neutral check cannot be provided, the frame-earth relays should have a short time delay.

When a check system is used, instantaneous relays can be used, with a setting of 30% of the minimum earth fault current and an operating time at five times setting of 15 milliseconds or less.

6. Frame-earth protection (Howard protection)

Figure C6.7 shows a frame-leakage scheme for a metalclad switchgear installation similar to that shown in Figure C6.4 and incorporating a neutral current check obtained from a suitable zero sequence current source, such as that shown in Figure C6.2.

The protection relays used for the discriminating and check functions are of the attracted armature type, with two normally open self reset contacts. The tripping circuits cannot be complete unless both the discriminating and check relays operate; this is because the discriminating and check relay contacts are connected in series. The tripping relays are of the attracted armature type.

It is usual to supervise the satisfactory operation of the protection scheme alarms and indications for the following:

a. busbar faults

b. busbar protection in service

c. busbar protection out of service

d. tripping supply healthy

e. alarm supply healthy

To enable the protection equipment of each zone to be taken out of service independently during maintenance periods, isolating switches - one switch per zone - are provided in the trip supply circuits and an alarm cancellation relay is used.

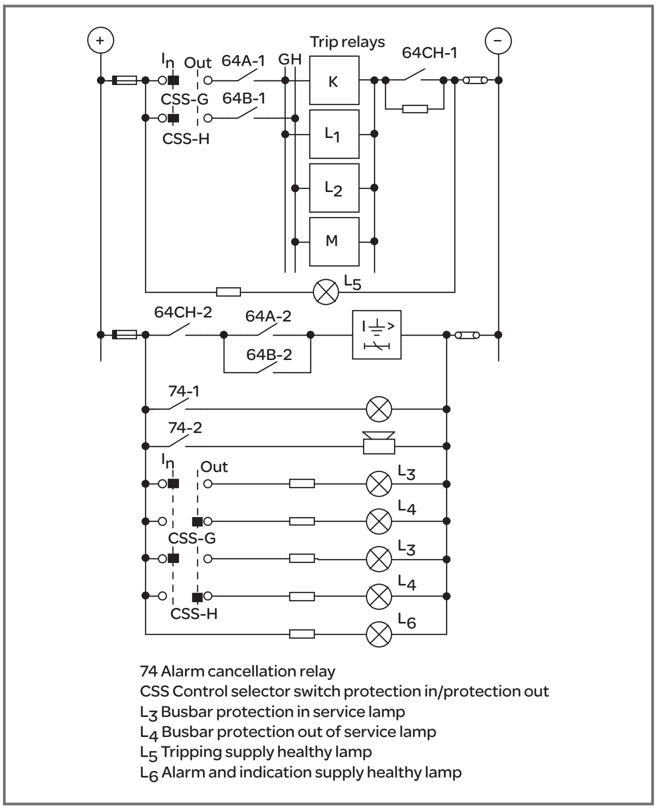

Figure C6.7:
Typical tripping and alarm circuits for a frame-leakage scheme

7. Differential protection principles

The Merz-Price principle is applicable to a multi-terminal zone such as a busbar. The principle is a direct application of Kirchhoff's first law. Usually, the circulating current arrangement is used, in which the current transformers and interconnections form an analogue of the busbar and circuit connections. A relay connected across the CT bus wires represents a fault path in the primary system in the analogue and hence is not energised until a fault occurs on the busbar; it then receives an input that, in principle at least, represents the fault current.

The scheme may consist of a single relay connected to the bus wires connecting all the current transformers in parallel, one set per circuit, associated with a particular zone, as shown in Figure C6.8(a). This will give earth fault protection for the busbar. This arrangement has often been thought to be adequate.

If the current transformers are connected as a balanced group for each phase together with a three-element relay, as shown in Figure C6.8(b), additional protection for phase faults can be obtained.

The phase and earth fault settings are identical, and this scheme is recommended for its ease of application and good performance.

7.1 Differential protection for sectionalised and duplicate busbars

Each section of a divided bus is provided with a separate circulating current system. The zones so formed are over-lapped across the section switches, so that a fault on the latter will trip the two adjacent zones. This is illustrated in Figure C6.9.

Tripping two zones for a section switch fault can be avoided by using the time-delayed technique of Section 6.2. However instantaneous operation is the preferred choice.

For double bus installation, the two busbars will be treated as separate zones. The auxiliary busbar zone will overlap the appropriate main busbar zone at the bus coupler.

Since any circuit may be transferred from one busbar to the other by isolator switches, these and the associated tripping

7. Differential protection principles

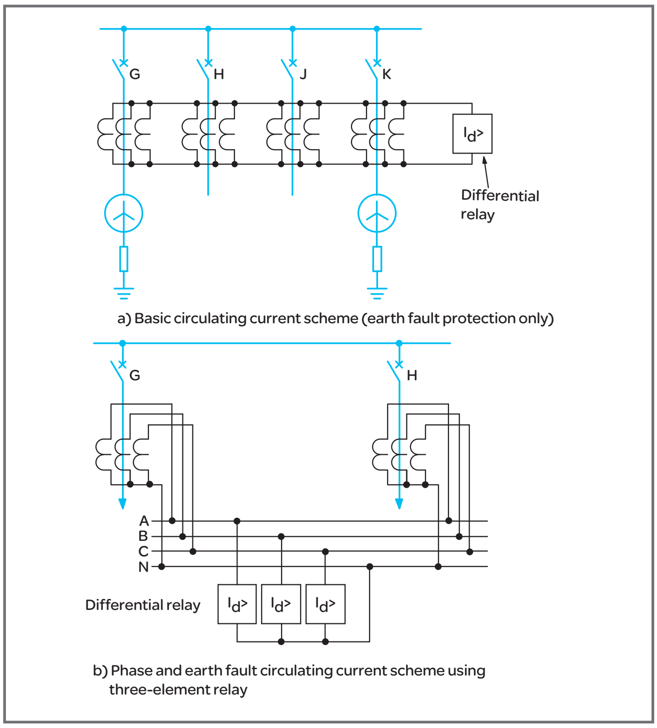

Figure C6.8:
Circulating current scheme

circuit must also be switched to the appropriate zone by 'early make' and 'late break' auxiliary contacts. This is to ensure that when the isolators are closing, the auxiliary switches make before the main contacts of the isolator, and that when the isolators are opened, their main contacts part before the auxiliary switches open. The result is that the secondary circuits of the two zones concerned are briefly paralleled while the circuit is being transferred; these two zones have in any case been united through the circuit isolators during the transfer operation.

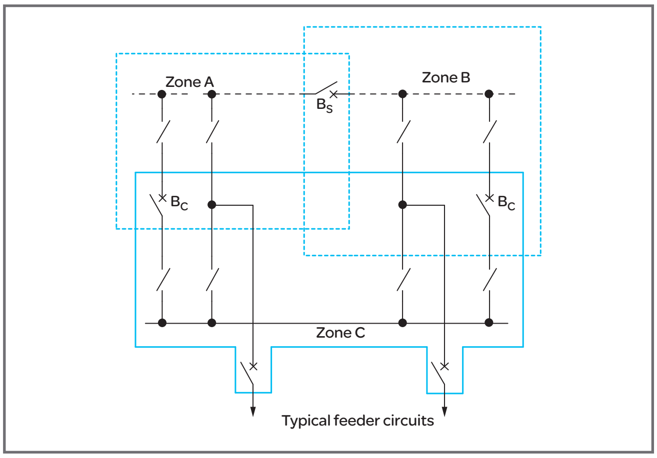

Figure C6.9:
Zones of protection for double bus station

7.2 Location of current transformers

Ideally, the separate discriminating zones should overlap each other and also the individual circuit protections. The overlap should occur across a circuit breaker, so that the latter lies in both zones. For this arrangement it is necessary to install current transformers on both sides of the circuit breakers, which is economically possible with many but not all types of switchgear. With both the circuit and the bus protection current transformers on the same side of the circuit breakers, the zones may be overlapped at the current transformers, but a fault between the CT location and the circuit breaker will not be completely isolated. This matter is important in all switchgear to which these conditions apply, and is particularly important in the case of outdoor switchgear where separately mounted, multi-secondary current transformers are generally used. The conditions are shown in Figure C6.10(a). Figure C6.10 (a) shows the ideal arrangement in which both the circuit and busbar zones are overlapped, leaving no region of the primary circuit unprotected.

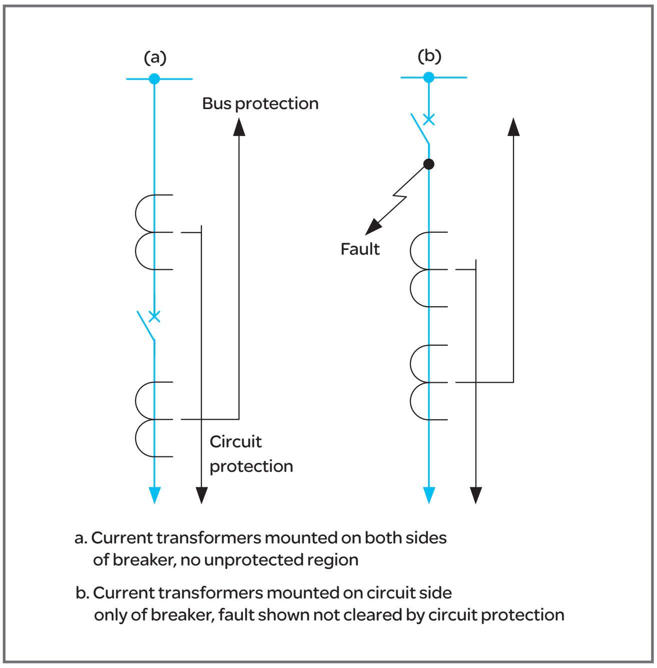

Figure C6.10:
Unprotected zone with current transformers mounted on one side of the circuit breaker only

Figure C6.10(b) shows how mounting all current transformers on the circuit side of the breaker results in a small region of the primary circuit unprotected. This unprotected region is typically referred to as the 'short zone'. The fault shown will cause operation of the busbar protection, tripping the circuit breaker, but the fault will continue to be fed from the circuit, if a source of power is present.

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7. Differential protection principles

It is necessary for the bus protection to intertrip the far end of the circuit protection, if the latter is of the unit type.

With reference to Figure C6.10(b), special 'short zone' protection can be provided to detect that the circuit breaker has opened but that the fault current is still flowing. Under these conditions, the protection can initiate an intertrip to the remote end of the circuit. This technique may be used, particularly when the circuit includes a generator. In this case the intertrip proves that the fault is in the switchgear connections and not in the generator; the latter is therefore tripped electrically but not shut down on the mechanical side so as to be immediately ready for further service if the fault can be cleared.

7.2.1 CT location for mesh-connected substations

The protection of busbars in mesh connected substations gives rise to additional considerations in respect of CT location. A single mesh corner is shown in Figure C6.11(a). Where only one connection to the mesh is made at a corner, CTs located as shown will provide protection not only to the line but also the corner of the mesh included between them. However, this arrangement cannot be used where more than one connection is made to a mesh corner. This is because a fault on any of the connected circuits would result in disconnection of them all, without any means of determining the faulted connection. Protection CTs must therefore be located on each connection, as shown in Figure C6.11(b). This leaves the corner of the mesh unprotected, so additional CTs and a relay to provide mesh-corner protection are added, as also shown in Figure C6.11(b).

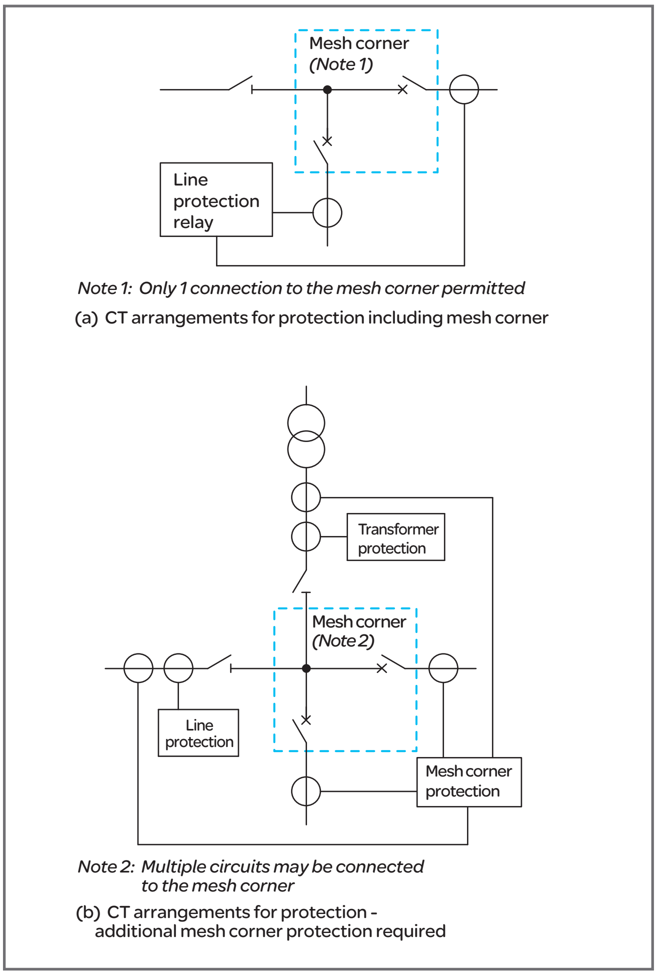

Figure C6.11: Mesh-corner protection

8. High impedance differential protection

This form of protection is still in common use. The considerations that have to be taken into account are detailed in the following sections.

8.1 Stability

The incidence of fault current with an initial unilateral transient component causes an abnormal build-up of flux in a current transformer, as described in Chapter [B2: Current and Voltage Transformers, Section 4.10]. When through-fault current traverses a zone protected by a differential system, the transient flux produced in the current transformers is not detrimental as long as it remains within the substantially linear range of the magnetising characteristic. With fault current of appreciable magnitude and long transient time constant, the flux density will pass into the saturated region of the characteristic; this will not in itself produce a spill output from a pair of balancing current transformers provided that these are identical and equally burdened. A group of current transformers, though they may be of the same design, will not be completely identical, but a more important factor is inequality of burden. In the case of a differential system for a busbar, an external fault may be fed through a single circuit, the current being supplied to the busbar through all other circuits. The faulted circuit is many times more heavily loaded than the others and the corresponding current transformers are likely to be heavily saturated, while those of the other circuits are not. Severe unbalance is therefore probable, which, with a relay of normal burden, could exceed any acceptable current setting. For this reason such systems were at one time always provided with a time delay. This practice is, however, no longer acceptable.

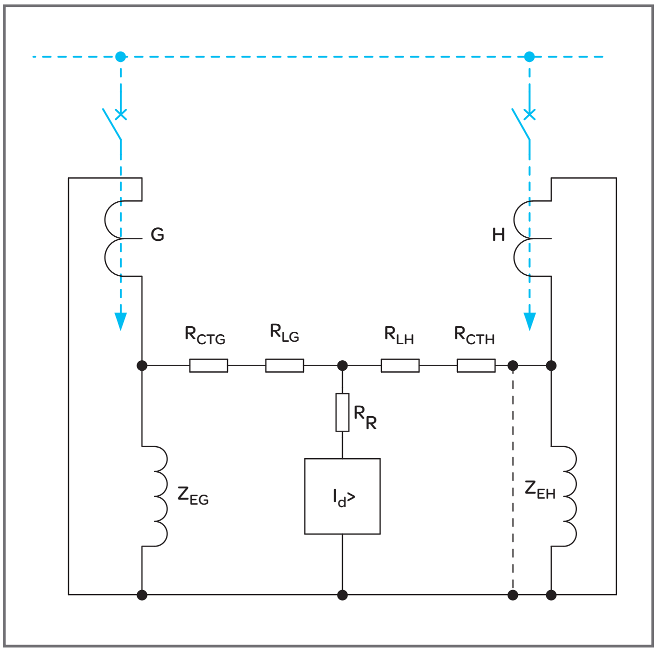

Figure C6.12:
Equivalent circuit of circulating current system

It is not feasible to calculate the spill current that may occur, but, fortunately this is not necessary; an alternative approach provides both the necessary information and the technique required to obtain a high performance.

An equivalent circuit, as in Figure C6.12, can represent a circulating current system.

The current transformers are replaced in the diagram by ideal current transformers feeding an equivalent circuit that represents the magnetising losses and secondary winding resistance, and also the resistance of the connecting leads. These circuits can then be interconnected as shown, with a relay connected to the junction points to form the complete equivalent circuit.

Saturation has the effect of lowering the exciting impedance, and is assumed to take place severely in current transformer H until, at the limit, the shunt impedance becomes zero and the CT can produce no output. This condition is represented by a short circuit, shown in broken line, across the exciting impedance. It should be noted that this is not the equivalent of a physical short circuit, since it is behind the winding resistance.

Applying the Thévenin method of solution, the voltage developed across the relay will be given by:

$$I_R = \frac{V_f}{R_R + R_{LH} + R_{CTH}} \qquad \textit{...Equation C6.1}$$

The current through the relay is given by:

$$= \frac{I_f\left(R_{LH} + R_{CTH}\right)}{R_R + R_{LH} + R_{CTH}} \qquad \textit{...Equation C6.2}$$

If R_R is small, I_R will approximate to I_F, which is unacceptable. On the other hand, if R_R is large I_R is reduced. Equation C6.2 can be written, with little error, as follows:

$$I_R = \frac{V_f}{R_R} = \frac{I_f\left(R_{LH} + R_{CTH}\right)}{R_R} \qquad \textit{...Equation C6.3}$$

or alternatively:

$$I_R R_R = V_f = I_f\left(R_{LH} + R_{CTH}\right) \qquad \textit{...Equation C6.4}$$

It is clear that, by increasing R_R, the spill current I_R can be reduced below any specified relay setting. R_R is frequently increased by the addition of a series-connected resistor which is known as the stabilising resistor.

It can also be seen from Equation C6.4 that it is only the voltage drop in the relay circuit at setting current that is important. The relay can be designed as a voltage measuring device consuming negligible current; and provided its setting voltage exceeds the value V_f of Equation C6.4, the system will be stable. In fact, the setting voltage need not exceed V_f, since the derivation of Equation C6.4 involves an extreme condition of unbalance between the G and H current transformers that is not completely realised. So a safety margin is built-in if the voltage setting is made equal to V_f.

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8. High impedance differential protection

It is necessary to realise that the value of I_f to be inserted in Equation C6.4 is the complete function of the fault current and the spill current I_R through the relay, in the limiting condition, will be of the same form. If the relay requires more time to operate than the effective duration of the d.c. transient component, or has been designed with special features to block the d.c. component, then this factor can be ignored and only the symmetrical value of the fault current need to be entered in Equation C6.4. If the relay setting voltage, V_S, is made equal to V_f, that is, $I_f (R_L + R_{CT})$, an inherent safety factor of the order of two will exist.

In the case of a faster relay, capable of operating in one cycle and with no special features to block the d.c. component, it is the r.m.s. value of the first offset wave that is significant. This value, for a fully offset waveform with no d.c. decrement, is $\sqrt{3}\, I_f$. If settings are then chosen in terms of the symmetrical component of the fault current, the $\sqrt{3}$ factor which has been ignored will take up most of the basic safety factor, leaving only a very small margin.

Finally, if a truly instantaneous relay were used, the relevant value of I_f would be the maximum offset peak. In this case, the factor has become less than unity, possibly as low as 0.7. It is therefore possible to rewrite Equation C6.4 as:

$$I_{SL} = \frac{K \times V_S}{R_L + R_{CT}} \qquad \text{...Equation C6.5}$$

where:

I_{SL} = stability of scheme current

V_S = relay circuit voltage setting

$R_L + R_{CT}$ = lead + CT winding resistance

K = factor depending on relay design (range 0.7 - 2.0)

It remains to be shown that the setting chosen is suitable.

The current transformers will have an excitation curve which has not so far been related to the relay setting voltage, the latter being equal to the maximum nominal voltage drop across the lead loop and the CT secondary winding resistance, with the maximum secondary fault current flowing through them. Under in-zone fault conditions it is necessary for the current transformers to produce sufficient output to operate the relay. This will be achieved provided the CT knee-point voltage exceeds the relay setting. In order to cater for errors, it is usual to specify that the current transformers should have a knee-point e.m.f. of at least twice the necessary setting voltage; a higher multiple is of advantage in ensuring a high speed of operation.

8.2 Effective setting or primary operating current

The minimum primary operating current is a further criterion of the design of a differential system. The secondary effective setting is the sum of the relay minimum operating current and the excitation losses in all parallel connected current transformers, whether carrying primary current or not. This summation should strictly speaking be vectorial, but is usually done arithmetically. It can be expressed as:

$$I_R = I_S + nI_{eS} \qquad \text{...Equation C6.6}$$

where:

I_R = effective setting current

I_S = relay circuit setting current

I_{eS} = CT excitation current at relay setting voltage

n = number of parallel - connected CTs

Having established the relay setting voltage from stability considerations, as shown in Section 8.1, and knowing the excitation characteristic of the current transformers, the effective setting can be computed. The secondary setting is converted to the primary operating current by multiplying by the turns ratio of the current transformers. The operating current so determined should be considered in terms of the conditions of the application.

For a phase and earth fault scheme the setting can be based on the fault current to be expected for minimum plant and maximum system outage conditions. However, it should be remembered that:

a. phase-phase faults give only 86% of the three-phase fault current

b. fault arc resistance and earth path resistance reduce fault currents somewhat

c. a reasonable margin should be allowed to ensure that relays operate quickly and decisively

It is desirable that the primary effective setting should not exceed 30% of the prospective minimum fault current.

In the case of a scheme exclusively for earth fault protection, the minimum earth fault current should be considered, taking into account any earthing impedance that might be present as well. Furthermore, in the event of a double phase to earth fault, regardless of the inter-phase currents, only 50% of the system e.m.f. is available in the earth path, causing a further reduction in the earth fault current.

The primary operating current must therefore be not greater than 30% of the minimum single-phase earth fault current. In order to achieve high-speed operation, it is desirable that settings should be still lower, particularly in the case of the solidly earthed power system. The transient component of the fault current in conjunction with unfavourable residual flux in the CT can cause a high degree of saturation and loss of output, possibly leading to a delay of several cycles additional to the natural operating time of the element.

This will not happen to any large degree if the fault current is a larger multiple of setting; for example, if the fault current is five times the scheme primary operating current and the CT knee-point e.m.f. is three times the relay setting voltage, the additional delay is unlikely to exceed one cycle.

8. High impedance differential protection

The primary operating current is sometimes designed to exceed the maximum expected circuit load in order to reduce the possibility of false operation under load current as a result of a broken CT lead. Desirable as this safeguard may be, it will be seen that it is better not to increase the effective current setting too much, as this will sacrifice some speed; the check feature in any case, maintains stability.

An overall earth fault scheme for a large distribution board may be difficult to design because of the large number of current transformers paralleled together, which may lead to an excessive setting. It may be advantageous in such a case to provide a three-element phase and earth fault scheme, mainly to reduce the number of current transformers paralleled into one group.

Extra-high-voltage substations usually present no such problem. Using the voltage-calibrated relay, the current consumption can be very small.

A simplification can be achieved by providing one relay per circuit, all connected to the CT paralleling buswires. This enables the trip circuits to be confined to the least area and reduces the risk of accidental operation.

8.3 Check feature

Schemes for earth faults only can be checked by a frame-earth system, applied to the switchboard as a whole, no subdivision being necessary. For phase fault schemes, the check will usually be a similar type of scheme applied to the switchboard as a single overall zone.

A set of current transformers separate from those used in the discriminating zones should be provided. No CT switching is required and no current transformers are needed for the check zone in bus-coupler and bus-section breakers.

8.4 Supervision of CT secondary circuits

Any interruption of a CT secondary circuit up to the paralleling interconnections will cause an unbalance in the system, equivalent to the load being carried by the relevant primary circuit. Even though this degree of spurious output is below the effective setting the condition cannot be ignored, since it is likely to lead to instability under any through fault condition.

Supervision can be carried out to detect such conditions by connecting a sensitive alarm relay across the bus wires of each zone. For a phase and earth fault scheme, an internal three-phase rectifier can be used to effect a summation of the bus wire voltages on to a single alarm element; see Figures C6.13 and C6.14.

The alarm relay is set so that operation does not occur with the protection system healthy under normal load. Subject to this proviso, the alarm relay is made as sensitive as possible; the desired effective setting is 125 primary amperes or 10% of the lowest circuit rating, whichever is the greater.

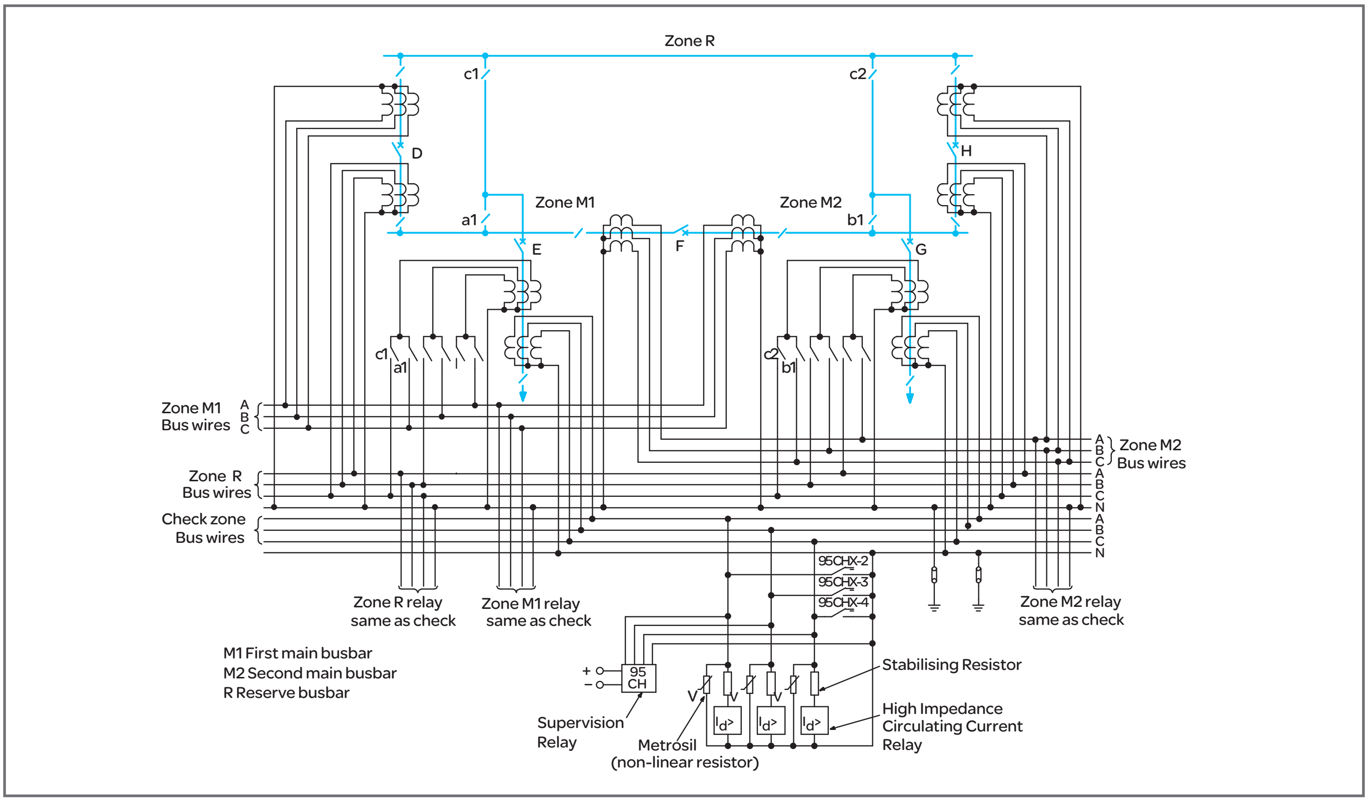

Figure C6.13:
A.C. circuits for high impedance circulating current scheme for duplicate busbars

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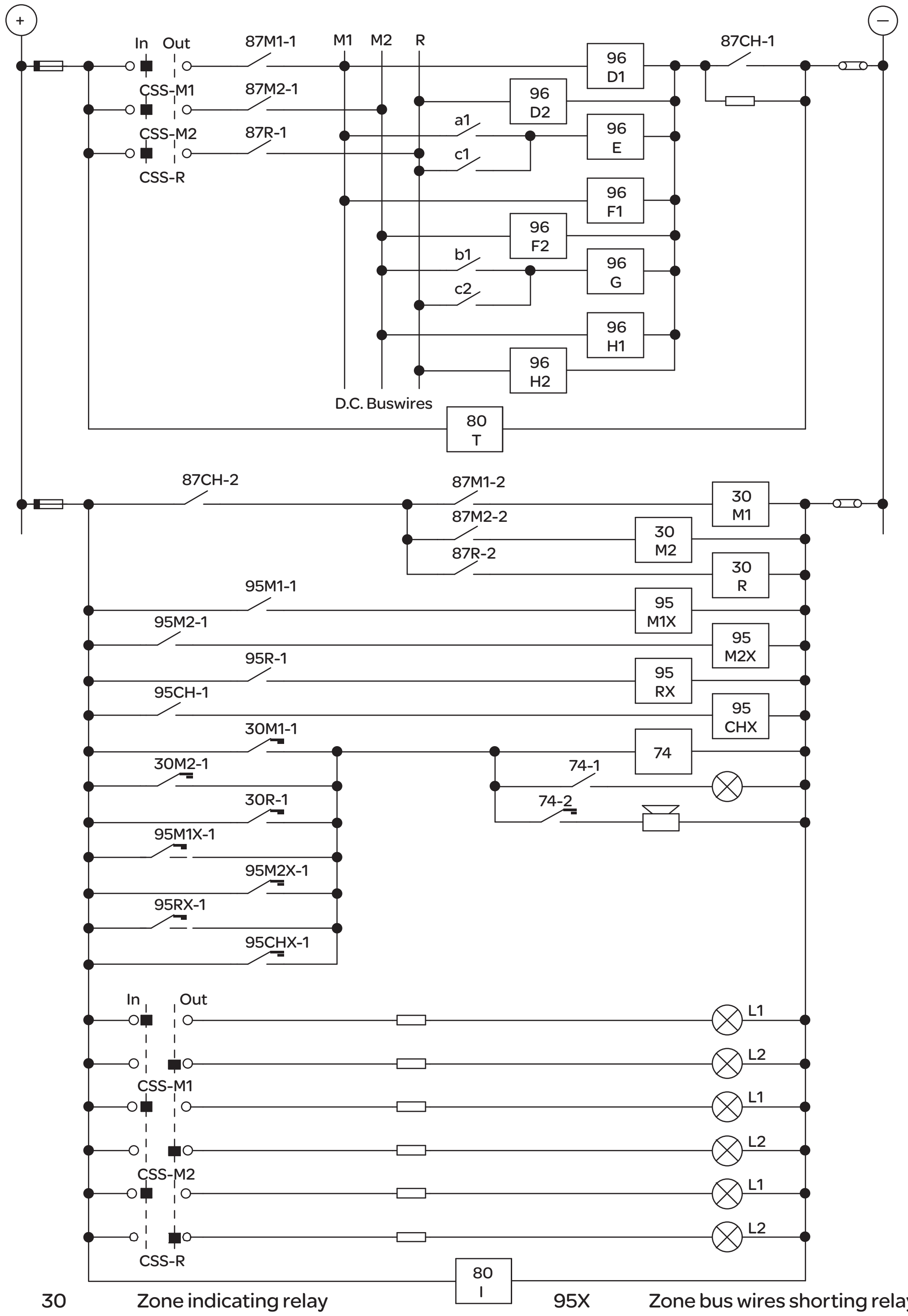
8. High impedance differential protection



30	Zone indicating relay	95X	Zone bus wires shorting relay
74	Alarm cancellation relay	CSS	Control selector switch
80	D.C. volts supervision relay	L1	Indicating lamp protection in service
87	High impedance circulating current relay	L2	Indicating lamp protection out of service
95	Bus wires supervision relay		

Figure C6.14:
D.C. circuits for high impedance circulating current scheme

8. High impedance differential protection

Since a relay of this order of sensitivity is likely to operate during through-faults, a time delay, typically of three seconds, is applied to avoid unnecessary alarm signals.

8.5 Arrangement of CT connections

It is shown in Equation C6.4 how the setting voltage for a given stability level is directly related to the resistance of the CT secondary leads. This should therefore be kept to a practical minimum. Taking into account the practical physical laying of auxiliary cables, the CT bus wires are best arranged in the form of a ring around the switchgear site.

In a double bus installation, the CT leads should be taken directly to the isolator selection switches. The usual routing of cables on a double bus site is as follows:

a. current transformers to marshalling kiosk

b. marshalling kiosk to bus selection isolator auxiliary switches

c. interconnections between marshalling kiosks to form a closed ring

The relay for each zone is connected to one point of the ring bus wire. For convenience of cabling, the main zone relays will be connected through a multicore cable between the relay panel and the bus section-switch marshalling cubicle. The reserve bar zone and the check zone relays will be connected together by a cable running to the bus coupler circuit breaker marshalling cubicle. It is possible that special circumstances involving onerous conditions may over-ride this convenience and make connection to some other part of the ring desirable.

Connecting leads will usually be not less than 7/0.67mm (2.5mm²), but for large sites or in other difficult circumstances it may be necessary to use cables of, for example 7/1.04mm (6mm²) for the bus wire ring and the CT connections to it. The cable from the ring to the relay need not be of the larger section.

When the reserve bar is split by bus section isolators and the two portions are protected as separate zones, it is necessary to common the bus wires by means of auxiliary contacts, thereby making these two zones into one when the section isolators are closed.

8.6 Summary of practical details

This section provides a summary of practical considerations when implementing a high-impedance busbar protection scheme.

8.6.1 Designed stability level

For normal circumstances, the stability level should be designed to correspond to the switchgear rating; even if the available short-circuit power in the system is much less than this figure, it can be expected that the system will be developed up to the limit of rating.

8.6.2 Current transformers

Current transformers must have identical turns ratios, but a turns error of one in 400 is recognised as a reasonable manufacturing tolerance. Also, they should preferably be of similar design; where this is not possible the magnetising characteristics should be reasonably matched.

Current transformers for use with high impedance protection schemes should meet the requirements of Class PX of IEC 60044-1.

8.6.3 Setting voltage

The setting voltage is given by the equation

$$V_s > I_f (R_L + R_{CT})$$

where:

V_s = relay circuit voltage setting

I_f = steady-state through fault current

R_L = CT lead loop resistance

R_{CT} = CT secondary winding resistance

8.6.4 Knee-point voltage of current transformers

This is given by the formula

$$V_K \geq 2V_S$$

8.6.5 Effective setting (secondary)

The effective setting of the relay is given by

$$I_R = I_S + nI_{eS}I_R$$

where:

I_S = relay circuit current setting

I_{eS} = CT excitation current at voltage setting

n = number of CTs in parallel

For the primary fault setting multiply I_R by the CT turns ratio.

8.6.6 Current transformer secondary rating

It is clear from Equations C6.4 and C6.6 that it is advantageous to keep the secondary fault current low; this is done by making the CT turns ratio high. It is common practice to use current transformers with a secondary rating of 1A.

It can be shown that there is an optimum turns ratio for the current transformers; this value depends on all the application parameters but is generally about 2000/1. Although a lower ratio, for instance 400/1, is often employed, the use of the optimum ratio can result in a considerable reduction in the physical size of the current transformers.

8.6.7 Peak voltage developed by current transformers

Under in-zone fault conditions, a high impedance relay constitutes an excessive burden to the current transformers, leading to the development of a high voltage; the voltage waveform will be highly distorted but the peak value may be many times the nominal saturation voltage.

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8. High impedance differential protection

When the burden resistance is finite although high, an approximate formula for the peak voltage is:

$$V_P = 2\sqrt{2V_K\,(V_F - V_K)}$$ ...Equation C6.7

where:

V_P = peak voltage developed

V_K = knee-point voltage

V_F = prospective voltage in absence of saturation

This formula does not hold for the open circuit condition and is inaccurate for very high burden resistances that approximate to an open circuit, because simplifying assumptions used in the derivation of the formula are not valid for the extreme condition.

Another approach applicable to the open circuit secondary condition is:

$$V_P = \sqrt{2}\,\frac{I_f}{I_{ek}}\,V_K$$ ...Equation C6.8

where:

I_f = fault current

I_{ek} = exciting current at knee - point voltage

V_K = knee - point voltage

Any burden connected across the secondary will reduce the voltage, but the value cannot be deduced from a simple combination of burden and exciting impedances.

These formulae are therefore to be regarded only as a guide to the possible peak voltage. With large current transformers, particularly those with a low secondary current rating, the voltage may be very high, above a suitable insulation voltage. The voltage can be limited without detriment to the scheme by connecting a ceramic non-linear resistor in parallel with the relay having a characteristic given by:

$$V = C I^{\beta}$$

where C is a constant depending on dimensions and β is a constant in the range 0.2-0.25.

The current passed by the non-linear resistor at the relay voltage setting depends on the value of C; in order to keep the shunting effect to a minimum it is recommended to use a non-linear resistor with a value of C of 450 for relay voltages up to 175V and one with a value of C of 900 for setting voltages up to 325V.

8.6.8 High impedance relay

Instantaneous attracted armature relays are used. Simple fast-operating relays would have a low safety factor constant in the stability equation, Equation C6.5, as discussed in Section 8.1. The performance is improved by series-tuning the relay coil, thereby making the circuit resistive in effect. Inductive reactance would tend to reduce stability, whereas the action of capacitance is to block the unidirectional transient component of fault current and so raise the stability constant.

An alternative technique used in some relays is to apply the limited spill voltage principle shown in Equation C6.4. A tuned element is connected via a plug bridge to a chain of resistors; and the relay is calibrated in terms of voltage.

9. Low impedance biased differential protection

The principles of low impedance differential protection have been described in Chapter [C2: Line Differential Protection, Section 4], including the principle advantages to be gained by the use of a bias technique. Most modern busbar protection schemes use this technique.

The principles of a check zone, zone selection, and tripping arrangements can still be applied. Current transformer secondary circuits are not switched directly by isolator contacts but instead by isolator repeat relays after a secondary stage of current transformation. These switching relays form a replica of the busbar within the protection and provide the complete selection logic.

9.1 Stability

With some biased relays, the stability is not assured by the through current bias feature alone, but is enhanced by the addition of a stabilising resistor, having a value which may be calculated as follows.

The through current will increase the effective relay minimum operating current for a biased relay as follows:

$$I_R = I_S + BI_F$$

where:

I_R = effective minimum oprating current

I_S = relay setting current

9. Low impedance biased differential protection

I_F = through fault current

B = percentage restraint

As I_F is generally much greater than I_S, the relay effective current, $I_R = B\ I_F$ approximately.

From Equation C6.4, the value of stabilising resistor is given by:

$$R_R = \frac{I_f\left(R_{LH} + R_{CTH}\right)}{I_R} = \frac{R_{LH} + R_{CTH}}{B}$$

It is interesting to note that the value of the stabilising resistance is independent of current level, and that there would appear to be no limit to the through-faults stability level. This has been identified [Ref C6.1: The Behaviour of Current Transformers subjected to Transient Asymmetric Currents and the Effects on Associated Protective Relays] as 'The Principle of Infinite Stability'. The stabilising resistor still constitutes a significant burden on the current transformers during internal faults.

An alternative technique, used by some older systems described in Section 9.6, is to block the differential measurement during the portion of the cycle that a current transformer is saturated. If this is achieved by momentarily short-circuiting the differential path, a very low burden is placed on the current transformers. In this way the differential circuit of the relay is prevented from responding to the spill current.

It must be recognised though that the use of any technique for inhibiting operation, to improve stability performance for through faults, must not be allowed to diminish the ability of the relay to respond to internal faults.

9.2 Effective setting or primary operating current

For an internal fault, and with no through fault current flowing, the effective setting (I_R) is raised above the basic relay setting (I_S) by whatever biasing effect is produced by the sum of the CT magnetising currents flowing through the bias circuit. With low impedance biased differential schemes particularly where the busbar installation has relatively few circuits, these magnetising currents may be negligible, depending on the value of I_S.

The basic relay setting current was formerly defined as the minimum current required solely in the differential circuit to cause operation – Figure C6.15(a). This approach simplified analysis of performance, but was considered to be unrealistic, as in practice any current flowing in the differential circuit must flow in at least one half of the relay bias circuit causing the practical minimum operating current always to be higher than the nominal basic setting current. As a result, a later definition, as shown in Figure C6.15(b) was developed.

Conversely, it needs to be appreciated that applying the later definition of relay setting current, which flows through at least half the bias circuit, the notional minimum operation current in the differential circuit alone is somewhat less, as shown in Figure C6.15(b).

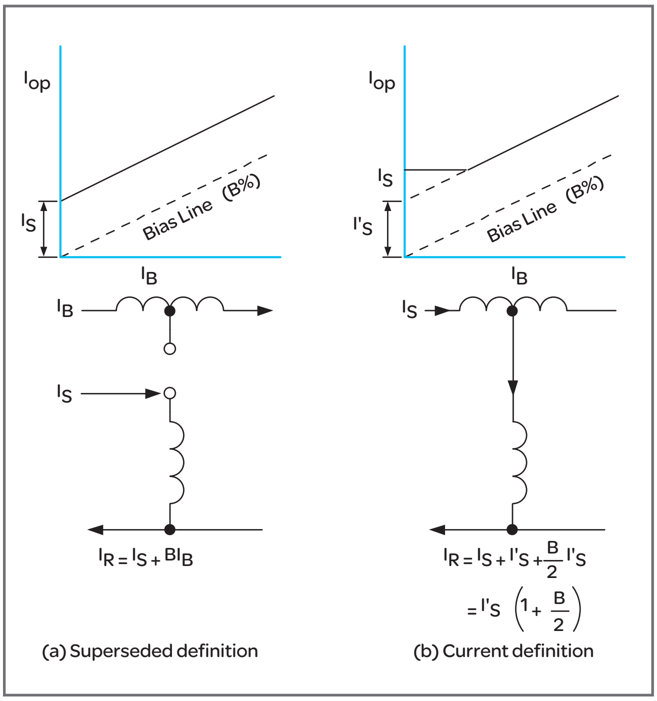

Figure C6.15:
Definitions of relay setting current for biased relays

Using the definition presently applicable, the effective minimum primary operating current

$= N\ [\ I_S + B \sum I_{eS}\ ]$

where:

N = CT ratio

Unless the minimum effective operating current of a scheme has been raised deliberately to some preferred value, it will usually be determined by the check zone, when present, as the latter may be expected to involve the greatest number of current transformers in parallel.

A slightly more onerous condition may arise when two discriminating zones are coupled, transiently or otherwise, by the closing of primary isolators.

It is generally desirable to attain an effective primary operating current that is just greater than the maximum load current, to prevent the busbar protection from operating spuriously from load current should a secondary circuit wiring fault develop. This consideration is particularly important where the check feature is either not used or is fed from common main CTs.

9.3 Check feature

For some low impedance schemes, only one set of main CTs is required. This seems to contradict the general principle of all busbar protection systems with a check feature that complete duplication of all equipment is required, but it is

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9. Low impedance biased differential protection

claimed that the spirit of the checking principle is met by making operation of the protection dependent on two different criteria such as directional and differential measurements.

In the scheme, described in Section 9.6, the provision of auxiliary CTs as standard for ratio matching also provides a ready means for introducing the check feature duplication at the auxiliary CTs and onwards to the relays. This may be an attractive compromise when only one set of main CTs is available.

9.4 Supervision of CT secondary circuits

In low impedance schemes the integrity of the CT secondary circuits can also be monitored. A current operated auxiliary relay, or element of the main protection equipment, may be applied to detect any unbalanced secondary currents and give an alarm after a time delay. For optimum discrimination, the current setting of this supervision relay must be less than that of the main differential protection.

In modern busbar protection schemes, the supervision of the secondary circuits typically forms only a part of a comprehensive supervision facility.

9.5 Arrangement of CT connections

It is a common modern requirement of low impedance schemes that none of the main CT secondary circuits should be switched, in the previously conventional manner, to match the switching of primary circuit isolators.

The usual solution is to route all the CT secondary circuits back to the protection panel.

In static protection equipment it is undesirable to use isolator auxiliary contacts directly for the switching without some form of insulation barrier. Position transducers that follow the opening and closing of the isolators may provide the latter.

Alternatively, a simpler arrangement may be provided on multiple busbar systems where the isolators switch the auxiliary current transformer secondary circuits via auxiliary relays within the protection. These relays form a replica of the busbar and perform the necessary logic. It is therefore necessary to route all the current transformer secondary circuits to the relay to enable them to be connected into this busbar replica.

Some installations have only one set of current transformers available per circuit. Where the facility of a check zone is still required, this can still be achieved with the low impedance biased protection. In the past, connection was made to the auxiliary circuit current transformers at the input of the main and check zones in series, as shown in Figure C6.16.

9.6 Static low impedance biased differential protection

This older scheme conforms in general to the principles outlined earlier and comprises a system of standard modules that can be assembled to suit a particular busbar installation. Additional modules can be added at any time as the busbar is extended.

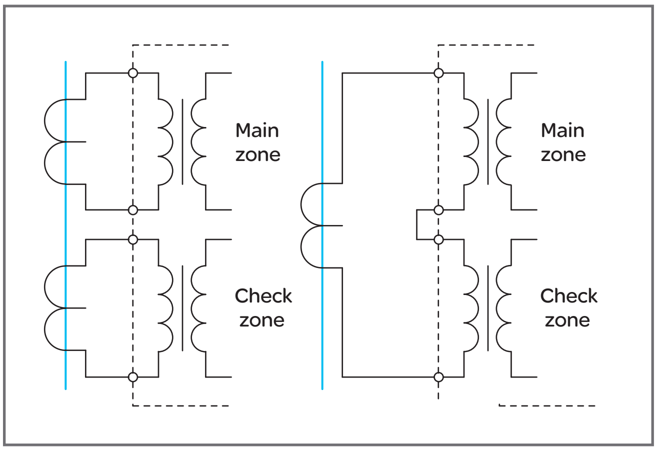

Figure C6.16: Alternative CT connections

A separate module is used for each circuit breaker and also one for each zone of protection. In addition to these there is a common alarm module and a number of power supply units. Ratio correction facilities are provided within each differential module to accommodate a wide range of CT mismatch.

Figure C6.17 shows the correlation between the circuit breakers and the protection modules for an old double busbar installation. In practice the modules are mounted in a multi-tier rack or cubicle.

The modules are interconnected via a multicore cable that is plugged into the back of the modules. There are five main groups of buswires, allocated for:

a. protection for main busbar

b. protection for reserve busbar

c. protection for the transfer busbar. When the reserve busbar is also used as a transfer bar then this group of buswires is used

d. auxiliary connections used by the protection to combine modules for some of the more complex busbar configurations

e. protection for the check zone

One extra module, not shown in this diagram, is plugged into the multicore bus. This is the alarm module, which contains the common alarm circuits and the bias resistors. The power supplies are also fed in through this module.

9.6.1 Bias

All zones of measurement are biased by the total current flowing to or from the busbar system via the feeders. This ensures that all zones of measurement will have similar fault sensitivity under all load conditions. The bias is derived from the check zone and fixed at 20% with a characteristic generally as shown in Figure C6.15(b). Thus some ratio mismatch is tolerable.

9. Low impedance biased differential protection

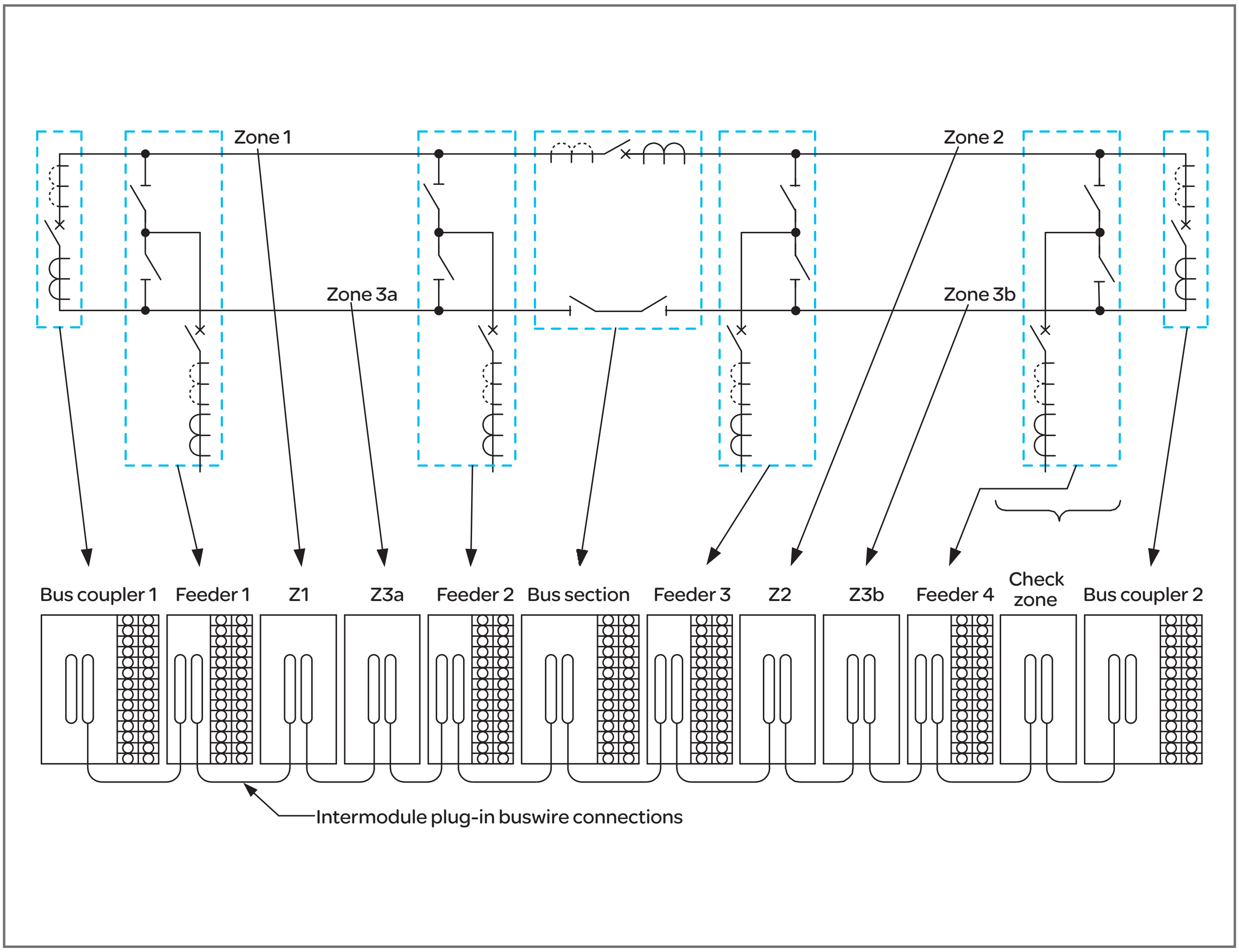

Figure C6.17:
Older type busbar protection showing correlation between circuit breakers and protection modules

9.6.2 Stability with saturated current transformers

The traditional method for stabilising a differential relay is to add a resistor to the differential path. Whilst this improves stability it increases the burden on the current transformer for internal faults. The technique used in this scheme overcomes this problem.

The scheme design detects when a CT is saturated and short-circuits the differential path for the portion of the cycle for which saturation occurs. The resultant spill current does not then flow through the measuring circuit and stability is assured.

This principle allows a very low impedance differential circuit to be developed that will operate successfully with relatively small CTs.

9.6.3 Operation for internal faults

If the CTs carrying fault current are not saturated there will be ample current in the differential circuit to operate the differential relay quickly for fault currents exceeding the minimum operating level, which is adjustable between 20%-200% rated current.

When the only CT(s) carrying internal fault current become saturated, it might be supposed that the CT saturation detectors may completely inhibit operation by short-circuiting the differential circuit. However, the resulting inhibit pulses remove only an insignificant portion of the differential current, so operation of the relay is therefore virtually unaffected.

9.6.4 Discrepancy alarm feature

As shown in Figure C6.18, each measuring module contains duplicated biased differential elements and also a pair of supervision elements, which are a part of a comprehensive supervision facility.

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9. Low impedance biased differential protection

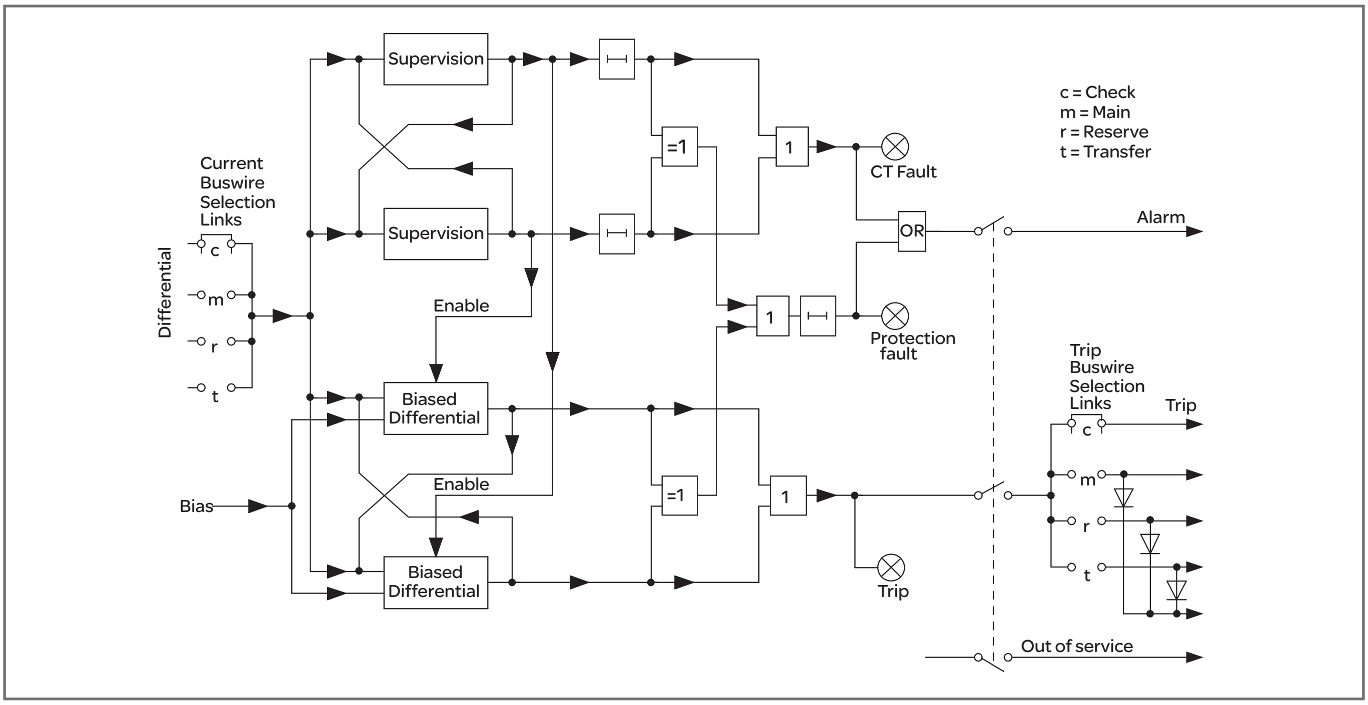

Figure C6.18:
Block diagram of measuring unit

This arrangement provides supervision of CT secondary circuits for both open circuit conditions and any impairment of the element to operate for an internal fault, without waiting for an actual system fault condition to show this up. For a zone to operate it is necessary for both the differential supervision element and the biased differential element to operate. For a circuit breaker to be tripped it requires the associated main zone to be operated and also the overall check zone, as shown in Figure C6.19.

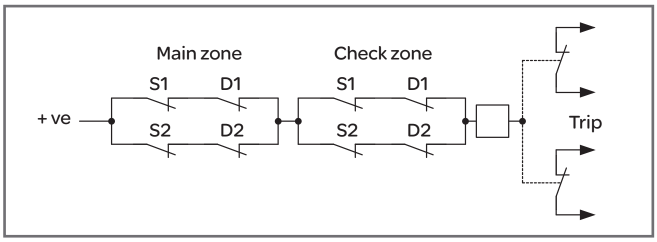

Figure C6.19:
Busbar protection trip logic

9.6.5 Master/follower measuring units

When two sections of a busbar are connected together by isolators it will result in two measuring elements being connected in parallel when the isolators are closed to operate the two busbar sections as a single bar. The fault current will then divide between the two measuring elements in the ratio of their impedances. If both of the two measuring elements are of low and equal impedance the effective minimum operating current of the scheme will be doubled.

This is avoided by using a 'master/follower' arrangement. By making the impedance of one of the measuring elements very much higher than the other it is possible to ensure that one of the relays retains its original minimum operation current. Then to ensure that both the parallel-connected zones are tripped the trip circuits of the two zones are connected in parallel. Any measuring unit can have the role of 'master' or 'follower' as it is selectable by means of a switch on the front of the module.

9.6.6 Transfer tripping for breaker failure

Serious damage may result, and even danger to life, if a circuit breaker fails to open when called upon to do so. To reduce this risk breaker fail protection schemes were developed some years ago.

These schemes are generally based on the assumption that if current is still flowing through the circuit breaker a set time after the trip command has been issued, then it has failed to function. The circuit breakers in the next stage back in the system are then automatically tripped.

For a bus coupler or section breaker this would involve tripping all the breakers to the adjacent zone, a facility that is included in the busbar protection scheme.

10. Numerical busbar protection schemes

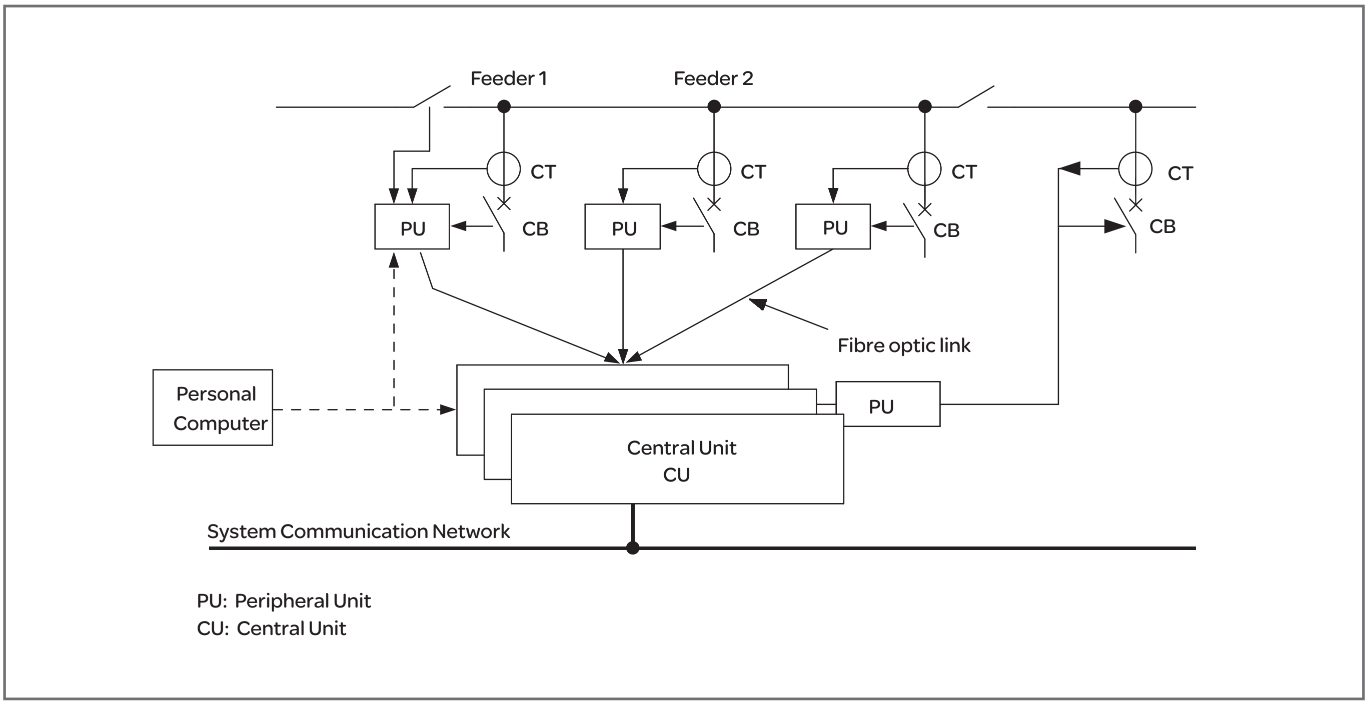

Figure C6.20:
Architecture for distributed bus bar protection

The application of numerical relay technology to busbar protection has lagged behind that of other protection functions. Static technology is no longer usual for such schemes, but numerical technology is now readily available. The very latest developments in the technology are included, such as extensive use of a data bus to link the various units involved, and fault tolerance against loss of a particular link by providing multiple communications paths. The development process has been very rigorous, because the requirements for busbar protection in respect of immunity to maloperation are very high.

The philosophy adopted is one of distributed processing of the measured values, as shown in Figure C6.20. Feeders each have their own processing unit, which collects together information on the state of the feeder (currents, voltages, CB and isolator status, etc.) and communicates it over high-speed fibre-optic data links to a central unit. For large substations, more than one central unit may be used, while in the case of small installations, all of the units can be co-located, leading to the appearance of a traditional centralised architecture.

For simple feeders, interface units at a bay may be used with the data transmitted to a single centrally located peripheral unit. The central unit performs the calculations required for the protection functions. Available protection functions are:

a. busbar protection

b. backup overcurrent protection

c. breaker failure

d. dead zone protection

In addition, monitoring functions such as CB and isolator monitoring, disturbance recording and transformer supervision are provided.

Because of the distributed topology used, synchronisation of the measurements taken by the peripheral units is of vital importance. A high stability numerically-controlled oscillator is fitted in each of the central and peripheral units, with time synchronisation between them. In the event of loss of the synchronisation signal, the high stability of the oscillator in the affected feeder unit(s) enables processing of the incoming data to continue without significant errors until synchronisation can be restored.

The peripheral units have responsibility for collecting the required data, such as voltages and currents, and processing it into digital form for onwards transmission to the central unit. Modelling of the CT response is included, to eliminate errors caused by effects such as CT saturation. Disturbance recording for the monitored feeder is implemented, for later download as required. Because each peripheral unit is concerned only with an individual feeder, the protection algorithms must reside in the central unit.

The differential protection algorithm can be much more sophisticated than with earlier technology, due to improvements in processing power. In addition to calculating the sum of the

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10. Numerical busbar protection schemes

measured currents, the algorithm can also evaluate differences between successive current samples, since a large change above a threshold may indicate a fault – the threshold being chosen such that normal load changes, apart from inrush conditions do not exceed the threshold. The same considerations can also be applied to the phase angles of currents, and incremental changes in them.

One advantage gained from the use of numerical technology is the ability to easily re-configure the protection to cater for changes in configuration of the substation. For example, addition of an extra feeder involves the addition of an extra peripheral unit, the fibre-optic connection to the central unit and entry via the MMI of the new configuration into the central unit. Figure C6.21 illustrates the latest numerical technology employed.

Figure C6.21:
Busbar protection relays using numerical technology (MiCOM P740 range)

10.1 Reliability considerations

In considering the introduction of numerical busbar protection schemes, users have been concerned with reliability issues such as security and availability. Conventional high impedance schemes have been one of the main protection schemes used for busbar protection. The basic measuring element is simple in concept and has few components. Calculation of stability limits and other setting parameters is straightforward and scheme performance can be predicted without the need for costly testing. Practically, high impedance schemes have proved to be a very reliable form of protection.

In contrast, modern numerical schemes are more complex, with a much greater range of facilities and a much high component count. Based on low impedance bias techniques, and with a greater range of facilities to set, setting calculations can also be more complex, studies of the comparative reliability of conventional high impedance schemes and modern numerical schemes have shown that assessing relative reliability is not quite so simple as it might appear. The numerical scheme has two advantages over its older counterpart:

a. there is a reduction in the number of external components such as switching and other auxiliary relays, many of the functions of which are performed internally within the software algorithms

b. numerical schemes include sophisticated monitoring features which provide alarm facilities if the scheme is faulty. In certain cases, simulation of the scheme functions can be performed on line from the CT inputs through to the tripping outputs and thus scheme functions can be checked on a regular basis to ensure a full operational mode is available at all times

Reliability analyses using fault tree analysis methods have examined issues of dependability (e.g. the ability to operate when required) and security (e.g. the ability not to provide spurious/ indiscriminate operation). These analyses have shown that:

a. dependability of numerical schemes is better than conventional high impedance schemes

b. security of numerical and conventional high impedance schemes are comparable

In addition, an important feature of numerical schemes is the in-built monitoring system. This considerably improves the potential availability of numerical schemes compared to conventional schemes as faults within the equipment and its operational state can be detected and alarmed. With the conventional scheme, failure to re-instate the scheme correctly after maintenance may not be detected until the scheme is required to operate. In this situation, its effective availability is zero until it is detected and repaired.

11. References

[C6.1] The Behaviour of Current Transformers subjected to Transient Asymmetric Currents and the Effects on Associated Protective Relays.

J. W. Hodgkiss.
CIGRE Paper Number 329, Session 15-25 June 1960.

C7

Transformer and Transformer-Feeder Protection

Network Protection & Automation Guide

Chapter C7

Transformer and Transformer-Feeder Protection

1. Introduction

The development of modern power systems has been reflected in the advances in transformer design. This has resulted in a wide range of transformers with sizes ranging from a few kVA to several hundred MVA being available for use in a wide variety of applications.

The considerations for a transformer protection package vary with the application and importance of the transformer. To reduce the effects of thermal stress and electrodynamic forces, it is advisable to ensure that the protection package used minimises the time for disconnection in the event of a fault occurring within the transformer. Small distribution transformers can be protected satisfactorily, from both technical and economic considerations, by the use of fuses or overcurrent relays. This results in time-delayed protection due to downstream co-ordination requirements. However, time-delayed fault clearance is unacceptable on larger power transformers used in distribution, transmission and generator applications, due to system operation/stability and cost of repair/ length of outage considerations.

Transformer faults are generally classified into six categories:

a. winding and terminal faults

b. core faults

c. tank and transformer accessory faults

d. on–load tap changer faults

e. abnormal operating conditions

f. sustained or uncleared external faults

For faults originating in the transformer itself, the approximate proportion of faults due to each of the causes listed above is shown in Figure C7.1.

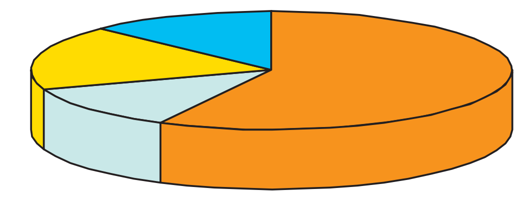

Figure C7.1:
Transformer fault statistics

2. Winding faults

A fault on a transformer winding is controlled in magnitude by the following factors:

a. source impedance

b. neutral earthing impedance

c. transformer leakage reactance

d. fault voltage

e. winding connection

Several distinct cases arise and are examined below.

2.1 Star-connected winding with neutral point earthed through an impedance

The winding earth fault current depends on the earthing impedance value and is also proportional to the distance of the fault from the neutral point, since the fault voltage will be directly proportional to this distance.

For a fault on a transformer secondary winding, the corresponding primary current will depend on the transformation ratio between the primary winding and the short-circuited secondary turns. This also varies with the position of the fault, so that the fault current in the transformer primary winding is proportional to the square of the earth fault current in resistance-earthed star winding fraction of the winding that is short-circuited. The effect is shown in Figure C7.2. Faults in the lower third of the winding produce very little current in the primary winding, making fault detection by primary current measurement difficult.

2.2 Star-connected winding with neutral point solidly earthed

The fault current is controlled mainly by the leakage reactance of the winding, which varies in a complex manner with the position of the fault. The variable fault point voltage is also an important factor, as in the case of impedance earthing. For

2. Winding faults

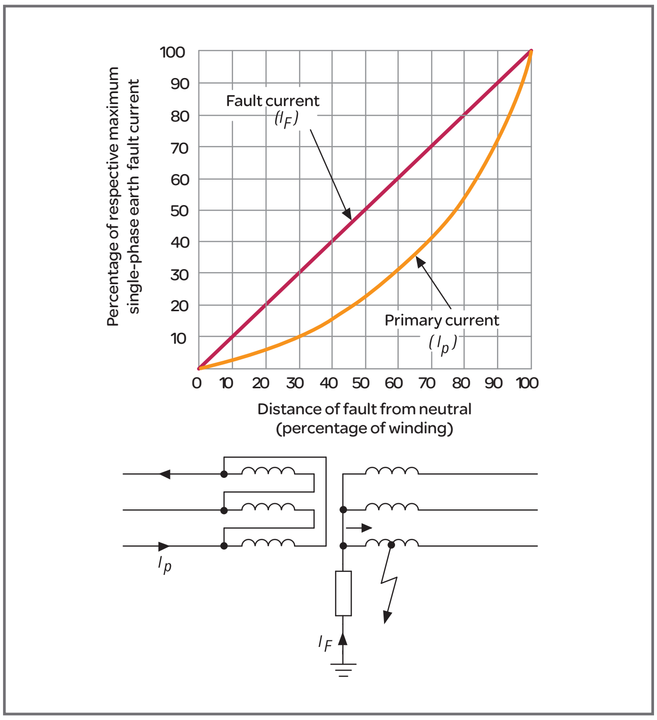

Figure C7.2:
Earth fault current in resistance-earthed star winding

faults close to the neutral end of the winding, the reactance is very low, and results in the highest fault currents. The variation of current with fault position is shown in Figure C7.3.

For secondary winding faults, the primary winding fault current is determined by the variable transformation ratio; as the secondary fault current magnitude stays high throughout the winding, the primary fault current is large for most points along the winding.

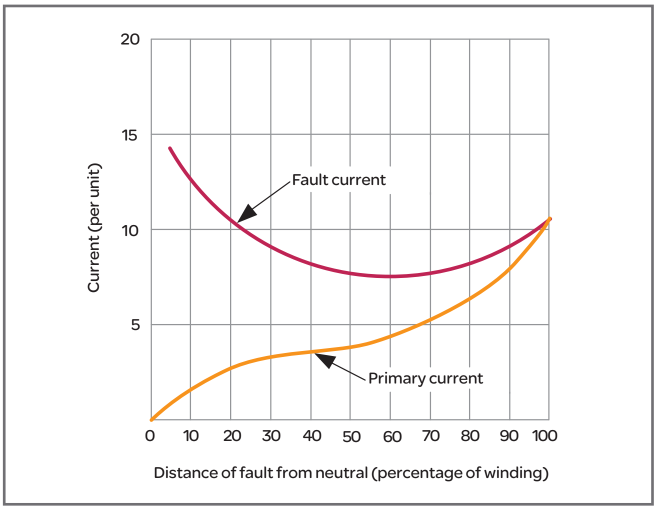

Figure C7.3:
Earth fault current in solidly earthed star winding

2.3 Delta-connected winding

No part of a delta-connected winding operates with a voltage to earth of less than 50% of the phase voltage. The range of fault current magnitude is therefore less than for a star winding. The actual value of fault current will still depend on the method of system earthing; it should also be remembered that the impedance of a delta winding is particularly high to fault currents flowing to a centrally placed fault on one leg. The impedance can be expected to be between 25% and 50%, based on the transformer rating, regardless of the normal balanced through-current impedance. As the prefault voltage to earth at this point is half the normal phase voltage, the earth fault current may be no more than the rated current, or even less than this value if the source or system earthing impedance is appreciable. The current will flow to the fault from each side through the two half windings, and will be divided between two phases of the system. The individual phase currents may therefore be relatively low, resulting in difficulties in providing protection.

2.4 Phase to phase faults

Faults between phases within a transformer are relatively rare; if such a fault does occur it will give rise to a substantial current comparable to the earth fault currents discussed in Section 2.2.

2.5 Interturn faults

In low voltage transformers, interturn insulation breakdown is unlikely to occur unless the mechanical force on the winding due to external short circuits has caused insulation degradation, or insulating oil (if used) has become contaminated by moisture.

A high voltage transformer connected to an overhead transmission system will be subjected to steep fronted impulse voltages, arising from lightning strikes, faults and switching operations. A line surge, which may be of several times the rated system voltage, will concentrate on the end turns of the winding because of the high equivalent frequency of the surge front. Part-winding resonance, involving voltages up to 20 times rated voltage may occur. The interturn insulation of the end turns is reinforced, but cannot be increased in proportion to the insulation to earth, which is relatively great. Partial winding flashover is therefore more likely. The subsequent progress of the fault, if not detected in the earliest stage, may well destroy the evidence of the true cause.

A short circuit of a few turns of the winding will give rise to a heavy fault current in the short-circuited loop, but the terminal currents will be very small, because of the high ratio of transformation between the whole winding and the short-circuited turns. The graph in Figure C7.4 shows the corresponding data for a typical transformer of 3.25% impedance with the short-circuited turns symmetrically located in the centre of the winding.

C7

2. Winding faults

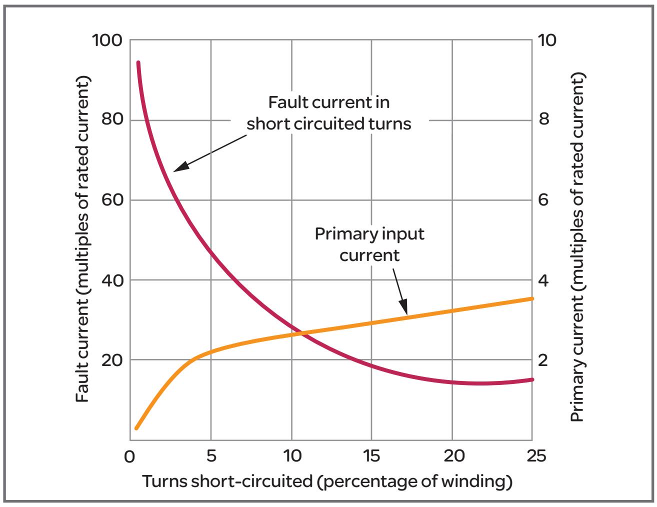

Figure C7.4:
Interturn fault current/number of turns short- circuited

2.6 Core faults

A conducting bridge across the laminated structures of the core can permit sufficient eddy-current to flow to cause serious overheating. The bolts that clamp the core together are always insulated to avoid this trouble. If any portion of the core insulation becomes defective, the resultant heating may reach a magnitude sufficient to damage the winding.

The additional core loss, although causing severe local heating, will not produce a noticeable change in input current and could not be detected by the normal electrical protection; it is nevertheless highly desirable that the condition should be detected before a major fault has been created. In an oil-immersed transformer, core heating sufficient to cause winding insulation damage will also cause breakdown of some of the oil with an accompanying evolution of gas. This gas will escape to the conservator, and is used to operate a mechanical relay; see Section 15.3.

2.7 Tank faults

Loss of oil through tank leaks will ultimately produce a dangerous condition, either because of a reduction in winding insulation or because of overheating on load due to the loss of cooling.

Overheating may also occur due to prolonged overloading, blocked cooling ducts due to oil sludging or failure of the forced cooling system, if fitted.

2.8 Externally applied conditions

Sources of abnormal stress in a transformer are:

a. overload

b. system faults

c. overvoltage

d. reduced system frequency

2.8.1 Overload

Overload causes increased 'copper loss' and a consequent temperature rise. Overloads can be carried for limited periods and recommendations for oil-immersed transformers are given in IEC 60354.

The thermal time constant of naturally cooled transformers lies between 2.5-5 hours. Shorter time constants apply in the case of force-cooled transformers.

2.8.2 System faults

System short circuits produce a relatively intense rate of heating of the feeding transformers, the copper loss increasing in proportion to the square of the per unit fault current. The typical duration of external short circuits that a transformer can sustain without damage if the current is limited only by the self-reactance is shown in Table C7.1. IEC 60076 provides further guidance on short-circuit withstand levels.

Maximum mechanical stress on windings occurs during the first cycle of the fault. Avoidance of damage is a matter of transformer design.

Transformer reactance (%)	Fault current (Multiple of rating)	Permitted fault duration (seconds)
4	25	2
5	20	2
6	16.6	2
7	14.2	2

Table C7.1:
Fault withstand levels

2.8.3 Overvoltages

Overvoltage conditions are of two kinds:

a. transient surge voltages

b. power frequency overvoltage

Transient overvoltages arise from faults, switching, and lightning disturbances and are liable to cause interturn faults, as described in Section 2.5. These overvoltages are usually limited by shunting the high voltage terminals to earth either with a plain rod gap or by surge diverters, which comprise a stack of short gaps in series with a non-linear resistor. The surge diverter, in contrast to the rod gap, has the advantage of extinguishing the flow of power current after discharging a surge, in this way avoiding subsequent isolation of the transformer.

Power frequency overvoltage causes both an increase in stress on the insulation and a proportionate increase in the working flux. The latter effect causes an increase in the iron loss and a disproportionately large increase in magnetising current. In

2. Winding faults

addition, flux is diverted from the laminated core into structural steel parts. The core bolts, which normally carry little flux, may be subjected to a large flux diverted from the highly saturated region of core alongside. This leads to a rapid temperature rise in the bolts, destroying their insulation and damaging coil insulation if the condition continues.

2.8.4 Reduced system frequency

Reduction of system frequency has an effect with regard to flux density, similar to that of overvoltage.

It follows that a transformer can operate with some degree of overvoltage with a corresponding increase in frequency, but operation must not be continued with a high voltage input at a low frequency. Operation cannot be sustained when the ratio of voltage to frequency, with these quantities given values in per unit of their rated values, exceeds unity by more than a small amount, for instance if $V/f > 1.1$. If a substantial rise in system voltage has been catered for in the design, the base of 'unit voltage' should be taken as the highest voltage for which the transformer is designed.

3. Magnetising inrush

The phenomenon of magnetising inrush is a transient condition that occurs primarily when a transformer is energised. It is not a fault condition, and therefore transformer protection must remain stable during the inrush transient.

Figure C7.5(a) shows a transformer magnetising characteristic. To minimise material costs, weight and size, transformers are generally operated near to the 'knee point' of the magnetising characteristic., only a small increase in core flux above normal operating levels will result in a high magnetising current.

Under normal steady-state conditions, the magnetising current associated with the operating flux level is relatively small (Figure C7.5(b)). However, if a transformer winding is energised at a voltage zero, with no remanent flux, the flux level during the first voltage cycle (2 x normal flux) will result in core saturation and a high non-sinusoidal magnetising current waveform – see Figure C7.5(c). This current is referred to as magnetising inrush current and may persist for several cycles.

A number of factors affect the magnitude and duration of the magnetising current inrush:

a. residual flux – worst-case conditions result in the flux peak value attaining 280% of normal value

b. point on wave switching

c. number of banked transformers

d. transformer design and rating

e. system fault level

The very high flux densities quoted above are so far beyond the normal working range that the incremental relative permeability of the core approximates to unity and the inductance of the winding falls to a value near that of the 'air-cored' inductance. The current wave, starting from zero, increases slowly at first, the flux having a value just above the residual value and the permeability of the core being

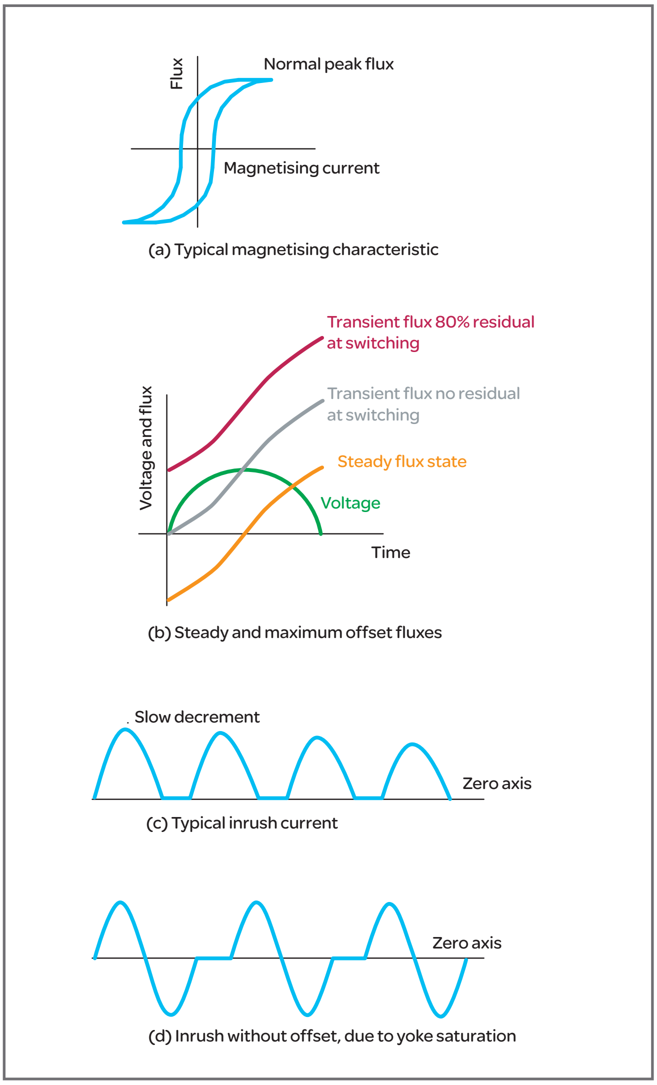

Figure C7.5:
Transformer magnetising inrush

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3. Magnetising inrush

moderately high. As the flux passes the normal working value and enters the highly saturated portion of the magnetising characteristic, the inductance falls and the current rises rapidly to a peak that may be 500% of the steady state magnetising current. When the peak is passed at the next voltage zero, the following negative half cycle of the voltage wave reduces the flux to the starting value, the current falling symmetrically to zero. The current wave is therefore fully offset and is only restored to the steady state condition by the circuit losses. The time constant of the transient has a range between 0.1 second (for a 100kVA transformer) to 1.0 second (for a large unit). As the magnetising characteristic is non-linear, the envelope of the transient current is not strictly of exponential form; the magnetising current can be observed to be still changing up to 30 minutes after switching on.

Although correct choice of the point on the wave for a single–phase transformer will result in no transient inrush, mutual effects ensure that a transient inrush occurs in all phases for three-phase transformers.

3.1 Harmonic content of inrush waveform

The waveform of transformer magnetising current contains a proportion of harmonics that increases as the peak flux density is raised to the saturating condition. The magnetising current of a transformer contains a third harmonic and progressively smaller amounts of fifth and higher harmonics. If the degree of saturation is progressively increased, not only will the harmonic content increase as a whole, but the relative proportion of fifth harmonic will increase and eventually exceed the third harmonic. At a still higher level the seventh would overtake the fifth harmonic but this involves a degree of saturation that will not be experienced with power transformers.

The energising conditions that result in an offset inrush current produce a waveform that is asymmetrical. Such a wave typically contains both even and odd harmonics. Typical inrush currents contain substantial amounts of second and third harmonics and diminishing amounts of higher orders. As with the steady state wave, the proportion of harmonics varies with the degree of saturation, so that as a severe inrush transient decays, the harmonic makeup of the current passes through a range of conditions.

4. Transformer overheating

The rating of a transformer is based on the temperature rise above an assumed maximum ambient temperature; under this condition no sustained overload is usually permissible. At a lower ambient temperature some degree of sustained overload can be safely applied. Short-term overloads are also permissible to an extent dependent on the previous loading conditions. IEC 60354 provides guidance in this respect.

The only certain statement is that the winding must not overheat; a temperature of about 95 °C is considered to be the normal maximum working value beyond which a further rise of 8°C-10°C, if sustained, will halve the insulation life of the unit.

Protection against overload is therefore based on winding temperature, which is usually measured by a thermal image technique. Protection is arranged to trip the transformer if excessive temperature is reached. The trip signal is usually routed via a digital input of a protection relay on one side of the transformer, with both alarm and trip facilities made available through programmable logic in the relay. Intertripping between the relays on the two sides of the transformer is usually applied to ensure total disconnection of the transformer.

Winding temperature protection may be included as a part of a complete monitoring package – see Section 18 for more details.

5. Transformer protection - overview

The problems relating to transformers described in Sections 2-4 above require some means of protection. Table C7.2 summarises the problems and the possible forms of protection that may be used. The following sections provide more detail on the individual protection methods. It is normal for a modern relay to provide all of the required protection functions in a single package, in contrast to electromechanical types that would require several relays complete with interconnections and higher overall CT burdens.

Fault type	Protection used
Primary winding phase-phase fault	Differential; overcurrent
Primary winding phase-earth fault	Differential; overcurrent
Secondary winding phase-phase fault	Differential
Secondary winding phase-earth fault	Differential; restricted earth fault
Interturn fault	Differential, Buchholz
Core fault	Differential, Buchholz
Tank fault	Differential, Buchholz; tank-earth
Overfluxing	Overfluxing
Overheating	Thermal

Table C7.2:
Transformer faults/protection

6. Transformer overcurrent protection

Fuses may adequately protect small transformers, but larger ones require overcurrent protection using a relay and CB, as fuses do not have the required fault breaking capacity.

6.1 Fuses

Fuses commonly protect small distribution transformers typically up to ratings of 1MVA at distribution voltages. In many cases no circuit breaker is provided, making fuse protection the only available means of automatic isolation. The fuse must have a rating well above the maximum transformer load current in order to withstand the short duration overloads that may occur. Also, the fuses must withstand the magnetising inrush currents drawn when power transformers are energised. High Rupturing Capacity (HRC) fuses, although very fast in operation with large fault currents, are extremely slow with currents of less than three times their rated value. It follows that such fuses will do little to protect the transformer, serving only to protect the system by disconnecting a faulty transformer after the fault has reached an advanced stage.

Table C7.3 shows typical ratings of fuses for use with 11kV transformers.

This table should be taken only as a typical example; considerable differences exist in the time characteristic of different types of HRC fuses. Furthermore grading with protection on the secondary side has not been considered.

6.2 Overcurrent relays

With the advent of ring main units incorporating SF6 circuit breakers and isolators, protection of distribution transformers can now be provided by overcurrent trips (e.g. tripping controlled by time limit fuses connected across the secondary windings of in-built current transformers) or by relays connected to current transformers located on the transformer primary side. Overcurrent relays are also used on larger transformers provided with standard circuit breaker control. Improvement in protection is obtained in two ways; the excessive delays of the HRC fuse for lower fault currents are avoided and an earth-fault tripping element is provided in addition to the overcurrent feature.

The time delay characteristic should be chosen to discriminate with circuit protection on the secondary side.

A high-set instantaneous relay element is often provided, the current setting being chosen to avoid operation for a secondary short circuit. This enables high-speed clearance of primary terminal short circuits.

Transformer rating		Fuse	
kVA	Full load current (A)	Rated current (A)	Operating time at 3 x rating(s)
100	5.25	16	3.0
200	10.5	25	3.0
315	15.8	36	10.0
500	26.2	50	20.0
1000	52.5	90	30.0

Table C7.3:
Typical fuse ratings

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7. Restrictor earth fault protection

Conventional earth fault protection using overcurrent elements fails to provide adequate protection for transformer windings. This is particularly the case for a star-connected winding with an impedance-earthed neutral, as considered in Section 2.1.

The degree of protection is very much improved by the application of restricted earth fault protection (or REF protection). This is a unit protection scheme for one winding of the transformer. It can be of the high impedance type as shown in Figure C7.6, or of the biased low-impedance type. For the high-impedance type, the residual current of three line current transformers is balanced against the output of a current transformer in the neutral conductor. In the biased low-impedance version, the three phase currents and the neutral current become the bias inputs to a differential element.

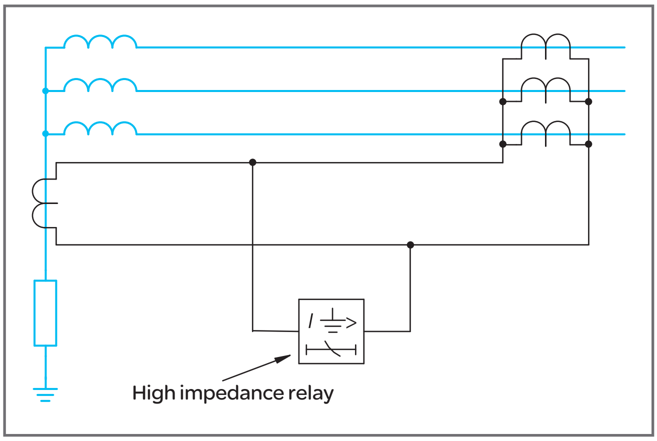

Figure C7.6:
Restricted earth fault protection for a star winding

The system is operative for faults within the region between current transformers, that is, for faults on the star winding in question. The system will remain stable for all faults outside this zone.

The gain in protection performance comes not only from using an instantaneous relay with a low setting, but also because the whole fault current is measured, not merely the transformed component in the HV primary winding (if the star winding is a secondary winding). Hence, although the prospective current level decreases as fault positions progressively nearer the neutral end of the winding are considered, the square law which controls the primary line current is not applicable, and with a low effective setting, a large percentage of the winding can be covered.

Restricted earth fault protection is often applied even when the neutral is solidly earthed. Since fault current then remains at a high value even to the last turn of the winding (Figure C7.2), virtually complete cover for earth faults is obtained. This is an improvement compared with the performance of systems that do not measure the neutral conductor current.

Earth fault protection applied to a delta-connected or unearthed star winding is inherently restricted, since no zero sequence components can be transmitted through the transformer to the other windings.

Both windings of a transformer can be protected separately with restricted earth fault protection, thereby providing high-speed protection against earth faults for the whole transformer with relatively simple equipment. A high impedance relay is used, giving fast operation and phase fault stability.

8. Differential protection

The restricted earth fault schemes described above in Section 7 depend entirely on the Kirchhoff principle that the sum of the currents flowing into a conducting network is zero. A differential system can be arranged to cover the complete transformer; this is possible because of the high efficiency of transformer operation, and the close equivalence of ampere-turns developed on the primary and secondary windings. Figure C7.7 illustrates the principle. Current transformers on the primary and secondary sides are connected to form a circulating current system.

8.1 Basic considerations for transformer differential protection

In applying the principles of differential protection to transformers, a variety of considerations have to be taken into account. These include:

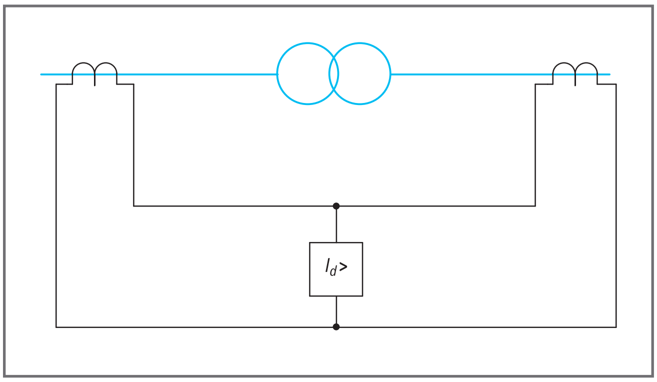

Figure C7.7:
Principle of transformer differential protection

8. Differential protection

a. correction for possible phase shift across the transformer windings (phase correction)

b. the effects of the variety of earthing and winding arrangements (filtering of zero sequence currents)

c. correction for possible unbalance of signals from current transformers on either side of the windings (ratio correction)

d. the effect of magnetising inrush during initial energisation

e. the possible occurrence of overfluxing

In traditional transformer differential schemes, the requirements for phase and ratio correction were met by the application of external interposing current transformers (ICTs), as a secondary replica of the main winding connections, or by a delta connection of the main CTs to provide phase correction only. Digital/numerical relays implement ratio and phase correction in the relay software instead, thus enabling most combinations of transformer winding arrangements to be catered for, irrespective of the winding connections of the primary CTs. This avoids the additional space and cost requirements of hardware interposing CTs.

8.2 Line current transformer primary ratings

Line current transformers have primary ratings selected to be approximately equal to the rated currents of the transformer windings to which they are applied. Primary ratings will usually be limited to those of available standard ratio CTs.

8.3 Phase correction

Correct operation of transformer differential protection requires that the transformer primary and secondary currents, as measured by the relay, are in phase. If the transformer is connected delta/star, as shown in Figure C7.8, balanced three-phase through current suffers a phase change of 30°. If left uncorrected, this phase difference would lead to the relay seeing through current as an unbalanced fault current, and result in relay operation. Phase correction must be implemented

Electromechanical and static relays use appropriate CT/ICT connections to ensure that the primary and secondary currents applied to the relay are in phase.

For digital and numerical relays, it is common to use star-connected line CTs on all windings of the transformer and compensate for the winding phase shift in software. Depending on relay design, the only data required in such circumstances may be the transformer vector group designation. Phase compensation is then performed automatically. Caution is required if such a relay is used to replace an existing electromechanical or static relay, as the primary and secondary line CTs may not have the same winding configuration. Phase compensation and associated relay data entry require more detailed consideration in such circumstances. Rarely, the available phase compensation facilities cannot accommodate the transformer winding connection, and in such cases interposing CTs must be used.

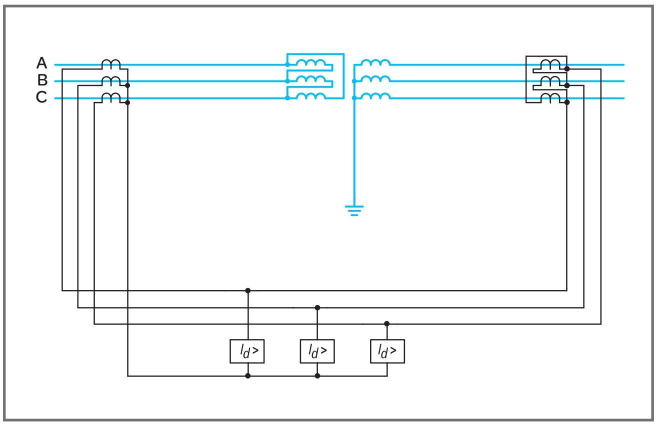

Figure C7.8:
Differential protection for two-winding delta/star transformer

8.4 Filtering of zero sequence currents

It is essential to provide some form of zero sequence filtering where a transformer winding can pass zero sequence current to an external earth fault. This is to ensure that out-of-zone earth faults are not seen by the transformer protection as an in-zone fault. This is achieved by use of delta-connected line CTs or interposing CTs for older relays, and hence the winding connection of the line and/or interposing CTs must take this into account, in addition to any phase compensation necessary. For digital/numerical relays, the required filtering is applied in the relay software. Table C7.4 summarises the phase compensation and zero sequence filtering requirements. An example of an incorrect choice of ICT connection is given in Section 19.1.

8.5 Ratio correction

Correct operation of the differential element requires that currents in the differential element balance under load and through fault conditions. As the primary and secondary line CT ratios may not exactly match the transformer rated winding currents, digital/ numerical relays are provided with ratio correction factors for each of the CT inputs. The correction factors may be calculated automatically by the relay from knowledge of the line CT ratios and the transformer MVA rating. However, if interposing CTs are used, ratio correction may not be such an easy task and may need to take into account a factor of $\sqrt{3}$ if delta-connected CTs or ICTs are involved. If the transformer is fitted with a tap changer, line CT ratios and correction factors are normally chosen to achieve current balance at the mid tap of the transformer. It is necessary to ensure that current mismatch due to off-nominal tap operation will not cause spurious operation.

The example in Section 19.2 provides an illustration of how ratio correction factors are used, and that of Section 9.3 shows how to set the ratio correction factors for a transformer with an unsymmetrical tap range.

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8. Differential protection

Transformer connection		Transformer phase shift	Clock face vector	Phase compensation required	HV Zero sequence filtering	LV Zero sequence filtering
Yy0		0°	0	0°	Yes	Yes
Zd0					Yes	
Dz0						Yes
Dd0						
Yz1	*Zy1*	-30°	1	30°	Yes	Yes
Yd1					Yes	
Dy1						Yes
Yy6		-180°	6	180°	Yes	Yes
Zd6					Yes	
Dz6						Yes
Dd6						
Yz11	*Zy11*	30	11	-30°	Yes	Yes
Yd11					Yes	
Dy11						Yes
YyH	*YzH*	(H / 12) x 360°	Hour 'H'	-(H / 12) x 360°	Yes	Yes
YdH	*ZdH*				Yes	
DzH	*DyH*					Yes
DdH						
'H': phase displacement 'clock number', according to IEC 60076-1						

Table C7.4:
Current transformer connections for power transformers of various vector groups

8.6 Bias setting

Bias is applied to transformer differential protection for the same reasons as any unit protection scheme – to ensure stability for external faults while allowing sensitive settings to pick up internal faults. The situation is slightly complicated if a tap changer is present. With line CT / ICT ratios and correction factors set to achieve current balance at nominal tap, an off-nominal tap may be seen by the differential protection as an internal fault. By selecting the minimum bias to be greater than the sum of the maximum tap of the transformer and possible CT errors, maloperation due to this cause is avoided. Some relays use a bias characteristic with three sections, as shown in Figure C7.9. The first section is set higher than the transformer magnetising current. The second section is set to allow for off-nominal tap settings, while the third has a larger bias slope beginning well above rated current to cater for heavy through-fault conditions.

8.7 Transformers with multiple windings

The unit protection principle remains valid for a system having more than two connections, so a transformer with three or more windings can still be protected by the application of the above principles. The power transformer has only one of its three windings connected to a source of supply, with the other two windings feeding loads, a relay with only two sets

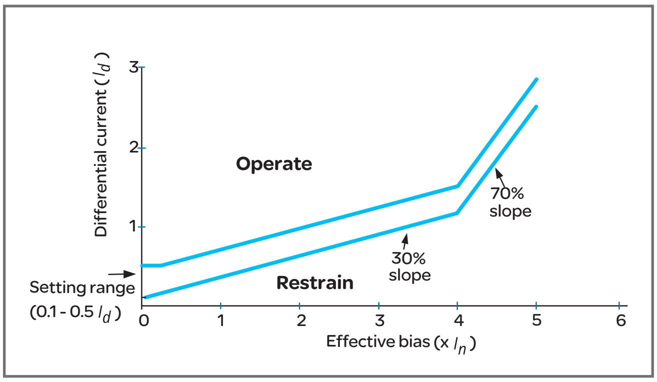

Figure C7.9:
Typical bias characteristic

of CT inputs can be used, connected as shown in Figure C7.10(a). The separate load currents are summated in the CT secondary circuits, and will balance with the infeed current on the supply side.

When more than one source of fault current infeed exists, there is a danger in the scheme of Figure C7.10(a) of current circulating between the two paralleled sets of current transformers without producing any bias. It is therefore important a relay is used with separate CT inputs for the two secondaries - Figure C7.10(b).

When the third winding consists of a delta-connected tertiary with no connections brought out, the transformer may be regarded as a two winding transformer for protection purposes and protected as shown in Figure C7.10(c).

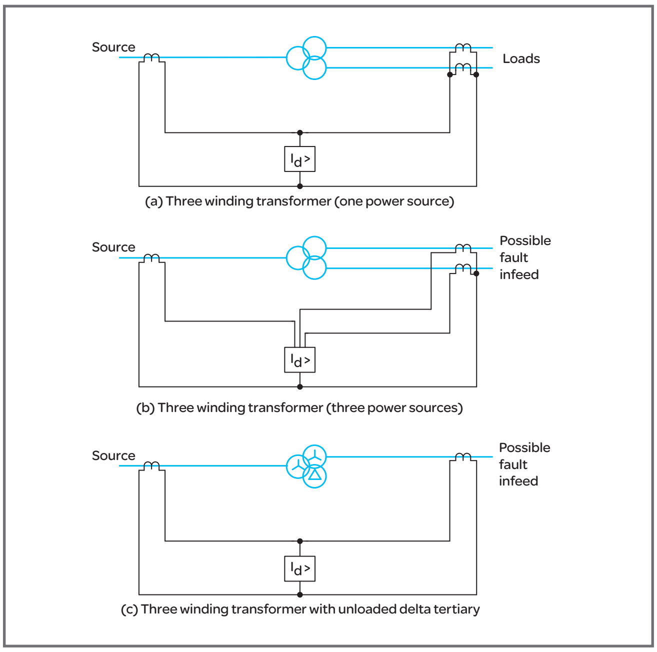

Figure C7.10: Differential protection arrangements for three-winding transformers (shown single phase for simplicity)

9. Differential protection stabilisation during magnetising inrush conditions

The magnetising inrush phenomenon described in Section 3 produces current input to the energised winding which has no equivalent on the other windings. The whole of the inrush current appears, therefore, as unbalance and the differential protection is unable to distinguish it from current due to an internal fault. The bias setting is not effective and an increase in the protection setting to a value that would avoid operation would make the protection of little value. Methods of delaying, restraining or blocking of the differential element must therefore be used to prevent mal-operation of the protection.

9.1 Time delay

Since the phenomenon is transient, stability can be maintained by providing a small time delay. However, because this time delay also delays operation of the relay in the event of a fault occurring at switch-on, the method is no longer used.

9.2 Harmonic restraint

The inrush current, although generally resembling an in-zone fault current, differs greatly when the waveforms are compared. The difference in the waveforms can be used to distinguish between the conditions.

As stated before, the inrush current contains all harmonic orders, but these are not all equally suitable for providing bias. In practice, only the second harmonic is used.

This component is present in all inrush waveforms. It is typical of waveforms in which successive half period portions do not repeat with reversal of polarity but in which mirror-image symmetry can be found about certain ordinates.

The proportion of second harmonic varies somewhat with the degree of saturation of the core, but is always present as long as the uni-directional component of flux exists. The amount varies according to factors in the transformer design. Normal fault currents do not contain second or other even harmonics, nor do distorted currents flowing in saturated iron cored coils under steady state conditions.

The output current of a current transformer that is energised into steady state saturation will contain odd harmonics but not even harmonics. However, should the current transformer be saturated by the transient component of the fault current, the resulting saturation is not symmetrical and even harmonics are introduced into the output current. This can have the advantage of improving the through fault stability performance of a differential relay.

The second harmonic is therefore an attractive basis for a stabilising bias against inrush effects, but care must be taken to ensure that the current transformers are sufficiently large so that the harmonics produced by transient saturation do not delay normal operation of the relay. The differential current is passed through a filter that extracts the second harmonic; this component is then applied to produce a restraining quantity sufficient to overcome the operating tendency due to the whole of the inrush current that flows in the operating circuit. By this means a sensitive and high-speed system can be obtained.

9.3 Inrush detection blocking – Gap detection technique

Another feature that characterizes an inrush current can be seen from Figure C7.5 where the two waveforms (c) and (d) have periods in the cycle where the current is zero. The minimum duration of this zero period is theoretically one quarter of the cycle and is easily detected by a simple timer t_1 that is set to $1/f$ seconds. Figure C7.11 shows the circuit in block diagram form. Timer t_1 produces an output only if the current is zero for a time exceeding $1/f$ seconds. It is reset when the instantaneous value of the differential current exceeds the setting reference.

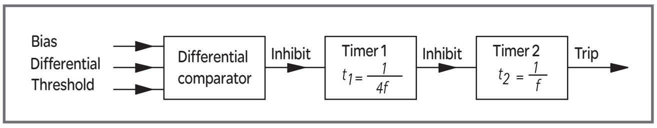

Figure C7.11:
Block diagram to show waveform gap-detecting principle

As the zero in the inrush current occurs towards the end of the cycle, it is necessary to delay operation of the differential relay by $1/f$ seconds to ensure that the zero condition can be detected if present. This is achieved by using a second timer t_2 that is held reset by an output from timer t_1.

When no current is flowing for a time exceeding $1/f$ seconds, timer t_2 is held reset and the differential relay that may be controlled by these timers is blocked. When a differential current exceeding the setting of the relay flows, t_1 timer is reset and timer t_2 times out to give a trip signal in $1/f$ seconds. If the differential current is characteristic of transformer inrush then timer t_2 will be reset on each cycle and the trip signal is blocked.

Some numerical relays may use a combination of the harmonic restraint and gap detection techniques for magnetising inrush detection.

10. Combined differential and resticted earth fault schemes

The advantages to be obtained by the use of restricted earth fault protection, discussed in Section 7, lead to the system being frequently used in conjunction with an overall differential system. The importance of this is shown in Figure C7.12, from which it will be seen that if the neutral of a star-connected winding is earthed through a resistance of one per unit, an overall differential system having an effective setting of 20% will detect faults in only 42% of the winding from the line end.

Implementation of a combined differential/REF protection scheme is made easy if a numerical relay with software ratio/phase compensation is used. All compensation is made internally in the relay.

Where software ratio/phase correction is not available, either summation transformer or auxiliary CTs can be used. The connections are shown in Figures C7.13 and C7.14 respectively.

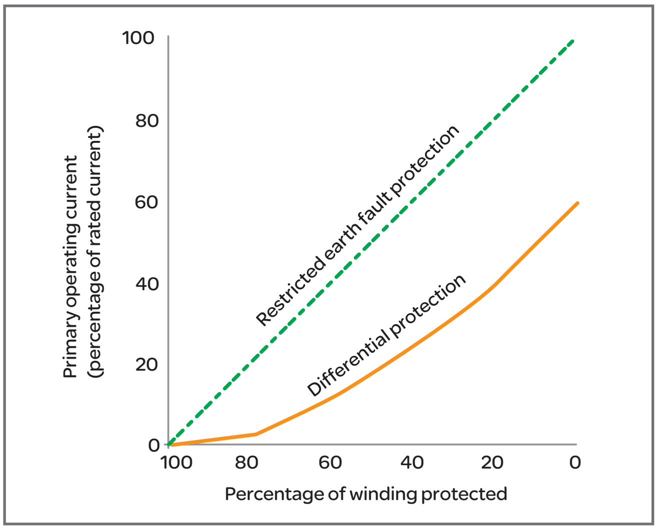

Figure C7.12:
Amount of winding protected when transformer is resistance earthed and ratings of transformer and resistor are equal

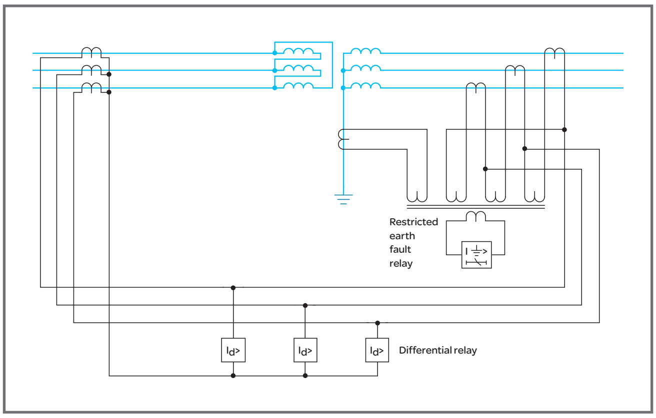

Figure C7.13:
Combined differential and earth fault protection using summation current transformer

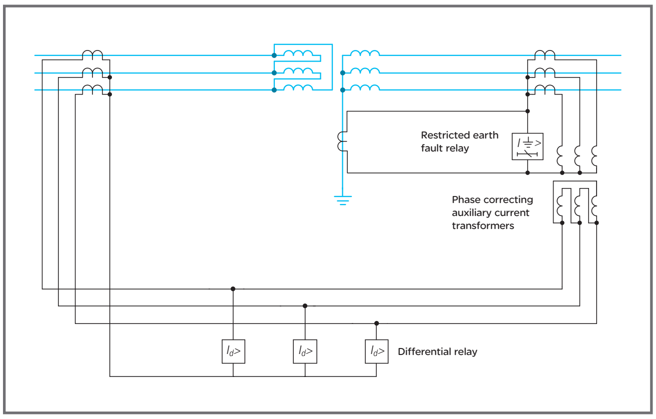

Figure C7.14:
Combined differential and restricted earth fault protection using auxiliary CTs

Care must be taken in calculating the settings, but the only significant disadvantage of the Combined Differential/REF scheme is that the REF element is likely to operate for heavy internal faults as well as the differential elements, thus making subsequent fault analysis somewhat confusing. However, the saving in CTs outweighs this disadvantage.

10.1 Application when an earthing transformer is connected within the protected zone

A delta-connected winding cannot deliver any zero sequence current to an earth fault on the connected system, any current that does flow is in consequence of an earthed neutral elsewhere on the system and will have a 2-1-1 pattern of current distribution between phases. When the transformer in question represents a major power feed, the system may be earthed at that point by an earthing transformer or earthing reactor. They are frequently connected to the system, close to the main supply transformer and within the transformer protection zone. Zero sequence current that flows through the earthing transformer during system earth faults will flow through the line current transformers on this side, and, without an equivalent current in the balancing current transformers, will cause unwanted operation of the relays.

The problem can be overcome by subtracting the appropriate component of current from the main CT output. The earthing transformer neutral current is used for this purpose. As this represents three times the zero sequence current flowing, ratio correction is required. This can take the form of interposing CTs of ratio 1/0.333, arranged to subtract their output from that of the line current transformers in each phase, as shown in Figure C7.15. The zero sequence component is cancelled, restoring balance to the differential system. Alternatively, numerical relays may use software to perform the subtraction, having calculated the zero sequence component internally.

10. Combined differential and resticted earth fault schemes

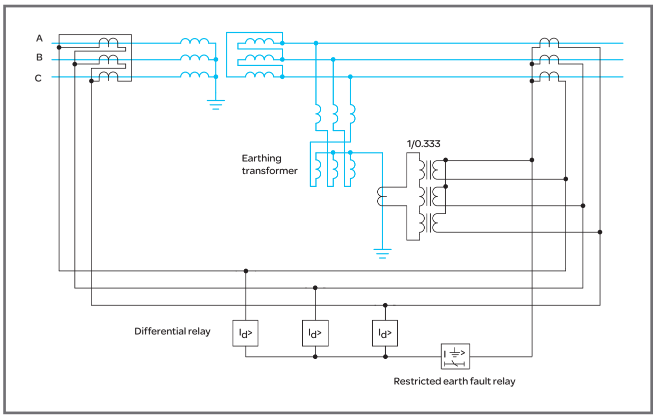

Figure C7.15:
Differential protection with in-zone earthing transformer, with restricted earth fault relay

A high impedance relay element can be connected in the neutral lead between current transformers and differential relays to provide restricted earth fault protection to the winding.

As an alternative to the above scheme, the circulating current system can be completed via a three-phase group of interposing transformers that are provided with tertiary windings connected in delta. This winding effectively short-circuits the zero sequence component and thereby removes it from the balancing quantities in the relay circuit; see Figure C7.16.

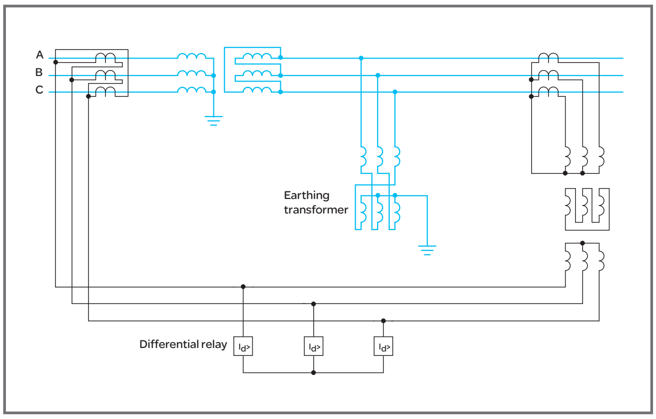

Figure C7.16:
Differential protection with in-zone earthing transformer; no earth fault relay

Provided restricted earth fault protection is not required, the scheme shown in Figure C7.16 has the advantage of not requiring a current transformer, with its associated mounting and cabling requirements, in the neutral-earth conductor. The scheme can also be connected as shown in Figure C7.17 when restricted earth fault protection is needed.

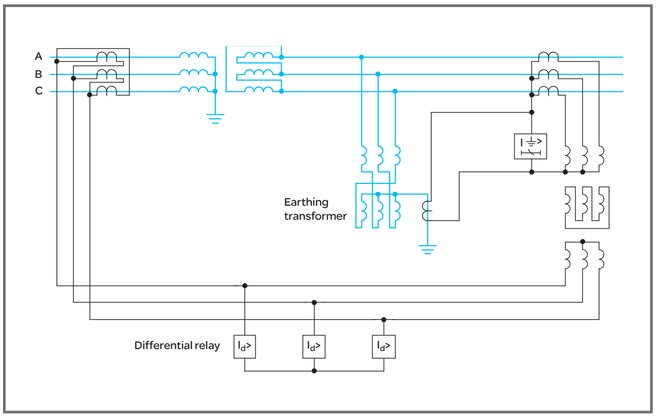

Figure C7.17:
Differential protection with in-zone earthing transformer, with alternative arrangement of restricted earth fault relay

C7

11. Earthing transformer protection

Earthing transformers not protected by other means can use the scheme shown in Figure C7.18. The delta-connected current transformers are connected to an overcurrent relay having three phase-fault elements. The normal action of the earthing transformer is to pass zero sequence current. The transformer equivalent current circulates in the delta formed by the CT secondaries without energising the relay. The latter may therefore be set to give fast and sensitive protection against faults in the earthing transformer itself.

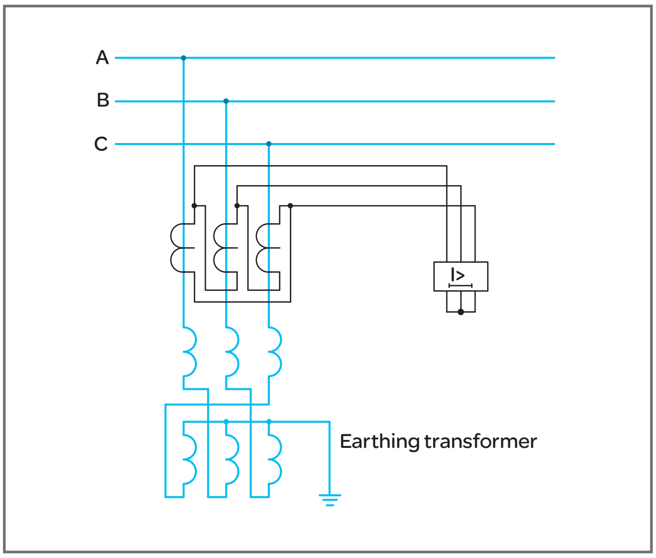

Figure C7.18:
Earthing transformer protection

12. Auto-transformer protection

Auto-transformers are used to couple EHV power networks if the ratio of their voltages is moderate. An alternative to Differential Protection that can be applied to auto-transformers is protection based on the application of Kirchhoff's law to a conducting network, namely that the sum of the currents flowing into all external connections to the network is zero.

A circulating current system is arranged between equal ratio current transformers in the two groups of line connections and the neutral end connections. If one neutral current transformer is used, this and all the line current transformers can be connected in parallel to a single element relay, thus providing a scheme responsive to earth faults only; see Figure C7.19(a).

If current transformers are fitted in each phase at the neutral end of the windings and a three-element relay is used, a differential system can be provided, giving full protection against phase and earth faults; see Figure C7.19(b). This provides high-speed sensitive protection. It is unaffected by ratio changes on the transformer due to tap-changing and is immune to the effects of magnetising inrush current.

It does not respond to interturn faults, a deficiency that is serious in view of the high statistical risk quoted in Section 1. Such faults, unless otherwise cleared, will be left to develop into earth faults, by which time considerably more damage to the transformer will have occurred.

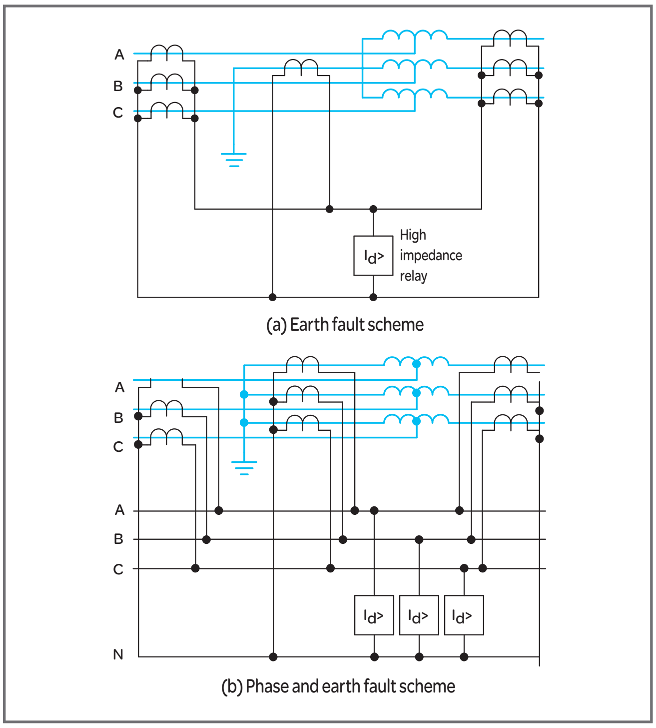

Figure C7.19:
Protection of auto-transformer by high impedance differential relays

12. Auto-transformer protection

In addition, this scheme does not respond to any fault in a tertiary winding. Unloaded delta-connected tertiary windings are often not protected; alternatively, the delta winding can be earthed at one point through a current transformer that energises an instantaneous relay. This system should be separate from the main winding protection. If the tertiary winding earthing lead is connected to the main winding neutral above the neutral current transformer in an attempt to make a combined system, there may be 'blind spots' which the protection cannot cover.

13. Overfluxing protection

The effects of excessive flux density are described in Section 2.8. Overfluxing arises principally from the following system conditions:

a. high system voltage

b. low system frequency

c. geomagnetic disturbances

The latter results in low frequency earth currents circulating through a transmission system.

Since momentary system disturbances can cause transient overfluxing that is not dangerous, time delayed tripping is required. The normal protection is an IDMT or definite time characteristic, initiated if a defined V/f threshold is exceeded. Often separate alarm and trip elements are provided. The alarm function would be definite time-delayed and the trip function would be an IDMT characteristic. A typical characteristic is shown in Figure C7.20.

Geomagnetic disturbances may result in overfluxing without the V/f threshold being exceeded. Some relays provide a 5th harmonic detection feature, which can be used to detect such a condition, as levels of this harmonic rise under overfluxing conditions.

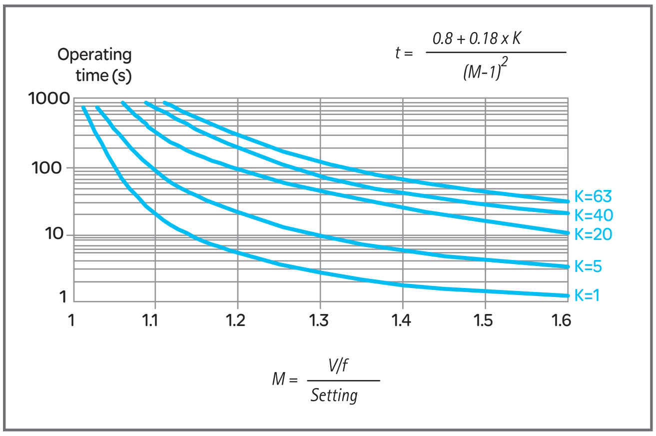

Figure C7.20:
Typical IDMT characteristic for overfluxing protection

14. Tank-earth protection

This is also known as Howard protection. If the transformer tank is nominally insulated from earth (an insulation resistance of 10 ohms being sufficient) earth fault protection can be provided by connecting a relay to the secondary of a current transformer the primary of which is connected between the tank and earth. This scheme is similar to the frame-earth fault busbar protection described in Chapter [C6: Busbar Protection].

15. Oil and gas devices

All faults below oil in an oil-immersed transformer result in localised heating and breakdown of the oil; some degree of arcing will always take place in a winding fault and the resulting decomposition of the oil will release gases. When the fault is of a very minor type, such as a hot joint, gas is released slowly, but a major fault involving severe arcing causes a very rapid release of large volumes of gas as well as oil vapour. The action is so violent that the gas and vapour do not have time to escape but instead build up pressure and bodily displace the oil.

When such faults occur in transformers having oil conservators, the fault causes a blast of oil to pass up the relief pipe to the conservator. A Buchholz relay is used to protect against such conditions. Devices responding to abnormally high oil pressure or rate-of-rise of oil pressure are also available and may be used in conjunction with a Buchholz relay.

15.1 Oil Pressure relief devices

The simplest form of pressure relief device is the widely used 'frangible disc' that is normally located at the end of an oil relief pipe protruding from the top of the transformer tank.

The surge of oil caused by a serious fault bursts the disc, so allowing the oil to discharge rapidly. Relieving and limiting the pressure rise avoids explosive rupture of the tank and consequent fire risk. Outdoor oil-immersed transformers are usually mounted in a catchment pit to collect and contain spilt oil (from whatever cause), thereby minimising the possibility of pollution.

A drawback of the frangible disc is that the oil remaining in the tank is left exposed to the atmosphere after rupture. This is avoided in a more effective device, the sudden pressure relief valve, which opens to allow discharge of oil if the pressure exceeds a set level, but closes automatically as soon as the internal pressure falls below this level. If the abnormal pressure is relatively high, the valve can operate within a few milliseconds, and provide fast tripping when suitable contacts are fitted.

The device is commonly fitted to power transformers rated at 2MVA or higher, but may be applied to distribution transformers rated as low as 200kVA, particularly those in hazardous areas.

15.2 Rapid pressure rise relay

This device detects rapid rise of pressure rather than absolute pressure and thereby can respond even quicker than the pressure relief valve to sudden abnormally high pressures. Sensitivities as low as 0.07bar/s are attainable, but when fitted to forced-cooled transformers the operating speed of the device may have to be slowed deliberately to avoid spurious tripping during circulation pump starts.

15.3 Buchholz protection

Buchholz protection is normally provided on all transformers fitted with a conservator. The Buchholz relay is contained in a cast housing which is connected in the pipe to the conservator, as in Figure C7.21.

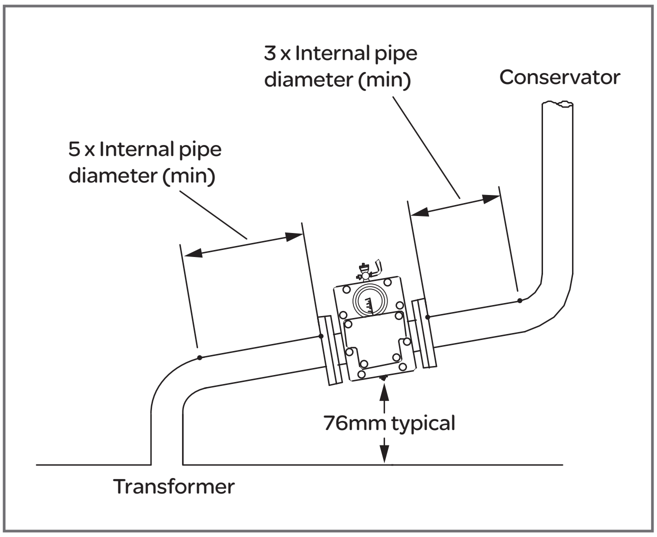

Figure C7.21:
Buchholz relay mounting arrangement

A typical Buchholz relay will have two sets of contacts. One is arranged to operate for slow accumulations of gas, the other for bulk displacement of oil in the event of a heavy internal fault. An alarm is generated for the former, but the latter is usually direct-wired to the CB trip relay.

The device will therefore give an alarm for the following fault conditions, all of which are of a low order of urgency:

a. hot spots on the core due to short circuit of lamination insulation

b. core bolt insulation failure

c. faulty joints

d. interturn faults or other winding faults involving only lower power infeeds

e. loss of oil due to leakage

When a major winding fault occurs, this causes a surge of oil, which displaces the lower float and thus causes isolation of the transformer. This action will take place for:

a. all severe winding faults, either to earth or interphase

b. loss of oil if allowed to continue to a dangerous degree

An inspection window is usually provided on either side of the gas collection space. Visible white or yellow gas indicates that insulation has been burnt, while black or grey gas indicates the presence of dissociated oil. In these cases the gas will probably be inflammable, whereas released air will not. A vent valve is provided on the top of the housing for the gas to be released or collected for analysis. Transformers with forced oil circulation may experience oil flow to/from the

15. Oil and gas devices

conservator on starting/stopping of the pumps. The Buchholz relay must not operate in this circumstance.

Cleaning operations may cause aeration of the oil. Under such conditions, tripping of the transformer due to Buchholz operation should be inhibited for a suitable period.

Because of its universal response to faults within the transformer, some of which are difficult to detect by other means, the Buchholz relay is invaluable, whether regarded as a main protection or as a supplement to other protection schemes. Tests carried out by striking a high voltage arc in a transformer tank filled with oil have shown that operation times of 0.05s-0.1s are possible. Electrical protection is generally used as well, either to obtain faster operation for heavy faults, or because Buchholz relays have to be prevented from tripping during oil maintenance periods. Conservators are fitted to oil-cooled transformers above 1000kVA rating, except those to North American design practice that use a different technique.

16. Transformer-feeder protection

A transformer-feeder comprises a transformer directly connected to a transmission circuit without the intervention of switchgear. Examples are shown in Figure C7.22.

The saving in switchgear so achieved is offset by increased complication in the necessary protection. The primary requirement is intertripping, since the feeder protection remote from the transformer will not respond to the low current fault conditions that can be detected by restricted earth fault and Buchholz protections.

Either unrestricted or restricted protection can be applied; moreover, the transformer-feeder can be protected as a single zone or be provided with separate protections for the feeder and the transformer. In the latter case, the separate protections can both be unit type systems. An adequate alternative is the combination of unit transformer protection with an unrestricted system of feeder protection, plus an intertripping feature.

16.1 Non-unit schemes

The following sections describe how non-unit schemes are applied to protect transformer-feeders against various types of fault.

16.1.1 Feeder phase and earth faults

High-speed protection against phase and earth faults can be provided by distance relays located at the end of the feeder remote from the transformer. The transformer constitutes an appreciable lumped impedance. It is therefore possible to set a distance relay zone to cover the whole feeder and reach part way into the transformer impedance. With a normal tolerance on setting thus allowed for, it is possible for fast Zone 1 protection to cover the whole of the feeder with certainty without risk of over-reaching to a fault on the low voltage side.

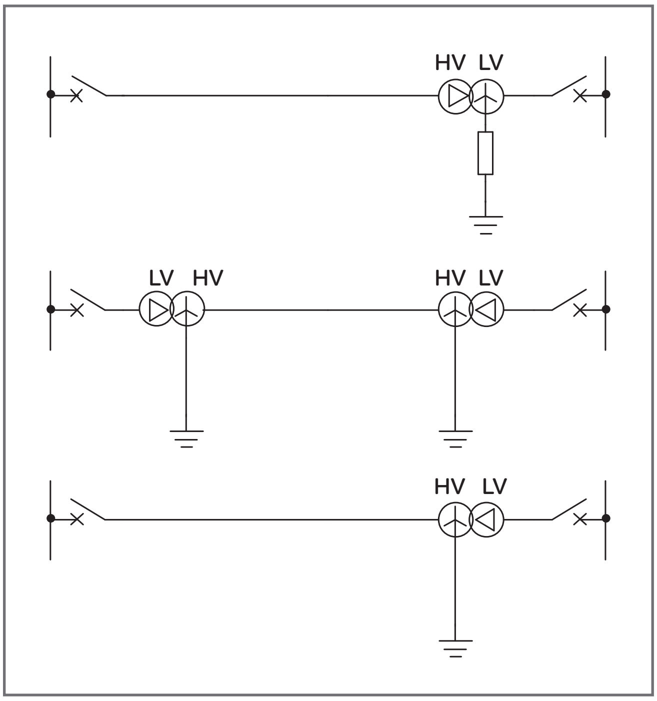

Figure C7.22:
Typical transformer-feeder circuits

Although the distance zone is described as being set 'half way into the transformer', it must not be thought that half the transformer winding will be protected. The effects of auto-transformer action and variations in the effective impedance of the winding with fault position prevent this, making the amount of winding beyond the terminals which is protected very small. The value of the system is confined to the feeder, which, as stated above, receives high-speed protection throughout.

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16. Transformer-feeder protection

16.1.2 Feeder phase faults

A distance scheme is not, for all practical purposes, affected by varying fault levels on the high voltage busbars and is therefore the best scheme to apply if the fault level may vary widely. In cases where the fault level is reasonably constant, similar protection can be obtained using high set instantaneous overcurrent relays.

These should have a low transient over-reach, defined as:

$$\frac{I_S - I_F}{I_F} \times 100\%$$

where:

I_s = setting current

I_F = steady - state r.m.s. value of fault current which when fully offset just operates the relay

The instantaneous overcurrent relays must be set without risk of them operating for faults on the remote side of the transformer.

Referring to Figure C7.23, the required setting to ensure that the relay will not operate for a fully offset fault I_{F2} is given by:

$$I_s = 1.2\ (1 + t)\ I_{F2}$$

where I_{F2} is the fault current under maximum source conditions, that is, when Z_S is minimum, and the factor of 1.2 covers possible errors in the system impedance details used for calculation of I_{F2}, together with relay and CT errors.

As it is desirable for the instantaneous overcurrent protection to clear all phase faults anywhere within the feeder under varying system operating conditions, it is necessary to have a relay setting less than I_{F1} in order to ensure fast and reliable operation.

Let the setting ratio resulting from setting I_S be

$$r = \frac{I_S}{I_{F1}}$$

Therefore,

$$rI_{F1} = 1.2\ (1 + t)\ I_{F2}$$

Hence,

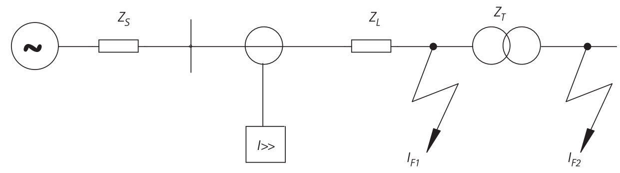
$$r = 1.2(1+t)\frac{Z_S + Z_L}{Z_S + Z_L + Z_T}$$

$$r = 1.2(1+t)\frac{Z_S + Z_L}{(1+x)(Z_S + Z_L)}$$

$$= \frac{1.2(1+t)}{1+x}$$

where:

$$x = \frac{Z_T}{Z_S + Z_L}$$



I_s = Relay setting = $1.2(1+t)I_{F2}$

t = Transient over-reach (p.u.)

		Setting ratio $r = \frac{I_S}{I_{F2}}$			
Transient over-reach (%)		5	25	50	100
$x = \frac{Z_T}{Z_S + Z_L}$	0.25	1.01	1.20	1.44	1.92
	0.5	0.84	1.00	1.20	1.60
	1.0	0.63	0.75	0.90	1.20
	2.0	0.42	0.50	0.60	0.80
	4.0	0.25	0.30	0.36	0.48
	8.0	0.14	0.17	0.20	0.27

Figure C7.23:
Over-reach considerations in the application of transformer-feeder protection

It can be seen that for a given transformer size, the most sensitive protection for the line will be obtained by using relays with the lowest transient overreach. It should be noted that where r is greater than 1, the protection will not cover the whole line. Also, any increase in source impedance above the minimum value will increase the effective setting ratios above those shown. The instantaneous protection is usually applied with a time delayed overcurrent element having a lower current setting. In this way, instantaneous protection is provided for the feeder, with the time-delayed element covering faults on the transformer.

When the power can flow in the transformer-feeder in either direction, overcurrent relays will be required at both ends. In the case of parallel transformer-feeders, it is essential that the overcurrent relays on the low voltage side be directional, operating only for fault current fed into the transformer-feeder, as described in Chapter [C1: Overcurrent Protection for Phase and Earth Faults, Section 14.3].

16.1.3 Earth faults

Instantaneous restricted earth fault protection is normally provided. When the high voltage winding is delta connected, a relay in the residual circuit of the line current transformers gives earth fault protection which is fundamentally limited to the feeder and the associated delta-connected transformer winding. The latter is unable to transmit any zero sequence current to a through earth fault.

16. Transformer-feeder protection

When the feeder is associated with an earthed star-connected winding, normal restricted earth fault protection as described in Section 7 is not applicable because of the remoteness of the transformer neutral.

Restricted protection can be applied using a directional earth fault relay. A simple sensitive and high-speed directional element can be used, but attention must be paid to the transient stability of the element. Alternatively, a directional IDMT relay may be used, the time multiplier being set low. The slight inverse time delay in operation will ensure that unwanted transient operation is avoided.

When the supply source is on the high voltage star side, an alternative scheme that does not require a voltage transformer can be used. The scheme is shown in Figure C7.24.

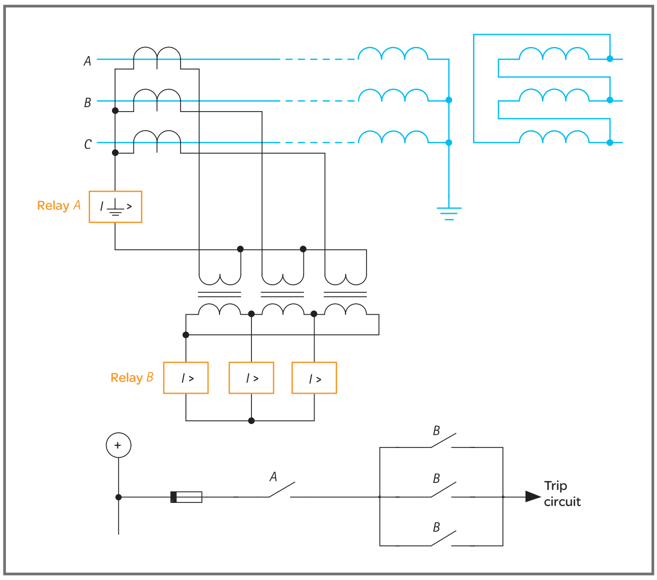


Figure C7.24:
Instantaneous protection of transformer-feeder

For the circuit breaker to trip, both relays A and B must operate, which will occur for earth faults on the feeder or transformer winding.

External earth faults cause the transformer to deliver zero sequence current only, which will circulate in the closed delta connection of the secondary windings of the three auxiliary current transformers. No output is available to relay B. Through phase faults will operate relay B, but not the residual relay A. Relay B must have a setting above the maximum load. As the earthing of the neutral at a receiving point is likely to be solid and the earth fault current will therefore be comparable with the phase fault current, high settings are not a serious limitation.

Earth fault protection of the low voltage winding will be provided by a restricted earth fault system using either three or four current transformers, according to whether the winding is delta or star-connected, as described in Section 7.

16.1.4 In-zone capacitance

The feeder portion of the transformer-feeder will have an appreciable capacitance between each conductor and earth. During an external earth fault the neutral will be displaced, and the resulting zero sequence component of voltage will produce a corresponding component of zero sequence capacitance current. In the limiting case of full neutral displacement, this zero sequence current will be equal in value to the normal positive sequence current.

The resulting residual current is equal to three times the zero sequence current and hence to three times the normal line charging current. The value of this component of in-zone current should be considered when establishing the effective setting of earth fault relays.

16.2 Unit schemes

The basic differences between the requirements of feeder and transformer protections lie in the limitation imposed on the transfer of earth fault current by the transformer and the need for high sensitivity in the transformer protection, suggesting that the two components of a transformer-feeder should be protected separately. This involves mounting current transformers adjacent to, or on, the high voltage terminals of the transformer. Separate current transformers are desirable for the feeder and transformer protections so that these can be arranged in two separate overlapping zones. The use of common current transformers is possible, but may involve the use of auxiliary current transformers, or special winding and connection arrangements of the relays. Intertripping of the remote circuit breaker from the transformer protection will be necessary, but this can be done using the communication facilities of the feeder protection relays.

Although technically superior, the use of separate protection systems is seldom justifiable when compared with an overall system or a combination of non-unit feeder protection and a unit transformer system.

An overall unit system must take into account the fact that zero sequence current on one side of a transformer may not be reproduced in any form on the other side. This represents little difficulty to a modern numerical relay using software phase/zero sequence compensation and digital communications to transmit full information on the phase and earth currents from one relay to the other. However, it does represent a more difficult problem for relays using older technology. The line current transformers can be connected to a summation transformer with unequal taps, as shown in Figure C7.25(a). This arrangement produces an output for phase faults and also some response for A and B phase-earth faults. However, the resulting settings will be similar to those for phase faults and no protection will be given for C phase-earth faults.

An alternative technique is shown in Figure C7.25(b).

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16. Transformer-feeder protection

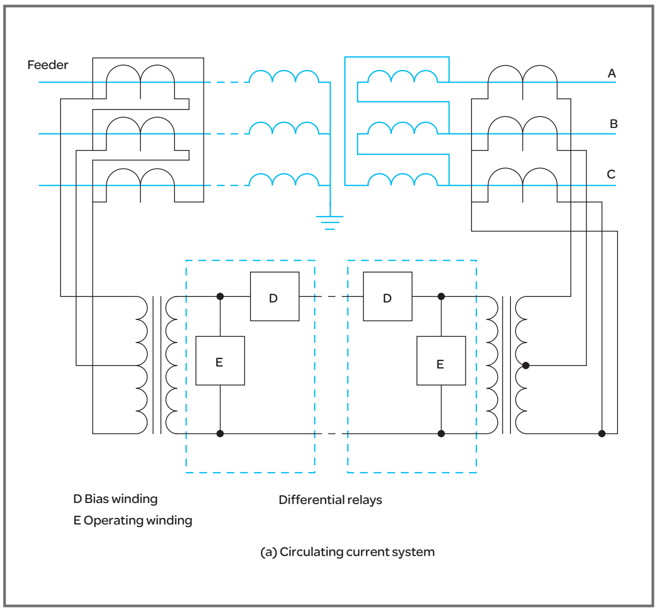

Figure C7.25 (a):
Methods of protection for transformer-feeders using electromechanical static technology

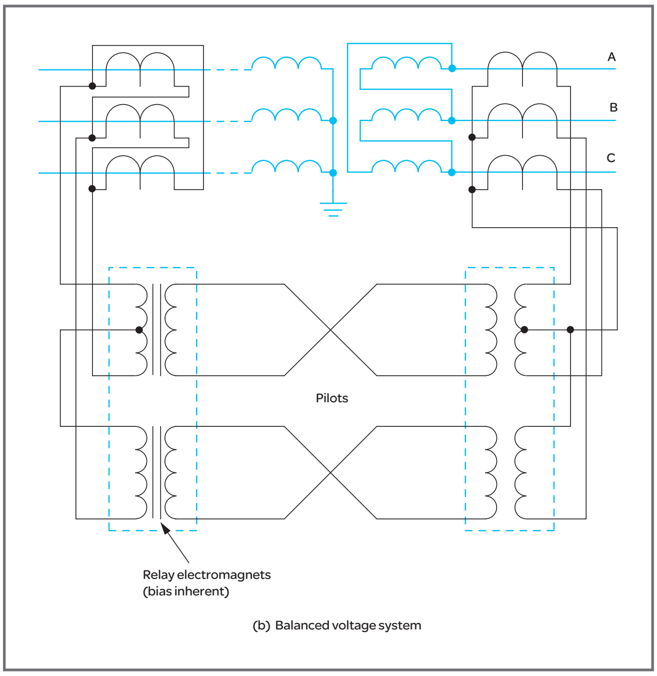

Figure C7.25 (b):
Methods of protection for transformer- feeders using electromechanical static technology

The B phase is taken through a separate winding on another transformer or relay electromagnet, to provide another balancing system. The two transformers are interconnected with their counterparts at the other end of the feeder-transformer by four pilot wires. Operation with three pilot cores is possible but four are preferable, involving little increase in pilot cost.

17. Intertripping

In order to ensure that both the high and low voltage circuit breakers operate for faults within the transformer and feeder, it is necessary to operate both circuit breakers from protection normally associated with one. The technique for doing this is known as intertripping.

The necessity for intertripping on transformer-feeders arises from the fact that certain types of fault produce insufficient current to operate the protection associated with one of the circuit breakers. These faults are:

a. faults in the transformer that operate the Buchholz relay and trip the local low voltage circuit breaker, while failing to produce enough fault current to operate the protection associated with the remote high voltage circuit breaker

b. earth faults on the star winding of the transformer, which, because of the position of the fault in the winding, again produce insufficient current for relay operation at the remote circuit breaker

c. earth faults on the feeder or high voltage delta-connected winding which trip the high voltage circuit breaker only, leaving the transformer energised from the low voltage side and with two high voltage phases at near line-to-line voltage above earth. Intermittent arcing may follow and there is a possibility of transient overvoltage occurring and causing a further breakdown of insulation

Several methods are available for intertripping; these are discussed in Chapter [D2: Signalling and Intertripping in Protection Schemes].

17.1 Neutral displacement

An alternative to intertripping is to detect the condition by measuring the residual voltage on the feeder. An earth fault occurring on the feeder connected to an unearthed transformer winding should be cleared by the feeder circuit, but if there is also a source of supply on the secondary side of the transformer, the feeder may be still live. The feeder will then be a local unearthed system, and, if the earth fault continues in an arcing condition, dangerous overvoltages may occur.

A voltage relay is energised from the broken-delta connected secondary winding of a voltage transformer on the high voltage line, and receives an input proportional to the zero sequence voltage of the line, that is, to any displacement of the neutral point; see Figure C7.26.

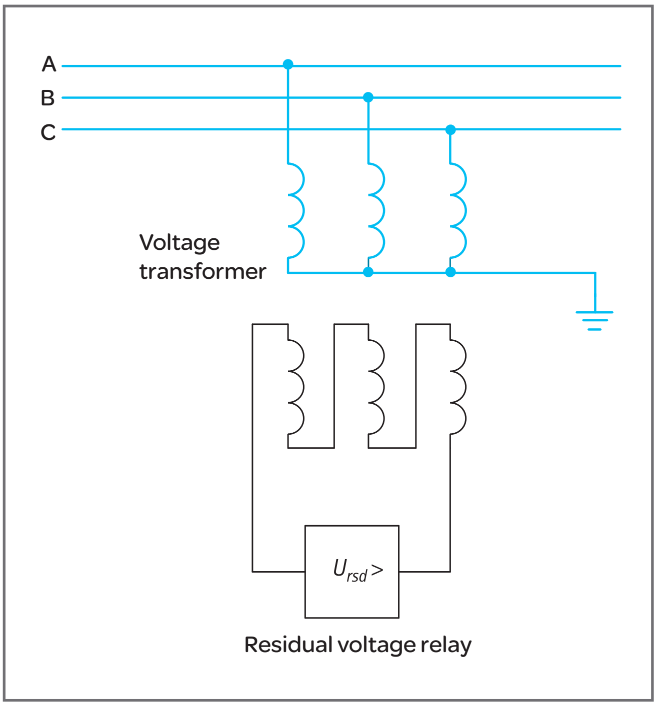

Figure C7.26:
Neutral displacement detection using voltage transformer

The relay normally receives zero voltage, but, in the presence of an earth fault, the broken-delta voltage will rise to three times the phase voltage. Earth faults elsewhere in the system may also result in displacement of the neutral and hence discrimination is achieved using definite or inverse time characteristics.

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18. Condition monitoring of transformers

It is possible to provide transformers with measuring devices to detect early signs of degradation in various components and provide warning to the operator in order to avoid a lengthy and expensive outage due to failure. The technique, which can be applied to other plant as well as transformers, is called condition monitoring, as the intent is to provide the operator with regular information on the condition of the transformer. By reviewing the trends in the information provided, the operator can make a better judgement as to the frequency of maintenance, and detect early signs of deterioration that, if ignored, would lead to an internal fault occurring. Such techniques are an enhancement to, but are not a replacement for, the protection applied to a transformer.

The extent to which condition monitoring is applied to transformers on a system will depend on many factors, amongst which will be the policy of the asset owner, the suitability of the design (existing transformers may require modifications involving a period out of service – this may be costly and not justified), the importance of the asset to system operation, and the general record of reliability. Therefore, it should not be expected that all transformers would be, or need to be, so fitted.

A typical condition monitoring system for an oil-immersed transformer is capable of monitoring the condition of various transformer components as shown in Table C7.5.

There can be some overlap with the measurements available from a digital/numerical relay. By the use of software to store and perform trend analysis of the measured data, the operator can be presented with information on the state of health of the transformer, and alarms raised when measured values exceed appropriate limits. This will normally provide the operator with early warning of degradation within one or more components of the transformer, enabling maintenance to be scheduled to correct the problem prior to failure occurring. The maintenance can obviously be planned to suit system conditions, provided the rate of degradation is not excessive.

As asset owners become more conscious of the costs of an unplanned outage, and electric supply networks are utilised closer to capacity for long periods of time, the usefulness of this technique can be expected to grow.

Monitored equipment	Measured quantity	Health information
Bushings	Voltage	Insulation quality
	Partial discharge measurement (wideband voltage)	
	Load current	Loading
		Permissible overload rating
		Hot-spot temperature
	Oil pressure	Insulation quality
Tank	Oil temperature	Hot-spot temperature
		Permissible overload rating
	Gas-in-oil content	Oil quality
		Winding insulation condition
	Buchholz gas content	Oil quality
	Moisture-in-oil content	Winding insulation condition
Tap changer	Position	Frequency of use of each tap position
	Drive power consumption	OLTC health
	Total switched load current	OLTC contact wear
	OLTC oil temperature	OLTC health
Coolers	Oil temperature difference	Cooler efficiency
	Cooling air temperature	
	Ambient temperature	
	Pump status	Cooling plant health
Conservator	Oil level	Tank integrity

Table C7.5:
Condition monitoring for transformers

19. Examples of transformer protection

This section provides three examples of the application of modern relays to transformer protection. The latest MiCOM P630 or P640 series relays provide advanced software to simplify the calculations, so an earlier relay is used to illustrate the complexity of the required calculations.

19.1 Provision of zero-sequence filtering

Figure C7.27 shows a delta-star transformer to be protected using a unit protection scheme. With a main winding connection of $Dyn11$, suitable choices of primary and secondary CT winding arrangements, and software phase compensation are to be made. With the MiCOM P630 or P640 series relays, phase compensation is selected by the user in the form of software-implemented Interposing Current Transformers (ICTs).

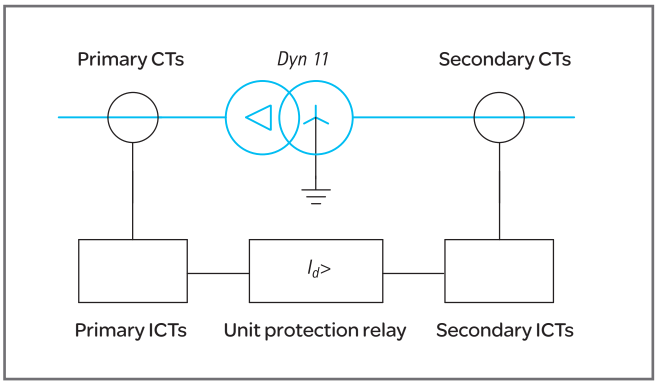

Figure C7.27:
Transformer zero sequence filtering example

With the $Dyn11$ connection, the secondary voltages and currents are displaced by +30° from the primary. Therefore, the combination of primary, secondary and phase correction must provide a phase shift of –30° of the secondary quantities relative to the primary.

For simplicity, the CTs on the primary and secondary windings of the transformer are connected in star. The required phase shift can be achieved either by use of ICT connections on the primary side having a phase shift of +30° or on the secondary side having a phase shift of –30°. There is a wide combination of primary and secondary ICT winding arrangements that can provide this, such as Y_{d10} (+60°) on the primary and Y_{d3} (-90°) on the secondary.

Another possibility is Y_{d11} (+30°) on the primary and Y_{y0} (0°) on the secondary. It is usual to choose the simplest arrangements possible, and therefore the latter of the above two possibilities might be selected.

However, the distribution of current in the primary and secondary windings of the transformer due to an external earth fault on the secondary side of the transformer must now be considered. The transformer has an earth connection on the secondary winding, so it can deliver zero sequence current to the fault. Use of star connected main CTs and Y_{y0} connected ICTs provides a path for the zero sequence current to reach the protection relay. On the primary side of the transformer, the delta connected main primary winding causes zero-sequence current to circulate round the delta and hence will not be seen by the primary side main CTs. The protection relay will therefore not see any zero-sequence current on the primary side, and hence detects the secondary side zero sequence current incorrectly as an in-zone fault.

The solution is to provide the ICTs on the secondary side of the transformer with a delta winding, so that the zero-sequence current circulates round the delta and is not seen by the relay. Therefore, a rule can be developed that a transformer winding with a connection to earth must have a delta-connected main or ICT for unit protection to operate correctly.

Selection of Y_{y0} connection for the primary side ICTs and Y_{d1} (–30°) for the secondary side ICTs provides the required phase shift and the zero-sequence trap on the secondary side.

19.2 Unit protection of a delta-star transformer

Figure C7.28 shows a delta-star transformer to which unit protection is to be applied, including restricted earth fault protection to the star winding.

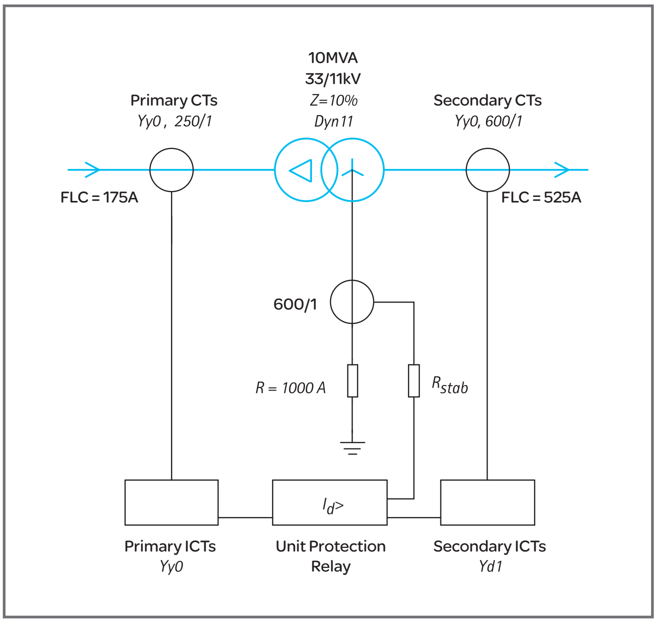

Figure C7.28:
Transformer unit protection example

Referring to the figure, the ICTs have already been correctly selected, and are conveniently applied in software. It therefore remains to calculate suitable ratio compensation (it is assumed that the transformer has no taps), transformer differential protection settings and restricted earth fault settings.

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19. Examples of transformer protection

19.2.1 Ratio compensation

Transformer HV full load current on secondary of main CTs is:

175 / 250	= 0.7	
Ratio compensation	= 1/0.7	= 1.428
Select nearest value	= 1.43	
LV secondary current	= 525/600	= 0.875
Ratio compensation	= 1 / 0.875	= 1.14

19.2.2 Transformer unit protection settings

A current setting of 20% of the rated relay current is recommended. This equates to 35A primary current. Some protection relays have a dual slope bias characteristic with fixed bias slope settings of 20% up to rated current and 80% above that level. The corresponding characteristic is shown in Figure C7.29.

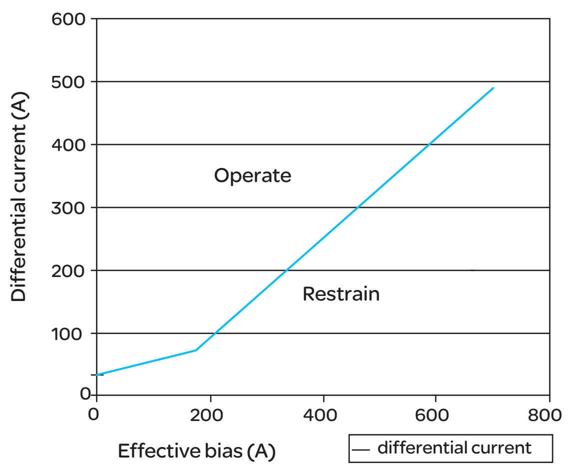

Figure C7.29:
Transformer unit protection characteristic

19.2.3 Restricted earth fault protection

MiCOM P630 series relay implements high-impedance Restricted Earth Fault (REF) protection. Operation is required for a primary earth fault current of 25% rated earth fault current (i.e. 250A). The prime task in calculating settings is to calculate the value of the stabilising resistor R_{stab} and stability factor K.

A stabilising resistor is required to ensure through fault stability when one of the secondary CTs saturates while the others do not.

The requirements can be expressed as:

$V_S = I_S R_{stab}$ and $V_S > KI_f (R_{ct} + 2R_L + R_B)$

where:

V_S = stability voltage setting

V_K = CT knee point voltage

K = relay stability factor

I_S = relay current setting

R_{ct} = CT winding resistance

R_L = CT secondary lead resistance

R_B = resistance of any other components in the relay circuit

R_{stab} = stabilising resistor

For this example:

V_K = 97V

R_{ct} = 3.7Ω

R_L = 0.057Ω

For the relay used, the various factors are related by the graph of Figure C7.30.

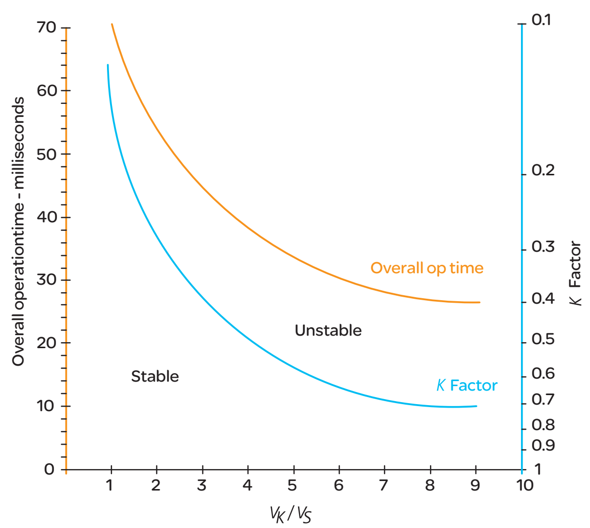

Figure C7.30:
REF operating characteristic for KBCH relay

Starting with the desired operating time, the V_K / V_S ratio and K factor can be found.

An operating time of 40ms (2 cycles at 50Hz) is usually acceptable, and hence, from Figure C7.30,

V_K / V_S = 4

K = 0.5

19. Examples of transformer protection

The maximum earth fault current is limited by the earthing resistor to 1000A (primary). The maximum phase fault current can be estimated by assuming the source impedance to be zero, so it is limited only by transformer impedance to 5250A, or 10A secondary after taking account of the ratio compensation. Hence the stability voltage can be calculated as

$$VS = 0.5 \times 10\ (3.7 + 2\ 0.057) = 19.07V$$

Hence,

Calculated $VK = 4 \times 19.07 = 76.28V$

However,

Actual $V_K = 91V$ and $VK\ /\ VS = 4.77$

Thus from Figure C7.30, with K = 0.5, the protection is unstable.

By adopting an iterative procedure for values of $V_K\ /\ V_S$ and K, a final acceptable result of $V_K\ /\ V_S$ = 4.55, K = 0.6, is obtained. This results in an operating time of 40ms.

The required earth fault setting current I_{op} is 250A. The chosen $E\ /\ F$ CT has an exciting current I_e of 1%, and hence using the equation:

I_{op} = CT ratio x ($I_S + nI_e$)

where:

n = no of CTs in parallel (= 4)

I_S = 0.377, use 0.38 nearest settable value.

The stabilising resistance R_{stab} can be calculated as 60.21Ω.

The relay can only withstand a maximum of 3kV peak under fault conditions. A check is required to see if this voltage is exceeded – if it is, a non-linear resistor, known as a Metrosil, must be connected across the relay and stabilising resistor. The peak voltage is estimated using the formula:

$$V_P = 2\sqrt{2V_K\left(V_F - V_K\right)}$$

where:

$$V_F = I_f\,(R_{ct} + 2R_L + R_{stab})$$

and

I_f = fault current in secondary of CT circuit and substituting values,

V_p = 544V. Thus a Metrosil is not required.

19.3 Unit protection for on-load tap changing transformer

The previous example deals with a transformer having no taps. In practice, most transformers have a range of taps to cater for different loading conditions. While most transformers have an off-load tap-changer, transformers used for voltage control in a network are fitted with an on-load tap-changer. The protection settings must then take the variation of tap-change position into account to avoid the possibility of spurious trips at extreme tap positions. For this example, the same transformer as in Section 19.2 will be used, but with an on-load tapping range of +5% to -15%. The tap-changer is located on the primary winding, while the tap-step usually does not matter.

The stages involved in the calculation are as follows:

a. determine ratio correction at mid-tap and resulting secondary currents

b. determine HV currents at tap extremities with ratio correction

c. determine the differential current at the tap extremities

d. determine bias current at tap extremities

e. check for sufficient margin between differential and operating currents

19.3.1 Ratio correction

In accordance with Section 8.4, the mid-tap position is used to calculate the ratio correction factors. The mid tap position is –5%, and at this tap position:

Primary voltage to give rated secondary voltage:

= 33 x 0.95 = 31.35kV

and

Rated primary current = 184A

Transformer HV full load current on secondary of main CTs is:

184/250	= 0.737
Ratio compensation	= 1/0.737
	= 1.357
Select nearest value	= 1.36
LV secondary current	= 525/600
	= 0.875
Ratio compensation	= 1/0.875
	= 1.14

Both of the above values can be set in the relay.

19.3.2 HV currents at tap extremities

At the +5% tap, the HV full-load current will be:

$$\frac{10}{33 \times 1.05 \times \sqrt{3}}$$

$= 166.6A$ primary

Hence, the secondary current with ratio correction:

$$= \frac{166.6 \times 1.36}{250}$$

$= 0.906A$

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19. Examples of transformer protection

At the -15% tap, the HV full-load current on the primary of the CTs:

$$= \frac{10}{33 \times 0.85 \times \sqrt{3}}$$

$$= 205.8\,A$$

Hence, the secondary current with ratio correction:

$$= \frac{205.8 \times 1.36}{250}$$

$$= 1.12\,A$$

19.3.3 Determine differential current at tap extremities

The full load current seen by the relay, after ratio correction is $0.875 \times 1.14 = 0.998A$.

At the +5% tap, the differential current

$$I_{difft2} = 0.998 - 0.906 = 0.092A$$

At the –15% tap,

$$I_{difft2} = 1.12 - 0.998 = 0.122A$$

19.3.4 Determine bias currents at tap extremities

The bias current is given by the formula:

$$I_{bias} = \frac{1}{2} \times \left(I_{RHV} + I_{RLV}\right)$$

where:

I_{RHV} = relay HV current

I_{RLV} = relay LV current

Hence,

$$I_{biast1} = \frac{1}{2} \times \left(0.998 + 0.906\right)$$

$$= 0.952A$$

and

$$I_{biast\,2} = \frac{1}{2} \times \left(0.998 + 1.12\right)$$

$$= 1.059A$$

19.3.5 Margin between differential and operating currents

The operating current of the relay is given by the formula

$$I_{op} = I_S + 0.2I_{bias}$$

Hence, at the +5% tap, with $I_S = 0.2$

$$I_{opt1} = 0.2 + (0.2 \times 0.952)$$

$$= 0.3904A$$

At the –15% tap,

$$I_{op} = I_S + 0.2 + (I_{bias} - 1) \times 0.8$$

(since the bias >1.0)

$$I_{opt2} = 0.2 + 0.2 + (1.059 - 1) \times 0.8$$

$$= 0.4472A$$

For satisfactory operation of the relay, the operating current should be no greater than 90% of the differential current at the tap extremities.

For the +5% tap, the differential current is 24% of the operating current, and at the –15% tap, the differential current is 27% of the operating current. Therefore, a setting of I_S is satisfactory.

C8 Generator and Generator-Transformer Protection

Network Protection & Automation Guide

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Chapter C8

Generator and Generator-Transformer Protection

C8

1. Introduction

The core of an electric power system is the generation. With the exception of emerging fuel cell and solar-cell technology for power systems, the conversion of the fundamental energy into its electrical equivalent normally requires a ‘prime mover’ to develop mechanical power as an intermediate stage.

The nature of this machine depends upon the source of energy and in turn this has some bearing on the design of the generator. Generators based on steam, gas, water or wind turbines, and reciprocating combustion engines are all in use. Electrical ratings extend from a few hundred kVA (or even less) for reciprocating engine and renewable energy sets, up to steam turbine sets exceeding 1200MVA.

Small and medium sized sets may be directly connected to a power distribution system. A larger set may be associated with an individual transformer, through which it is coupled to the EHV primary transmission system.

Switchgear may or may not be provided between the generator and transformer. In some cases, operational and economic advantages can be attained by providing a generator circuit breaker in addition to a high voltage circuit breaker, but special demands will be placed on the generator circuit breaker for interruption of generator fault current waveforms that do not have an early zero crossing.

A unit transformer may be tapped off the interconnection between generator and transformer for the supply of power to auxiliary plant, as shown in Figure C8.1. The unit transformer could be of the order of 10% of the unit rating for a large fossil-fuelled steam set with additional flue-gas desulphurisation plant, but it may only be of the order of 1% of unit rating for a hydro set.

A modern generating unit is a complex system comprising the generator stator winding, associated transformer and unit transformer (if present), the rotor with its field winding and excitation system, and the prime mover with its associated auxiliaries. Faults of many kinds can occur within this system for which diverse forms of electrical and mechanical protection are required. The amount of protection applied will be governed by economic considerations, taking into account the value of the machine, and the value of its output to the plant owner.

The following problems require consideration when applying the protection system:

a. stator electrical faults

b. overvoltage

c. low power / reverse power

d. overload / unbalanced loading

e. overfrequency / underfrequency

f. inadvertent energisation

g. rotor electrical faults

h. overfluxing

i. loss of excitation

j. loss of synchronism

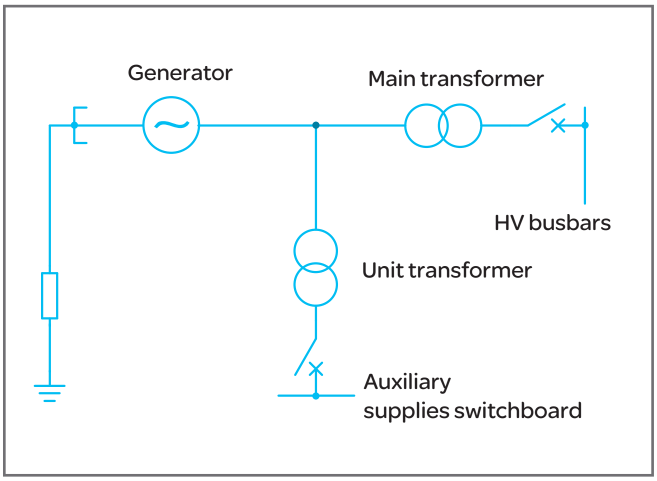

Figure C8.1: Generator-transformer unit

2. Generator earthing

The single-phase earthfault of the stator winding is the most common fault of a generator. In order to reduce the damage to generators and other electric equipment under single-phase earthfaults, different generator grounding methods are applied in the different application scenarios. The main purposes are to restrain the fault currents, the transient overvoltage and to improve the sensitivity of the earthfault protection. The grounding methods widely used are as follows:

Ungrounded: This ungrounded method is common for the smaller generators especially when the machine's capacity is less than 10MW. For the ungrounded machine, the single-phase earthfault current is the sum of the capacitive currents. When the fault current is less than 5A, it will not damage the iron. When the machine's capacity increases, the capacitive currents increase. This is especially true for the hydro-turbine generator. The higher fault current causes electric arcs and transient overvoltage. So for larger generators other grounding methods are applied.

Resonant ground with a ground fault neutraliser: This grounding method illustrates the ground fault neutraliser (GFN) arrangement. In this grounding method, a distribution transformer is used with a secondary reactor. The ohmic value of this secondary reactor is carefully selected to compensate for the capacitive reactance. This type of grounding limits the single phase to ground fault current to values that will not sustain an electric arc. It is applicable only where the zero sequence capacitive reactance of the circuit does not change significantly for different system conditions. In general, the resonant grounding method suppresses a phase to ground fault current in less than 1 A primary current. The majority of existing generators having resonant grounding methods are not tripped immediately, but an alarm is raised and an orderly shutdown is started. This grounding method has the risk of LC resonant overvoltage under some special scenarios. So care is needed when applying this grounding method on large HV generators.

High resistance ground with a distribution transformer (equivalent to high resistance grounding): This grounding method utilises a distribution transformer that provides high resistance in the primary circuit with a small resistance in the secondary of the distribution transformer. The equivalent primary resistance shall be no greater than the capacitive reactance of the subsystem from generator to the LV windings of the step-up transformer. It limits the maximum single phase to ground fault current to a value in the range of approximately 3 A to 25 A, which is not of sufficient magnitude to operate standard generator differential relays. Although this grounding method cannot block the electric arc effectively, it can restrain the transient overvoltage and trigger the sensitive earthfault protection relay. This grounding method is common for generators larger than 300MVA.

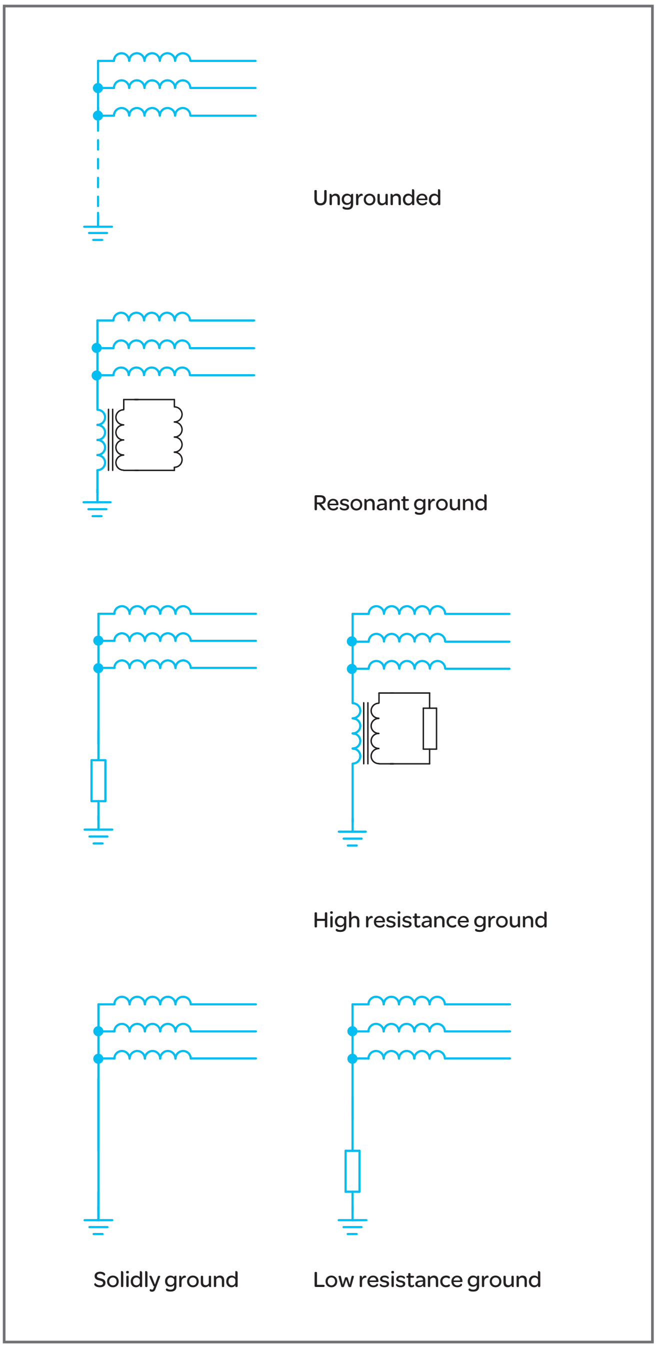

Figure C8.2:
Methods of generator earthing

In industrial applications which are mainly feeding local loads many generators are connected directly to the system bus without any interposing step-up transformers. In general, these may be relatively small generators and they will be connected to a solid or low impedance grounded system [Ref C8.1: IEEE Guide for Generator Ground Protection].

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3. Generator differential protection

Failure of the stator windings or connection insulation can result in severe damage to the windings and stator core. The extent of the damage will depend on the magnitude and duration of the fault current. To respond quickly to a phase fault, sensitive and high-speed differential protection is normally applied to generators rated in excess of 1MVA.

If CTs are connected as shown in Figure C8.3, it can be seen that current flowing through the zone of protection will cause current to circulate around the secondary wiring. If the CTs are of the same ratio and have identical magnetising characteristics they will produce identical secondary currents and so zero current will flow through the relay. If a fault exists within the zone of protection there will be a difference between the outputs from these two CTs. This difference flowing through the relay causes it to operate.

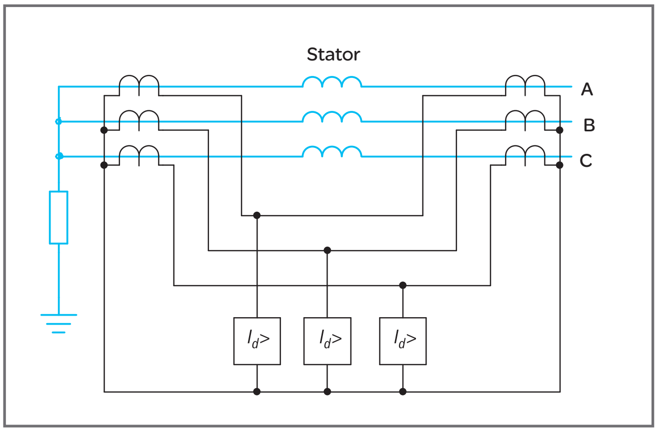


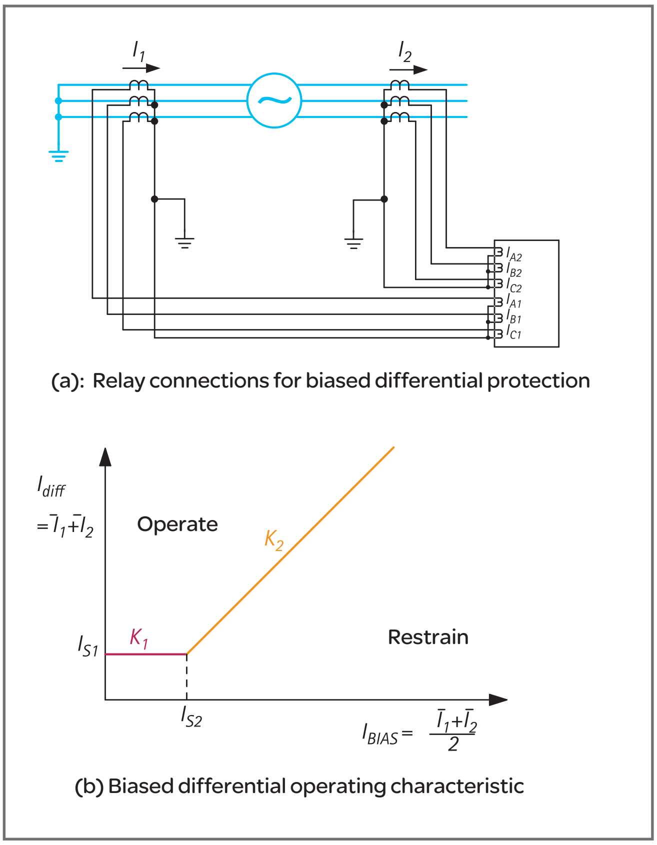
Figure C8.3:
Stator differential protection

Heavy through current, arising from an external fault condition can cause one CT to saturate more than the other, resulting in a difference between the secondary current produced by each CT. It is essential to stabilise the protection for these conditions. Two methods are commonly used. One is biasing technique, where the relay setting is raised as the through current increases. Another is a high impedance technique, where the relay impedance is such that under maximum through fault conditions, the current in the differential element is insufficient for the relay to operate.

3.1 Biased differential protection

The relay connections for this form of protection are shown in Figure C8.4(a) and a typical bias characteristic is shown in Figure C8.4(b). The differential current is the vector sum of the terminal currents I_1 and I_2. The bias current is half of the scalar sum of the terminal currents. Normally a dual slope percentage bias characteristic is implemented. The lower slope provides sensitivity for internal faults, whereas the higher slope provides stability under through-fault conditions, during which there may be transient differential currents due to the saturation effect of the generator CTs, but the bias current will increase the relay setting, such that the differential spill current is insufficient to operate the relay.

In normal conditions, there is very small differential current caused by the unbalance current between two CTs. The threshold of the differential current I_{s1} shall avoid the mal-operation under this normal unbalance current. The threshold setting I_{s1} can be set as low as 5% of rated generator current to provide protection for as much of the winding as possible. The bias slope break-point threshold setting I_{s2} would typically be set to a value (such as 120%) above generator rated current, to achieve external fault stability in the event of transient asymmetric CT saturation. Bias slope setting K_1 would typically be set at 0 to ensure high sensitivity for internal faults while K_2 would typically be set at 150% to provide stability for external faults.



(a): Relay connections for biased differential protection

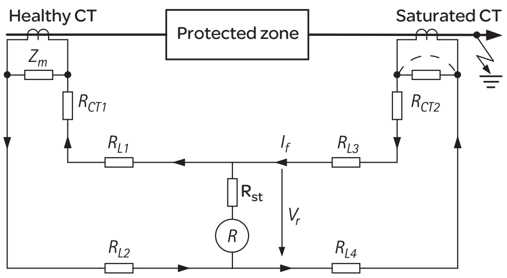
(b) Biased differential operating characteristic

Figure C8.4:
Typical generator biased differential protection

3.2 High impedance differential protection

The principle of the high-impedance protection application is illustrated in Figure C8.5, together with a summary of the calculations required to determine the value of external stabilising resistance.

3. Generator differential protection



Voltage across relay circuit

$$V_s = K I_f (R_{CT} + 2R_L) \text{ - where } K = 1.5$$

Stabilising resistor, R_{ST}, limits spill current to I_s (relay setting)

$$R_{ST} = \frac{V_s}{I_s} - R_R$$

Where
I_F = Maximum secondary through-fault current
R_R = Relay burden
R_{CT} = Current transformer secondary winding resistance
R_L = Resistance of a single lead from the relay to the current transformer

Figure C8.5:
Principle of high impedance differential protection

If the relay circuit is considered to be very high impedance, the secondary current produced by the healthy CT will flow through the saturated CT. If the magnetising impedance of the saturated CT is considered to be negligible, the maximum voltage across the relay (V_S) circuit will be equal to the secondary fault current multiplied by the connected impedance ($R_{L3} + R_{L4} + R_{CT2}$).

The relay can be made stable for this maximum applied voltage by increasing the overall impedance of the relay circuit, such that the resulting current through the relay is less than its current setting. As the impedance of the relay input alone is relatively low, a series connected external resistor is required. The value of this resistor, R_{ST}, is calculated by the formula shown in Figure C8.5. An additional non-linear resistor, Metrosil, may be required to limit the peak secondary circuit voltage during internal fault conditions, as shown in Figure C8.6. But this is not commonly a requirement for generator differential applications unless very high impedance relays are applied.

To calculate the primary operating current, the following expression is used:

$$I_{op} = N \times (I_{s1} + nI_e)$$

Where:

I_{op} = primary operating current

N = CT ratio

I_{s1} = relay setting

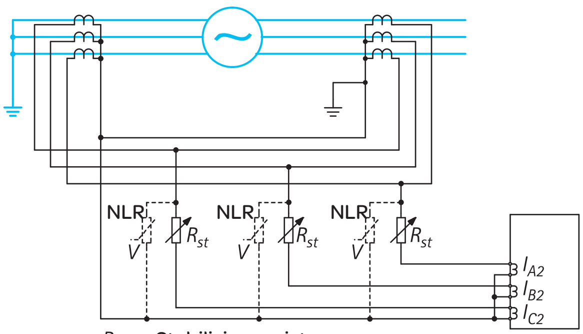
n = number of CTs in parallel with relay element

I_e = CT magnetising current at Vs

I_{s1} is typically set to 5% of generator rated secondary current.

It can be seen from the above that the calculations for the application of high impedance differential protection are more complex than for biased differential protection. However, the protection scheme is actually quite simple and it offers a high level of stability for through-faults and external switching events.

With the advent of multi-function numerical relays and with a desire to dispense with external components, high impedance differential protection is not as popular as biased differential protection in modern relaying practice.



R_{st} = Stabilising resistor
NLR = Non-linear resistance (Metrosil)

Figure C8.6:
Relay connections for high impedance differential protection

3.3 CT requirements

The CT requirements for differential protection will vary according to the relay used. Modern numerical relays may not require CTs specifically designed for differential protection to IEC 60044-1 class PX (or BS 3938 class X). However, requirements in respect of CT knee-point voltage will still have to be checked for the specific relays used. High impedance differential protection may be more onerous in this respect than biased differential protection. Normally to ensure the high impedance differential protection will operate quickly during an internal fault the CTs used to operate the protection must have a knee-point voltage of at least 2 x Vs. Many factors affect this, including the other protection functions fed by the CTs and the knee-point requirements of the particular relay concerned. Relay manufacturers are able to provide detailed guidance on this matter.

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4. Differential protection of generator-transformers

A common connection arrangement for large generators is to operate the generator and associated step-up transformer as a unit without any intervening circuit breaker. The unit transformer supplying the generator auxiliaries is tapped off the connection between generator and step-up transformer. Differential protection can be arranged as follows.

4.1 Generator/step-up transformer differential protection

The generator stator and step-up transformer can be protected by a single zone of overall differential protection (Figure C8.7). This will be in addition to differential protection applied to the generator only.

The current transformers should be located in the generator neutral connections and in the transformer HV connections. Alternatively, CTs within the HV switchyard may be employed if the distance is not technically prohibitive. Even where there is a generator circuit breaker, overall differential protection can still be provided if desired.

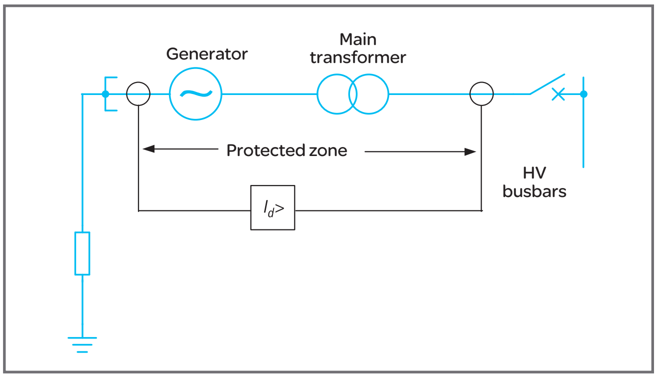

Figure C8.7:
Overall generator-transformer differential protection

Since a power transformer is included within the zone of protection, biased transformer differential protection, with magnetising inrush restraint should be applied, as discussed in Chapter [C7: Transformer and Transformer-Feeder Protection, Section 8.5]. Transient overfluxing of the generator transformer may arise due to overvoltage following generator load rejection. In some applications, this may threaten the stability of the differential protection. In such cases, consideration should be given to applying protection with transient overfluxing restraint/blocking (e.g. based on a 5th harmonic differential current threshold). Protection against sustained overfluxing is covered in Section 14.

4.2 Unit transformer differential protection

The current taken by the unit transformer must be allowed by arranging the generator differential protection as a three-ended scheme as shown in Figure C8.1. Unit transformer current transformers are usually applied to balance the generator differential protection and prevent the unit transformer through current being seen as differential current. An exception might be where the unit transformer rating is extremely low in relation to the generator rating, e.g. for some hydro applications. The location of the third set of current transformers is normally on the primary side of the unit transformer. One advantage is that unit transformer faults would be within the zone of protection of the generator. However, the sensitivity of the generator protection to unit transformer phase faults would be considered inadequate, due to the relatively low rating of the transformer in relation to that of the generator. Thus, the unit transformer should have its own differential protection scheme. Protection for the unit transformer is covered in Chapter [C7: Transformer and Transformer-Feeder Protection], including methods for stabilising the protection against magnetising inrush conditions.

5. Inter-turn protection

5.1 Inter-turn protection

For the large generator, there are usually several parallel-connected branches of the stator winding for each phase. The parallel-connected branches are good for the heat dissipation and reduce the internal electromagnetic force. On large steam generators, the stator winding usually has two parallel-connected branches on each phase. The stator winding of a large hydro-generator can have 4 branches, 6 branches, or more on each phase.

The stator windings are normally formed into double-layer structure except in very small generators. There are two stator bars on each slot of the stator core so it is possible that two stator bars of the same phase or even the same branch are on the same slot of stator core. These two stator bars on the same slot are fully insulated under the normal conditions. However due to the complicated structure of the stator winding and the stress damage during the operation, it is possible that inter-turn faults happen between two stator bars on the same slot as shown in Figure C8.8. Furthermore, if the stator bar has multi turns, it has small insulation between each turn. A fault between turns in a multi turn bar can be catastrophic. Inter-turn faults can happen between the branches of the same phase or within the coils of the same branch, as shown in Figure C8.9.

5. Inter-turn protection

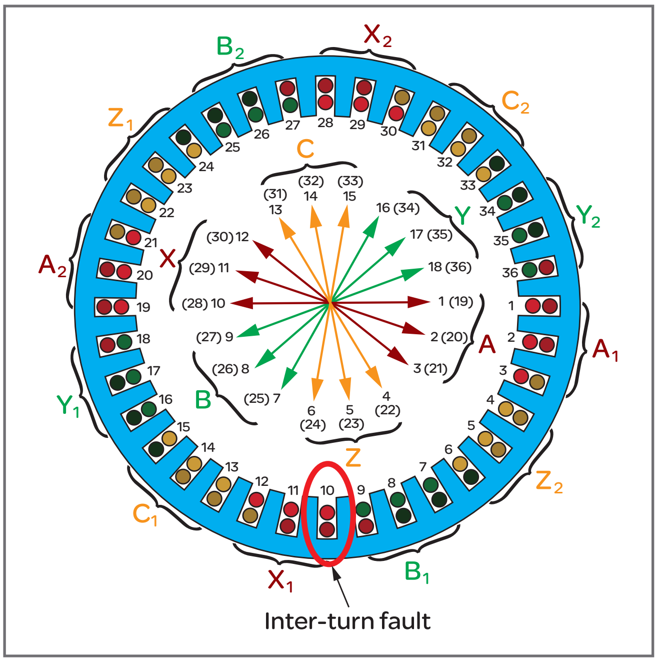

Figure C8.8:
Inter-turn fault in double-layer winding

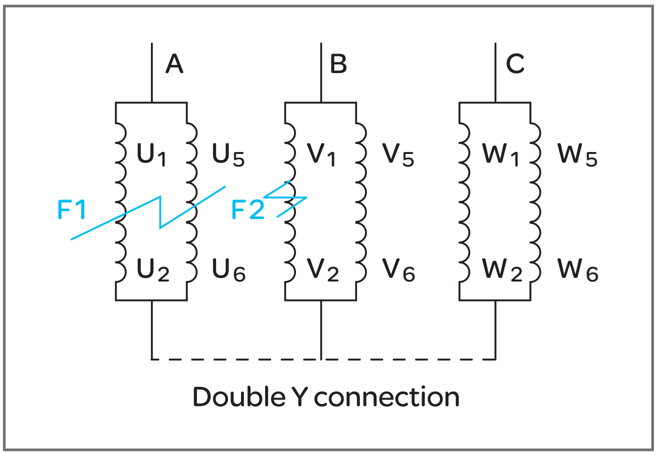

Figure C8.9
Inter-turn faults indication

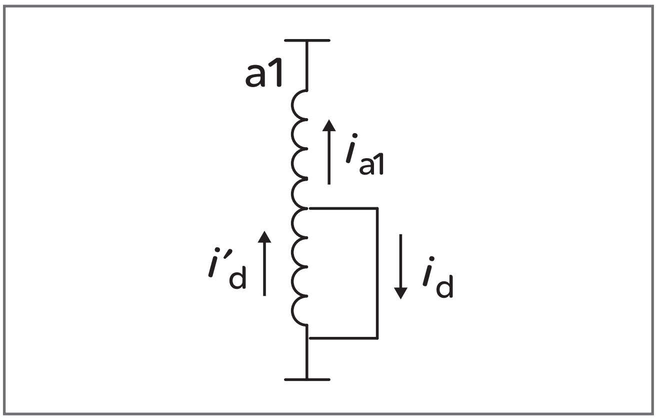

Figure C8.10:
Illustration of inter-turn fault on one branch

The severity of the inter-turn fault is related with the turns in the short circuit. Under the inter-turn fault, there are short circuit rings and additional circulation currents within the winding, which could burn the winding and even stator core, as shown in Figure C8.10. However the variations of the currents on the generator terminal or the generator neutral are slight, especially when the inter-turn fault is on the same branch and involves only limited turns. The conventional current differential protection compares the currents incoming and outgoing, it cannot detect any inter-turn faults regardless of the number of turns involved.

For the large hydro-generator with several parallel-connected branches, normally the line terminals of the parallel-connected branches are available on the generator neutral, so it can apply the split-phase transverse current differential protection, or incomplete longitudinal differential protection or zero sequence current differential protection. These current based protections, described in later sections, can detect all the stator winding internal faults.

For the large steam machine, normally there are only three line terminals on the generator neutral. Without enough line terminals, it is impossible to install the current based protections in the same way as for a hydro-generator. However, it can apply the zero sequence overvoltage protection to detect the inter-turn faults and also internal phase-phase faults. This is described later in this section.

5.2 Split phase transverse current differential protection

In split phase transverse current differential protection schemes, the parallel-connected branches in each phase of the stator winding are split into two groups, as shown in Figure C8.11. If the numbers of the parallel-connected branches are not the same in these two groups, a scale conversion is necessary before the calculation of the differential current. The ratio of the CT should be selected carefully to ensure the unbalanced current is at the minimum when under normal conditions.

Except for the different CT connections, the implementation of transverse biased current differential protection is the same as conventional biased current differential protection (refer to section 3). It can provide both better sensitivity and better stability but it requires one specific relay with two CT inputs, which is used only for inter-turn protection. An additional relay is necessary for other protection purposes.

The philosophy of the setting calculation for transverse biased current differential protection is the same as conventional biased current differential protection. The threshold of the

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5. Inter-turn protection

differential current and restraint factor shall avoid maloperation due to the maximum unbalanced currents on both normal condition and external fault condition. Normally, the threshold of the differential current for transverse biased current differential protection and the restraint factor are all a little higher than the conventional biased current differential protection, as the unbalanced current is likely to be greater. A setting of 10% of rated current of the machine is generally considered to be adequate.

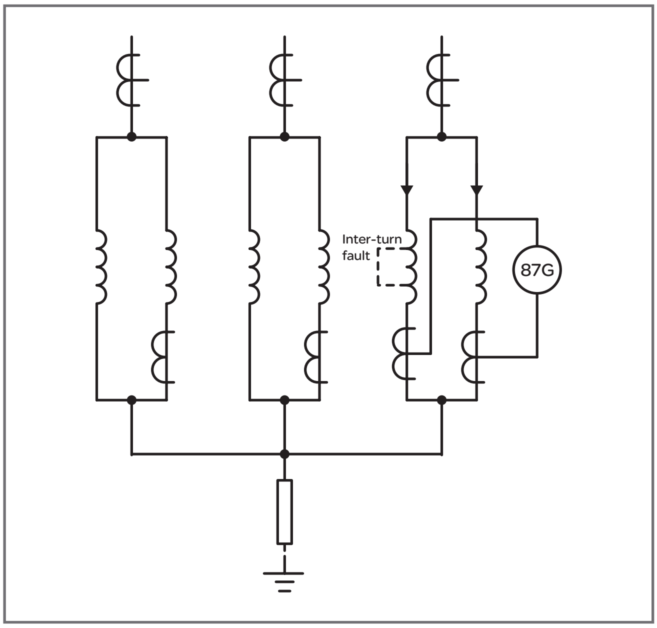

Figure C8.11:
Transverse biased current differential protection for inter-turn fault

5.3 Incomplete longitudinal current differential protection

Another scheme that could be used on this type of hydro-generator is shown in Figure C8.12. This arrangement is an attempt to get the benefits of the biased differential scheme for inter-turn protection with a saving in CTs and relays. However, this arrangement is not as sensitive as the scheme using separate inter-turn relays or differential relays, due to the relatively higher operation threshold and relatively lower fault currents flowing in the CTs. If the inter-turn fault is only on one branch and the neutral end CT does not collect the current from that branch with the fault, the current flowing in the CT normally is less than the threshold and this protection will not operate. Normally, this scheme requires the neutral end CTs having half the turns ratio of the terminal end CTs and collecting the currents from half the parallel-connected branches. The typical threshold of differential current is about 10%-15% of rated current of the machine.

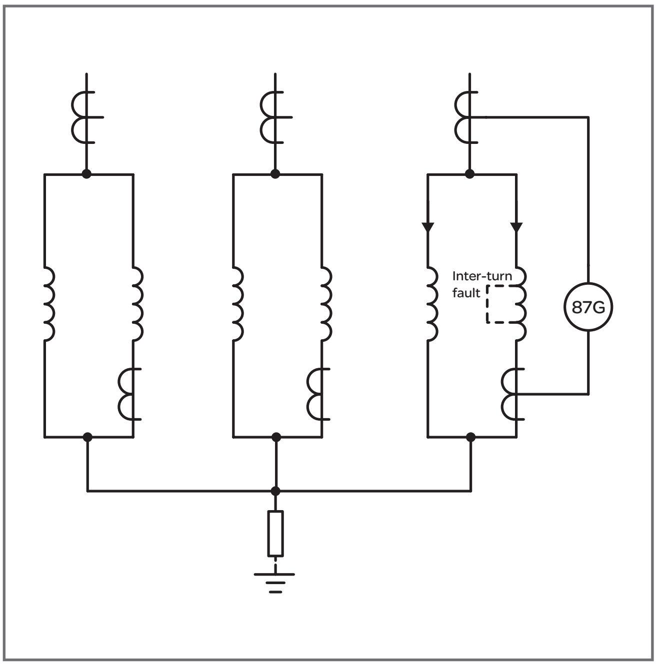

Figure C8.12:
Incomplete longitudinal current differential protection

5.4 Transverse zero sequence current differential protection

Another method that could be used for inter-turn protection is to use the zero sequence overcurrent protection function using an additional single CT as shown in Figure C8.13. Ideally, in the normal condition with balanced burden, there is no current flowing between these two neutral points. However due to the complicated machine structure, there are usually unbalanced current components between neutral points, especially the third harmonic current. For better performance of this application, it is essential to filter out the third harmonic current with a high attenuation such as 40db to avoid maloperation due to the large third harmonic content. Choosing a suitable ratio of the single CT for this application can improve the sensitivity. With the same current threshold, the smaller ratio can obtain higher measurements of the fault current and then be more sensitive to the faults. However it has to ensure CT saturation will not occur for the maximum fault currents and the maximum unbalance current shall also be less than the CT primary rated current.

To ensure stability under an external fault the current threshold for the transverse zero sequence current differential protection shall be greater than maximum unbalanced current under an external fault condition. This is typically set to 20% of the generator rated current.

An alternative to achieve both sensitivity and stability is to apply an adaptive current threshold. Whilst the maximum generator terminal current is less than the generator rated

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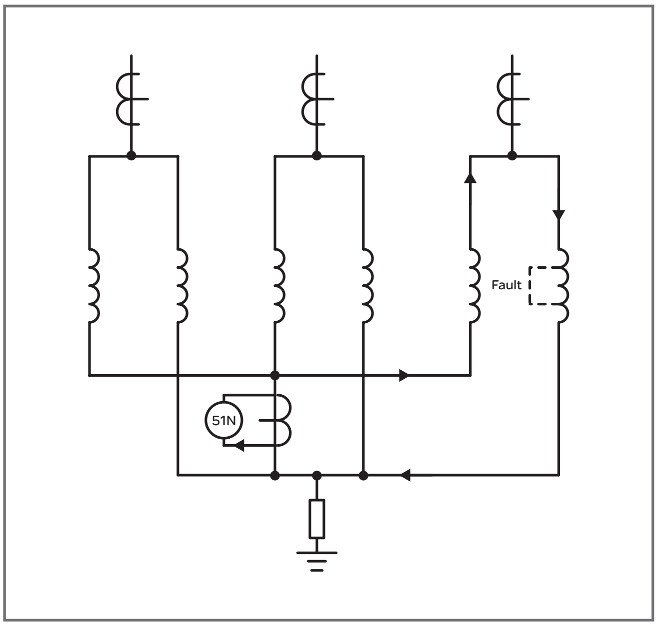

Figure C8.13:
Transverse zero-sequence current differential protection

current, the current threshold is only greater than the maximum unbalanced current under normal conditions. The default sensitivity setting can be 5% of the generator rated current. When the maximum generator terminal current is larger than the generator rated current, the current threshold shall increase linearly until the maximum unbalanced current under external faults is reached. It is not easy to calculate the exact maximum unbalanced currents under different operating conditions. Normally it relies on the measurement data from field tests.

5.5 Longitudinal zero sequence overvoltage protection

For a typical steam generator without enough line terminals on the generator neutral, it can apply the longitudinal zero sequence overvoltage protection to detect the inter-turn faults and internal phase to phase faults. On the large steam generator, the branches and turns of the stator winding are limited. Even if the inter-turn fault involves only very limited turns, there will be obvious longitudinal zero sequence voltage. However on the large hydro-generator, normally there are several branches and many turns, therefore the minor inter-turn faults will not cause enough zero sequence voltage. So the longitudinal zero sequence overvoltage protection has higher sensitivity on the steam generator. Normally it is not applied on hydro-generators.

An inter-turn fault on one phase will reduce its voltage output, creating zero sequence voltage components. So the inter-turn faults in a generator can be detected by observing the zero sequence voltage across the machine between the generator terminal and generator neutral. Normally one set of VTs is installed specifically for inter-turn protection applications. This set of VTs is connected to the generator terminal, with the start point of the primary winding connected to the generator neutral as shown in Figure C8.14. The cable between these two star points must be rated to full line volts to cope with neutral displacement faults. The zero sequence voltage can be measured directly from the voltage transformer broken delta winding or derived from the three phase to neutral voltages. In addition, one specific filter is necessary to remove the 3rd harmonics, to ensure the stability of this protection scheme. It is preferable that the attenuation of the 3rd harmonics is greater than 40db.

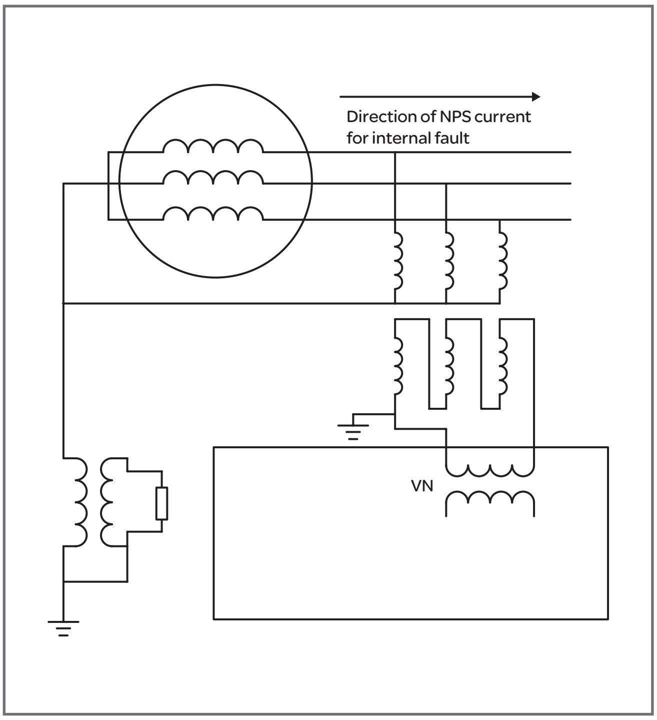

Figure C8.14:
Longitudinal zero sequence overvoltage protection

Under the normal condition, the unbalanced voltage from the VT broken delta winding is very small. So a smaller setting is acceptable, which can ensure this protection scheme has a high sensitivity to detect an inter-turn fault with only a few turns involved. Under external faults, the unbalanced electric and magnetic parameters during the complicated transient states of the generator can cause some zero sequence voltages. From the practical engineering measurements [Ref C8.1: IEEE Guide for Generator Ground Protection], there are some zero sequence voltages under the external fault, which could be larger than the setting for inter-turn protection, as shown in Figure C8.15 [Ref C8.2: Problems in Voltage-Type Longitudinal Zero-Sequence Inter-Turn Protection for Generators]. So, to prevent this inter-turn protection element from maloperation for the external faults, the element can be interlocked with a directional NPS overcurrent element. Only when the direction

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5. Inter-turn protection

of the NPS current is looking away from the machine, the inter-turn protection can issue a trip signal. The directional NPS overcurrent element shall be based on the CT at the generator terminal side. A short time delay is usually used to ensure the correct block from both directional NPS overcurrent and VTS.

The inter-turn protection by zero sequence overvoltage protection avoids the maloperation due to the maximum unbalanced voltage under normal conditions. Normally the maximum unbalanced voltage can be measured during the generator field test before normal operation. The default setting is 2% of the generator rated voltage. A typical time setting would be 0.1 s - 0.2 s. A long time delay increases the risk of damage to the stator core.

5.6 Summary

This section introduces four inter-turn protection solutions. The split phase transverse current differential protection has high sensitivity and stability but more CTs and addition protection relay are necessary. Transverse zero sequence current differential protection also has good sensitivity and application scheme is more simple. Incomplete longitudinal current differential protection has a wider protection range including the generator terminal lines, but it may not detect the inter-turn faults only on one branch and the current flowing in the faulted branch is not collected in this solution.

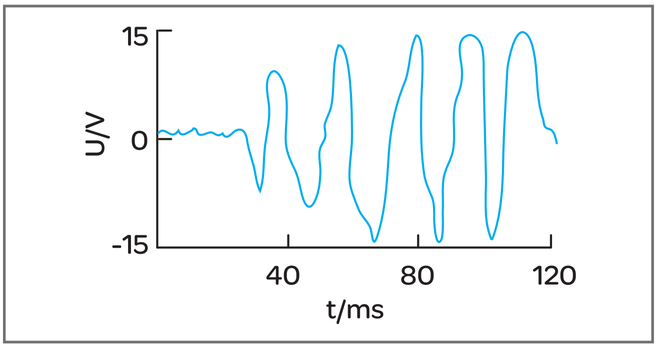

Figure C8.15: Zero sequence voltage across the generator under external transformer HV earthfault

Normally for the large hydro-generator inter-turn protection, two protection solutions are needed. Often, one solution is split phase transverse current differential protection and another is transverse zero sequence current differential protection. Longitudinal zero sequence overvoltage protection is normally for the inter-turn faults on a large steam generator. It has high sensitivity but a short time delay is necessary for good stability with direction NPS overcurrent blocking and VTS blocking.

6. Overcurrent protection

Overcurrent protection of generators may take two forms. Plain overcurrent protection may be used as the principle form of protection for small generators, and back-up protection for larger ones where differential protection is used as the primary method of generator stator winding protection. Voltage dependent overcurrent protection may be applied where differential protection is not justified on larger generators, or where problems are met in applying plain overcurrent protection.

6.1 Plain overcurrent protection

It is usual to apply time-delayed plain overcurrent protection to generators. For generators rated less than 1 MVA, this will form the principal stator winding protection for phase faults. For larger generators, overcurrent protection can be applied as remote back-up protection, to disconnect the unit from any uncleared external fault. Where there is only one set of differential main protection, for a smaller generator, the overcurrent protection will also provide local back-up protection for the protected plant, in the event that the main protection fails to operate. The general principles of setting overcurrent relays are given in Chapter [C1: Overcurrent Protection for Phase and Earthfaults].

In the case of a single generator feeding an isolated system, current transformers at the neutral end of the machine should energise the overcurrent protection, to allow a response to winding fault conditions. Relay characteristics should be selected to take into account the fault current decrement behaviour of the generator, with allowance for the performance of the excitation system and its field-forcing capability. Without the provision of fault current compounding from generator CTs, an excitation system that is powered from an excitation transformer at the generator terminals will exhibit a pronounced fault current decrement for a terminal fault. With failure to consider this effect, the potential exists for the initial high fault current to decay to a value below the overcurrent protection pick-up setting before a relay element can operate, unless a low current setting and/or time setting is applied. The protection would then fail to trip the generator. The settings chosen must be the best compromise between assured operation in the foregoing circumstances and discrimination with the system protection and passage of normal load current, but this can be impossible with plain overcurrent protection.

In the more usual case of a generator that operates in parallel with others and which forms part of an extensive interconnected system, back-up phase fault protection for a generator and its transformer will be provided by HV overcurrent protection. This will respond to the higher-level backfeed from the power system to a unit fault. Other generators in parallel would supply this current and, being

6. Overcurrent protection

stabilised by the system impedance; it will not suffer a major decrement. This protection is usually a requirement of the power system operator. Settings must be chosen to prevent operation for external faults fed by the generator. It is common for the HV overcurrent protection relay to provide both time-delayed and instantaneous high-set elements.

The time-delayed elements should be set to ensure that the protected items of plant cannot pass levels of through fault current in excess of their short-time withstand limits.

The instantaneous elements should be set above the maximum possible fault current that the generator can supply, but less than the system-supplied fault current in the event of a generator winding fault. This back-up protection will minimise plant damage in the event of main protection failure for a generating plant fault and instantaneous tripping for an HV-side fault will aid the recovery of the power system and parallel generation.

6.2 Voltage-dependent overcurrent protection

The plain overcurrent protection setting difficulty referred to in the previous section arises because allowance has to be made both for the decrement of the generator fault current with time and for the passage of full load current. To overcome the difficulty of discrimination, the generator terminal voltage can be measured and used to dynamically modify the basic relay current/time overcurrent characteristic for faults close to the generating plant. There are two basic alternatives for the application of voltage-dependent overcurrent protection, which are discussed in the following sections. The choice depends upon the power system characteristics and level of protection to be provided. Voltage-dependent overcurrent relays are often found applied to generators used on industrial systems as an alternative to full differential protection.

6.2.1 Voltage controlled overcurrent protection

Voltage controlled overcurrent protection has two time/current characteristics which are selected according to the status of a generator terminal voltage measuring element. The voltage threshold setting for the switching element is chosen according to the following criteria.

1. during overloads, when the system voltage is sustained near normal, the overcurrent protection should have a current setting above full load current and an operating time characteristic that will prevent the generating plant from passing current to a remote external fault for a period in excess of the plant short-time withstand limits
2. under close-up fault conditions, the busbar voltage must fall below the voltage threshold so that the second protection characteristic will be selected. This characteristic should be set to allow relay operation with fault current decrement for a close-up fault at the generator terminals or at the HV busbars. The protection should also time-grade with external circuit protection. There may be additional infeeds to an external circuit fault that will assist with grading.

Typical characteristics are shown in Figure C8.16.

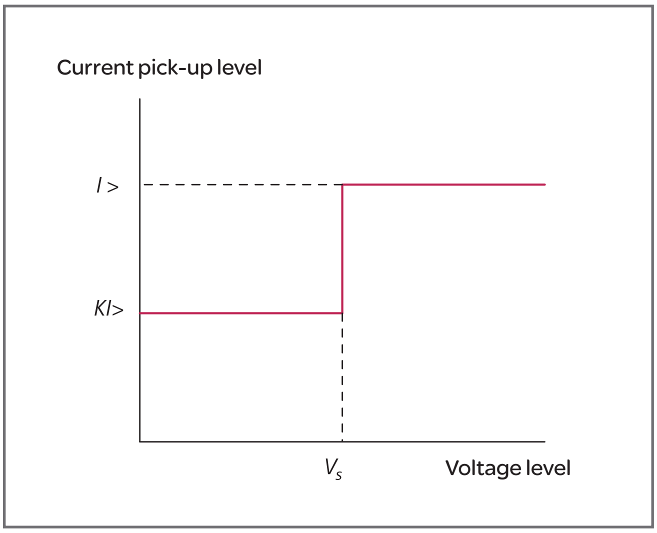

Figure C8.16:
Voltage controlled relay characteristics

6.2.2 Voltage restrained overcurrent protection

The alternative technique is to continuously vary the relay element pickup setting with generator voltage variation between upper and lower limits. The voltage is said to restrain the operation of the current element.

The effect is to provide a dynamic I.D.M.T. protection characteristic, according to the voltage at the machine terminals. Alternatively, the relay element may be regarded as an impedance type with a long dependent time delay. In consequence, for a given fault condition, the relay continues to operate more or less independently of current decrement in the machine. A typical characteristic is shown in Figure C8.17.

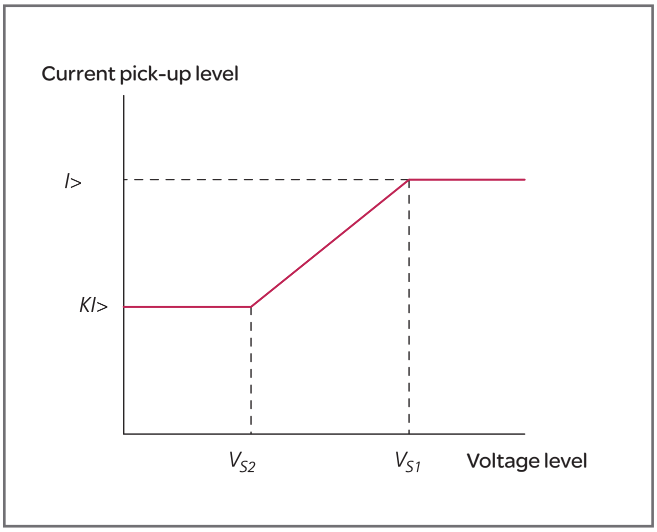

Figure C8.17:
Voltage restrained relay characteristics

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7. Stator earthfault protection

The most probable mode of insulation failure is phase to earth. An earthfault involving the stator core results in damage to the iron at the point of fault and welds laminations together. The damaged area can sometimes be repaired, but if severe damage has occurred, a partial core rebuild will be necessary. Earthfault protection must be applied where impedance earthing is employed that limits the earthfault current to less than the pick-up threshold of the overcurrent and/or differential protection for a fault located down to the bottom 5% of the stator winding from the star-point. The type of protection required will depend on the method of earthing and connection of the generator to the power system.

7.1 Direct-connected generators

A single direct-connected generator operating on an isolated system will normally be directly earthed. However, if several direct-connected generators are operated in parallel, only one generator is normally earthed at a time. For the unearthed generators, a simple measurement of the neutral current is not possible, and other methods of protection must be used. The following sections describe the methods available.

7.1.1 Neutral overcurrent protection

With this form of protection, a current transformer in the neutral- earth connection energises an overcurrent relay element. This provides unrestricted earth-fault protection and so it must be graded with feeder protection. The relay element will therefore have a time-delayed operating characteristic. Grading must be carried out in accordance with the principles detailed in Chapter [C1: Overcurrent Protection for Phase and Earthfaults]. The setting should not be more than 33% of the maximum earthfault current of the generator, and a lower setting would be preferable, depending on grading considerations.

7.1.2 Sensitive earthfault protection

This method is used in the following situations:

a. direct-connected generators operating in parallel

b. generators with high-impedance neutral earthing, the earth fault current being limited to a few tens of amps

c. installations where the resistance of the ground fault path is very high, due to the nature of the ground In these cases, conventional earthfault protection as described in Section 7.1.1 is of little use.

The principles of sensitive earthfault protection are described in Chapter [C1: Overcurrent Protection for Phase and Earthfaults, Section 17.1, 18 and 19]. The earthfault (residual) current can be obtained from residual connection of line CTs, a line-connected Core Balance CT, or a CT in the generator neutral. The latter is not possible if directional protection is used. The polarising voltage is usually the neutral voltage displacement input to the relay, or the residual of the three phase voltages, so a suitable VT must be used. For Petersen Coil earthing, directional sensitive earthfault based on Icos characteristic or a wattmetric technique (Chapter [C1: Overcurrent Protection for Phase and Earthfaults, Section 19]) can also be used.

For direct-connected generators operating in parallel, directional sensitive earthfault protection may be necessary. This is to ensure that a faulted generator will be tripped before there is any possibility of the neutral overcurrent protection tripping a parallel healthy generator. When being driven by residually-connected phase CTs, the protection must be stabilised against incorrect tripping with transient spill current in the event of asymmetric CT saturation when phase fault or magnetising inrush current is being passed. Stabilising techniques include the addition of relay circuit impedance and/or the application of a time delay. Where the required setting of the protection is very low in comparison to the rated current of the phase CTs, it would be necessary to employ a single Core Balance CT for the earthfault protection to ensure transient stability.

Since any generator in the paralleled group may be earthed, all generators will require to be fitted with both neutral overcurrent protection and sensitive directional earthfault protection.

The setting of the sensitive directional earthfault protection is chosen to co-ordinate with generator differential protection and/or neutral voltage displacement protection to ensure that 95% of the stator winding is protected. Figure C8.18 illustrates the complete scheme, including optional blocking signals where difficulties in co-ordinating the generator and downstream feeder earthfault protection occur.

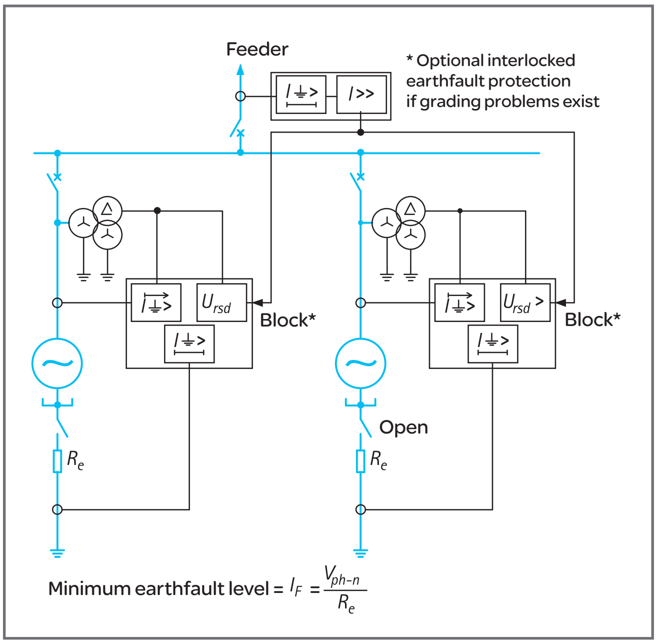

Figure C8.18:
Comprehensive earthfault protection scheme for direct-connected generators operating in parallel

7. Stator earthfault protection

For cases (b) and (c) above, it is not necessary to use a directional facility. Care must be taken to use the correct RCA setting – for instance if the earthing impedance is mainly resistive, this should be 0°. On insulated or very high impedance earthed systems, an RCA of -90° would be used, as the earthfault current is predominately capacitive.

Directional sensitive earthfault protection can also be used for detecting winding earthfaults in an unearthed generator. In the application case where several generators operate in parallel and there is only one earthed generator, the relay element is applied to the terminals of the generator and the directional sensitive earthfault protection responds to faults only within the unearthed machine windings. While there are earthfaults on the external system, the zero sequence current cannot flow through the relay and hence the relay does not operate. It will also not operate on the winding earthfault of the only earthed generator without the circulation path for the zero sequence current, so that other types of earthfault protection must also be applied. As any of the generators could operate as the earthed machine each will require the same protection.

7.1.3 Neutral voltage displacement protection

In a balanced network, the addition of the three phase-neutral voltages produces a nominally zero residual voltage, since there would be little zero sequence voltage present. Any earthfault will set up a zero sequence system voltage, which will give rise to a non-zero residual voltage. This can be measured by a suitable relay element. The voltage signal must be derived from a VT that is suitable – i.e. it must be capable of transforming zero-sequence voltage, so 3-limb types and those without a primary earth connection are not suitable. This unbalance voltage provides a means of detecting earthfaults. The relay element must be insensitive to third harmonic voltages that may be present in the system voltage waveforms, as these will sum residually.

As the protection is still unrestricted, the voltage setting of the relay must be greater than the effective setting of any downstream earthfault protection. It must also be time-delayed to co-ordinate with such protection. Sometimes, a second high-set element with short time delay is used to provide fast-acting protection against major winding earthfaults. Figure C8.19 illustrates the possible connections that may be used.

7.2 Indirectly-connected generators

A directly-earthed generator-transformer unit cannot interchange zero-sequence current with the remainder of the network, and hence an earthfault protection grading problem does not exist. The following sections detail the protection methods for the various forms of impedance earthing of generators.

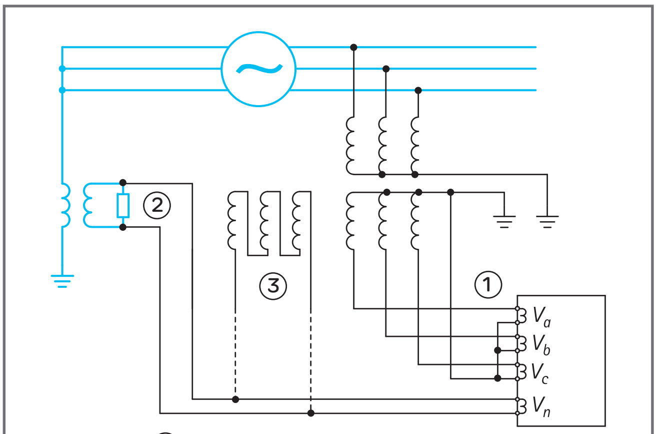

Figure C8.19:
Neutral voltage displacement protection

7.2.1 High resistance earthing – neutral overcurrent protection

A current transformer mounted on the neutral-earth conductor can drive an instantaneous and/or time delayed overcurrent relay element, as shown in Figure C8.20. It is impossible to provide protection for the whole of the winding, and Figure C8.20 also details how the percentage of winding covered can be calculated. For a relay element with an instantaneous setting, protection is typically limited to 90% of the winding. This is to ensure that the protection will not maloperate with zero sequence current during operation of a primary fuse for a VT earthfault or with any transient surge currents that could flow through the interwinding capacitance of the step-up transformer for an HV system earthfault.

A time-delayed relay is more secure in this respect, and it may have a setting to cover 95% of the stator winding. Since the generating units under consideration are usually large, instantaneous and time delayed relay elements are often applied, with settings of 10% and 5% of maximum earthfault current respectively; this is the optimum compromise in performance. The portion of the winding left unprotected for an earthfault is at the neutral end. Since the voltage to earth at this end of the winding is low, the probability of an earthfault occurring is also low. Hence additional protection is often not applied.

7.2.2 Distribution transformer earthing using a current element

In this arrangement, shown in Figure C8.21(a), the generator is earthed via the primary winding of a distribution transformer. The secondary winding is fitted with a loading resistor to limit the earthfault current.

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7. Stator earthfault protection

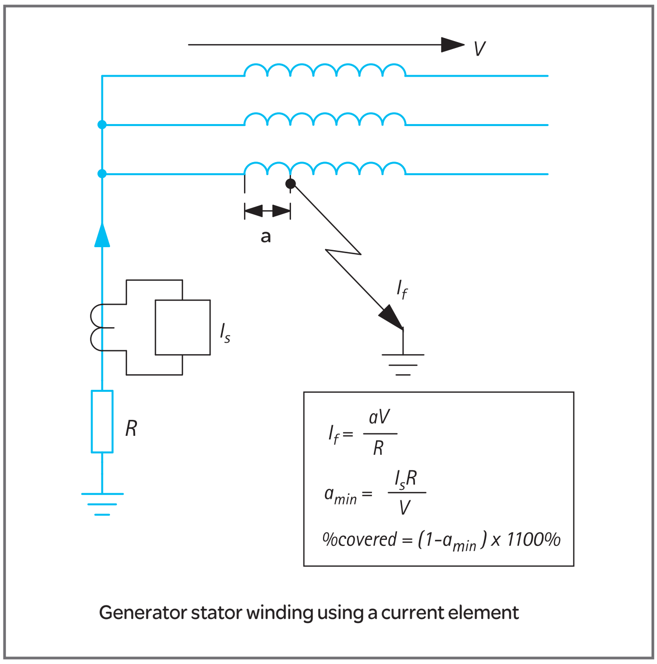

Figure C8.20:
Earthfault protection of high-resistance earthed generator stator winding using a current element

An overcurrent relay element energised from a current transformer connected in the resistor circuit is used to measure secondary earthfault current. The relay should have an effective setting equivalent to 5% of the maximum earthfault current at rated generator voltage, in order to protect 95% of the stator winding. The relay element response to third harmonic current should be limited to prevent incorrect operation when a sensitive setting is applied.

As discussed in Section 7.2.1 for neutral overcurrent protection, the protection should be time delayed when a sensitive setting is applied, in order to prevent maloperation under transient conditions. It also must grade with generator VT primary protection (for a VT primary earthfault). An operation time in the range 0.5 s - 3 s is usual. Less sensitive instantaneous protection can also be applied to provide fast tripping for a heavier earthfault condition.

7.2.3 Distribution transformer earthing using a voltage element

Earthfault protection can also be provided using a voltage-measuring element in the secondary circuit instead. The setting considerations would be similar to those for the current operated protection, but transposed to voltage. The circuit diagram is shown in Figure C8.21(b).

Application of both voltage and current operated elements to a generator with distribution transformer earthing provides some advantages. The current operated function will continue to operate in the event of a short-circuited loading resistor and the voltage protection still functions in the event of an open-circuited resistor. However, neither scheme will operate in the event of a flashover on the primary terminals of the transformer or of the neutral cable between the generator and the transformer during an earthfault. A CT could be added in the neutral connection close to the generator, to energise a high-set overcurrent element to detect such a fault, but the fault current would probably be high enough to operate the phase differential protection.

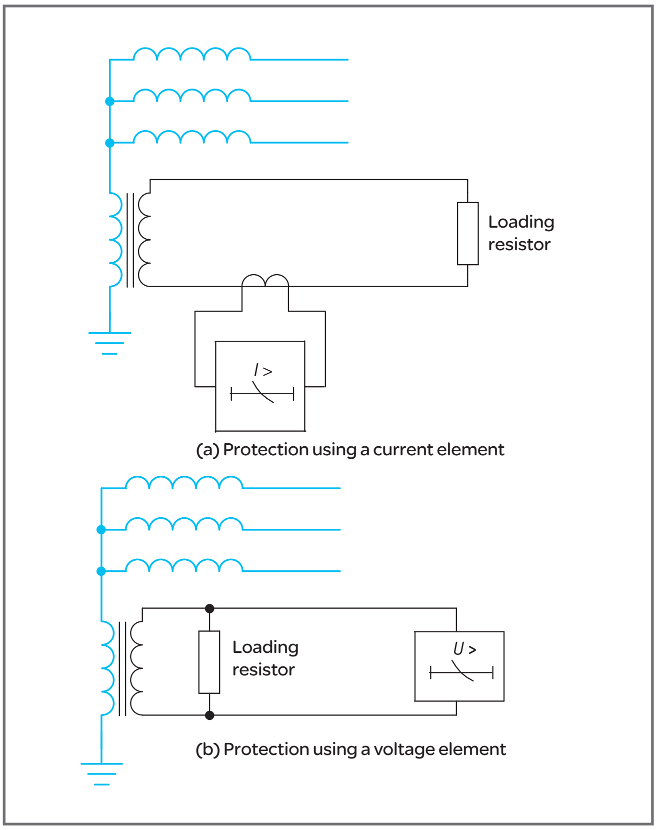

Figure C8.21:
Generator winding earthfault protection - distribution transformer earthing

7.2.4 Neutral voltage displacement protection

This can be applied in the same manner as for direct-connected generators (Section 7.1.3). The only difference is that there are no grading problems as the protection is inherently restricted.

A sensitive setting can therefore be used, enabling cover of up to 95% of the stator winding to be achieved.

7.3 Restricted earthfault protection

This technique can be used on small generators not fitted with differential protection to provide fast acting earthfault protection within a defined zone that encompasses the

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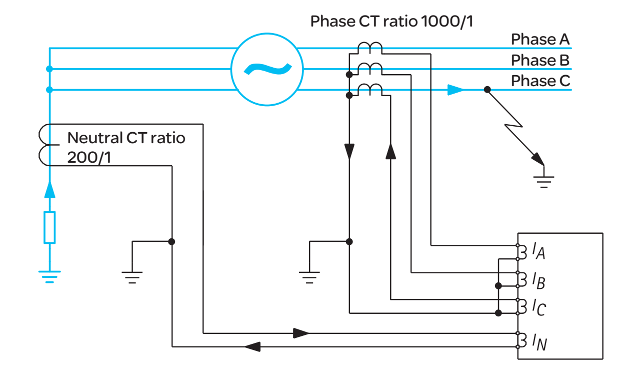
generator. It is cheaper than full differential protection but only provides protection against earthfaults. The principle is that used for transformer REF protection, as detailed in Chapter [C7: Transformer and Transformer-Feeder Protection, Section 7]. However, in contrast to transformer REF protection, both biased low-impedance and high-impedance techniques can be used.

7.3.1 Low-impedance biased REF protection

This is shown in Figure C8.22. The main advantage is that the neutral CT can also be used in a modern relay to provide conventional earthfault protection and no external resistors are used. Relay bias is required, as described in Chapter [C2: Line Differential Protection, Section 4.2], but the formula for calculating the bias is slightly different and also shown in Figure C8.22.



$$I_{BIAS} = \frac{(\text{highest of } I_A, I_B, I_C) + (I_N \times \text{scaling factor})}{2}$$

$$\text{where scaling factor} = \frac{\text{neutral CT ratio}}{\text{phase CT ratio}} = \frac{200}{1000} = 0.2$$

$$I_{DIFF} = \bar{I}_A + \bar{I}_B + \bar{I}_C + (\text{scaling factor} \times \bar{I}_N)$$

Figure C8.22:
Low impedance biased REF protection of a generator

The initial bias slope is commonly set to 0% to provide maximum sensitivity, and applied up to the rated current of the generator. It may be increased to counter the effects of CT mismatch. The bias slope above generator rated current is typically set to 150% of rated value. The initial current setting is typically 5% of the minimum earthfault current for a fault at the machine terminals.

7.3.2 High impedance REF protection

The principle of high impedance differential protection is given in Chapter [C2: Line Differential Protection] and also described further in Section 3.2. The same technique can be used for earthfault protection of a generator, using three residually connected phase CTs balanced against a similar single CT in the neutral connection, as shown in Figure C8.23. Settings of the order of 5% of maximum earthfault current at the generator terminals are typical. The usual requirements in respect of stabilising resistor and non-linear resistance to guard against excessive voltage across the relay must be taken, where necessary.

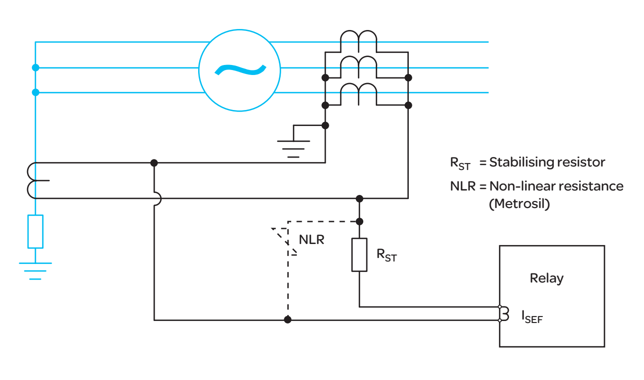


Figure C8.23:
High impedance REF protection

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8. Earthfault protection for entire stator winding

All of the methods for earthfault protection detailed in Section 7 leave part of the winding unprotected. In most cases, this is of no consequence as the probability of a fault occurring in the 5% of the winding nearest the neutral connection is very low, due to the reduced phase to earth voltage. However, a fault can occur anywhere along the stator windings in the event of insulation failure due to localised heating from a core fault. In cases where protection for the entire winding is required, perhaps for alarm only, there are various methods available.

8.1 Protection based on third harmonic voltage

Most generators will produce third harmonic voltages to some degree due to non-linearity in the magnetic circuits of the generator design. Under normal operating conditions the distribution of the third harmonic voltage along the stator windings corresponds to Figure C8.24(a). The maxima occur at the star point N and the terminal T. The values increase with generator load, as shown in Figure C8.24(a). U'_{TE} is the third harmonic voltage when the generator is off load and U''_{TE} is the third harmonic voltage when the generator is fully loaded. When a fault occurs in the part of the stator winding nearest the neutral end, the third harmonic voltage at the star point N drops to near zero but the third harmonic voltage at the terminal T increases significantly, as shown in Figure C8.24(b). Hence a relay element that responds to third harmonic voltage can be used to detect the fault near the neutral end. If the third harmonic voltage is measured at the generator star point, an undervoltage characteristic is used. An overvoltage characteristic is used if the measurement is taken from the generator line VT. The measurement of third harmonic voltage can be taken either from a star-point VT or the generator line VT. In the latter case, the VT must be capable of carrying residual flux, and this prevents the use of 3-limb types.

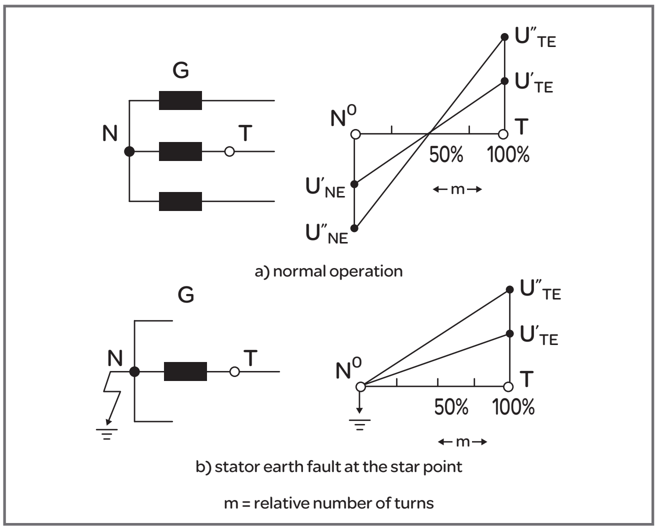

Figure C8.24 Distribution of the 3rd harmonic component along the stator winding of a large generator

A problem encountered is that the level of third harmonic voltage generated is related to the output of the generator. The voltage is low when generator output is low. In order to avoid maloperation when operating at low power output, the third harmonic neutral undervoltage element can be inhibited by a power element (kW, kVar or kVA). It can also be inhibited when all the phase-phase voltages at the generator terminal are below the threshold.

For effective application of this form of protection, there should be at least 1% Vn third harmonic voltage across the generator neutral earthing impedance under all normal operating conditions. The third harmonic undervoltage threshold must be set below the level of third harmonic voltage present under normal conditions. A typical value for this threshold could be 0.5% Vn. The third harmonic overvoltage threshold must be set above the level of third harmonic voltage present under normal conditions. A typical value for this threshold could be 1% Vn. A time delay for these elements can be set to ensure the stability.

As the fault location moves progressively away from the neutral end, the drop in third harmonic voltage becomes less, so that at around 20-30% of the winding distance, it no longer becomes possible to discriminate between a healthy and a faulty winding. Hence, a conventional earthfault scheme should be used in conjunction with a third harmonic scheme, to provide overlapping cover of the entire stator winding. The 3rd harmonic technique has to be blocked or is not operational when the machine is stopped and when the machine is running up and down. Also, some machines only produce a low level of 3rd harmonic voltage (<1% Vn) and for these machines the 3rd harmonic method of 100% stator earthfault protection cannot be used.

One alternative is to compare the third harmonic voltage at the neutral end U_{NE} with the third harmonic voltage at the terminal U_{TE}. The operation setting is the ratio between these two third harmonic voltages (U_{NE}/U_{TE}). When there is earthfault near the neutral end, the third harmonic voltage at the neutral end decreases while the third harmonic voltage at the terminal increases. So the ratio will be less than the setting. For this solution there is no need to inhibit the operation when the power output is low. The setting shall be greater than the maximum ratio U_{NE}/U_{TE} under normal conditions.

8.2 Protection based on low frequency injection

Another method for protecting the entire stator winding of a generator is to deploy signal injection equipment to inject a low frequency voltage into the star point or the terminals of the machine as shown in Figure C8.25. Typical injection frequencies are 12.5 Hz or 20 Hz with 20 Hz being the most popular. Under normal healthy conditions only a very small current flows via the stator earth capacitance due to the high impedance of this path at low frequencies ($X_c = 1/2\pi fc$, where f is the low frequency injected signal and c is earth capacitance). In the event of an earthfault the measured

8. Earthfault protection for entire stator winding

current increases due to the smaller impedance of the earthfault path. From the injected voltage and the fault current the relay can determine the fault resistance. The protection can also detect earthfaults at the generator terminals including connected components such as voltage transformers. This form of protection can provide earthfault protection when the generator is at standstill, prior to run-up. It is also an appropriate method to apply to variable speed synchronous machines. Such machines may be employed for variable speed motoring in pumped-storage generation schemes or for starting a large gas turbine prime mover.

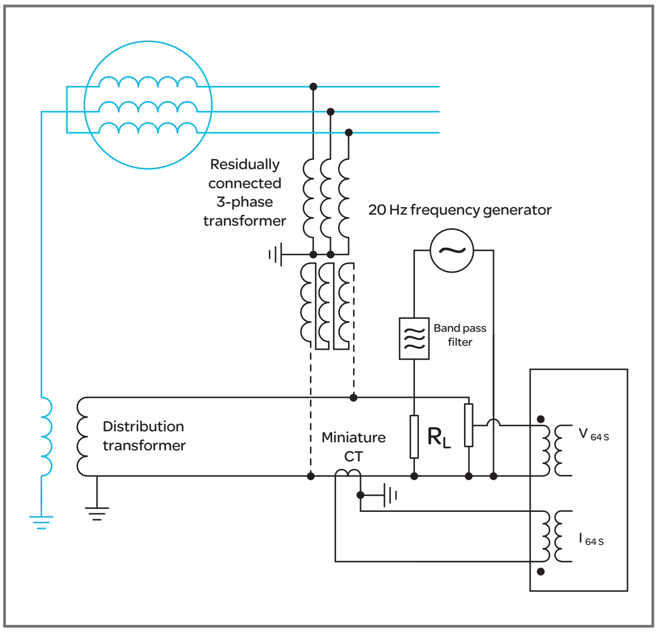

Figure C8.25: Circuit diagram of the 100% stator earthfault protection with earthing (broken delta) transformer or neutral transformer

The voltage to be injected into the generator neutral depends on the driving low frequency voltage (voltage divider, load resistor and bandpass filter) and on the transformation ratio of the neutral or earthing transformer. To prevent the secondary load resistance from becoming too small and ensure better measurement accuracy, a high secondary voltage, such as 500 V, should be chosen for the neutral or earthing transformer. The low frequency voltage is fed to the relay via a voltage divider which is applied when the secondary rated voltage of the distribution transformer is higher than relay maximum voltage input. The low frequency measuring current is fed via a miniature current transformer. All interference deviating from the nominal low frequency signal is filtered out. The fault resistance can be derived by the low frequency voltage and current fed to the relay.

Normally two stages of under-resistance element with definite time delay are applied. The higher setting stage is to issue the alarm signal. Typically the value for the primary fault resistance alarm setting is 3-8 k Ohms with typically 1-5 s delay. The lower setting stage is to issue the trip signal. Typically the value for the primary fault resistance trip setting is 1-2 k Ohms with typically 0.3-1 s delay.

C8

9. Overvoltage protection

Overvoltages on a generator may occur due to transient surges on the network, or prolonged power frequency overvoltages may arise from a variety of conditions. Surge arrestors may be required to protect against transient overvoltages, but relay protection may be used to protect against power frequency overvoltages.

A sustained overvoltage condition should not occur for a machine with a healthy voltage regulator, but it may be caused by the following contingencies:

a. defective operation of the automatic voltage regulator when the machine is in isolated operation

b. operation under manual control with the voltage regulator out of service. A sudden variation of the load, in particular the reactive power component, will give rise to a substantial change in voltage because of the large voltage regulation inherent in a typical alternator

c. sudden loss of load (due to tripping of outgoing feeders, leaving the set isolated or feeding a very small load) may cause a sudden rise in terminal voltage due to the trapped field flux and/ or overspeed

Sudden loss of load should only cause a transient overvoltage while the voltage regulator and governor act to correct the situation. A maladjusted voltage regulator may trip to manual, maintaining excitation at the value prior to load loss while the generator supplies little or no load. The terminal voltage will increase substantially, and in severe cases it would be limited only by the saturation characteristic of the generator. A rise in speed simply compounds the problem. If load that is sensitive to overvoltages remains connected, the consequences in terms of equipment damage and lost revenue can be severe. Prolonged overvoltages may also occur on isolated networks, or ones with weak interconnections, due to the fault conditions listed earlier.

For these reasons, it is prudent to provide power frequency overvoltage protection, in the form of a time-delayed element, either IDMT or definite time. The overvoltage threshold should typically be set to 100% - 120% of the nominal phase-phase voltage seen by the relay. The time delay should be long enough to prevent operation during normal regulator action, and therefore should take account of the type of AVR fitted and its transient response. The typical delay to be applied would be 1 s - 3 s, with a longer delay being applied for lower voltage threshold settings.

Sometimes a high-set element is provided as well, with a very short definite-time delay or instantaneous setting to provide a rapid trip in extreme circumstances. The typical threshold setting to be applied would be 130 - 150% of the nominal phase-phase voltage, depending on generator manufacturers' advice.

10. Undervoltage protection

Undervoltage protection is rarely fitted to generators. It is sometimes used as an interlock element for another protection function or scheme, such as field failure protection or inadvertent energisation protection, where the abnormality to be detected leads directly or indirectly to an undervoltage condition.

A transmission system undervoltage condition may arise when there is insufficient reactive power generation to maintain the system voltage profile and the condition must be addressed to avoid the possible phenomenon of system voltage collapse.

However, it should be addressed by the deployment of 'system protection' schemes. The generation should not be tripped. The greatest case for undervoltage protection being required would be for a generator supplying an isolated power system, where undervoltage may occur for several reasons, typically overloading or failure of the AVR. In some cases, the performance of generator auxiliary plant fed via a unit transformer from the generator terminals could be adversely affected by prolonged undervoltage.

Where undervoltage protection is required, it should comprise an undervoltage element and an associated time delay. Settings must be chosen to avoid maloperation during the inevitable voltage dips during power system fault clearance or associated with motor starting. Transient reductions in voltage down to 80% or less may be encountered during motor starting. The time delay should be set to coordinate with downstream protection and the System Back-up protection of the relay. The time delay would typically be in excess of 3 s - 5 s.

11. Low forward power / reverse power protection

Low forward power or reverse power protection may be required for some generators to protect the prime mover. Parts of the prime mover may not be designed to experience reverse torque or they may become damaged through continued rotation after the prime mover has suffered some form of failure.

11.1 Low forward power protection

Low forward power protection is often used as an interlocking function to enable opening of the main circuit breaker for non-urgent trips – e.g. for a stator earthfault on a high-impedance earthed generator, or when a normal shutdown of a set is taking place. This is to minimise the risk of plant overspeeding when the electrical load is removed from a high-speed cylindrical rotor generator. The rotor of this type of generator is highly stressed mechanically and cannot tolerate much overspeed. While the governor should control overspeed conditions, it is not good practice to open the main circuit breaker simultaneously with tripping of the prime mover for non-urgent trips. For a steam turbine, for example, there is a risk of overspeeding due to energy storage in the trapped steam, after steam valve tripping, or in the event that the steam valve(s) do not fully close for some reason. For urgent trip conditions, such as stator differential protection operation, the risk involved in simultaneous prime mover and 0.5 - 6 generator breaker tripping must be accepted.

When required for interlocking of non-urgent tripping applications, the threshold setting of the low forward power protection function should be less than 50% of the power level that could result in a dangerous overspeed transient on loss of electrical loading. Some delay is desirable to avoid maloperation in the event of power fluctuations arising from sudden steam valve/throttle closure. A typical time delay is 2 s.

Another typical application of low forward power protection would be for pump storage generators operating in the motoring mode, where there is a need to prevent the machine becoming unprimed (loss of load protection) which can cause blade and runner cavitations. It is typically set to 80 - 90% of the minimum load. For loss of load applications the pickup time delay is necessary to avoid the maloperation during machine starting or interlock logic is applied to inhibit low forward power protection for a required time.

To prevent unwanted relay alarms and flags, a low forward power protection element can be disabled when the circuit breaker is open.

11.2 Reverse power protection (motoring protection)

Reverse power protection is applied to prevent damage to mechanical plant items in the event of failure of the prime mover. Table C8.1 gives details of the potential problems for various prime mover types and the typical settings for reverse power protection.

The power threshold setting of the reverse power protection shall be set according to Table C8.1 and depends on the application. A definite time delay on operation is necessary to prevent spurious operation with transient power swings that may arise following synchronization or in the event of a power transmission system disturbance.

Reverse power protection may also be used to interlock the opening of the generator set circuit breaker for 'non-urgent' tripping, as discussed in the above section.

As shown in Table C8.1, the motoring power of the generator set would be as small as 0.2% rated power. For applications where a protection sensitivity of better than 3% is required, a metering class CT should be employed to avoid incorrect protection behaviour due to CT phase angle errors when the generator supplies a significant level of reactive power at close to zero power factor. Besides, the angle compensation setting can compensate for the angle error introduced by the system CT and VT.

<table>
<tr><th>Prime mover</th><th>Motoring power (% of rated)</th><th>Possible damage</th></tr>
<tr><td rowspan="2">Diesel engine</td><td rowspan="2">5% - 25%</td><td>Fire/explosion due to unburnt fuel</td></tr>
<tr><td>Mechanical damage to gearbox/shafts</td></tr>
<tr><td colspan="3">Motoring level depends on compression ratio and cylinder bore stiffness. Rapid disconnection is required to limit power loss and risk of damage.</td></tr>
<tr><td rowspan="2">Gas turbine</td><td>10-15 (split shaft)</td><td rowspan="2">gearbox damage</td></tr>
<tr><td>> 50% (single shaft)</td></tr>
<tr><td colspan="3">Compressor load on single shaft machines leads to a high motoring power compared to split-shaft machines. Rapid disconnection is required to limit power loss or damage.</td></tr>
<tr><td rowspan="2">Hydro</td><td>0.2%-2% (blades out of water)</td><td rowspan="2">blade and runner cavitation</td></tr>
<tr><td>> 2% (blades in water)</td></tr>
<tr><td colspan="3">Power is low when blades are above tail-race water level. Hydraulic flow detection devices are often the main means of detecting loss of drive. Automatic disconnection is recommended for unattended operation.</td></tr>
<tr><td rowspan="2">Steam turbine</td><td>0.5% - 3% (Condensing sets)</td><td rowspan="2">Thermal stress damage on low-pressure turbine blades</td></tr>
<tr><td>3% - 6% (Non-condensing sets)</td></tr>
<tr><td colspan="3">Damage may occur rapidly with non-condensing sets or when vacuum is lost with condensing sets. Reverse power protection may be used as a secondary method of detection and might only be used to raise an alarm.</td></tr>
</table>

Table C8.1:
Generator reverse power problems

C8

12. Unbalanced loading

A three-phase balanced load produces a reaction field that, to a first approximation, is constant and rotates synchronously with the rotor field system. Any unbalanced condition can be resolved into positive, negative and zero sequence components. The positive sequence component is similar to the normal balanced load. The zero sequence component produces no main armature reaction.

12.1 Effect of negative sequence current

The negative sequence component is similar to the positive sequence system, except that the resulting reaction field rotates in the opposite direction to the d.c. field system. Hence, a flux is produced which cuts the rotor at twice the rotational velocity, thereby inducing double frequency currents in the field system and in the rotor body. The resulting eddy-currents are very large and cause severe heating of the rotor.

So severe is this effect that a single-phase load equal to the normal three-phase rated current can quickly heat the rotor slot wedges to the softening point. They may then be extruded under centrifugal force until they stand above the rotor surface, when it is possible that they may strike the stator core.

Synchronous machines will be able to withstand a certain level of negative phase sequence stator current continuously. All synchronous machines will be assigned a continuous maximum negative phase sequence current (I_{2MCR} per-unit) rating by the manufacturer. For various categories of generator, minimum negative phase sequence current withstand levels have been specified by international standards, such as IEC 60034-1, as shown in Table C8.2.

Short time heating is of interest during system fault conditions and it is usual in determining the generator negative sequence withstand capability to assume that the heat dissipation during such periods is negligible. Using this approximation it is possible to express the heating by the law:

$I_2{}^2 t = K$

Where:

I_2 = negative sequence component (per unit of MCR)

t = time (seconds)

K = constant proportional to the thermal capacity of the generator rotor

For heating over a period of more than a few seconds, it is necessary to allow for the heat dissipation, otherwise the generator maybe cut off incorrectly while the rotor temperature still remains within the machine's design thermal limits. As shown in Figure C8.26, the true thermal model is above the $I_2{}^2 t$ model when the negative sequence current is lower.

To consider the heat dissipation, the temperature depends on both the negative sequence component and the thermal time constant, as follows:

$$\theta \triangleq I_2^2 \, (1-e^{-\frac{t}{\tau}})$$

Generator type		Maximum I_2/I_n for continuous operation	Maximum $(I_2/I_n)^2t$ for operation under faults, Kg
Salient-pole:			
Indirectly cooled		0.08	20
Directly cooled (inner cooled stator and/or field		0.05	15
Cylindrical rotor synchronous:			
Indirectly cooled rotor			
Air cooled rotor		0.1	15
Directly cooled (inner cooled) rotor			
350>	350 MVA	0.08	8
900>	900 MVA	*	**
1250	1250 MVA	*	5
	1600 MVA	0.05	5
** For these generators, the value of I_2/I_n is calculated as follows:			
$\frac{I_2}{I_n} = 0.8 - \frac{S_n - 350}{3 \times 10^4}$			
** For these generators, the value of $(I_2/I_n)^2t$ is calculated as follows:			
$\left(\frac{I_2}{I_n}\right)^2 t = 8 - 0.00545\,(S_n - 350)$			
where S_n is the rated power in MVA			

Table C8.2:
IEC 60034-1 Minimum negative sequence current withstand levels

Where:

$\tau = K_g / I_{2MCR}^2$, the thermal time constant

K_g is the generator's per-unit thermal capacity constant in seconds.

I_{2MCR} is the generator's per-unit maximum continuous I_2 rating.

The limiting maximum continuous temperature (θ_{MCR}) would be in the form $\theta_{MCR} = I_{2MCR}^2$, as follow:

$$\theta_{MCR} = I_{2MCR}^2 \, (1-e^{-\frac{t}{\tau}})\ ,\ t = \infty$$

12.2 Negative phase sequence protection

This protection is applied to prevent overheating due to negative sequence currents. Small salient-pole generators have a proportionately larger negative sequence capacity and may not require protection. A true thermal replica approach which considers the heat dissipation is often applied in numerical relays.

12. Unbalanced loading

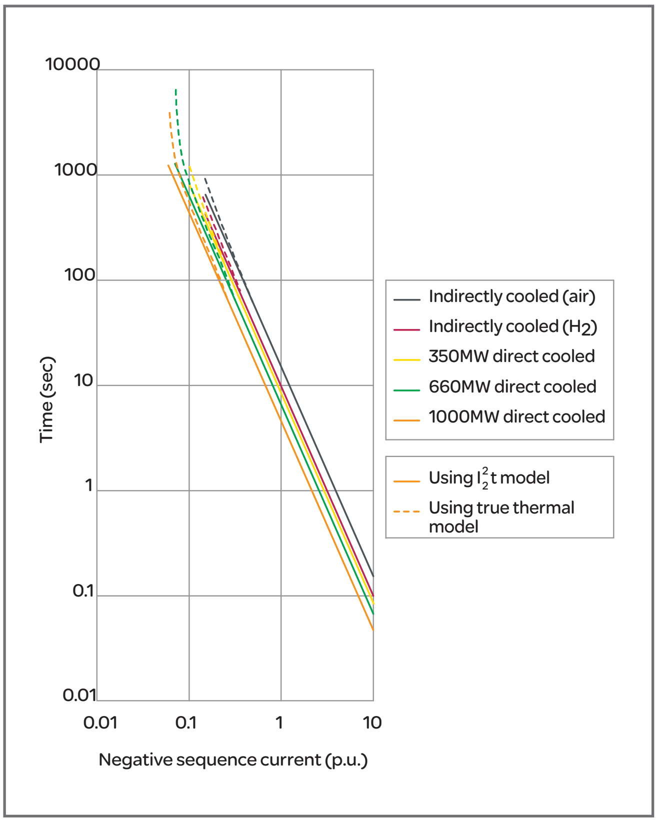

Figure C8.26:
Typical negative phase sequence current withstand of cylindrical rotor generators

From the above section 12.1, the time for which a level of negative phase sequence current in excess of I_{2MCR} can be maintained is expressed as follows:

$$t = -\frac{K}{I_{2MCR}^2} \times ln\left[1 - \left(\frac{I_{2MCR}^2}{I_2}\right)^2\right] \qquad \textit{...Equation C8.1}$$

The typical negative phase sequence thermal protection element characteristic takes the form of

$$t = -\frac{K}{I_{2set}^2} \times ln\left[1 - \left(\frac{I_{2set}^2}{I_2}\right)^2\right]$$

Where K is the thermal capacity setting, I_{2set} is thermal current setting per unit.

To obtain correct thermal protection K and $I_{2set}>$ should be set as follows:

Set K as $\left(\frac{I_{flc}}{I_p}\right)^2 \times K_g$

Set $I_{2set} >$ as $I_{2MCR} \times \left(\frac{I_{flc}}{I_p}\right)$

Where:

I_{2MCR} = Generator per unit maximum continuous I_2 rating

K_g = Generator thermal capacity constant(s)

I_{flc} = Generator primary full-load current (A)

I_p = CT primary current rating (A)

The negative sequence protection element will respond to system phase to earth and phase to phase faults. Therefore, the element must be set to grade with downstream earth and phase fault protections. To aid grading with downstream devices a definite minimum operating time for the operating characteristic can be set, as the $I_2> t_{MIN}$ setting shown in Figure C8.27. This definite minimum time setting should be set to provide an adequate margin between the operation of the negative phase sequence thermal protection function and external protection.

For levels of negative phase sequence current that are only slightly in excess of the thermal element pick-up setting, there will be a noticeable deviation between negative phase sequence thermal protection current-time characteristic and that of the simple I_2^2t characteristic. For this reason, a maximum negative phase sequence protection trip time setting is provided, as the $I_2> t_{MAX}$ setting shown in Figure C8.27. This maximum time setting also limits the tripping time of the negative phase sequence protection for levels of unbalance where there maybe uncertainty about the machine's thermal withstand.

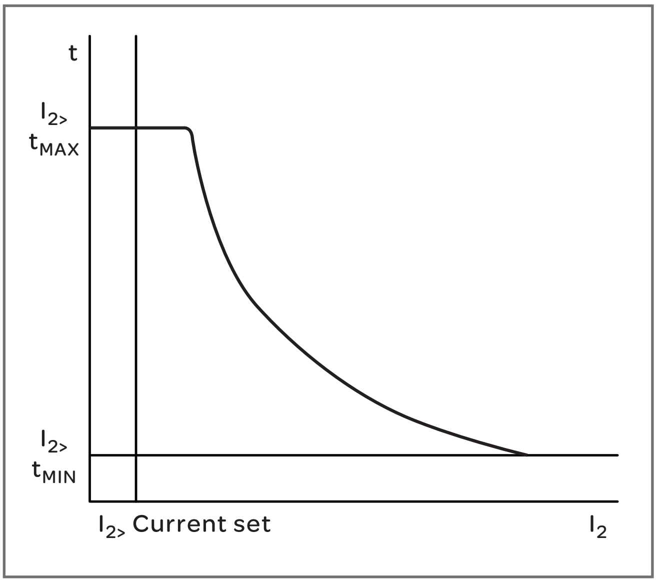

Figure C8.27:
Negative phase sequence thermal characteristic

13. Protection against inadvertent energisation

Accidental energisation of a generator when it is not running may cause severe damage to it. With the generator at standstill, closing the circuit breaker results in the generator acting as an induction motor; the field winding (if closed) and the rotor solid iron/damper circuits acting as rotor circuits. Very high currents are induced in these rotor components, and also occur in the stator, with resultant rapid overheating and damage. Protection against this condition is therefore desirable.

A combination of stator undervoltage and overcurrent can be used to detect this condition. An instantaneous overcurrent element is used, and gated with a three-phase undervoltage element (fed from a VT on the generator side of the circuit breaker) to provide the protection. The overcurrent element can have a low setting, as operation is blocked by three-phase undervoltage element when the generator is operating normally. The voltage setting should be low enough to ensure that operation cannot occur for transient faults. A setting of about 50% of rated voltage is typical. VT failure can cause maloperation of the protection, so the element should be inhibited under these conditions.

The pick-up time delay is necessary. It is to prevent initialisation of the element during system faults. The typical pick-up time delay is 5 s or it is at least in excess of the protection clearance time for a close up phase to phase fault. In addition the drop-off time delay is also necessary to ensures that the element remains initialised following accidental closure of the circuit breaker when the undervoltage detector could reset. A drop-off delay of 0.5 s - 1 s will ensure that the element can operate when required.

14. Under/overfrequency/overfluxing protection

These conditions are grouped together because these problems often occur due to a departure from synchronous speed.

14.1 Overfluxing

Overfluxing occurs when the ratio of voltage to frequency is too high. Either excessive voltage, or low frequency, or a combination of both can produce high flux densities in the magnetic core of the generator or transformer. This could cause the core of the generator or transformer to saturate and stray flux to be induced in un-laminated components that have not been designed to carry flux. Overheating can then occur, resulting in damage.

Both the generator and transformer shall have the capability to tolerate the transient overfluxing, which may be caused by the sudden loss of load. The typical overfluxing withstand characteristics of the generator is shown in Figure C8.28. Sustained overfluxing can arise during the generator running up if excitation is applied too early with the AVR in service or if the generator is run down with the excitation still applied. Other overfluxing instances can occur from the failure of AVR or the errors in the manual control of the machine field circuit. The sustained overfluxing conditions must be detected by a dedicated protection function that will raise an alarm and possibly force an immediate reduction in excitation.

It is usual to provide a definite time-delayed alarm setting and an instantaneous or inverse time-delayed trip setting, to match the withstand characteristics of the protected generator and transformer. Reference should be made to manufacturers withstand characteristics before formulating these settings.

In general, a generator or step-up transformer overfluxing condition will occur if the V/Hz ratio exceeds 1.05 p.u, such as a 5% overvoltage condition at rated frequency.

Besides, it is very important that the VT reference for overfluxing protection is not the same as that used for the AVR. The overfluxing protection based on V/Hz ratio shall reference the phase to phase voltage to avoid the maloperation under the earthfault condition which could cause the increase of phase voltage.

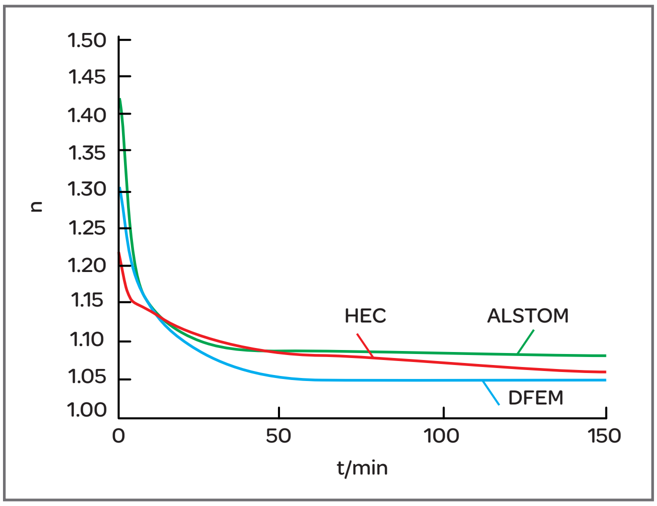

Figure C8.28:
Generator overfluxing withstand characteristics (three manufacturers), where n means per unit of V/Hz ratio with rated values

14. Under/overfrequency/overfluxing protection

14.2 Under/overfrequency

The most common occurrence of overfrequency is after substantial loss of load. Severe overfrequency operation of a high-speed generating set could result in plant damage as a result of the high centrifugal forces that would be imposed on rotating components. The governor fitted to the prime mover normally provides protection against overfrequency. When a rise in running speed occurs, the governor should quickly respond to reduce the mechanical input power, so that normal running speed is quickly regained. Overfrequency protection may be required as a back-up protection function to cater for governor or throttle control failure following loss of load or during unsynchronized running.

Overfrequency settings should be selected to coordinate with normal, transient overfrequency excursions following full-load rejection. The generator manufacturer should declare the expected transient overfrequency behaviour that should comply with international governor response standards. A typical overfrequency setting would be 10% above nominal.

Underfrequency may occur as a result of overload of generators operating on an isolated system, or a serious fault on the power system that results in a deficit of generation compared to load. Such events could be compensated for by automatic load shedding. In this case, underfrequency operation would be a transient condition. In the event of the load shedding being unsuccessful, the generators should be provided with back-up underfrequency protection. For the high-speed turbine generators, not running at nominal frequency can cause abnormal blade resonances. If prolonged, it could lead to turbine disc component fractures. Such effects can be accumulative and so operation at frequencies away from nominal should be limited as much as possible, to avoid the need for early plant overhaul. So the prime movers may have to be protected against excessively low frequency by tripping of the generators concerned. The protection function should be set so that declared frequency-time limits for the generating set are not infringed. Typically, a 10% underfrequency condition should be continuously sustainable.

Where separate load shedding equipment is provided, the underfrequency protection should coordinate with it. This will ensure that generator tripping will not occur in the event of successful load shedding following a system overload. Underfrequency protection could be set-up to coordinate with multi-stage system load shedding.

15. Rotor faults

The field circuit of a generator, comprising the field winding of the generator and the armature of the exciter, together with any associated field circuit breaker if it exists, is an isolated d.c. circuit which is not normally earthed. If an earthfault occurs, there will be no steady-state fault current and the need for action will not be evident.

Danger arises if a second earthfault occurs at a separate point in the field system, to cause the high field current to be diverted, in part at least, from the intervening turns. Serious damage to the conductors and possibly the rotor can occur very rapidly under these conditions.

More damage may be caused mechanically. If a large portion of the winding is short-circuited, the flux may adopt a pattern such as that shown in Figure C8.29. The attracting force at the surface of the rotor is given by:

$$F = \frac{B^2 A}{8\pi}$$

where:

A = area

B = flux density

It will be seen from Figure C8.29 that the flux is concentrated on one pole but widely dispersed over the other and intervening surfaces. The attracting force is in consequence large on one pole but very weak on the opposite one, while flux on the quadrature axis will produce a balancing force on this axis. The result is an unbalanced force that in a large machine may be of the order of 50-100 tonnes.

A violent vibration is set up that may damage bearing surfaces or even displace the rotor by an amount sufficient to cause it to foul the stator.

15.1 Rotor earthfault protection

Two methods are available to detect this type of fault. The first method is suitable for generators that incorporate brushes in the main generator field winding. The second method requires at least a slip-ring connection to the field circuit:

a. potentiometer method

b. a.c. injection method

15. Rotor faults

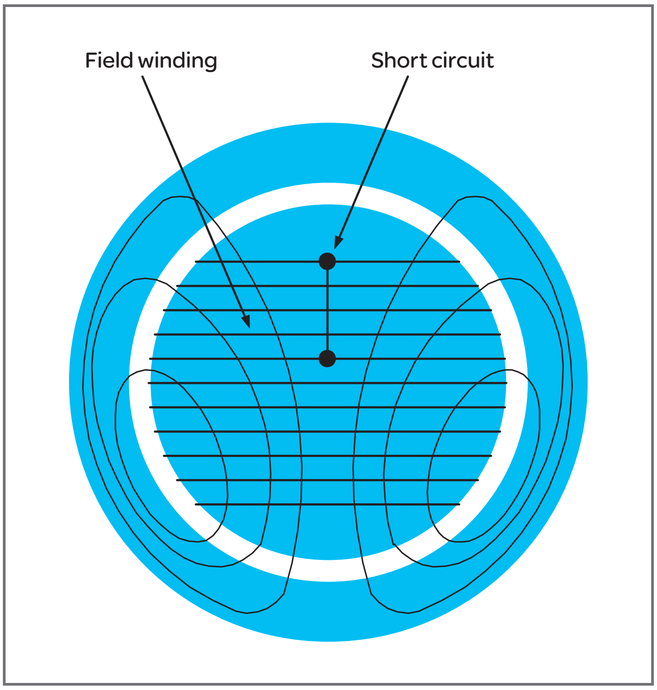

Figure C8.29:
Flux distribution on rotor with partial winding short circuit

15.1.1 Potentiometer method

This is a scheme that was fitted to older generators, and it is illustrated in Figure C8.30. An earthfault on the field winding would produce a voltage across the relay, the maximum voltage occurring for faults at the ends of the winding.

A 'blind spot' would exist at the centre of the field winding. To avoid a fault at this location remaining undetected, the tapping point on the potentiometer could be varied by a pushbutton or switch. The relay setting is typically about 5% of the exciter voltage.

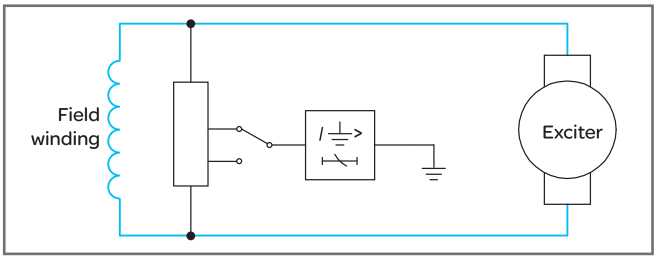

Figure C8.30:
Earthfault protection of field circuit by potentiometer method

15.1.2 Injection methods

Two methods are in common use. The first is based on low frequency signal injection, with series filtering, as shown in Figure C8.31(a). It comprises an injection source that is connected between earth and one side of the field circuit, through capacitive coupling and the measurement circuit. The field circuit is subjected to an alternating potential at substantially the same level throughout. An earthfault anywhere in the field system will give rise to a current that is detected as an equivalent voltage across the adjustable resistor by the relay. The capacitive coupling blocks the normal d.c. field voltage, preventing the discharge of a large direct current through the protection scheme. The combination of series capacitor and reactor forms a low-pass tuned circuit, the intention being to filter higher frequency rotor currents that may occur for a variety of reasons.

Other schemes are based on power frequency signal injection. An impedance relay element is used, a field winding earthfault reducing the impedance seen by the relay. These suffer the draw back of being susceptible to static excitation system harmonic currents when there is significant field winding and excitation system shunt capacitance.

Greater immunity for such systems is offered by capacitively coupling the protection scheme to both ends of the field winding, where brush or slip ring access is possible (Figure C8.31(b)).

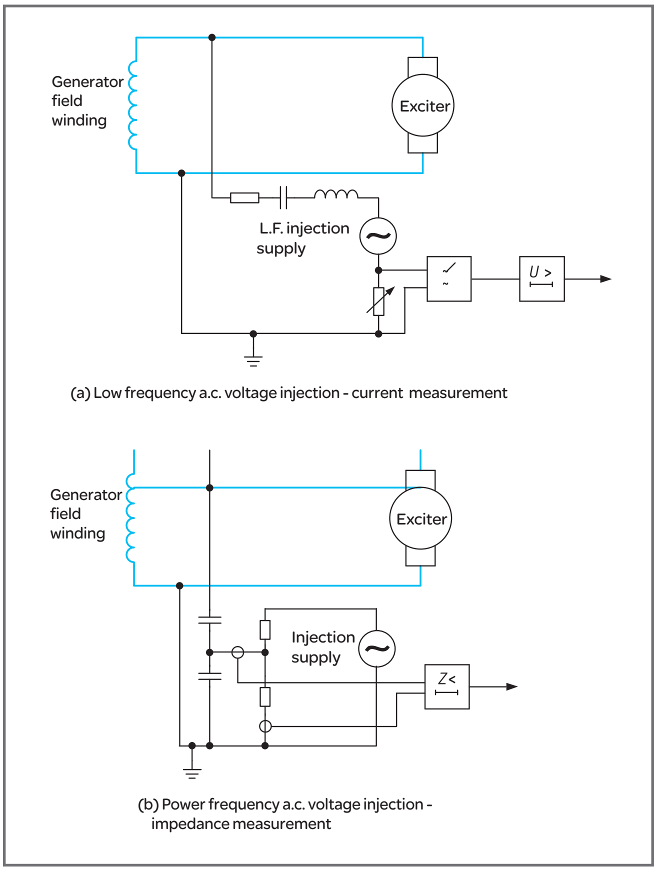

Figure C8.31:
Earthfault protection of field circuit by a.c. injection

15. Rotor faults

The low–frequency injection scheme is also advantageous in that the current flow through the field winding shunt capacitance will be lower than for a power frequency scheme. Such current would flow through the machine bearings to cause erosion of the bearing surface. For power frequency schemes, a solution is to insulate the bearings and provide an earthing brush for the shaft.

15.2 Rotor earthfault protection for brushless generators

A brushless generator has an excitation system consisting of:

a. a main exciter with rotating armature and stationary field windings

b. a rotating rectifier assembly, carried on the main shaft line out

c. a controlled rectifier producing the d.c. field voltage for the main exciter field from an a.c. source (often a small 'pilot' exciter)

Hence, no brushes are required in the generator field circuit. All control is carried out in the field circuit of the main exciter. Detection of a rotor circuit earthfault is still necessary, but this must be based on a dedicated rotor-mounted system that has a telemetry link to provide an alarm/data.

15.3 Rotor shorted turn protection

As detailed in Section 15 a shorted section of field winding will result in an unsymmetrical rotor flux pattern and in potentially damaging rotor vibration. Detection of such an electrical fault is possible using a probe consisting of a coil placed in the airgap. The flux pattern of the positive and negative poles is measured and any significant difference in flux pattern between the poles is indicative of a shorted turn or turns. Automated waveform comparison techniques can be used to provide a protection scheme, or the waveform can be inspected visually at regular intervals. An immediate shutdown is not normally required unless the effects of the fault are severe. The fault can be kept under observation until a suitable shutdown for repair can be arranged. Repair will take some time, since it means unthreading the rotor and dismantling the winding.

Since short-circuited turns on the rotor may cause damaging vibration and the detection of field faults for all degrees of abnormality is difficult, the provision of a vibration detection scheme is desirable – this forms part of the mechanical protection of the generator.

16. Loss of excitation protection

Loss of excitation may occur for a variety of reasons. If the generator was initially operating at only 20%-30% of rated power, it may settle to run super-synchronously as an induction generator, at a low level of slip. In doing so, it will draw reactive current from the power system for rotor excitation. This form of response is particularly true of salient pole generators. In these circumstances, the generator may be able to run for several minutes without requiring to be tripped. There may be sufficient time for remedial action to restore the excitation, but the reactive power demand of the machine during the failure may severely depress the power system voltage to an unacceptable level. For operation at high initial power output, the rotor speed may rise to approximately 105% of rated speed, where there would be low power output and where a high reactive current of up to 2.0p.u. may be drawn from the supply. Rapid automatic disconnection is then required to protect the stator windings from excessive current and to protect the rotor from damage caused by induced slip frequency currents.

16.1 Protection against loss of excitation

The protection used varies according to the size of generator being protected.

16.1.1 Small generators

On the smaller machines, protection against asynchronous running has tended to be optional, but it may now be available by default, where the functionality is available within a modern numerical generator protection package. If fitted, it is arranged either to provide an alarm or to trip the generator. If the generator field current can be measured, a relay element can be arranged to operate when this drops below a preset value. However, depending on the generator design and size relative to the system, it may well be that the machine would be required to operate synchronously with little or no excitation under certain system conditions.

The field undercurrent relay must have a setting below the minimum exciting current, which may be 8% of that corresponding to the MCR of the machine. Time delay relays

16. Loss of excitation protection

are used to stabilise the protection against maloperation in response to transient conditions and to ensure that field current fluctuations due to pole slipping do not cause the protection to reset.

If the generator field current is not measurable, then the technique detailed in the following section is utilised.

16.1.2 Large generators (>5 MVA)

For generators above about 5 MVA rating, protection against loss of excitation and pole slipping conditions is normally applied.

Consider a generator connected to network, as shown in Figure C8.32. On loss of excitation, the terminal voltage will begin to decrease and the stator current will increase, resulting in a decrease of impedance viewed from the generator terminals and also a change in power factor.

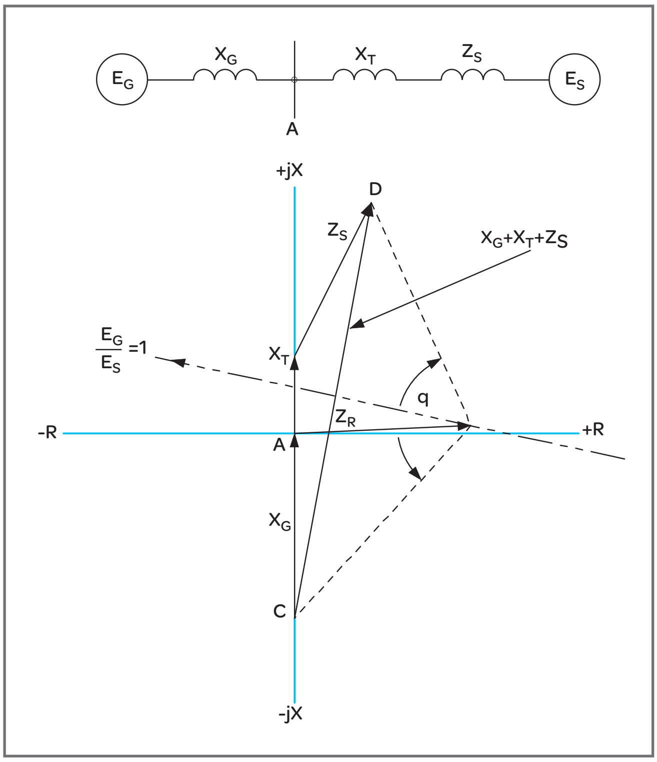

Figure C8.32:
Basic interconnected system

A relay to detect loss of synchronism can be located at point A. It can be shown that the impedance presented to the relay under loss of synchronism conditions (phase swinging or pole slipping) is given by:

$$Z_R = \frac{(X_G + X_T + Z_S)\, n\, (n - \cos\theta - j\sin\theta)}{(n - \cos\theta)^2 + \sin^2\theta} - X_G$$

...Equation C8.2

where:

$$n = {}^{E_G}\!/_{E_S} = \frac{\text{generated}}{\text{system}}\text{voltage}$$

θ = angle by which E_G leads E_S

If the generator and system voltages are equal, the above expression becomes:

$$Z_R = \frac{(X_G + X_T + Z_S)(1 - j\cot\theta/2)}{2} - X_G$$

The general case can be represented by a system of circles with centres on the line CD; see Figure C8.33. Also shown is a typical machine terminal impedance locus during loss of excitation conditions.

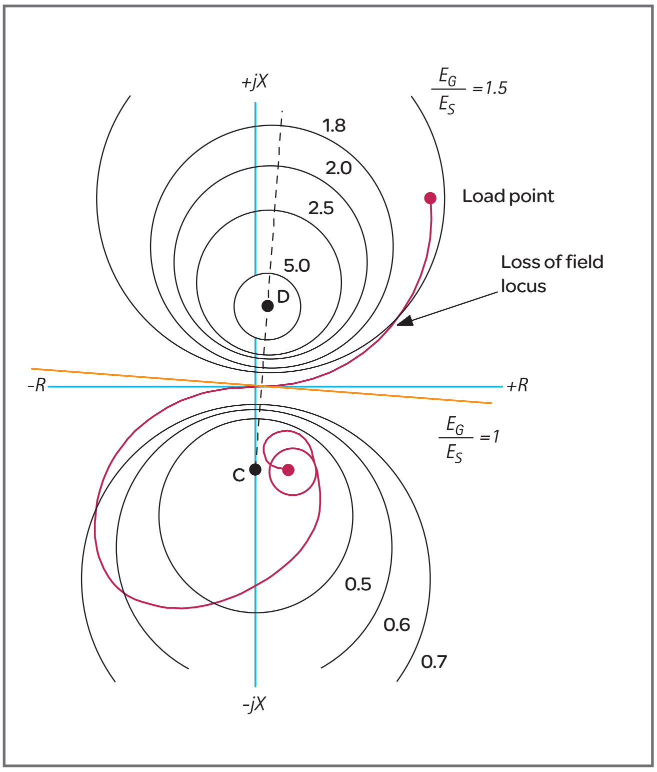

Figure C8.33:
Swing curves and loss of synchronism locus

The special cases of $E_G = E_S$ and $E_G = 0$ result in a straight-line locus that is the right-angled bisector of CD, and in a circular locus that is shrunk to point C, respectively.

When excitation is removed from a generator operating synchronously the flux dies away slowly, during which period the ratio of E_G / E_S is decreasing, and the rotor angle of the machine is increasing. The operating condition plotted on an impedance diagram therefore travels along a locus that crosses the power swing circles. At the same time, it progresses

16. Loss of excitation protection

in the direction of increasing rotor angle. After passing the anti-phase position, the locus bends round as the internal e.m.f. collapses, condensing on an impedance value equal to the machine reactance. The locus is illustrated in Figure C8.33.

The relay location is displaced from point C by the generator reactance X_G. One problem in determining the position of these loci relative to the relay location is that the value of machine impedance varies with the rate of slip. At zero slip X_G is equal to X_D, the synchronous reactance, and at 100% slip X_G is equal to X''_d, the sub-transient reactance. The impedance in a typical case has been shown to be equal to X'_d, the transient reactance, at 50% slip, and to $2X''_d$ with a slip of 0.33%. The slip likely to be experienced with asynchronous running is low, perhaps 1%, so that for the purpose of assessing the power swing locus it is sufficient to take the value $X_G = 2X''_d$.

This consideration has assumed a single value for X_G. However, the reactance X_q on the quadrature axis differs from the direct-axis value, the ratio of X_d / X_g being known as the saliency factor. This factor varies with the slip speed. The effect of this factor during asynchronous operation is to cause X_G to vary at slip speed. In consequence, the loss of excitation impedance locus does not settle at a single point, but it continues to describe a small orbit about a mean point.

A protection scheme for loss of excitation must operate decisively for this condition, but its characteristic must not inhibit stable operation of the generator. One limit of operation corresponds to the maximum practicable rotor angle, taken to be at 120°. The locus of operation can be represented as a circle on the impedance plane, as shown in Figure C8.34, stable operation conditions lying outside the circle.

On the same diagram the full load impedance locus for one per unit power can be drawn. Part of this circle represents a condition that is not feasible, but the point of intersection with the maximum rotor angle curve can be taken as a limiting operating condition for setting impedance-based loss of excitation protection.

16.2 Impedance-based protection characteristics

Figure C8.33 alludes to the possibility that a protection scheme for loss of excitation could be based on impedance measurement. The impedance characteristic must be appropriately set or shaped to ensure decisive operation for loss of excitation whilst permitting stable generator operation within allowable limits. One or two offset mho under impedance elements (see Chapter [C3: Distance Protection] for the principles of operation) are ideally suited for providing loss of excitation protection as long as a generator operating at low power output (20-30% P_n) does not settle down to operate as an induction generator. The characteristics of a typical two-stage loss of excitation protection scheme are illustrated in Figure C8.35. The first stage, consisting of settings X_{a1} and X_{b1} can be applied to provide detection of loss of excitation even where a generator initially operating at low power output (20-30% P_n) might settle down to operate as an induction generator.

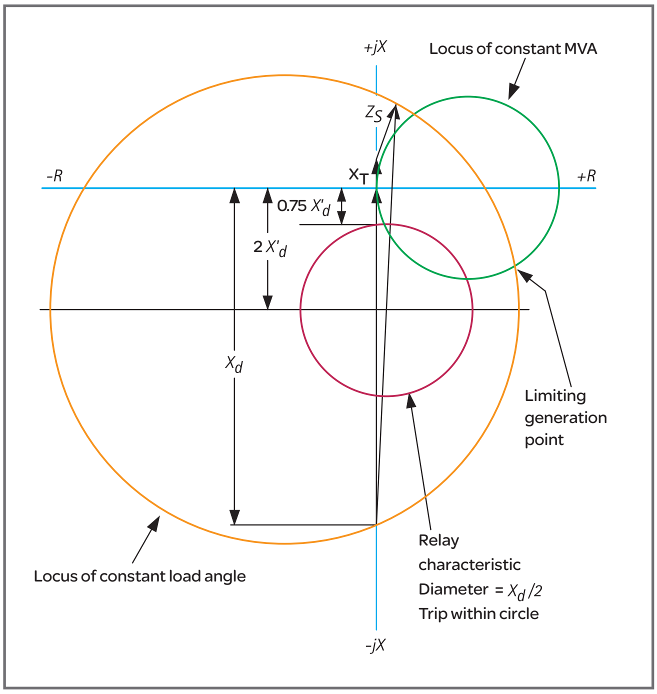

Figure C8.34:
Locus of limiting operating conditions of synchronous machine

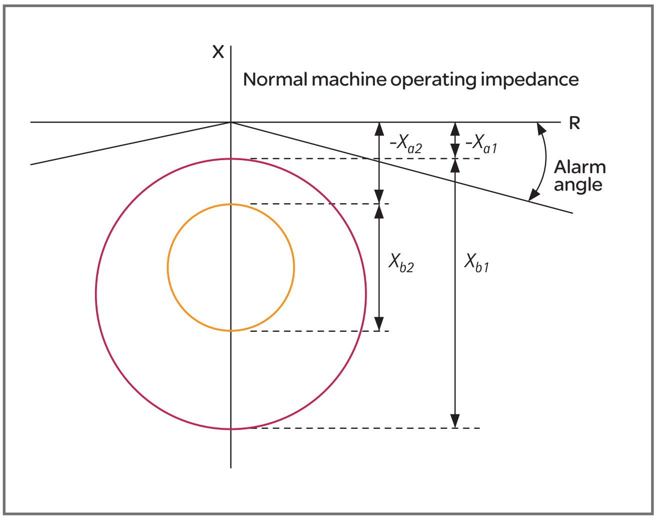

Figure C8.35:
Loss of excitation protection characteristics

Pick-up and drop-off time delays t_{d1} and t_{do1} are associated with this impedance element. Timer t_{d1} is used to prevent operation during stable power swings that may cause the

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16. Loss of excitation protection

impedance locus of the generator to transiently enter the locus of operation set by X_{b1}. However, the value must short enough to prevent damage as a result of loss of excitation occurring. If pole-slipping protection is not required (see Section 17.2), timer t_{do1} can be set to give instantaneous reset. The second field failure element, comprising settings X_{a2}, X_{b2}, and associated timers t_{d2} and t_{do2} can be used to give instantaneous tripping following loss of excitation under full load conditions.

16.3 Protection settings

The typical setting values for the two elements vary according to the excitation system and operating regime of the generator concerned, since these affect the generator impedance seen by the relay under normal and abnormal conditions. For a generator that is never operated at leading power factor, or at load angles in excess of 90° the typical settings are:

a. impedance element diameter $X_{b1} = X_d$

b. impedance element offset $X_{a1} = -0.5X'_d$

c. time delay on pick-up, $t_{d1} = 0.5s - 10s$

d. time delay on drop-off, $t_{do1} = 0s$

If a fast excitation system is employed, allowing load angles of up to 120° to be used, the impedance diameter must be reduced to take account of the reduced generator impedance seen under such conditions. The offset also needs revising. In these circumstances, typical settings would be:

a. impedance element diameter $X_{b1} = 0.5X_d$

b. impedance element offset $X_{a1} = -0.75X'_d$

c. time delay on pick-up, $t_{d1} = 0.5s - 10s$

d. time delay on drop-off, $t_{do1} = 0s$

The typical impedance settings for the second element, if used, are:

- impedance element diameter

$$X_{b2} = \frac{kV^2}{MVA}$$

$$X_{a2} = -0.5X'_d$$

The time delay settings t_{d2} and t_{do2} are set to zero to give instantaneous operation and reset.

17. Pole slipping protection

A generator may pole-slip, or fall out of synchronism with the power system for a number of reasons. The principal causes are prolonged clearance of a heavy fault on the power system, when the generator is operating at a high load angle close to the stability limit, or partial or complete loss of excitation. Weak transmission links between the generator and the bulk of the power system aggravate the situation. It can also occur with embedded generators running in parallel with a strong Utility network if the time for a fault clearance on the Utility network slow, perhaps because only IDMT relays are provided. Pole slipping is characterised by large and rapid oscillations in active and reactive power. Rapid disconnection of the generator from the network is required to ensure that damage to the generator is avoided and that loads supplied by the network are not affected for very long.

Protection can be provided using several methods. The choice of method will depend on the probability of pole slipping occurring and on the consequences should it occur.

17.1 Protection using reverse power element

During pole-slipping, there will be periods where the direction of active power flow will be in the reverse direction, so a reverse power relay element can be used to detect this, if not used for other purposes. However, since the reverse power conditions are cyclical, the element will reset during the forward power part of the cycle unless either a very short pick-up time delay and/or a suitable drop-off time delay is used to eliminate resetting.

The main advantage of this method is that a reverse power element is often already present, so no additional relay elements are required. The main disadvantages are the time taken for tripping and the inability to control the system angle at which the generator breaker trip command would be issued, if it is a requirement to limit the breaker current interruption duty. There is also the difficulty of determining suitable settings. Determination of settings in the field, from a deliberate pole-slipping test, is not possible and analytical studies may not discover all conditions under which pole-slipping will occur.

17.2 Protection using an under impedance element

With reference to Figure C8.33, a loss of excitation under impedance characteristic may also be capable of detecting loss of synchronism, in applications where the electrical centre of the power system and the generator lies ‘behind’ the relaying point. This would typically be the case for a relatively small generator that is connected to a power transmission system

17. Pole slipping protection

$X_G >> (X_T + X_S)$. With reference to Figure C8.35; if pole-slipping protection response is required, the time delay on drop-off t_{do1} of the large diameter impedance measuring element should be set to prevent its reset in each slip cycle, until the trip time delay on pick-up t_{d1} has expired.

As with reverse power protection, this would be an elementary form of pole-slipping protection. It may not be suitable for large machines where rapid tripping is required during the first slip cycle and where some control is required for the system angle at which the generator circuit breaker trip command is given. Where protection against pole-slipping must be guaranteed, a more sophisticated method of protection should be used. A typical reset timer delay for pole-slipping protection might be 0.6s. For generator transformer units, the additional impedance in front of the relaying point may take the system impedance outside the under impedance relay characteristic required for loss of excitation protection. Therefore, the acceptability of this pole-slipping protection scheme will be dependent on the application.

17.3 Dedicated pole-slipping protection

Large generator-transformer units directly connected to grid systems often require a dedicated pole-slipping protection scheme to ensure rapid tripping and with system angle control. Pole-slipping protection can be directly based on the internal phase angle between the generator terminal voltage and electromotive force. If the internal phase angle exceeds the configured angle for a definite period the pole-slipping element can trip out. Pole-slipping protection can also be based on the detection of the active power inversion within a definite period. Two consecutive active power inversions mean one rotation of the internal angle. When the number of active power inversions achieves the setting the relay will trip. Historically, dedicated pole-slipping protection schemes have usually been based on an ohm-type impedance measurement characteristic.

17.3.1 Pole slipping protection by impedance measurement

Although a mho type element for detecting the change in impedance during pole-slipping can be used in some applications, but with performance limits, a straight line ohm characteristic is more suitable. The protection principle is that of detecting the passage of the generator impedance through a zone defined by two such impedance characteristics, as shown in Figure C8.36.

The characteristic is divided into three zones, A, B, and C. Normal operation of the generator lies in zone A. When a pole-slip occurs, the impedance traverses zones B and C, and tripping occurs when the impedance characteristic enters zone C.

Tripping only occurs if all zones are traversed sequentially. Power system faults should result in the zones not being fully traversed so that tripping will not be initiated. The security of this type of protection scheme is normally enhanced by the addition of a plain underimpedance control element (circle about the origin of the impedance diagram) that is set to prevent tripping for impedance trajectories for remote power system faults.

Setting of the ohm elements is such that they lie parallel to the total system impedance vector, and enclose it, as shown in Figure C8.36.

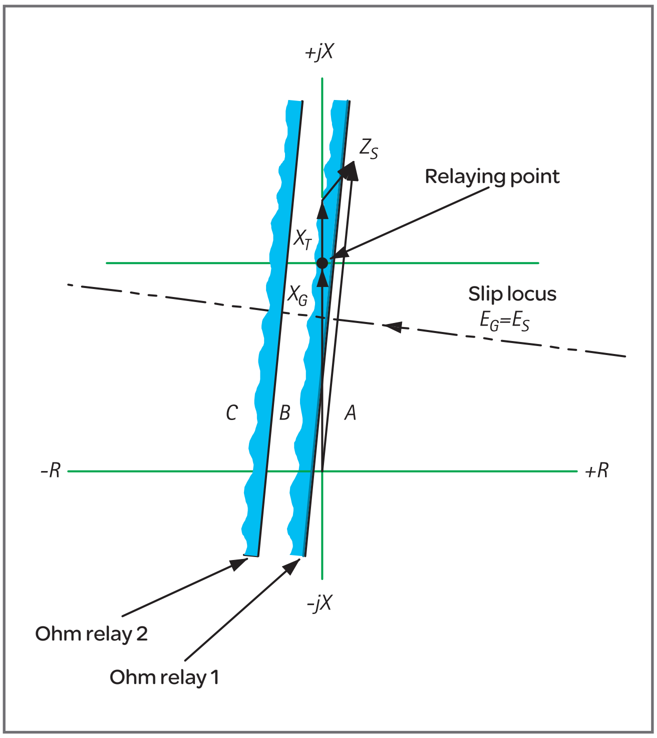

Figure C8.36:
Pole slipping detection by ohm relays

17.3.2 Use of lenticular characteristic

A more sophisticated approach is to measure the impedance of the generator and use a lenticular impedance characteristic to determine if a pole-slipping condition exists. The lenticular characteristic is shown in Figure C8.37. The characteristic is divided into two halves by a straight line, called the blinder.

The inclination, θ, of the lens and blinder is determined by the angle of the total system impedance. The impedance of the system and generator-transformer determines the forward reach of the lens, Z_A, and the transient reactance of the generator determines the reverse reach Z_B.

The width of the lens is set by the angle θ and the line PP', perpendicular to the axis of the lens, is used to determine if the centre of the impedance swing during a transient is located in the generator or power system.

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17. Pole slipping protection

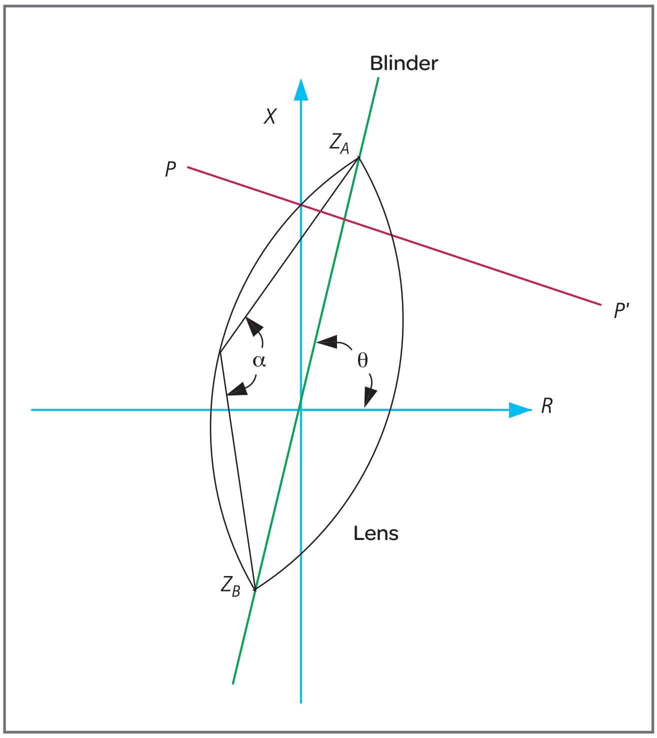

Figure C8.37:
Pole-slipping protection using lenticular characteristic and blinder

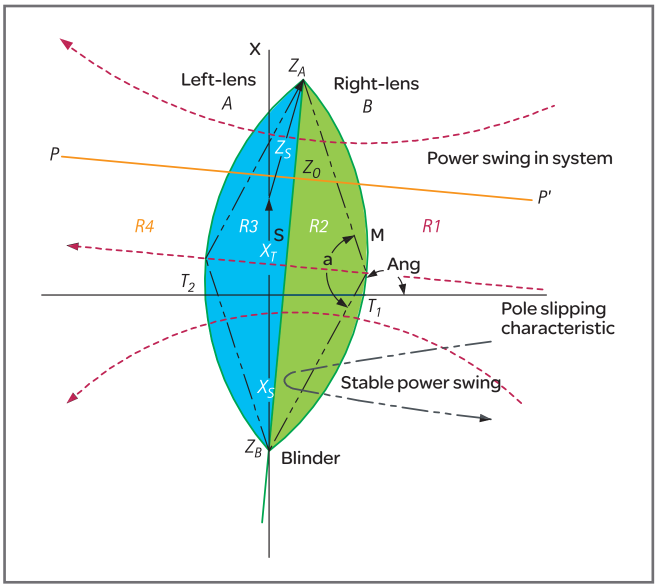

Figure C8.38:
Definition of zones for lenticular characteristic

Operation in the case of a generator is as follows. The characteristic is divided into 4 zones and 2 regions, as shown in Figure C8.38.

Normal operation is with the measured impedance in zone $R1$. If a pole slip develops, the impedance locus will traverse though zones $R2$, $R3$, and $R4$. When entering zone $R4$, a trip signal is issued, provided the impedance lies below reactance line PP' and hence the locus of swing lies within or close to the generator – i.e. the generator is pole slipping with respect to the rest of the system.

If the impedance locus lies above line PP', the swing lies far out in the power system – i.e. one part of the power system, including the protected generator, is swinging against the rest of the network. Tripping may still occur, but only if swinging is prolonged – meaning that the power system is in danger of complete break-up. Further confidence checks are introduced by requiring that the impedance locus spends a minimum time within each zone for the pole-slipping condition to be valid. The trip signal may also be delayed for a number of slip cycles even if a generator pole-slip occurs – this is to both provide confirmation of a pole-slipping condition and allow time for other relays to operate if the cause of the pole slip lies somewhere in the power system. Should the impedance locus traverse the zones in any other sequence, tripping is blocked.

18. Stator overheating faults

Overheating of the stator may result from:

a. overload

b. failure of the cooling system

c. overfluxing

d. core faults

With a modern protection relay, it is relatively simple to provide a current-operated thermal replica protection element to estimate the thermal state of the stator windings. The generator is considered to be a homogeneous body, developing heat internally at a constant rate and dissipating heat at a rate directly proportional to its temperature rise, it can be shown that the temperature at any instant is given by:

$$T = T_{max} \times (1 - e^{-\frac{t}{\tau}})$$

Where:

T_{max} = final steady state temperature with the specific stator current I

τ = heating time constant

With the thermal accumulation, the actual temperature in the relay execution cycle is given by:

$$T(n) = T_{max} \times \left(1 - e^{-\frac{\Delta t}{\tau}}\right) + T(n-1) \times e^{-\frac{\Delta t}{\tau}}$$

This assumes a thermal equilibrium in the form: Heat developed = Heat stored + Heat dissipated.

Although current-operated thermal replica protection cannot take into account the effects of ambient, it is often applied as a back-up to direct stator temperature measuring devices (RTD) to prevent overheating due to high stator current. With some relays, the thermal replica temperature estimate can be made more accurate through the integration of direct measuring resistance temperature devices.

Irrespective of whether current-operated thermal replica protection is applied or not, it is a requirement to monitor the stator temperature of a large generator in order to detect overheating from whatever cause. Temperature sensitive elements, usually of the resistance type, are embedded in the stator winding at hot-spot locations envisaged by the manufacturer, the number used being sufficient to cover all variations. The elements are connected to a temperature sensing relay element arranged to provide alarm and trip outputs. The settings will depend on the type of stator winding insulation and on its permitted temperature rise.

19. Complete generator protection schemes

From the preceding sections, it is obvious that the protection scheme for a generator has to take account of many possible faults and plant design variations. Determination of the types of protection used for a particular generator will depend on the nature of the plant and upon economic considerations, which in turn is affected by set size. Fortunately, modern, multi-function, numerical relays are sufficiently versatile to include all of the commonly required protection functions in a single package, thus simplifying the decisions to be made. The following sections provide illustrations of typical protection schemes for generators connected to a grid network, but not all possibilities are illustrated, due to the wide variation in generator sizes and types.

19.1 Direct-connected generator

A typical protection scheme for a direct-connected generator is shown in Figure C8.39. It comprises the following protection functions:

a. stator differential protection

b. overcurrent protection – conventional or voltage dependent

c. stator earthfault protection

d. overvoltage protection

e. undervoltage protection

f. overload/low forward power/ reverse power protection (according to prime mover type)

g. unbalanced loading

h. overheating

i. pole slipping

k. loss of excitation

l. underfrequency

m. inadvertent energisation

n. overfluxing

o. mechanical faults

Figure C8.39 illustrates which trips require an electrical trip and which can be time delayed until electrical power has been reduced to a low value. The faults that require tripping of the prime mover as well as the generator circuit breaker are also shown.

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19. Complete generator protection schemes

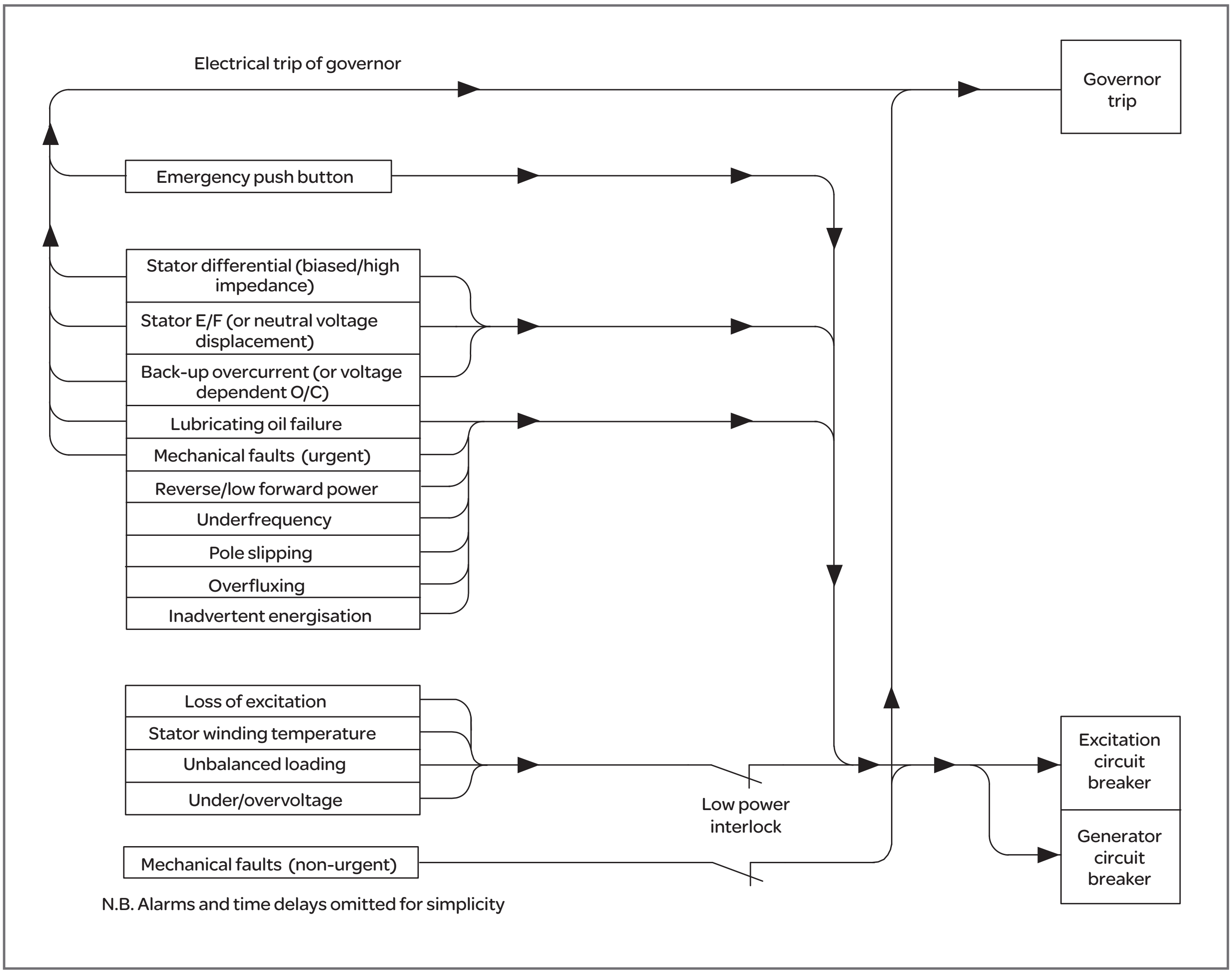

Figure C8.39:
Typical protection arrangement for a direct-connected generator

19.2 Generator-transformer units

These units are generally of higher output than direct-connected generators, and hence more comprehensive protection is warranted. In addition, the generator transformer also requires protection, for which the protection detailed in Chapter [C7: Transformer and Transformer-Feeder Protection] is appropriate.

Overall biased generator/generator transformer differential protection is commonly applied in addition, or instead of, differential protection for the transformer alone. A single protection relay may incorporate all of the required functions, or the protection of the transformer (including overall generator/generator transformer differential protection) may utilise a separate relay.

Figure C8.40 shows a typical overall scheme.

19. Complete generator protection schemes

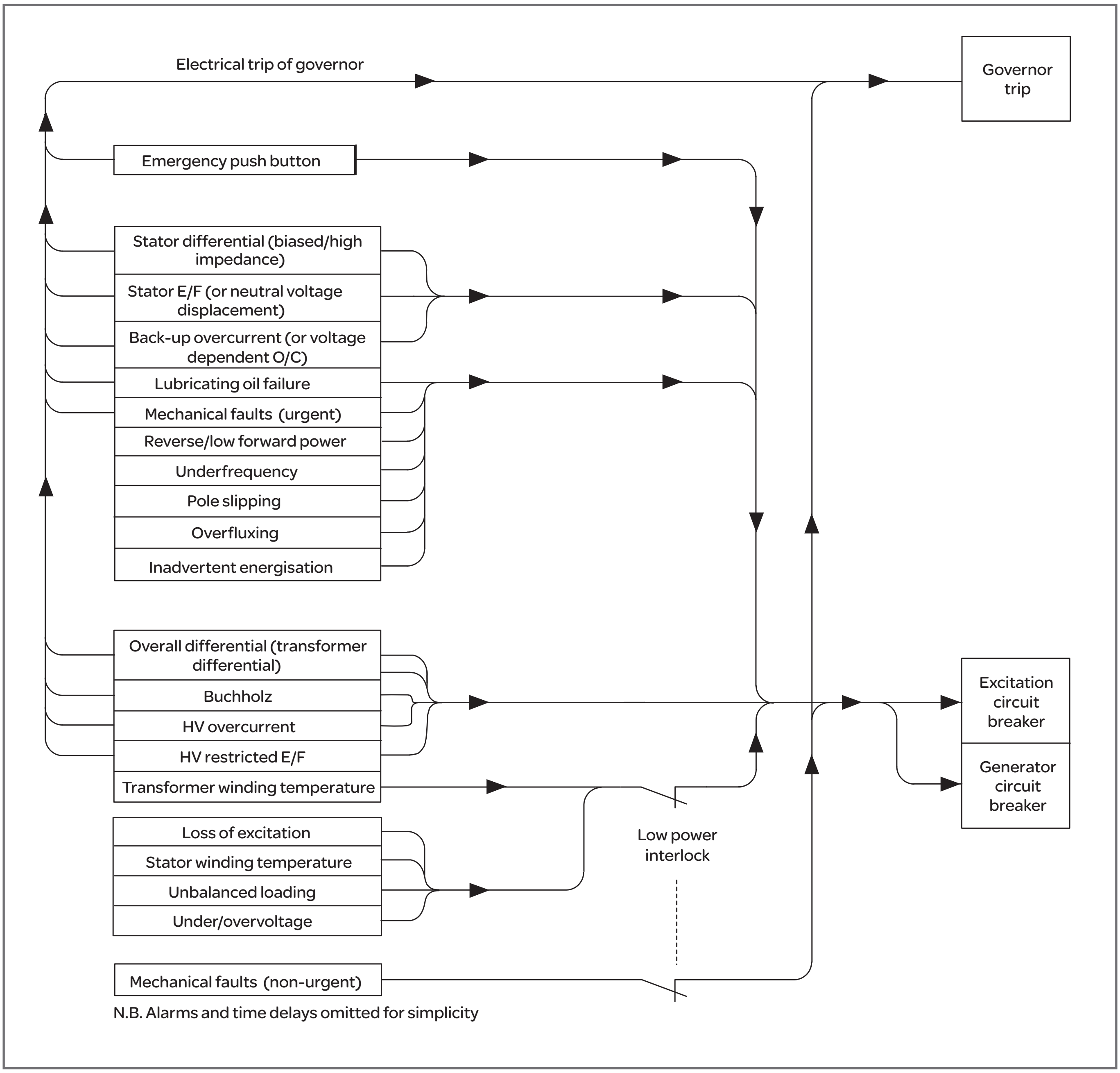

Figure C8.40:
Typical tripping arrangements for generator-transformer unit

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20. Distributed generation

The limitation of fossil primary energy sources and the worldwide growing demand for electrical energy leads to the need for alternative (renewable) energy source usage. This trend is also driven by subsidies for renewable energy in some countries. Especially wind and solar power plants are built decentralised and distributed into the existing medium and high voltage grid especially in the European countries.

These new types and small generator sizes are changing the existing grid and the protection needs.

The main challenges with these DGs are:

a. fluctuation in produced electrical power

b. bi-directional load flow: MV grid ◄──► HV grid

c. reduced rotating mass ◄── impact on grid stability

d. reduced short-circuit power

e. detection of islanded sub-grids

f. neutral treatment in islanded sub-grids

g. stable operation of islanded sub-grids

h. voltage control of power electronic converters at the same speed as digital protection

j. radiation of harmonics ──► impact on power quality

20.1 Generator types

The generator types used depend mainly on the energy source. Synchronous machines are often used for small hydro plants, thermal power or (bio)gas plants. Power electronic converters are used for solar power plants, battery storage systems and fuel cells. The power ratings of these smaller DGs is in the range of some ten to hundreds of kVA.

Wind turbine power plants of several MW often use a synchronous machine in connection with a power electronic converter of the same rated power (Figure C8.41). Another design uses Doubly-Fed Induction Generators (DFIG) as asynchronous machine with power electronic converters of approximately a third of the rated machine power (Figure C8.42). Smaller units will be equipped with directly coupled asynchronous machines.

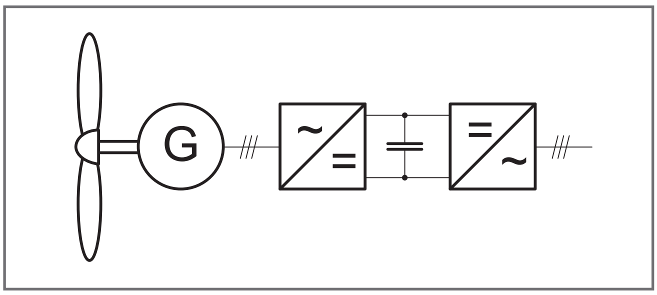

Figure C8.41:
Wind turbine generator system using full rated power electronic converters

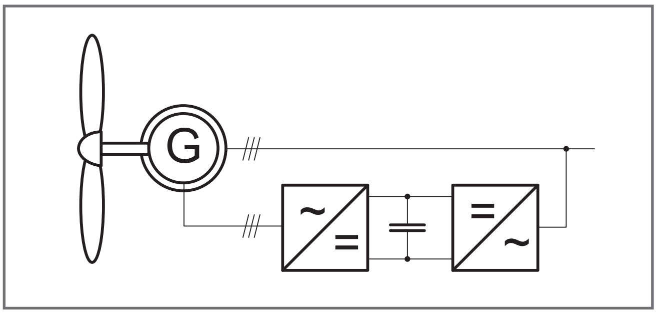

Figure C8.42:
Wind turbine generator system with DFIG

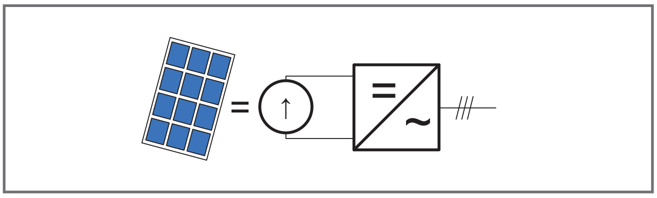

Figure C8.43:
Solar power plant modeled as current source

There is no clear definition of the size of distributed generators. In the following small generators units of some 100 kVA up to a few megawatts are considered.

20.2 Protection aspects

Depending on the generator type of the DG, common MV protection methods (i. e. non-directional overcurrent protection) are only suitable to a limited extent or cannot be applied.

20.2.1 Low fault currents

The thermal and electrical design of a.c./a.c. or d.c./a.c. converters (Figure C8.41 and Figure C8.43) will typically allow a max. output of 110 … 120 % rated active power for several seconds. The transient capability will be in the same range due to the small thermal time constants of the power electronic semiconductors. The transient reactive power output of DG – and therefore the fault current contribution – depends on the converter controllers. Newer converters are able to provide a reactive current I_{reac} in case of voltage drops ΔV (see Figure C8.44). The amount of reactive current can be set via a slope [Ref C8.3: Verordnung zu Systemdienstleistungen durch Windenergieanlagen (Systemdienstleistungsverordnung)].

In all cases the fault current contribution of a converter-driven DGs is in the range of the normal load current (or even lower). Overcurrent protection is not suitable in such case. Using distance or differential protection will allow the fault detection but increases the investment costs.

20.2.2 Tapped lines

Smaller (resp. bigger) DGs (e.g. wind or solar power plants) are typically connected to the MV (resp. HV) grid. In rural

20. Distributed generation

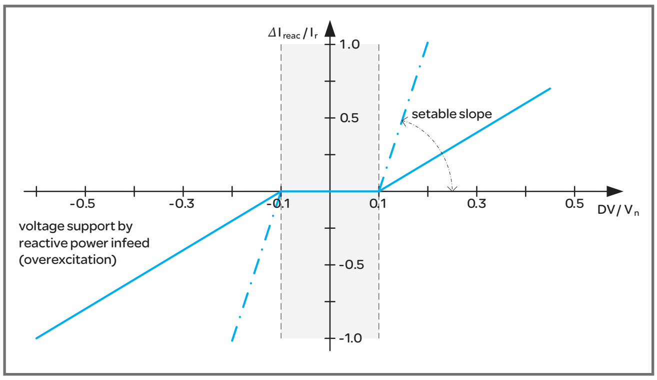

Figure C8.44:
Voltage support of newer DGs in case of voltage drops

areas this is usually done by tapping an existing OHL nearby.

The protection of the power plant itself will be done by directional overcurrent (MV) or distance or differential protection (HV) and depends on the low voltage ride trough (LVRT) capabilities (Figure C8.45 [Ref C8.5: Grid code requirements for large wind farms]) of the DG. The impact of the line protection will depend on the rated power of the plant. If auto-reclose is applied the DGs power plant must be tripped in case of a fault on the line.

In case the intermediate infeed is of significant power the following should be considered:

a. intermediate infeed influences the distance measurements (see Chapter [C3: Distance Protection])

b. distance protection using aided schemes need to be extended to multi-ended aided schemes

c. application of multi-ended differential protection

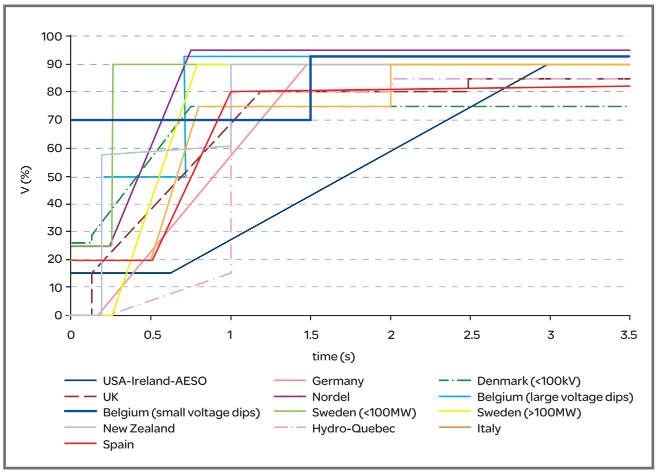

Figure C8.45:
Required low voltage ride through capabilities of wind power plants by different grid codes

20.2.3 Active power dependent underfrequency load shedding

Underfrequency load shedding (UFLS) is used to prevent an electrical network from outages (blackouts). If the system frequency gets below a certain threshold, portions of the connected loads are disconnected to prevent further frequency decay. The amounts and frequency levels are typically defined in Grid Codes.

Due to increasing DGs in distribution networks it is necessary to distinguish between pure load feeders and feeders with generation (and loads) connected. It is advantageous not to disconnect feeders with active power feed to the electrical network in case of underfrequency events. UFLS schemes evaluating the direction of active power P are required to distinguish between load and generation feeders (refer to Chapter [D4: Frequency and Load Shedding]).

20.2.4 Reactive power dependent undervoltage Q-V protection

Especially wind power plants of the first generation used simple asynchronous machines as generators. In case of voltage drops these machines consume reactive power and therefore further reduce the voltage at the PCC (point of common coupling) – the grid connection. To prevent a voltage collapse such DGs need to be tripped in case of faults close to the PCC. Newer DGs with full converters are able to provide reactive power during faults and support the voltage in such a case (Figure C8.46).

By evaluating the reactive power direction it's possible to trip the DGs in case of voltage drops. It is a requirement in some Grid Codes [Ref C8.7: Transmission Code 2007], Figure C8.46 and [Ref C8.6: Lastenheft Blindleistungsrichtungs-Unterspannungsschutz (Q-U-Schutz)].

To ensure the correct directional decision a minimum level of reactive power flow and/or a minimum angle between P and Q needs to be fulfilled. Q-V protection is typically time delayed by approx. 500 ms before tripping the local DGs.

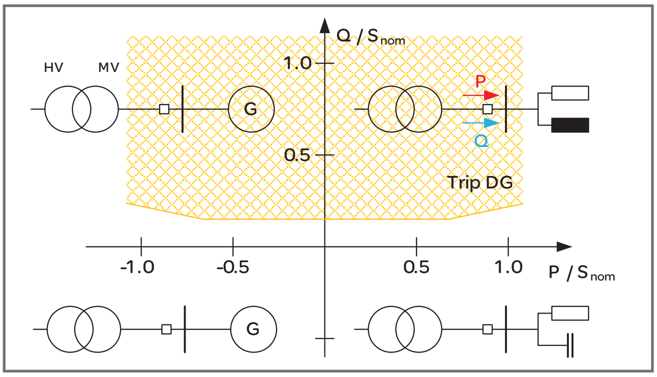

Figure C8.46:
Tripping area in case of voltage drops at the PCC in consumer reference arrow system

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20. Distributed generation

20.3 Islanding detection

In the case of separating a network with distributed generators an island could be formed (Figure C8.47).

If there is a balance between generation and load in the separated (medium voltage) network a stable operation of several minutes has been observed in practice. This typically is an unwanted situation due to the unknown star point treatment / earthing conditions. To prevent such operation the islanding needs to be detected. This can be done at the line feeder 1 and/or at the distributed generator 2.

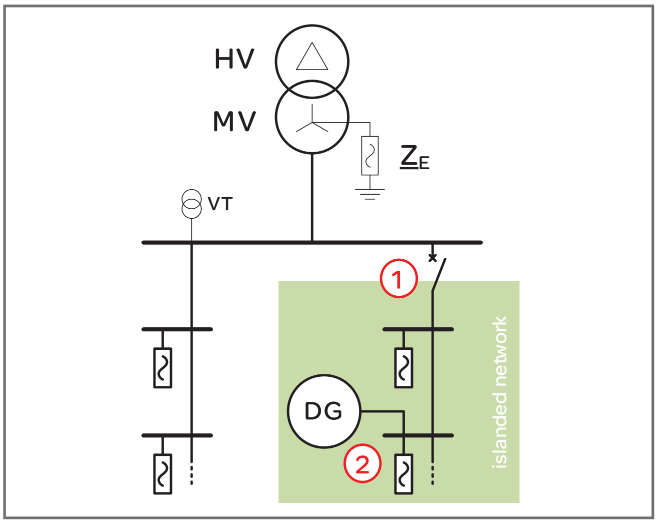

Figure C8.47:
MV islanded network with DG

Detection methods can be grouped into (Figure C8.48 [Ref C8.8: Protection of Distributed Systems with Distributed Energy Resources]):

a. passive, based on local voltage (and current) measurements

b. active, interfering the network and/or the DG

c. communication based

Most common passive methods using over- and undervoltage, over- and underfrequency, ROCOF and voltage vector shift. There will be load flow situations with a local balanced generation and load resulting in the non-detection of the island.

20.3.1 Voltage vector shift relay

A voltage vector shift relay detects the sudden change in voltage phase angle beyond a defined setpoint. Again, the voltage signal is obtained from a voltage transformer connected close to the Point of Common Coupling (PCC). One method used is to measure the time period between successive zero-crossings to determine the duration of each half-cycle, and then to compare the durations with the memorised average duration of earlier half-cycles in order to determine the phase angle drift.

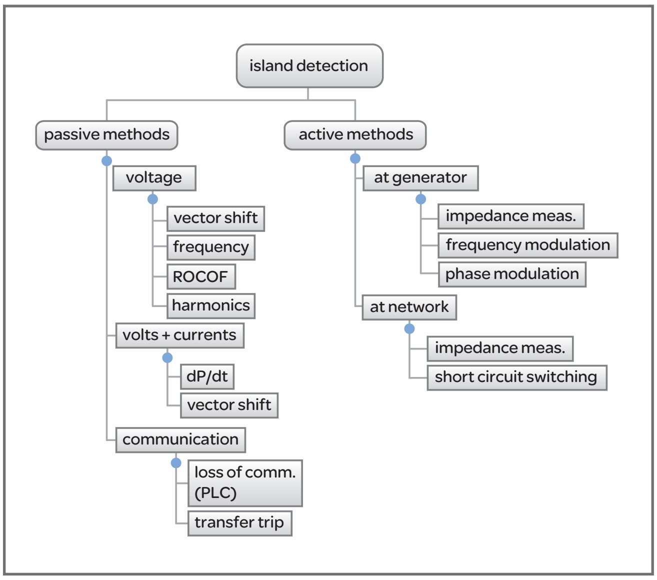

Figure C8.48:
Islanding detection methods

20.3.2 Rate of change of frequency relay

A ROCOF relay detects the rate of change of frequency in excess of a defined setpoint. The signal is obtained from a voltage transformer connected close to the Point of Common Coupling (PCC). One method used is to measure the time period between successive zero-crossings to determine the average frequency for each half-cycle and hence the rate of change of frequency. The result is usually averaged over a number of cycles. Another common method used to get the df/dt value is based on the Discrete Fourier Transformer (DFT). The difference between the phase angles from two consecutive DTFs can derive the frequency and the frequency difference over several cycles can derive the df/dt value.

20.3.3 Setting guidelines

Should loss of the Utility supply occur, it is extremely unlikely that there will be an exact match between the output of the distributed generator(s) and the connected load in the remaining island. A small frequency change or voltage phase angle change will therefore occur, to which can be added any changes due to the small natural variations in loading of an isolated generator with time. Once the rate of change of frequency exceeds the setting of the ROCOF relay for a set time, or once the voltage phase angle drift exceeds the set angle, tripping occurs to open the connection between the in-plant and Utility networks.

While it is possible to estimate the rate of change of frequency from knowledge of the generator set inertia and MVA rating, this is not an accurate method for setting a ROCOF relay because the rotational inertia of the complete network being fed by the embedded generation is required. For example, there may be other DG to consider. As a result, it is invariably

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the case that the relay settings are determined at site during commissioning. This is to ensure that the Utility requirements are met while reducing the possibility of a spurious trip under the various operating scenarios envisaged. However, it is very difficult to determine whether a given rate of change of frequency will be due to a 'loss of mains' incident or a load/ frequency change on the public power network, and hence spurious trips are impossible to eliminate. Thus the provision of Loss of Utility Supply protection to meet power distribution Utility interface protection requirements may actually conflict with the interests of the national power system operator. With the growing contribution of non-dispatched embedded generation to the aggregate national power demand, the loss of the embedded generation following a transmission system incident that may already challenge the security of the system can only aggravate the problem. [Ref C8.9: Survey of Rate Of Change of Frequency Relays and Voltage] provides further details of the operation of ROCOF relays and the problems that may be encountered.

Nevertheless, because such protection is a common requirement of some Utilities, the 'loss of mains' protection may have to be provided and the possibility of spurious trips will have to be accepted in those cases. Site measurements over a period of time of the typical rates of frequency change occurring may assist in negotiations of the settings with the Utility, and with the fine-tuning of the protection that may already be commissioned.

21. Examples of generator protection settings

This section gives examples of the calculations required for generator protection. The first is for a typical small generator installed on an industrial system that runs in parallel with the Utility supply. The second is for a larger generator-transformer unit connected to a grid system.

21.1 Protection settings of a small industrial generator

Salient details of the generator, network and protection required are given in Table C8.3. The example calculations are based on a MiCOM P343 relay in respect of setting ranges, etc.

21.1.1 Differential protection

Biased differential protection involves the determination of values for four setting values: I_{s1}, I_{s2}, K_1 and K_2 in Figure C8.4. I_{s1} can be set at 5% of the generator rating, in accordance with the recommendations for the relay, and similarly the values of I_{s2} (120%) and K_2 (150%) of generator rating. It remains for the value of K_1 to be determined. The recommended value is generally 0%, but this only applies where CTs that conform to IEC 60044-1 class PX (or the superseded BS 3938 Class X) are used – i.e. CTs specifically designed for use in differential

Generator data							
kVA	kW	PF	Rated voltage	Rated current	Rated frequency	Rated speed	Prime mover type
6250	5000	0.8	11000	328	50	1500	Steam turbine

Generator parameters				
Generator type	Xd p.u.	X'd p.u.	CT Ratio	VT Ratio
Salient Pole	2.349	0.297	500/1	11000/110

Network data			
Earthing resistor	Maximum earth fault current	Minimum phase fault current	Maximum downstream phase fault current
31.7 Ω	200A	145A	850A

Existing protection						
Ct Ratio	Overcurrent settings			Earthfault settings		
	Charact.	Setting	TMS	Charact.	Setting	TMS
200/1	SI	144A	0.176	SI	48A	0.15

Table C8.3:
Data for small generator protection example

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21. Examples of generator protection settings

protection schemes. In this application, the CTs are conventional class 5P CTs that meet the relay requirements in respect of knee-point voltage, etc.

Where neutral tail and terminal CTs can saturate at different times due to transiently offset magnetising inrush or motor starting current waveforms with an r.m.s. level close to rated current and where there is a high L/R time constant for the offset, the use of a 0% bias slope may give rise to maloperation. Such waveforms can be encountered when plant of similar rating to the generator is being energised or started. Differences between CT designs or differing remanent flux levels can lead to asymmetric saturation and the production of a differential spill current. Therefore, it is appropriate to select a non-zero setting for K_1, and a value of 5% is usual in these circumstances.

21.1.2 Voltage controlled overcurrent protection

This protection is applied as remote backup to the downstream overcurrent protection in the event of protection or breaker failure conditions. This ensures that the generator will not continue to supply the fault under these conditions.

At normal voltage, the current setting must be greater than the maximum generator load current of 328 A. A margin must be allowed for resetting of the relay at this current (reset ratio = 95%) and for the measurement tolerances of the relay (5% of I_S under reference conditions), therefore the current setting is calculated as:

$$I_{vcset} > \frac{328}{0.95} \times 1.05$$

$$> 362.5\ A$$

The nearest settable value is 365 A, or 0.73 I_n.

The minimum phase-phase voltage for a close-up single-phase to earthfault is 57%, so the voltage setting V_S must be less than this. A value of 30% is typically used, giving $V_S = 33\ V$. The current setting multiplying factor K must be chosen such that KI_S is less than 50% of the generator steady-state current contribution to an uncleared remote fault. This information is not available (missing data being common in protection studies). However, the maximum sustained close-up phase fault current (neglecting AVR action) is 145 A, so that a setting chosen to be significantly below this value will suffice. A value of 87.5 A (60% of the close-up sustained phase fault current) is therefore chosen, and hence K = 0.6. This is considered to be appropriate based on knowledge of the system circuit impedances. The TMS setting is chosen to co-ordinate with the downstream feeder protection such that:

a. for a close-up feeder three-phase fault, that results in almost total voltage collapse as seen by the relay

b. for a fault at the next downstream relay location, if the relay voltage is less than the switching voltage

It should also be chosen so that the generator cannot be subjected to fault or overload current in excess of the stator short-time current limits. A curve should be provided by the manufacturer, but IEC 60034-1 demands that an AC generator should be able to pass 1.5 times rated current for at least 30 seconds. The operating time of the downstream protection for a three-phase fault current of 850 A is 0.682 s, so the voltage controlled relay element should have a minimum operating time of 1.09 s (0.4 s time grading margin is used to cooperate with the downstream relay - see table C8.2). With a current setting of 87.5 A, the operating time of the voltage controlled relay element at a TMS of 1.0 is:

$$\frac{0.14}{\left(\frac{850}{87.5}\right)^{0.02} - 1} = 3.01\ s$$

Therefore a TMS of:

$$\frac{1.09}{3.01} = 0.362$$

is required. Use 0.375, nearest available setting.

21.1.3 Stator earthfault protection

The maximum earthfault current, from Table C8.3, is 200 A. Protection for 95% of the winding can be provided if the relay is set to detect a primary earthfault current of 16.4 A, and this equates to a CT secondary current of 0.033 A. The nearest relay setting is 0.04 A, providing protection for 90% of the winding.

The protection must grade with the downstream earthfault protection, the settings of which are also given in Table C8.3. At an earthfault current of 200 A, the downstream protection has an operation time of 0.73 s. The generator earthfault protection must therefore have an operation time of not less than 1.13 s. At a TMS of 1.0, the generator protection relay operating time will be:

$$\left[\frac{0.14}{\left(200/20\right)^{0.02} - 1}\right] s$$

= 2.97 s, so the required TMS is $\frac{1.13}{2.97} = 0.38$

Use a setting of 0.4, nearest available setting.

21.1.4 Neutral voltage displacement protection

This protection is provided as back-up earthfault protection for the generator and downstream system (direct-connected generator). It must therefore have a setting that grades with the downstream protection. The protection is driven from the generator star- connected VT, while the downstream protection is current operated.

21. Examples of generator protection settings

It is therefore necessary to translate the current setting of the downstream setting of the current-operated earthfault protection into the equivalent voltage for the NVD protection. The equivalent voltage is found from the formula:

$$V_{eff} = \frac{(I_{pe} \times Z_e) \times 3}{VT\ ratio}$$

$$= \frac{48 \times 31.7 \times 3}{100}$$

$$= 45.6\ V$$

where:

V_{eff} = effective voltage setting

I_{pe} = downstream earthfault current setting

Z_e = earthing resistance

Hence a setting of 48 V is acceptable. Time grading is required, with a minimum operating time of the NVD protection of 1.13 s at an earthfault current of 200 A. Using the expression for the operation time of the NVD element:

$$t = K/(M-1) sec$$

where:

$$M = \left(\frac{V}{V_{snvd}}\right)$$

and

V = voltage seen by relay

V_{snvd} = relay setting voltage

the value of K can be calculated as 3.34. The nearest settable value is 3.5, giving an operation time of 1.18 s.

21.1.5 Loss of excitation protection

Loss of excitation is detected by a mho impedance relay element, as detailed in Section 16.2. The standard settings for the MiCOM P340 series relay are:

$$X_a = -0.5\, X'_d \times (CT\ ratio/VT\ ratio)$$

$$(in\ secondary\ quantities)$$

$$= -0.5 \times 0.297 \times 19.36 \times 500/100$$

$$= -14.5\ \Omega$$

$$X_b = X_d \times (CT\ ratio/VT\ ratio)$$

$$= 2.349\ \Omega \times 19.36 \times (500/100)$$

$$= 227\ \Omega$$

The nearest settings provided by the relay are

$X_a = -14.5\ \Omega$ $\qquad X_b = -227\ \Omega$

The time delay t_{d1} should be set to avoid relay element operation on power swings and a typical setting of 3 s is used. This value may need to be modified in the light of operating experience. To prevent cyclical pick-up of the relay element without tripping, such as might occur during pole-slipping conditions, a drop-off time delay t_{d2} is provided and set to 0.5 s.

21.1.6 Negative phase sequence current protection

This protection is required to guard against excessive heating from negative phase sequence currents, whatever the cause. The generator is of salient pole design, so from IEC 60034-1, the continuous withstand is 8% of rating and the $I_2^2 t$ value is 20 s. Using Equation C8.1, the required relay settings can found as

I_2>> = 0.05 and $\qquad K$ = 8.6 s.

The nearest available values are I_2>> = 0.05 and K = 8.6 s.

The relay also has a cooling time constant K_{reset} that is normally set equal to the value of K. To co-ordinate with clearance of heavy asymmetric system faults, that might otherwise cause unnecessary operation of this protection, a minimum operation time t_{min} should be applied. It is recommended to set this to a value of 1. Similarly, a maximum time can be applied to ensure that the thermal rating of the generator is not exceeded (as this is uncertain, data not available) and to take account of the fact that the MiCOM P343 characteristic is not identical with that specified in IEC 60034.

The recommended setting for t_{max} is 600 s.

21.1.7 Overvoltage protection

This is required to guard against various failure modes, e.g. AVR failure, resulting in excessive stator voltage. A two-stage protection is available, the first being a low-set time-delayed stage that should be set to grade with transient overvoltages that can be tolerated following load rejection. The second is a high-set stage used for instantaneous tripping in the event of an intolerable overvoltage condition arising.

Generators can normally withstand 105% of rated voltage continuously, so the low-set stage should be set higher than this value. A setting of 117.7 V in secondary quantities (corresponding to 107% of rated stator voltage) is typically used, with a definite time delay of 10 s to allow for transients due to load switch-off/rejection, overvoltages on recovery from faults or motor starting, etc.

The second element provides protection in the event of a large overvoltage, by tripping excitation and the generator circuit breaker (if closed). This must be set below the maximum stator voltage possible, taking into account saturation. As the open circuit characteristic of the generator is not available, typical values must be used. Saturation will normally limit the maximum overvoltage on this type of generator to 130%, so a setting of 120% (132 V secondary) is typically used. Instantaneous operation is required. Generator manufacturers are normally able to provide recommendations for the relay settings. For embedded generators, the requirements of the local Utility may also have to be taken into account. For both elements, a variety of voltage measurement modes are available to take account of possible VT connections (single

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21. Examples of generator protection settings

or three-phase, etc.), and conditions to be protected against. In this example, a three-phase VT connection is used, and overvoltages on any phase are to be detected, so a selection of 'Any' is used for this setting.

Protection	Quantity	Value
Differential protection	I_{s1}	5%
	I_{s2}	120%
	K_1	5%
	K_2	150%
Stator earthfault	I_{se}	0.04
	TMS	0.4
Neutral voltage displacement	V_{snvd}	48 V
	K	3.5
Loss of excitation	X_a	-14.5 Ω
	X_b	227 Ω
	t_{d1}	3 s
	t_{DO1}	0.5 s
Voltage controlled overcurrent	I_{vcset}	0.73
	V_s	33
	K	0.6
	TMS	0.375
Negative phase sequence	I_2>>	0.05
	K	8.6 s
	K_{reset}	8.6 s
	t_{min}	1.5 s
	t_{max}	600 s
Overvoltage	*V*> meas mode	three-phase
	V> operate mode	any
	V> 1 setting	107%
	V> 1 function	DT
	V> time delay	10 s
	V> 2 setting	120%
	V> 2 function	DT
	V> 2 time delay	0 sec
Underfrequency	*F*< 1 setting	49 Hz
	F< 1 time delay	20 s
	F< 2 setting	48 Hz
	F< 2 time delay	0.5 s
Reverse power	*P1* function	reverse power
	P1 setting	5 W
	P1 time delay	5 s
	P1 DO time	0 s

Table C8.4:
Small generator protection example – relay settings

21.1.8 Underfrequency protection

This is required to protect the generator from sustained overload conditions during periods of operation isolated from the Utility supply. The generating set manufacturer will normally provide the details of machine short-time capabilities. The example relay provides four stages of underfrequency protection. In this case, the first stage is used for alarm purposes and a second stage would be applied to trip the set.

The alarm stage might typically be set to 49 Hz, with a time delay of 20 s, to avoid an alarm being raised under transient conditions, e.g. during plant motor starting. The trip stage might be set to 48 Hz, with a time delay of 0.5 s, to avoid tripping for transient, but recoverable, dips in frequency below this value.

21.1.9 Reverse power protection

The relay setting is 5% of rated power.

$$setting = \left(\frac{0.05 \times 5 \times 10^6}{CT\ ratio \times VT\ ratio} \right)$$

$$= \left(\frac{0.05 \times 5 \times 10^6}{500 \times 100} \right)$$

$$= 5\ W$$

This value can be set in the relay. A time delay is required to guard against power swings while generating at low power levels, so use a time delay of 5 s. No reset time delay is required.

21.2 Large generator transformer unit protection

The data for this unit are given in Table C8.5. It is fitted with two main protection systems to ensure security of tripping in the event of a fault. To economise on space, the setting calculations for only one system, that using a MiCOM P343 relay are given. Settings are given in primary quantities throughout.

21.2.1 Biased differential protection

The settings follow the guidelines previously stated. As 100% stator winding earthfault protection is provided, high sensitivity is not required and hence I_{s1} can be set to 10% of generator rated current. This equates to 602 A, and the nearest settable value on the relay is 640 A (= 0.08 of rated CT current). The settings for K_1, I_{s2} and K_2 follow the guidelines in the relay manual.

21. Examples of generator protection settings

Parameter		Value	Unit
Generator MVA rating		187.65	MVA
Generator MW rating		160	MW
Generator voltage		18	kV
Synchronous reactance		1.93	pu
Direct-axis transient reactance		0.189	pu
Minimum operating voltage		0.8	pu
Generator negative sequence capability		0.08	pu
Generator negative sequence factor, K_g		10	s
Generator third harmonic voltage under load		0.02	pu
Generator motoring power		0.02	pu
Generator overvoltage	alarm	1.1	pu
	time delay	5	s
	trip	1.3	pu
Generator undervoltage		not required	
Max pole slipping frequency		10	Hz
Generator transformer rating		360	MVA
Generator transformer leakage reactance		0.244	pu
Generator transformer overflux alarm		1.1	pu
Generator transformer overflux alarm		1.2	pu
Network resistance (referred to 18kV)		0.56	mΩ
Network reactance (referred to 18kV)		0.0199	Ω
System impedance angle (estimated)		80	deg
Minimum load resistance		0.8	Ω
Generator CT ratio		8000/1	
Generator VT ratio		18000/120	
Number of generators in parallel		2	

Table C8.5:
System data for large generator protection example

21.2.2 Voltage restrained overcurrent protection

The setting current I_{set} has to be greater than the full-load current of the generator (6019 A). A suitable margin must be allowed for operation at reduced voltage, so use a multiplying factor of 1.2. The nearest settable value is 7200 A. The factor K is calculated so that the operating current is less than the current for a remote end three phase fault. The steady-state current and voltage at the generator for a remote-end three-phase fault are given by the expression:

$$I_{flt} = \frac{V_N}{\sqrt{(nR_f)^2 + (X_d + X_t + nX_f)^2}}$$

I_{flt} = minimum generator primary current for a multi-phase feeder-end fault

V_N = no-load phase-neutral generator voltage

X_d = generator d-axis synchronous reactance

X_t = generator transformer reactance

R_f = feeder resistance

X_f = feeder reactance

n = number of parallel generators

Hence,

$I_{flt} = 2893\ A$

and

$$V_{flt} = \frac{V_N\sqrt{3((nR_f)^2 + (X_t + nX_f)^2)}}{\sqrt{(nR_f)^2 + (X_d + X_t + nX_f)^2}}$$

$$= 1304\ V$$

$I_{flt} / I_{set} = 2893 / 7200 = 0.4$

So a suitable value of K is 0.3.

A suitable value of V_{2set} is 120% of V_{flt}, giving a value of 1565 V. The nearest settable value is 3000 V, minimum allowable relay setting. The value of V_{1set} is required to be above the minimum voltage seen by the generator for a close-up phase-earthfault. A value of 80% of rated voltage is used for V_{1set}, 14400 V.

21.2.3 Inadvertent energisation protection

This protection is a combination of overcurrent with undervoltage, the voltage signal being obtained from a VT on the generator side of the system. The current setting used is that of rated generator current of 6019 A, in accordance with IEEE C37.102 as the generator is for installation in the USA. Use 6000 A nearest settable value. The voltage setting cannot be more than 85% of the generator rated voltage to ensure operation does not occur under normal operation. For this application, a value of 50% of rated voltage is chosen.

21.2.4 Negative phase sequence protection

The generator has a maximum steady-state capability of 8% of rating, and a value of K_g of 10. Settings of I_{2cmr} = 0.06 (=480 A) and K_g = 10 are therefore used. Minimum and maximum time delays of 1 s and 1300 s are used to co-ordinate with external protection and ensure tripping at low levels of negative sequence current are used.

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21. Examples of generator protection settings

21.2.5 Overfluxing protection

The generator-transformer manufacturer supplied the following characteristics:

Alarm: $V/f > 1.1$

Trip: $V/f > 1.2$, inverse time characteristic

Hence:

the alarm setting is $18000 \times 1.05/60 = 315V/Hz$

A time delay of 5 s is used to avoid alarms due to transient conditions.

the trip setting is $18000 \times 1.2/60 = 360V/Hz$

A TMS value of 10 is selected, to match the withstand curve supplied by the manufacturer.

21.2.6 100% Stator earthfault protection

This is provided by a combination of neutral voltage displacement and third harmonic undervoltage protection. For the neutral voltage displacement protection to cover 90% of the stator winding, the minimum voltage allowing for generator operation at a minimum of 92% of rated voltage is:

$$\frac{0.92 \times 18kV \times 0.1}{\sqrt{3}}$$

$$= 956.1\ V$$

Use a value of 935.3 V, nearest settable value that ensures 90% of the winding is covered. A 0.5 s definite time delay is used to prevent spurious trips. The third harmonic voltage under normal conditions is 2% of rated voltage, giving a value of:

$$\frac{18kV \times 0.02}{\sqrt{3}}$$

$$= 207.8\ V$$

The setting of the third harmonic undervoltage protection must be below this value, a factor of 80% being acceptable. Use a value of 166.3 V. A time delay of 0.5 s is used. Inhibition of the element at low generator output requires determination during commissioning.

21.2.7 Loss of excitation protection

The client requires a two-stage loss of excitation protection function. The first is alarm only, while the second provides tripping under high load conditions. To achieve this, the first impedance element of the MiCOM P343 loss of excitation protection can be set in accordance with the guidelines of Section 16.3 for a generator operating at rotor angles up to 120°, as follows:

$$X_{b1} = 0.5X_d = 1.666\ \Omega$$

$$X_{a1} = -0.75X'_d = -0.245\ \Omega$$

Use nearest settable values of 1.669 Ω and 0.253 Ω. A time delay of 5s is used to prevent alarms under transient conditions. For the trip stage, settings for high load as given in Section 16.3 are used:

$$X_{b2} = \frac{kV^2}{MVA}\ \frac{18^2}{187.65} = 1.727\ \Omega$$

$$X_{a2} = -0.5X'_d = -0.163\ \Omega$$

The nearest settable value for X_{b2} is 1.725 Ω. A time delay of 0.5 s is used.

21.2.8 Reverse power protection

The manufacturer-supplied value for motoring power is 2% of rated power. The recommended setting is therefore 1.6 MW. An instrumentation class CT is used in conjunction with the relay for this protection, to ensure accuracy of measurement. A time delay of 0.5 s is used. The settings should be checked at the commissioning stage.

21.2.9 Over/underfrequency protection

For underfrequency protection, the client has specified the following characteristics:

Alarm: 59.3 Hz, 0.5 s time delay

1st stage trip:	58.7 Hz, 100 s time delay
2nd stage trip:	58.2 Hz, 1 s time delay

Similarly, the overfrequency is required to be set as follows:

Alarm:	62 Hz, 30 s time delay
Trip:	63.5 Hz, 10 s time delay

These characteristics can be set in the relay directly.

21.2.10 Overvoltage protection

The generator manufacturers' recommendation is:

Alarm:	110% voltage for 5 s
Trip:	130% voltage, instantaneous

This translates into the following relay settings:

Alarm:	19800 V, 5 s time delay
Trip:	23400 V, 0.1 s time delay

21. Examples of generator protection settings

21.2.11 Pole slipping protection

This is provided by the method described in Section 17.3.2. Detection at a maximum slip frequency of 10 Hz is required. The setting data, according to the relay manual, is as follows.

Forward reach,

$$\begin{aligned} Z_A &= Z_n + Z_t \\ &= 0.02 + 0.22 \\ &= 0.24\ \Omega \end{aligned}$$

Reverse reach,

$$\begin{aligned} Z_B &= Z_{Gen} \\ &= 2 \times X'_d \\ &= 0.652\ \Omega \end{aligned}$$

Reactance line,

$$\begin{aligned} Z_C &= 0.9 \times Z_t \\ &= 0.9 \times 0.22 \\ &= 0.198\ \Omega \end{aligned}$$

where:

Z_t = generator transformer leakage impedance

Z_n = network impedance

The nearest settable values are 0.243 Ω, 0.656 Ω, and 0.206 Ω respectively.

The lens angle setting, α, is found from the equation:

$$\alpha_{min} = 180^o - 2tan^{-1}\left(\frac{1.54 - R_{lmin}}{(Z_A + Z_B)}\right)$$

and, substituting values,

α_{min} = 62.5°

Use the minimum settable value of 90°. The blinder angle, θ, is estimated to be 80°, and requires checking during commissioning. Timers T_1 and T_2 are set to 15 ms as experience has shown that these settings are satisfactory to detect pole slipping frequencies up to 10 Hz.

This completes the settings required for the generator, and the relay settings are given in Table C8.6. Of course, additional protection is required for the generator transformer, according to the principles described in Chapter [C7: Transformer and Transformer-Feeder Protection].

Table C8.6: Relay settings for large generator protection example

Protection	Quantity	Value
Differential protection	I_{s1}	8%
	I_{s2}	100%
	K_1	0%
	K_2	150%
Stator earthfault	$V_{n3H<}$	166.3 V
	V_{n3H} delay	0.5 s
Neutral voltage displacement	V_{snvd}	935.3 V
	Time delay	0.5 s
Loss of excitation	X_{1a}	-0.245 Ω
	X_{1b}	1.666 Ω
	t_{d1}	5 s
	X_{a2}	-0.163 Ω
	X_{b2}	1.725 Ω
	t_{d2}	0.5 s
	t_{D01}	0 s
Voltage restrained overcurrent	I_{set}	7200 A
	K	0.3
	V_{1set}	14400 V
	V_{2set}	3000 V
Negative phase sequence	$I_{2>>}$	0.06
	K_g	10
	K_{reset}	10
	t_{min}	1 s
	t_{max}	1300 s
Overvoltage	*V>* meas mode	three-phase
	V> operate mode	any
	V> 1 setting	19800 V
	V> 1 function	DT
	V> 1 time delay	5 s
	V> 2 setting	23400
	V> 2 function	DT
	V> 2 time delay	0.1 s
Reverse power	*P1* function	reverse power
	P1 setting	1.6 MW
	P1 time delay	0.5 s
	P1 DO time	0 s
Inadvertent energisation	Dead Mach *I>*	6000 A
	Dead Mach *V>*	9000 V
Pole slipping protection	Z_a	0.243 Ω
	Z_b	0.656 Ω
	Z_c	0.206 Ω
	α	90°
	θ	80°
	T_1	15ms
	T_2	15ms
Overfrequency	*F>1* setting	62 Hz
	F>1 time delay	30 s
	F>2 setting	63.5 Hz
	F>2 time delay	10 s
Underfrequency	*F<1* setting	59.3 Hz
	F<1 time delay	0.5 s
	F<2 setting	58.7 Hz
	F<2 time delay	100 s
	F<3 setting	58.2 Hz
	F<3 time delay	1 s

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A.C. Motor Protection

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Chapter C9

A.C. Motor Protection

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1. Introduction

There are a wide range of a.c. motors and motor characteristics in existence, because of the numerous duties for which they are used. All motors need protection, but fortunately, the more fundamental problems affecting the choice of protection are independent of the type of motor and the type of load to which it is connected. There are some important differences between the protection of induction motors and synchronous motors, and these are fully dealt with in the appropriate section.

Motor characteristics must be carefully considered when applying protection; while this may be regarded as stating the obvious, it is emphasised because it applies more to motors than to other items of power system plant. For example, the starting and stalling currents/times must be known when applying overload protection, and furthermore the thermal withstand of the machine under balanced and unbalanced loading must be clearly defined.

The conditions for which motor protection is required can be divided into two broad categories: imposed external conditions and internal faults. Table C9.1 provides details of all likely faults that require protection.

External faults	Internal faults
Unbalanced supplies	Bearing failures
Undervoltages	Winding faults
Single phasing	Overloads
Reverse phase sequence	

Table C9.1:
Causes of motor failures

2. Modern relay design

The design of a motor protection relay must be adequate to cater for the protection needs of any one of the vast range of motor designs in service, many of the designs having no permissible allowance for overloads. A relay offering comprehensive protection will have the following set of features:

a. thermal protection

b. extended start protection

c. stalling protection

d. number of starts limitation

e. short circuit protection

f. earth fault protection

g. winding RTD measurement/trip

h. negative sequence current detection

i. undervoltage protection

j. loss-of-load protection

k. out-of-step protection

l. loss-of-supply protection

m. auxiliary supply supervision

Note: *Items k and l apply to synchronous motors only.*

In addition, relays may offer options such as circuit breaker condition monitoring as an aid to maintenance. Manufacturers may also offer relays that implement a reduced functionality to that given above where less comprehensive protection is warranted (e.g. induction motors of low rating).

The following sections examine each of the possible failure modes of a motor and discuss how protection may be applied to detect that mode.

3. Thermal (overload) protection

The majority of winding failures are either indirectly or directly caused by overloading (either prolonged or cyclic), operation on unbalanced supply voltage, or single phasing, which all lead through excessive heating to the deterioration of the winding insulation until an electrical fault occurs. The generally accepted rule is that insulation life is halved for each 10° C rise in temperature above the rated value, modified by the length of time spent at the higher temperature. As an electrical machine has a relatively large heat storage capacity, it follows that infrequent overloads of short duration may not adversely affect the machine. However, sustained overloads of only a few percent may result in premature ageing and insulation failure.

Furthermore, the thermal withstand capability of the motor is affected by heating in the winding prior to a fault. It is therefore important that the relay characteristic takes account of the extremes of zero and full-load pre-fault current known respectively as the 'Cold' and 'Hot' conditions.

The variety of motor designs, diverse applications, variety of possible abnormal operating conditions and resulting modes of failure result in a complex thermal relationship. A generic mathematical model that is accurate is therefore impossible to create. However, it is possible to develop an approximate model if it is assumed that the motor is a homogeneous body, creating and dissipating heat at a rate proportional to temperature rise. This is the principle behind the 'thermal replica' model of a motor used for overload protection.

The temperature T at any instant is given by:

$$T=T_{max}\left(1-e^{-t/\tau}\right)$$

where:

T_{max} = final steady state temperature

τ = heating time constant

Temperature rise is proportional to the current squared:

$$T=K(I_R)^2\left(1-e^{-t/\tau}\right)$$

where:

I_R = current which, if flowing continuously, produces temperature T_{max} in the motor

Therefore, it can be shown that, for any overload current I, the permissible time t for this current to flow is:

$$t=\tau \log_e\left[\frac{1}{\left\{1-\left(I_R/I\right)^2\right\}}\right]$$

In general, the supply to which a motor is connected may contain both positive and negative sequence components, and both components of current give rise to heating in the motor.

Therefore, the thermal replica should take into account both of these components, a typical equation for the equivalent current being:

$$I_{eq}=\sqrt{\left(I_1^2+KI_2^2\right)}$$

where

I_1 = positive sequence current

I_2 = negative sequence current

$$K=\frac{\textit{negative sequence rotor resistance}}{\textit{positive sequence rotor resistance}} \text{ at rated speed.}$$

For an asynchronous motor, K can be estimated with the following formula:

$$K=2\frac{T_s/T_n}{S_n\left(I_s/I_n\right)^2}-1$$

Where

T_s : starting torque

T_n : rated torque

I_s : starting current

I_n : rated current

Normally K is within the range 2 to 9, according to motor data sheet. It is generally a setting of the thermal overload protection. A typical value of K is 3.

Finally, the thermal replica model needs to take into account the fact that the motor will tend to cool down during periods of light load, and the initial state of the motor. The motor will have a cooling time constant, τ_r , that defines the rate of cooling. Hence, the final thermal model can be expressed as:

$$t=\tau \log_e\left(k^2-A^2\right)\Big/\left(k^2-1\right) \quad \textit{...Equation C9.1}$$

where:

τ = heating time constant

$$k=\frac{I_{eq}}{I_{th}}$$

A^2 = initial state of motor (cold or hot) in percentage of the thermal state

If the initial thermal state is due to a constant load current I_L, the A^2 factor can be computed by the equation $A^2=(I_L=I_{th})^2$

I_{th} = thermal setting current

Equation C9.1 takes into account the 'cold' and 'hot' characteristics defined in IEC 60255 -149.

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3. Thermal (overload) protection

Some relays may use a dual slope characteristic for the heating time constant, and hence two values of the heating time constant are required. Switching between the two values takes place at a pre-defined motor current. This may be used to obtain better tripping performance during starting on motors that use a star-delta starter. During starting, the motor windings carry full line current, while in the 'run' condition, they carry only 57% of the current seen by the relay. Similarly, when the motor is disconnected from the supply, the heating time constant τ is set equal to the cooling time constant τ_r.

Most of motors are designed to operate at a maximum ambient temperature of 40°C. This value is defined in motor datasheet, as the rated ambient temperature, used to defined the thermal withstand (cold and hot curves).

The real operating ambient temperature could be less (e.g. motor in caves) or more than the rated value. Most of thermal relays proposed to connect an ambient temperature sensor (e.g. with RTDs sensors), and this temperature is taken into account in the thermal level estimation. The calculated heat rise value could be increased or decreased when the temperature is above or below the rated value. As defined in the IEC60255-151, the motor thermal level is compensated by a factor Fa, defined by the following equation:

$$F_a = \frac{T_{max} - T_{limit}}{T_{max} - T_a}$$

Where

T_{max} is the motor maximum temperature

T_a is the actual ambient temperature of the motor

T_{limit} is the ambient temperature design limits for operation at rated load without causing thermal degradation of insulation, typically 40°C

When temperature sensor is not available, a user setting could be provided to adjust the ambient temperature, when it is different from typical value (40°C).

Since the relay should ideally be matched to the protected motor and be capable of close sustained overload protection, a wide range of relay adjustment is desirable together with good accuracy and low thermal overshoot.

Typical relay setting curves are shown in Figure C9.1.

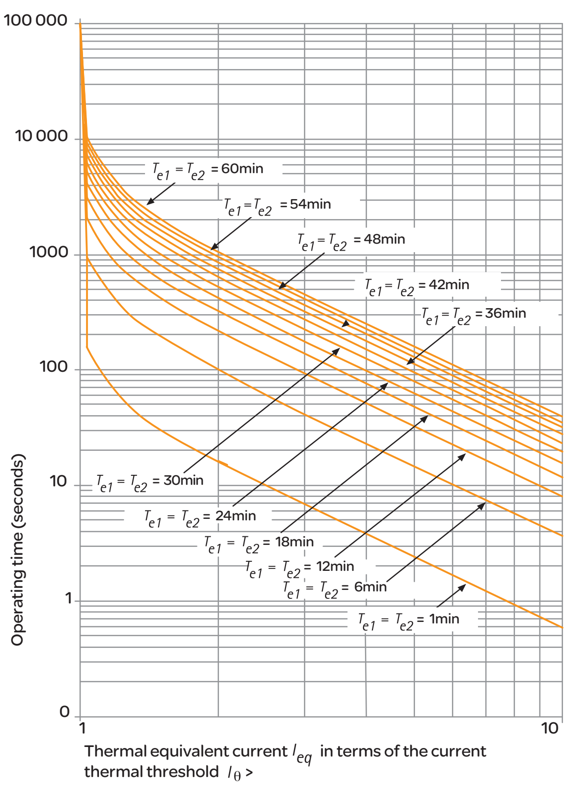

Figure C9.1:
Thermal overload characteristic curves.
Cold curves. Initial thermal state 0%

4. Start/stall protection

When a motor is started, it draws a current well in excess of full load rating throughout the period that the motor takes to run-up to speed. The motor starting current reduces somewhat as motor speed increases. The starting current will vary depending on the design of the motor and method of starting. For motors started DOL (direct-on-line), the nominal starting current can be 4-8 times full-load current.

However, when a star-delta starter is used, the line current will only be √3 of the DOL starting current.

Should a motor stall whilst running, or fail to start, due to excessive loading, the motor will draw a current equal to its' locked rotor current. It is not therefore possible to distinguish between a stall condition and a healthy start solely on the basis of the current drawn. Discrimination between the two conditions must be made based on the duration of the current

4. Start/stall protection

drawn. For motors where the starting time is less than the safe stall time of the motor, protection is easy to arrange.

However, where motors are used to drive high inertia loads, the stall withstand time can be less than the starting time. In these cases, an additional means must be provided to enable discrimination between the two conditions to be achieved.

4.1 Excessive start time/locked rotor protection

A motor may fail to accelerate from rest for a number of reasons:

a. loss of a supply phase

b. mechanical problems

c. low supply voltage

d. excessive load torque

... etc.

A large current will be drawn from the supply, and cause extremely high temperatures to be generated within the motor. This is made worse by the fact that the motor is not rotating, and hence no cooling due to rotation is available. Winding damage will occur very quickly – either to the stator or rotor windings depending on the thermal limitations of the particular design (motors are said to be stator or rotor limited in this respect). The method of protection varies depending on whether the starting time is less than or greater than the safe stall time. In both cases, from the motor standstill status, the initiation of the start may be sensed by detection of the closure of the switch in the motor feeder (contactor or CB) and optionally current rising above a starting current threshold value – typically 200% of motor rated current. For the case of both conditions being sensed, they may have to occur within a narrow aperture of time for a start to be recognised.

Special requirements may exist for certain types of motors installed in hazardous areas (e.g. motors with type of protection EEx 'e') and the setting of the relay must take these into account. Sometimes a permissive interlock for machine pressurisation (on EEx 'p' machines) may be required, and this can be conveniently achieved by use of a relay digital input and the in-built logic capabilities.

4.1.1 Start time < safe stall time

In the majority of cases the starting time of a normal induction motor is less than the maximum stall withstand time. Under this condition it is possible to discriminate on a time basis between the two conditions and thus provide protection against stalling.

Protection is achieved by use of a definite time overcurrent characteristic, the current setting being greater than full load current but less than the starting current of the machine. The time setting should be a little longer than the start time, but less than the maximum stall withstand time. Generally, the time setting should be set 1 or 2 seconds above the start time. Figure C9.2 illustrates the principle of operation for a successful start.

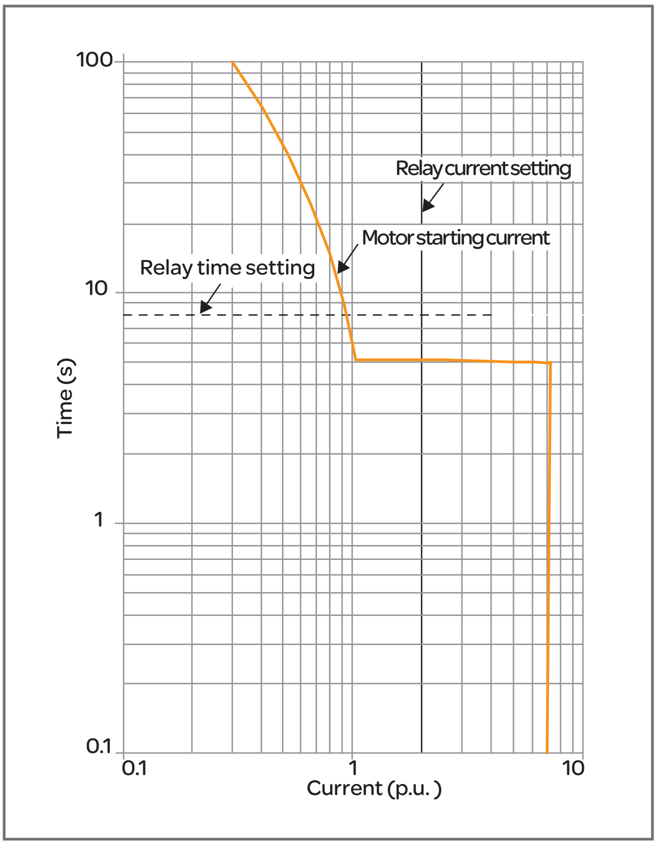

Figure C9.2:
Motor start protection start time < safe stall time

4.1.2 Start time => safe stall time

Where motors are used to drive high inertia loads, the stall withstand time can be less than the starting time. For this condition, a definite time overcurrent characteristic by itself is not sufficient, since the time delay required is longer than the maximum time that the motor can be allowed to carry stalling current safely. An additional means of detection of rotor movement, indicating a safe start, is required. A speed-sensing switch usually provides this function. Detection of a successful start is used to select the relay timer used for the safe run up time. This time can be longer than the safe stall time, as there is both a (small) decrease in current drawn by the motor during the start and the rotor fans begin to improve cooling of the machine as it accelerates. If a start is sensed by the relay through monitoring current and/or start device closure, but the speed switch does not operate, the relay element uses the safe stall time setting to trip the motor before damage can occur. Figure C9.3(a) illustrates the principle of operation for a successful start, and Figure C9.3(b) for an unsuccessful start.

4. Start/stall protection

Normally the speed sensor indicates motor start or not. Alternatively, some motor protection relays can distinguish start and stall without external speed information. Such a relay estimates the motor slip based on the calculation of the positive sequence resistance of the machine.

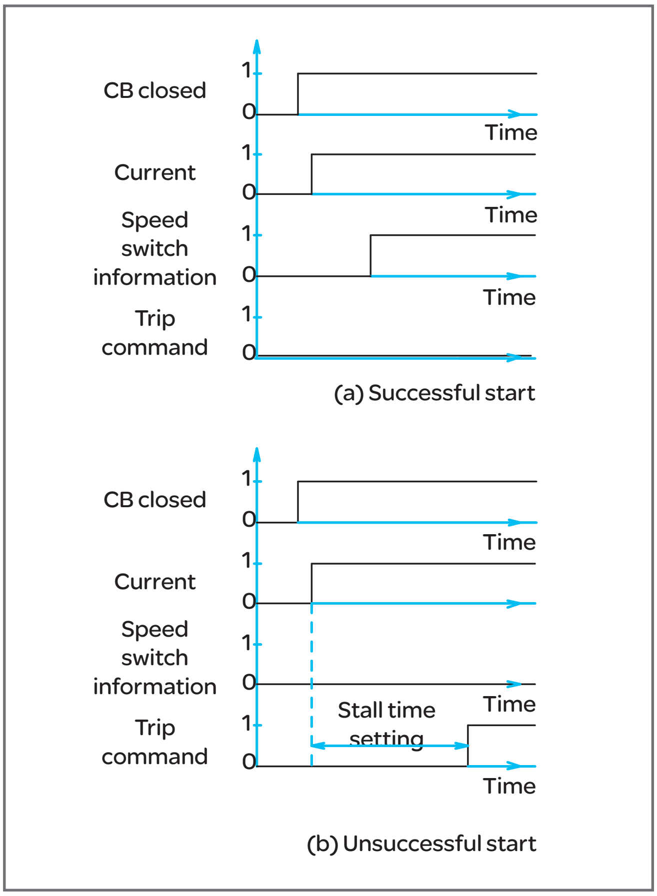

Figure C9.3:
Relay settings for start time> stall time

4.2 Stall protection

Should a motor stall when running or be unable to start because of excessive load, it will draw a current from the supply equivalent to the locked rotor current. It is obviously desirable to avoid damage by disconnecting the machine as quickly as possible if this condition arises.

Motor stalling can be recognised by the motor current exceeding the start current threshold after a successful start – i.e. a motor start has been detected and the motor current has dropped below the start current threshold within the motor safe start time. A subsequent rise in motor current above the motor starting current threshold is then indicative of a stall condition, and tripping will occur if this condition persists for greater than the setting of the stall timer. An instantaneous overcurrent relay element provides protection.

4.3 Re-acceleration

In many systems, transient supply voltage loss (typically up to 2 seconds) does not result in tripping of designated motors. They are allowed to re-accelerate upon restoration of the supply. During re-acceleration, they draw a current similar to the starting current for a period that may be several seconds. It is thus above the motor stall relay element current threshold. The stall protection would be expected to operate and defeat the object of the re-acceleration scheme if the allowable stall time is less than the re-acceleration time.

The undervoltage protection element can be used to detect the presence of the voltage dip and voltage recovery. If, on recovery of the voltage, the current exceeds the stalling current threshold within a definite time such as 5 seconds, then the re-acceleration is recognised. In that case, the re-acceleration timer replaces the stall timer, as shown in Figure C9.4. If the current falls below the stalling current threshold before the end of the expired of the re-acceleration timer, the re-acceleration is successful; otherwise the relay issues a trip signal.

This function is disabled during the starting period.

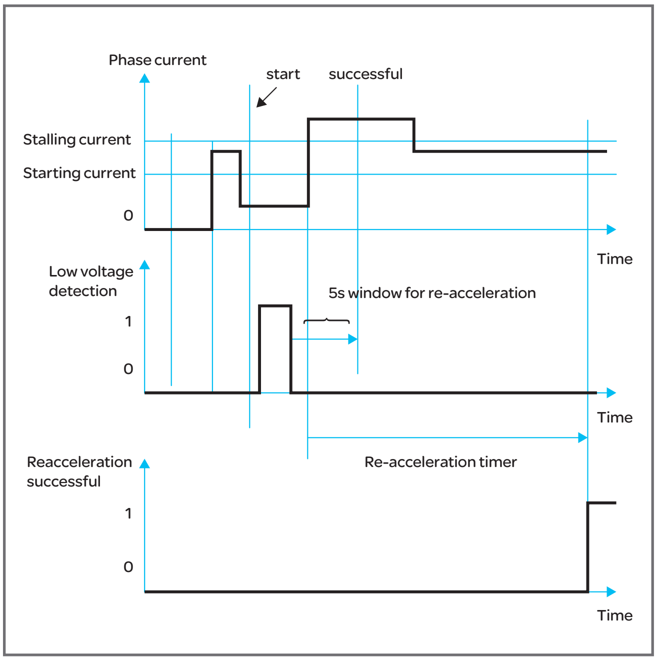

Figure C9.4:
Motor re-acceleration

4.4 Number of starts limitation

Any motor has a restriction on the number of starts that are allowed in a defined period to ensure that the thermal limit of the motor is not exceeded and to limit any mechanical impact from too many starts.

4. Start/stall protection

If the permitted number of starts in a given supervising period is reached, starting should be blocked for the remaining time of that supervising period or the defined start inhibit time which is greater, as shown in Figure C9.5 and Figure C9.6.

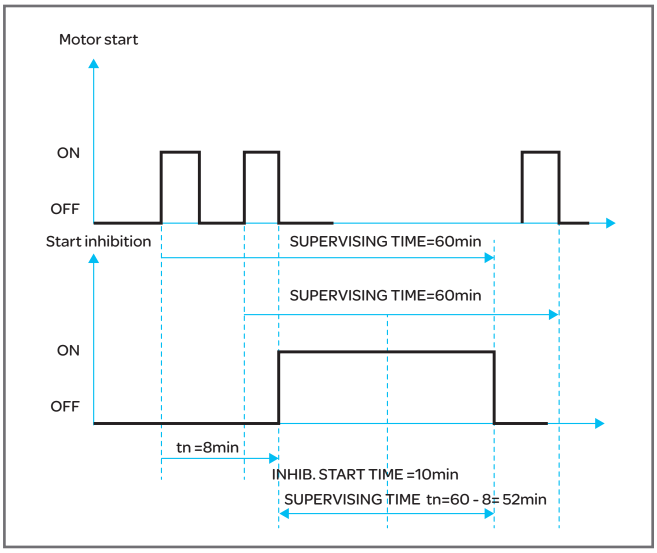

Figure C9.5:
Motor start inhibition (a)

In these two figures, the maximum number of starts is 2. Figure C9.5 shows the situation where two starts have occurred within 8 minutes. As the supervision time is set to 60 minutes no further starts are permitted for 52 minutes even if the Inhibit start time expires.

In Figure C9.6 two starts occur within 55 minutes. Without the Inhibit timer a new supervision period would start in 5 minutes and permit a new start however as the Inhibit timer is set to 10 minutes, starting is blocked until this expires (a further 5 minutes later).

The situation is complicated by the fact the number of permitted 'hot' starts in a given supervising period is less than the number of 'cold' starts, due to the differing initial temperatures of the motor. The relay must maintain a separate count of 'cold' and 'hot' starts. By making use of the data held in the motor thermal replica, 'hot' and 'cold' starts can be distinguished.

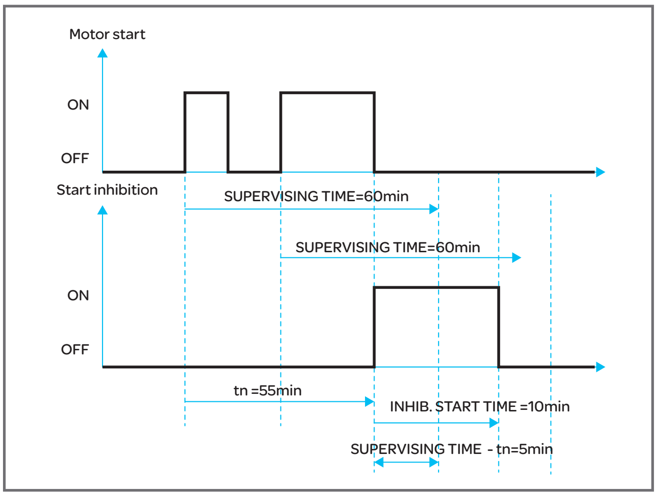

Figure C9.6:
Motor start inhibition (b)

5. Short circuit protection

Motor short-circuit protection is often provided to cater for major stator winding faults and terminal flashovers. Because of the relatively greater amount of insulation between phase windings, faults between phases seldom occur. As the stator windings are completely enclosed in grounded metal, the fault would very quickly involve earth, which would then operate the instantaneous earth fault protection. A single definite time overcurrent relay element is all that is required for this purpose, set to about 125% of motor starting current. The time delay is required to prevent spurious operation due to CT spill currents, and is typically set at 100ms. If the motor is fed from a fused contactor, co-ordination is required with the fuse, and this will probably involve use of a long time delay for the relay element. Since the object of the protection is to provide rapid fault clearance to minimise damage caused by the fault, the protection is effectively worthless in these circumstances. It is therefore only provided on motors fed via circuit breakers.

5.1 Motor differential protection

The over current protection is usually applied for the motor stator winding faults. However the sensitivity of the over current protection declines when the motor capacity increases. So when the motor capacity is more than 2000KW or the over current protection is not sufficiently sensitive, it is necessary to apply differential protection on larger motors via circuit breakers to protect against phase-phase and single phase earth faults. Damage to the motor in case of a fault is minimised, as the differential protection can be made quite sensitive and hence detecting faults in their early stages.

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5. Short circuit protection

For details on the conventional differential protection (both biased differential protection and the high impedance differential protection), refer to the section "Differential Protection of Direct Connected Generators" on chapter "Generator and Generator-Transformer Protection".

The reliability of conventional differential protection relies on the current transformer saturation characteristic, current transformer's secondary burden and so on. As explained in previous chapters, it is almost impossible that the two current transformers have the same transient characteristics during high current events such as motor starting. It is possible that the differential protection trips incorrectly under an external fault condition for similar reasons. So the settings for conventional bias differential protection cannot be very small or additional restraint elements (such as CT saturation detection) must be provided to ensure stability in all conditions.

5.2 Self balance differential protection

An alternative is to apply self balance winding differential protection. It is also named as magnetic balanced differential protection, as shown in Figure C9.7. Three core balance current transformers are applied in the self balance winding differential protection. As with the more conventional approach to differential protection both ends of the windings must be accessible at the motor terminals.

Both ends of each phase winding pass through the current transformer in different directions. The conductors shall be placed reasonably concentric within the window of the core balance current transformers to keep the spill current to a minimum.

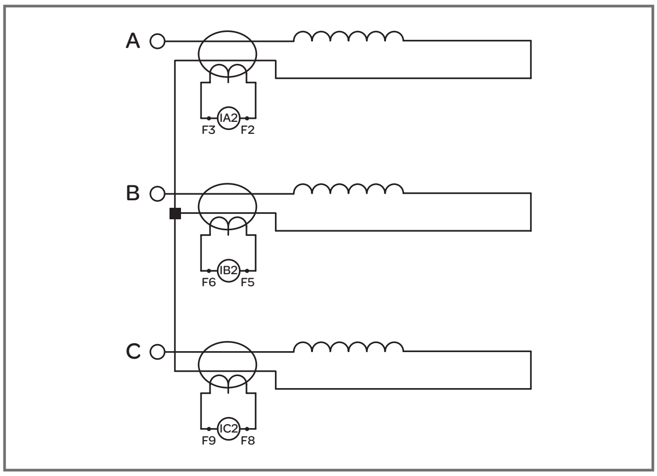

Figure C9.7:
Self balance winding differential protection

So under the normal condition, the magnetic flux and the secondary current shall be very small. When there are phase-phase or single phase earth faults within the stator windings, the magnetic balance is broken and there are secondary currents which will trigger the relay operation.

Unlike the other protection applications, here the current transformers are normally installed very near the motor output terminal to avoid long cabling. So it only protects the motor and does not include the longer cables between motor and the control switchgear.

5.2.1 Settings

In this section, it takes the unearthed system as example to introduce the setting rule for self balance differential protection.

In the normal condition, the unbalance current from the core balance current transformer is very small. The unbalance current is due to the capacitive current of the motor (I'cm) not including the capacitive current of the cable from motor to control switchgear.

The current setting for self balance winding differential protection shall be larger than the maximum capacitive current of the motor when there are external faults on the other feeds or equipment, as shown in Figure C9.8. Compared with the normal condition, the capacitive current will increase by a maximum √3 due to the increase of the phase voltage under the external single phase earth fault. Due to the relatively low value of this capacitive current the protection current setting can be very small and the sensitivity is high. The capacitive currents of the overall system under the distribution transformer return to the system via the fault point, as shown in Figure C9.9. The unbalance current of the core balance current transformer is the overall system capacitive current.

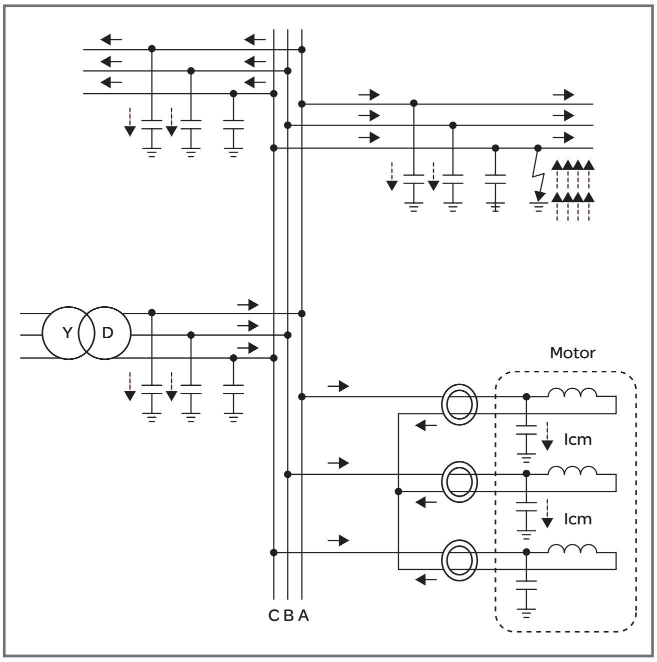

Figure C9.8:
Capacity current distribution under external single phase earth fault

5. Short circuit protection

So if the sum of the capacitive currents of the overall system is larger than the current setting, the self balance winding differential protection can detect the internal single phase earth fault.

5.2.2 Summary

Compared with the conventional differential protection, the self balance winding differential protection does not rely on the consistency of CT characteristics and its reliability is much higher.

The HV motor is connected within the distribution power system. The distribution power system is usually insulated system or high impedance earthing system. So the single phase earth fault current is lower and normally cannot trigger the conventional differential protection. However due to the lower current setting, the self balance differential protection can be sensitive to the single phase earth fault of the HV motor stator.

It should be noted that the protection zone of a self balance differential protection does not normally include the cable between the machine output terminals and controlling switchgear. An additional relay is needed to protect this cable.

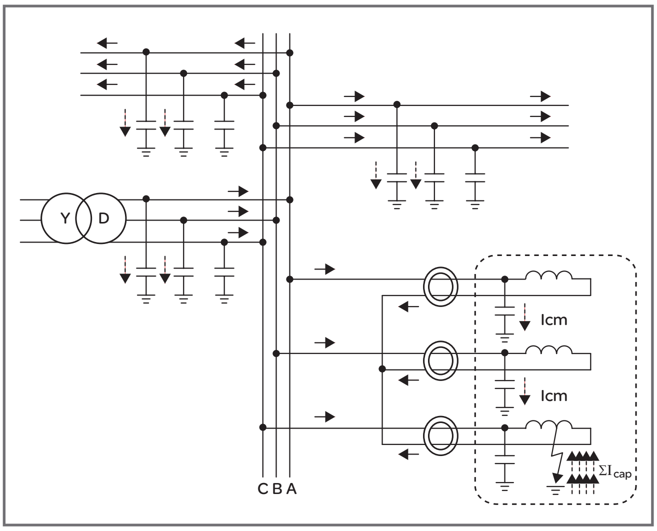

Figure C9.9:
Capacity current distribution under internal single phase earth fault

6. Earth fault protection

One of the most common faults to occur on a motor is a stator winding fault. Whatever the initial form of the fault (phase-phase, etc.) or the cause (cyclic overheating, etc.), the presence of the surrounding metallic frame and casing will ensure that it rapidly develops into a fault involving earth. Therefore, provision of earth fault protection is very important. The type and sensitivity of protection provided depends largely on the system earthing, so the various types will be dealt with in turn. It is common, however, to provide both instantaneous and time-delayed relay elements to cater for major and slowly developing faults.

6.1 Solidly-earthed system

Most LV systems fall into this category, for reasons of personnel safety. Two types of earth fault protection are commonly found – depending on the sensitivity required.

For applications where a sensitivity of > 20% of motor continuous rated current is acceptable, conventional earth fault protection using the residual CT connection of Figure C9.10 can be used.

A lower limit is imposed on the setting by possible load unbalance and/or (for HV systems) system capacitive currents.

Care must be taken to ensure that the relay does not operate from the spill current resulting from unequal CT saturation during motor starting, where the high currents involved will almost certainly saturate the motor CTs.

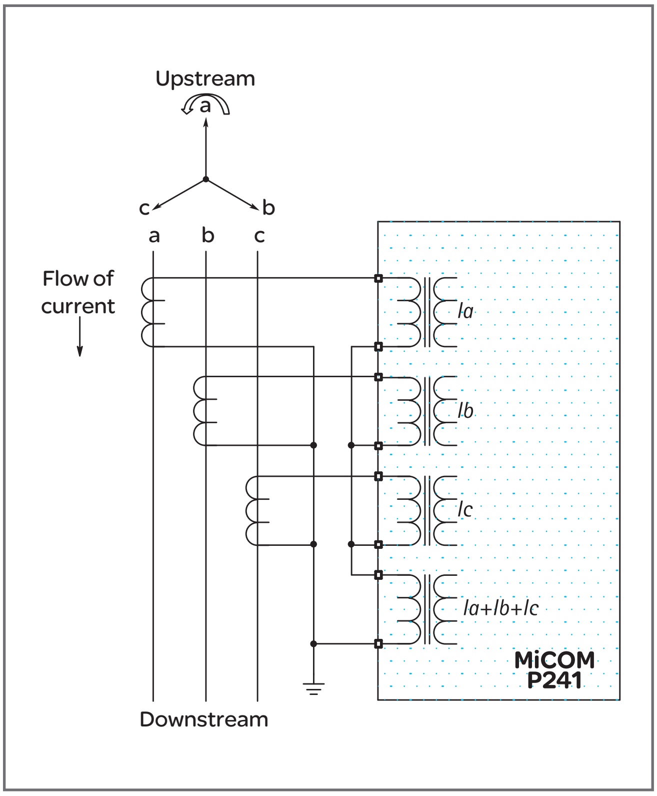

Figure C9.10:
Residual CT connection for earth fault protection

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6. Earth fault protection

It is common to use a stabilising resistor in series with the relay, with the value being calculated using the formula:

$$R_{stab} = \frac{I_{st}}{I_O}\left(R_{ct} + kR_l + R_r\right) \quad \text{...Equation C9.2}$$

where:

I_{st} = starting current referred to CT secondary

I_o = relay earth fault setting (A)

R_{stab} = stabilising resistor value (ohms)

R_{ct} = d.c. resistance of CT secondary (ohms)

R_l = CT single lead resistance (ohms)

k = CT connection factor

(= 1 for star pt at CT

= 2 for star pt at relay)

R_r = relay input resistance (ohms)

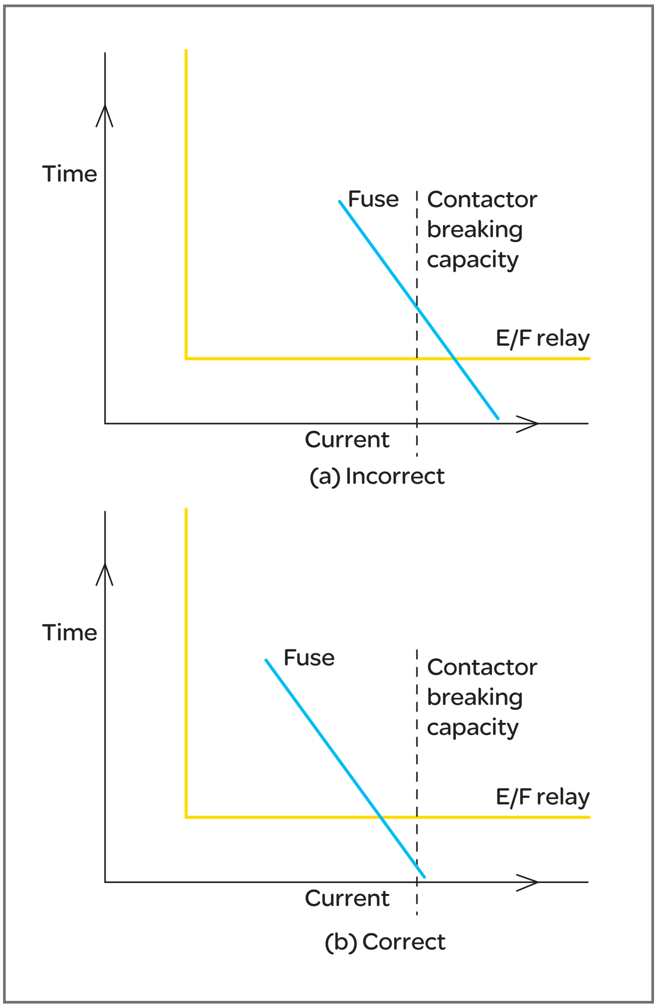

Figure C9.11:
Grading of relay with fused contactor

The effect of the stabilising resistor is to increase the effective setting of the relay under these conditions, and hence delay tripping. When a stabilising resistor is used, the tripping characteristic should normally be instantaneous. An alternative technique, avoiding the use of a stabilising resistor is to use a definite time delay characteristic.

The time delay used will normally have to be found by trial and error, as it must be long enough to prevent maloperation during a motor start, but short enough to provide effective protection in case of a fault.

Co-ordination with other devices must also be considered. A common means of supplying a motor is via a fused contactor The contactor itself is not capable of breaking fault current beyond a certain value, which will normally be below the maximum system fault current – reliance is placed on the fuse in these circumstances. As a trip command from the relay instructs the contactor to open, care must be taken to ensure that this does not occur until the fuse has had time to operate. Figure C9.11(a) illustrates incorrect grading of the relay with the fuse, the relay operating first for a range of fault currents in excess of the contactor breaking capacity. Figure C9.11(b) illustrates correct grading. To achieve this, it may require the use of an intentional definite time delay in the relay.

6.2 Resistance-earthed systems

These are commonly found on HV systems, where the intention is to limit damage caused by earth faults through limiting the earth fault current that can flow. Two methods of resistance earthing are commonly used:

6.2.1 Low resistance earthing

In this method, the value of resistance is chosen to limit the fault current to a few hundred amps – values of 200A-400A being typical. With a residual connection of line CTs, the minimum sensitivity possible is about 10% of CT rated primary current, due to the possibility of CT saturation during starting.

For better sensitivity with lower current setting, it is necessary to use a core-balance CT. The primary current of the core-balance CT is no longer related to the normal line current. For a core-balance CT, the relay may be set non-directional with a current sensitivity of less than 30% of the minimum earth fault level but greater than three times the steady state charging current of the motor feeder. The setting should not be greater than about 30% of the minimum earth fault current expected.

If the above setting guidelines for applying a non-directional relay cannot be achieved due to the current magnitudes, then a sensitive directional earth fault element will be required. This eliminates the need to set the relay in excess of the maximum capacitive charging current for the protected feeder.

6. Earth fault protection

The required time delay setting shall ensure that the contactor does not attempt to interrupt fault current in excess of its breaking capacity when the motor is supplied by a fused contactor.

6.2.2 High resistance earthing

In some HV systems, high resistance earthing is used to limit the earth fault current to a few amps. In this case, the system capacitive charging current will normally prevent conventional sensitive earth fault protection being applied, as the magnitude of the capacitive charging current will be comparable with the earth fault current in the event of a fault. The solution is to use a sensitive directional earth fault relay. A core balance CT is used in conjunction with a VT measuring the residual voltage of the system, with a relay characteristic angle setting of +45° (see Chapter [C1: Overcurrent Protection for Phase and Earth Faults, Section 17 and 18]) for details.

6.3 Insulated earth system

See Chapter [C1: Overcurrent Protection for Phase and Earth Faults, Section 18] for details.

6.4 Petersen coil earthed system

See Chapter [C1: Overcurrent Protection for Phase and Earth Faults, Section 19] for details.

7. Negative phase sequence protection

Negative phase sequence current is generated from any unbalanced voltage condition, such as unbalanced loading, loss of a single phase, or single-phase faults. The latter will normally be detected by earth fault protection, however, a fault location in a motor winding may not result in the earth fault protection operating unless it is of the sensitive variety.

The actual value of the negative sequence current depends on the degree of unbalance in the supply voltage and the ratio of the negative to the positive sequence impedance of the machine. The degree of unbalance depends on many factors, but the negative sequence impedance is more easily determined. Considering the classical induction motor equivalent circuit with magnetising impedance neglected of Figure C9.12:

- Motor positive sequence impedance at slip s

$$= \left[\left(R_{1p}+R'_{2p}/s\right)^2+\left(X_{1p}+X'_{2p}\right)^2\right]^{0.5}$$

Hence, at standstill (s=1.0), impedance

$$= \left[\left(R_{1p}+R'_{2p}\right)^2+\left(X_{1p}+X'_{2p}\right)^2\right]^{0.5}$$

- The motor negative sequence impedance at slip s

$$= \left[\left(R_{1p}+R'_{2p}/(2-s)\right)^2+\left(X_{1p}+X'_{2p}\right)^2\right]^{0.5}$$

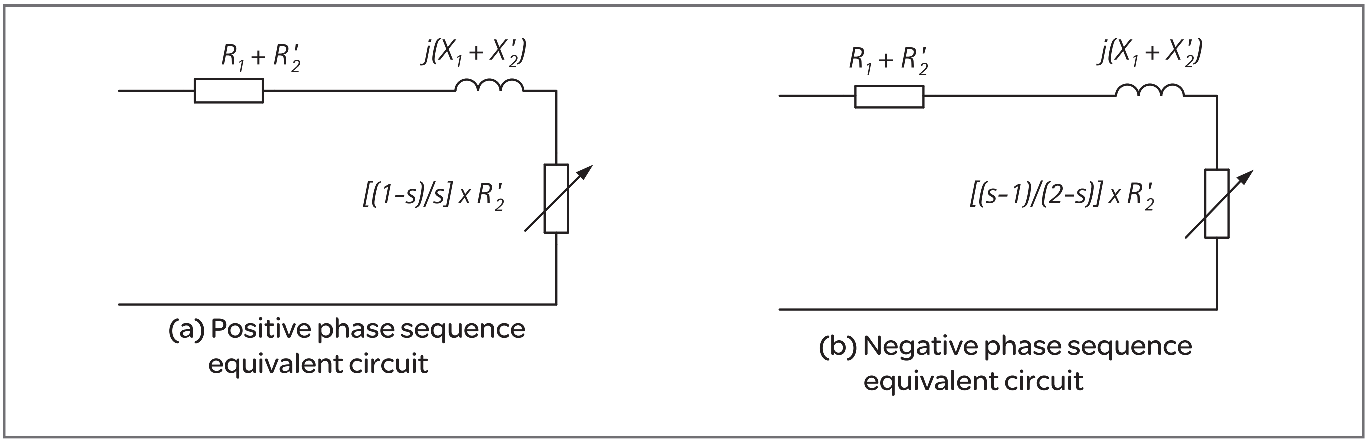

Figure C9.12:
Induction motor equivalent circuit

7. Negative phase sequence protection

and slip s is close to zero at normal running speed, the impedance

$$= \left[\left(R_{1n} + R'_{2n}/2 \right)^2 + \left(X_{1n} + X'_{2n} \right)^2 \right]^{0.5}$$

where:

R_1 is the stator resistance

X_1 is the stator leakage reactance

R'_2 is the rotor equivalent resistance referred to stator

X'_2 is the rotor equivalent leakage reactance referred to stator

suffix p indicates positive sequence quantities

and

suffix n indicates negative sequence quantities

Now, if resistance is neglected (justifiable as the resistance is small compared to the reactance), it can be seen that the negative sequence reactance at running speed is approximately equal to the positive sequence reactance at standstill. An alternative more meaningful way of expressing this is:

$$\frac{positive\ seq.\ impedance}{negative\ seq.\ impedance} = \frac{starting\ current}{rated\ current}$$

and it is noted that a typical LV motor starting current is 6xFLC.

Therefore, a 5% negative sequence voltage (due to, say, unbalanced loads on the system) would produce a 30% negative sequence current in the machine, leading to excessive heating. For the same motor, negative sequence voltages in excess of 17% will result in a negative sequence current larger than rated full load current.

Negative sequence current is at twice supply frequency. Skin effect in the rotor means that the heating effect in the rotor of a given negative sequence current is larger than the same positive sequence current. Thus, negative sequence current may result in rapid heating of the motor. Larger motors are more susceptible in this respect, as the rotor resistance of such machines tends to be higher. Protection against negative sequence currents is therefore essential.

Normally motor protection relays have a negative sequence current measurement capability, in order to provide such protection. The level of negative sequence unbalance depends largely upon the type of fault. For loss of a single phase at start, the negative sequence current will be 50% of the normal starting current. It is more difficult to provide an estimate of the negative sequence current if loss of a phase occurs while running. This is because the impact on the motor may vary widely, from increased heating to stalling due to the reduced torque available.

A typical setting for negative sequence current protection must take into account the fact that the motor circuit protected by the relay may not be the source of the negative sequence current. Time should be allowed for the appropriate protection to clear the source of the negative sequence current without introducing risk of overheating to the motor being considered. This indicates a two stage tripping characteristic, similar in principle to overcurrent protection. A low-set definite time-delay element can be used to provide an alarm, with an IDMT element used to trip the motor in the case of higher levels of negative sequence current, such as loss-of- phase conditions at start, occurring. This element should be set in excess of the anticipated negative phase sequence current resulting from asymmetric CT saturation during starting, but less than the negative phase sequence current resulting from loss of one phase during starting. Typical settings might be 20% of CT rated primary current for the definite time element and 50% for the IDMT element. The IDMT time delay has to be chosen to protect the motor while, if possible, grading with other negative sequence relays on the system. Some relays may not incorporate two elements, in which case the single element should be set to protect the motor, with grading being a secondary consideration.

8. Wound rotor induction motor protection

On wound rotor machines, some degree of protection against faults in the rotor winding can be given by an instantaneous stator current overcurrent relay element. As the starting current is normally limited by resistance to a maximum of twice full load, the instantaneous unit can safely be set to about three times full load if a slight time delay of approximately 30 milliseconds is incorporated. It should be noted that faults occurring in the rotor winding would not be detected by any differential protection applied to the stator.

9. RTD temperature detection

RTDs are used to measure temperatures of motor windings or shaft bearings. A rise in temperature may denote overloading of the machine, or the beginning of a fault in the affected part. A motor protection relay will therefore usually have the capability of accepting a number of RTD inputs and internal logic to initiate an alarm and/or trip when the temperature exceeds the appropriate setpoint(s). Occasionally, HV motors are fed via a unit transformer, and in these circumstances, some of the motor protection relay RTD inputs may be assigned to the transformer winding temperature RTDs, thus providing overtemperature protection for the transformer without the use of a separate relay.

10. Bearing failures

There are two types of bearings to be considered: the anti-friction bearing (ball or roller), used mainly on small motors (up to around 350kW), and the sleeve bearing, used mainly on large motors.

The failure of ball or roller bearings usually occurs very quickly, causing the motor to come to a standstill as pieces of the damaged roller get entangled with the others. There is therefore very little chance that any relay operating from the input current can detect bearing failures of this type before the bearing is completely destroyed. Therefore, protection is limited to disconnecting the stalled motor rapidly to avoid consequential damage. Refer to Section 4 on stall protection for details of suitable protection.

Failure of a sleeve bearing can be detected by means of a rise in bearing temperature. The normal thermal overload relays cannot give protection to the bearing itself but will operate to protect the motor from excessive damage. Use of RTD temperature detection, as noted in Section 9, can provide suitable protection, allowing investigation into the cause of the bearing running hot prior to complete failure.

11. Undervoltage protection

Motors may stall when subjected to prolonged undervoltage conditions. Transient undervoltages will generally allow a motor to recover when the voltage is restored, unless the supply is weak.

Motors fed by contactors have inherent undervoltage protection, unless a latched contactor is used. Where a specific undervoltage trip is required, a definite time undervoltage element is used. If two elements are provided, alarm and trip settings can be used. An interlock with the motor starter is required to block relay operation when the starting device is open, otherwise a start will never be permitted. The voltage and time delay settings will be system and motor dependent. They must allow for all voltage dips likely to occur on the system during transient faults, starting of motors, etc. to avoid spurious trips. As motor starting can result in a voltage depression to 80% of nominal, the voltage setting is likely to be below this value. Re-acceleration is normally possible for voltage dips lasting between 0.5-2 seconds, depending on system, motor and drive characteristics, and therefore the time delay will be set bearing these factors in mind.

12. Loss-of-load protection

Loss-of-load protection has a number of possible functions. It can be used to protect a pump against becoming unprimed, or to stop a motor in case of a failure in a mechanical transmission (e.g. conveyor belt), or it can be used with synchronous motors to protect against loss-of-supply conditions. Implementation of the function is by a low forward power relay element or a simple undercurrent relay when there is not voltage input, interlocked with the motor starting device to prevent operation when the motor is tripped and thus preventing a motor start. Where starting is against a very low load (e.g. a compressor), the function may also need to be inhibited for the duration of the start, to prevent maloperation.

The setting will be influenced by the function to be performed by the relay. A time delay may be required after pickup of the element to prevent operation during system transients. This is especially important for synchronous motor loss-of-supply protection.

13. Anti-backspin function

A motor may be driving a very high inertia load. Once the CB or contactor supplying power to the motor is switched off, the rotor may continue to turn for a considerable length of time as it decelerates. The motor has now become a generator and applying supply voltage out of phase may result in catastrophic failure. In some other applications for example when a motor is on a down-hole pump, after the motor stops, the liquid may fall back down the pipe and spin the rotor backwards. It would be very undesirable to start the motor at this time. In these circumstances the anti-backspin function is used to detect when the rotor has completely stopped, in order to allow re-starting of the motor.

This function uses an undervoltage if the phase-phase or single phase remanent voltage of the motor is connected to the relay. The voltage threshold setting for the anti-backspin protection should be set at some low value to indicate that the motor is stopped. If the relay can not get the remanent voltage, this function uses a simple time delay to indicate the motor is stopped after the CB or contactor is open.

14. Additional protection for synchronous motors

The differences in construction and operational characteristics of synchronous motors mean that additional protection is required for these types of motor. This additional protection is discussed in the following sections.

14.1 Out-of-step protection

A synchronous motor may decelerate and lose synchronism (fall out-of-step) if a mechanical overload exceeding the peak motor torque occurs. Other conditions that may cause this condition are a fall in the applied voltage to stator or field windings. Such a fall may not need to be prolonged, a voltage dip of a few seconds may be all that is required. An out-of-step condition causes the motor to draw excessive current and generate a pulsating torque. Even if the cause is removed promptly, the motor will probably not recover synchronism, but eventually stall. Hence, it must be disconnected from the supply.

The current drawn during an out-of-step condition is at a very low power factor. Hence a relay element that responds to low power factor can be used to provide protection. The element must be inhibited during starting, when a similar low power factor condition occurs. This can conveniently be achieved by use of a definite time delay, set to a value slightly in excess of the motor start time.

The power factor setting will vary depending on the rated power factor of the motor. It would typically be 0.1 less than the motor rated power factor i.e. for a motor rated at 0.85 power factor, the setting would be 0.75.

14. Additional protection for synchronous motors

14.2 Protection against sudden restoration of supply

If the supply to a synchronous motor is interrupted, it is essential that the motor breaker be tripped as quickly as possible if there is any possibility of the supply being restored automatically or without the machine operator's knowledge.

This is necessary in order to prevent the supply being restored out of phase with the motor generated voltage.

Two methods are generally used to detect this condition, in order to cover different operating modes of the motor.

14.2.1 Underfrequency protection

The underfrequency relay element will operate in the case of the supply failing when the motor is on load, which causes the motor to decelerate quickly. Typically, two elements are provided, for alarm and trip indications.

The underfrequency setting value needs to consider the power system characteristics. In some power systems, lengthy periods of operation at frequencies substantially below normal occur, and should not result in a motor trip. The minimum safe operating frequency of the motor under load conditions must therefore be determined, along with minimum system frequency.

14.2.2 Low-forward-power protection

This can be applied in conjunction with a time delay to detect a loss-of-supply condition when the motor may share a busbar with other loads. The motor may attempt to supply the other loads with power from the stored kinetic energy of rotation.

A low forward power relay can detect this condition. See Section 12 for details. A time delay will be required to prevent operation during system transients leading to momentary reverse power flow in the motor.

15. Motor protection examples

This section gives examples of the protection of HV and LV induction motors.

15.1 Protection of a HV motor

Table C9.2 gives relevant parameters of a HV induction motor to be protected. Using a MiCOM P241 motor protection relay, the important protection settings are calculated in the following sections.

Quantity	Value
Rated output	1000kW CMR
Rated Voltage	3.3kV
Rated frequency	50Hz
Rated power factor/efficiency	0.9/0.92
Stall withstand time cold/hot	20/7s
Starting current	550% DOL
Permitted starts cold/hot	3/2
CT ratio	250/1
Start time@100% voltage	4s
Start time@80% voltage	5.5s
Heating/cooling time constant	25/75 min
System earthing	Solid
Control device	Circuit Breaker

Table C9.2: Motor data for example

15.1.1 Thermal protection

The current setting I_{TH} is set equal to the motor full load current, as it is a CMR rated motor. Motor full load current can be calculated as 211A, therefore (in secondary quantities):

$$I_{TH} = \frac{211}{250} = 0.844$$

Use a value of 0.85, nearest available setting.

The relay has a parameter, K, to allow for the increased heating effect of negative sequence currents. In the absence of any specific information, use $K=3$.

Two thermal heating time constants are provided, τ_1 and τ_2. τ_2 is used for starting methods other than DOL, otherwise it is set equal to τ_1. τ_1 is set to the heating time constant, hence $\tau_1 = \tau_2$= 25mins. Cooling time constant τ_r is set as a multiple of τ_1. With a cooling time constant of 75mins,

$$\tau_r = 3 \times \tau_1$$

15.1.2 Short circuit protection

Following the recommendations of Section 5, with a starting current of 550% of full load current, the short-circuit element is set to 1.25 x 5.5 x 211A = 1450A. In terms of the relay nominal current, the setting value is 1450/250 = 5.8 I_N .

In order to avoid false tripping during start-up, there is a minimum time delay of 100ms for currents in the range 100% to 120% of the setting and a minimum time delay of 40ms for currents above 120% setting. These settings are satisfactory.

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15. Motor protection examples

15.1.3 Earth fault protection

It is assumed that no Core Balance CT is fitted. A typical setting of 30% of motor rated current is used, leading to an earth fault relay setting of 0.3 x 211/250 = 0.25 I_N. A stabilising resistor is required, calculated in accordance with Equation C9.2 to prevent maloperation due to CT spill current during starting as the CTs may saturate. With the stabilising resistor present, instantaneous tripping is permitted.

The alternative is to omit the stabilising resistor and use a definite time delay in association with the earth fault element. However, the time delay must be found by trial and error during commissioning.

15.1.4 Locked rotor/excessive start time protection

The current element must be set in excess of the rated current of the motor, but well below the starting current of the motor to ensure that a start condition is recognised (this could also be achieved by use of an auxiliary contact on the motor CB wired to the relay). A setting of 500A (2 x I_N) is suitable. The associated time delay needs to be set to longer than the start time, but less than the cold stall time. Use a value of 15s.

15.1.5 Stall protection

The same current setting as for locked rotor protection can be used – 500A. The time delay has to be less than the hot stall time of 7s but greater than the start time by a sufficient margin to avoid a spurious trip if the start time happens to be a little longer than anticipated. Use a value of 6.5s.

The protection characteristics for Sections 15.1.1-5 are shown in Figure C9.13.

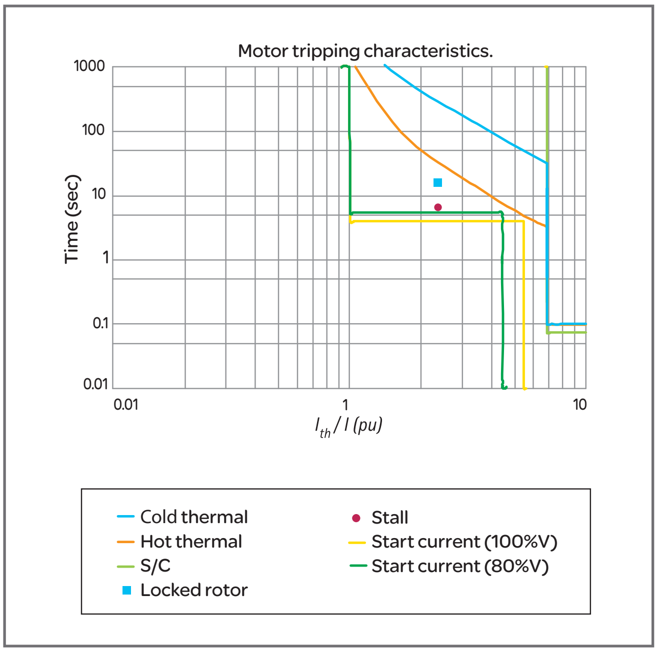

Figure C9.13:
Protection characteristics for motor protection example

15.1.6 Negative phase sequence protection

Two protection elements are provided, the first is definite time-delayed to provide an alarm. The second is an IDMT element used to trip the motor on high levels of negative sequence current, such as would occur on a loss of phase condition at starting.

In accordance with Section 7, use a setting of 20% with a time delay of 30s for the definite time element and 50% with a TMS of 1.0 for the IDMT element. The resulting characteristic is shown in Figure C9.14. The motor thermal protection, as it utilises a negative sequence component, is used for protection of the motor at low levels of negative sequence current.

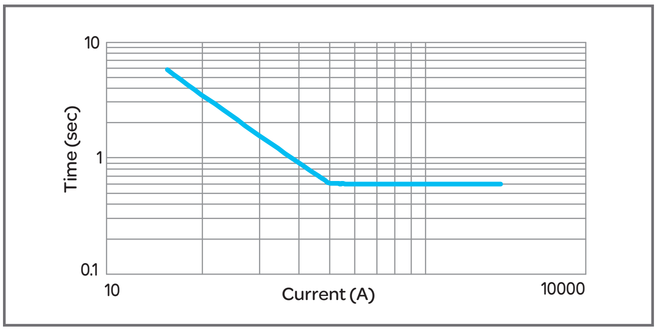

Figure C9.14:
Motor protection example negative sequence protection characteristic

15.1.7 Other protection considerations

If the relay can be supplied with a suitable voltage signal, stall protection can be inhibited during re-acceleration after a voltage dip using the undervoltage element (set to 80-85% of rated voltage). Undervoltage protection (set to approximately 80% voltage with a time delay of up to several seconds, dependent on system characteristics) and reverse phase protection can also be implemented to provide extra protection. Unless the drive is critical to the process, it is not justifiable to provide a VT specially to enable these features to be implemented.

15.2 Protection of an LV motor

LV motors are commonly fed via fused contactors and therefore the tripping times of a protection relay for overcurrent must be carefully co-ordinated with the fuse to ensure that the contactor does not attempt to break a current in excess of its rating. Table C9.3(a) gives details of an LV motor and associated fused contactor. A MiCOM P211 motor protection relay is used to provide the protection.

15.2.1 CT ratio

The relay is set in secondary quantities, and therefore a suitable CT ratio has to be calculated. From the relay manual, a CT with 5A secondary rating and a motor rated current inthe

15. Motor protection examples

(a) LV motor example data

Parameter	Value	Unit
Standard	IEC 60034	
Motor voltage	400	V
Motor kW	75	kW
Motor kVA	91.45	kVA
Motor FLC	132	A
Starting current	670	%
Starting time	4.5	s
Contactor rating	300	A
Contactor breaking capacity	650	A
Fuse rating	250	A

(b) Relay settings

Parameter	Symbol	Value	Unit
Overcurrent		Disabled	-
Overload setting	I_b	4.4	A
Overload time delay	$I>t$	15	s
Unbalance	I_2	20	%
Unbalance time delay	$I_2>t$	25	s
Loss of phase time delay	$<I_p$	5	s

Table C9.3:
LV Motor protection setting example

range of 4-6A when referred to the secondary of CT is required. Use of a 150/5A CT gives a motor rated current of 4.4A when referred to the CT secondary, so use this CT ratio.

15.2.2 Overcurrent (short-circuit) protection

The fuse provides the motor overcurrent protection, as the protection relay cannot be allowed to trip the contactor on overcurrent in case the current to be broken exceeds the contactor breaking capacity. The facility for overcurrent protection within the relay is therefore disabled.

15.2.3 Thermal (overload) protection

The motor is an existing one, and no data exists for it except the standard data provided in the manufacturers catalogue. This data does not include the thermal (heating) time constant of the motor.

In these circumstances, it is usual to set the thermal protection so that it lies just above the motor starting current.

The current setting of the relay, I_b, is found using the formula

$$I_b = 5 \times I_n / I_p$$

where

I_n = motor rated primary current

I_p = CT primary current

Hence,

$$I_b = 5 \times 132/150 = 4.4A$$

With a motor starting current of 670% of nominal, a setting of the relay thermal time constant with motor initial thermal state of 50% of 15s is found satisfactory, as shown in Figure C9.15.

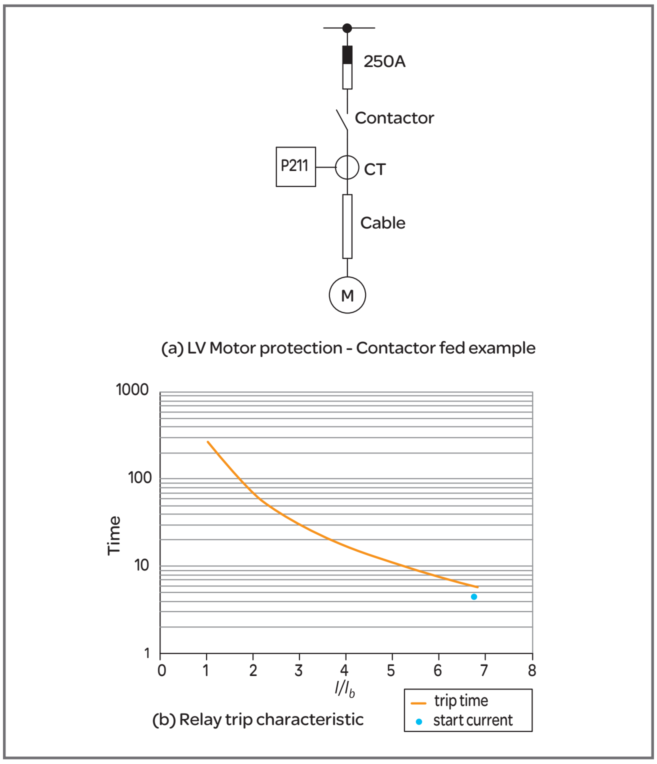

Figure C9.15:
Motor protection example - Contactor-fed motor

15.2.4 Negative sequence (phase unbalance) protection

The motor is built to IEC standards, which permit a negative sequence (unbalance) voltage of 1% on a continuous basis. This would lead to approximately 7% negative sequence current in the motor (Section 7). As the relay is fitted only with a definite time relay element, a setting of 20% (from Section 7) is appropriate, with a time delay of 25s to allow for short high-level negative sequence transients arising from other causes.

15.2.5 Loss of phase protection

The relay has a separate element for this protection. Loss of a phase gives rise to large negative sequence currents, and therefore a much shorter time delay is required. A definite time delay of 5s is considered appropriate.

The relay settings are summarised in Table C9.3(b).

C10 A.C. Railway Protection

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Chapter C10

A.C. Railway Protection

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1. Introduction

Many regional, urban and high-speed inter-urban rail networks worldwide are electrified, to provide the motive power for trains (Figure C10.1).

The electrification system serves as the contact interface for current collection by each train, and in a.c. electrified railways as the means to distribute power. In general, one of two philosophies are followed: an overhead catenary above the track, with power collection by a pantograph; or conductor-rail electrification, with current collection via contact shoes on a surface of a special metallic conductor laid close to the running rails. The latter arrangement is most commonly used for d.c. traction, while the former arrangement is used for a.c. and d.c. traction. Some rail routes have dual overhead and conductor-rail electrification to facilitate route sharing by different rail operators.

Overhead catenaries are generally considered to be safer, as they are above the track, out of reach of rail personnel and the public. They are the only way in which a traction feed at high voltages can be engineered. They provide a single-phase a.c. supply with a voltage in the range of 11kV-50kV with respect to the running rails, although 1.5kV and 3kV d.c. catenaries are predominant in some countries. When a conductor-rail system is used, the supply voltage is generally 600V to 1700V d.c.

This chapter covers protection associated with HV overhead a.c. catenary electrification. Due to the nature of many rail routes and the limited electrical clearances (especially where an existing non-electrified route is to be electrified), catenary faults are common. A typical fault rate is one fault per year per route kilometre of track. The relatively high fault rate, coupled with the high mechanical tension in the contact wire (typically 6-20kN) demands fast fault clearance. Should a fault not be cleared quickly, the conductors that form the catenary may break due to intense overheating, with the consequent risk of further severe damage caused by moving trains and lengthy disruption to train services.

Figure C10.1:
Modern high-speed a.c. electric inter-urban train

2. Protection philosophy

The application of protection to electrical power transmission schemes is biased towards security whilst ensuring dependability only for the most severe faults within the protected circuit. Being too adventurous with the application of remote back-up protection should be avoided, since the consequences of unwanted tripping are serious.

In the case of electrified railways, there is a high probability that sustained electrical faults of any type (high resistance, remote breaker/protection failure etc.) may be associated with overhead wire damage or a faulty traction unit. Fallen live wires caused by mechanical damage or accident represent a greater safety hazard with railways, due to the higher probability of people being close by (railway personnel working on the track, or passengers). Traction unit faults are a fire hazard and a safety risk to passengers, especially in tunnels. For these reasons, there will be a bias towards dependability of back-up protection at the expense of security. The consequences of an occasional unwanted trip are far more acceptable (the control centre simply recloses the tripped CB, some trains are delayed while the control centre ensures it is safe to reclose) than the consequences of a failure to trip for a fallen wire or a traction unit fault.

3. Classical single-phase feeding

Classical single-phase a.c. railway electrification has been used since the 1920's. Earlier systems used low frequency supplies and in many countries, electrification systems using 16.7Hz and 25Hz supplies are still in use. The cost of conversion of an extensive network, with a requirement for through working of locomotives, throughout the necessary changeover period, is usually prohibitive.

Starting from Western Europe and with the influence spreading worldwide, single-phase a.c. electrification at the standard power system frequency of 50/60Hz, has become the standard.

Figure C10.2 illustrates classical 25kV feeding with booster transformers (BT).

The booster transformers are used to force the traction return current to flow in an aerially mounted return conductor, anchored to the back of the supporting masts (Figure C10.3). This arrangement limits traction current returning through the rails and earth in a large cross-sectional loop, thereby reducing electromagnetic interference with adjacent telecommunication circuits. A step-down transformer connected phase to phase across the Utility grid is generally the source of the traction supply. The electrical feed to the train is via the overhead catenary, with the return current flowing via the rails and then through the return conductor.

As the running rails are bonded to earth at regular intervals, they are nominally at earth potential. A single-pole circuit breaker is all that is required to disconnect the supply to the catenary in the event of a fault.

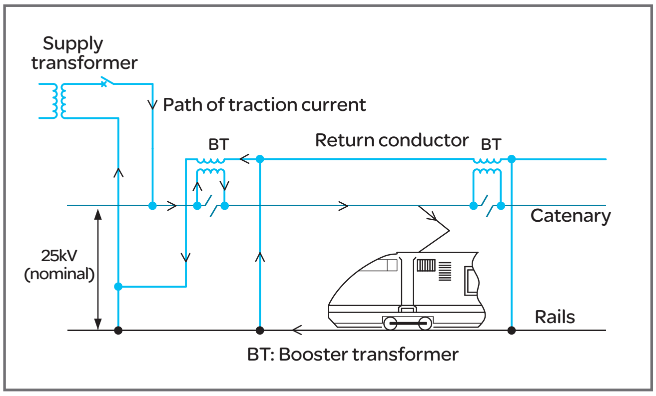

Figure C10.2:
Classical 25kV feeding with booster transformers

3.1 Classical system - Feeding diagram

In practice, single-track railway lines are rare, and two or four parallel tracks are more common. The overhead line equipment is then comprised of two or four electrically independent catenaries, running in parallel. Figure C10.4 shows the feeding diagram for a typical two-track railway using a classical electrification system.

The infeed to the tracks in the 'northbound' direction is via grid transformer $T1$ at the Feeder Station (FS). The power is then distributed via catenaries A and B above the northbound and southbound tracks. At intervals, it is usual to parallel the two catenaries at paralleling/sub-sectioning substations, as illustrated in the Figure C10.4. Load current can then flow in the parallel paths, which reduces the impedance to the load and hence the line voltage drops. As the substation terminology implies, the provision of circuit breakers for each of the outgoing feeds to the catenaries also allows subsectioning – i.e. the ability to disconnect supply from sections of catenary, in the event of a fault, or to allow for maintenance. For a fault on catenary 'A' in Figure C10.4, circuit breakers A at the feeder station and at $SS1$ would be tripped to isolate the faulted catenary. The supply to the healthy sections of catenary B, C, D, E and F would be maintained.

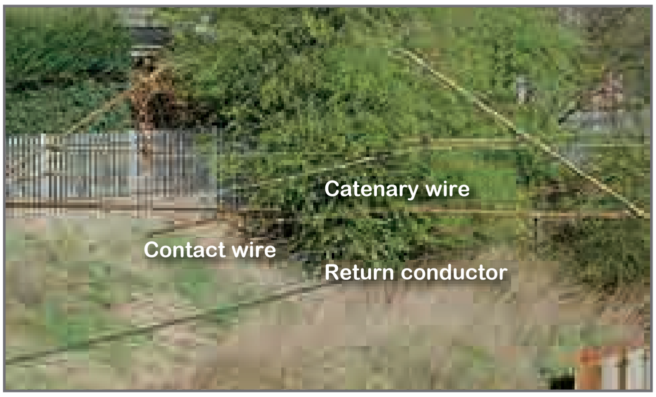

Figure C10.3:
Classical overhead line construction

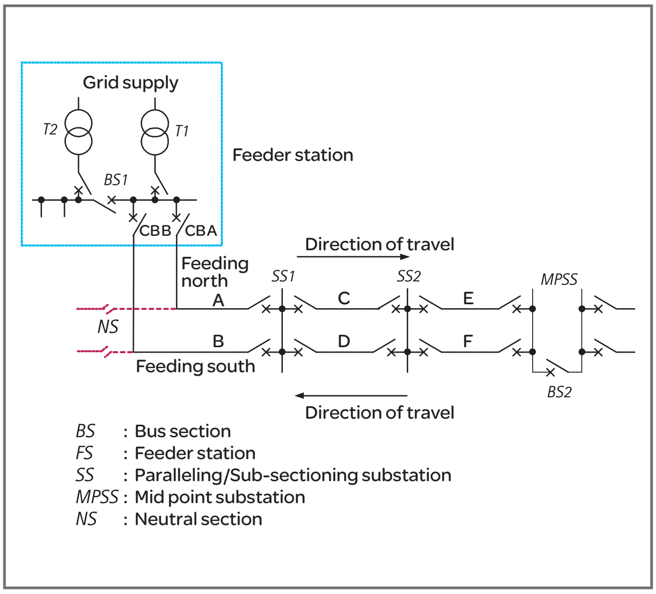

Figure C10.4:
Classical 25kV feeding diagram

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3. Classical single-phase feeding

The infeed from $T1$ generally feeds only as far as the normally open bus section circuit breaker ($BS2$) at the mid-point substation ($MPSS$). Beyond the $MPSS$ there is a mirror image of the electrical arrangements $T1$ to $BS2$ shown in Figure C10.4, with the remote end feeder station often 40-60km distant from $T1$. $BS2$ must remain open during normal feeding, to prevent Utility power transfer via the single-phase catenary, or to avoid parallelling supplies that may be derived from different phase pairs of the Utility grid – e.g. Phase A-B at $T1$, and B-C at the next FS to the north. The same is true for $BS1$, which normally remains open, as the $T1$ and $T2$ feeds are generally from different phase pairs, in an attempt to balance the loading on the three phase Utility grid. The neutral section (NS) is a non-conducting section of catenary used to provide continuity of the catenary for the pantographs of motive power units while isolating electrically the sections of track. While only two (one per rail track) are shown for simplicity, separating the tracks fed by $T1$ and $T2$ at the Feeder Station, they are located at every point where electrical isolation facilities are provided.

3.2 Classical system - Protection philosophy

The grid infeed transformers are typically rated at 10 to 25MVA, with a reactance of around 10% (or 2.5 Ω when referred to the 25kV winding). Thus, even for a fault at the Feeder Station busbar, the maximum prospective short circuit current is low in comparison to a Utility system (typically only 10 times the rating of a single catenary). If a fault occurs further down the track, there will be the additional impedance of the catenary and return conductor to be added to the impedance of the fault loop. A typical loop impedance would be 0.6Ω/km (1Ω /mile). Account may have to be taken of unequal catenary impedances – for instance on a four-track railway, the catenaries for the two centre tracks have a higher impedance than those for the outer tracks due to mutual coupling effects. For a fault at the remote end of a protected section (e.g. Catenary section 'A' in Figure C10.4), the current measured at the upstream circuit breaker location (CB A at the FS) may be twice rated current. Thus at Feeder Stations, overcurrent protection can be applied, as there is a sufficient margin between the maximum continuous load current and the fault current at the remote ends of catenary sections. However, overcurrent protection is often used only as time-delayed back-up protection on railways, for the following reasons:

a. the protection needs to be discriminative, to ensure that only the two circuit breakers associated with the faulted line section are tripped. This demands that the protection should be directional, to respond only to fault current flowing into the section. At location $SS1$, for example, the protection for catenaries A and B would have to look back towards the grid infeed. For a fault close to the FS on catenary A, the remote end protection will measure only the proportion of fault current that flows via healthy catenary B, along the 'hairpin' path to $SS1$ and back along catenary A to the location of the fault. This fault current contribution may be less than rated load current (see Figure C10.5)

b. the prospective fault current levels at $SS1$, $SS2$ and $MPSS$ are progressively smaller, and the measured fault currents at these locations may be lower than rated current

c. during outages of grid supply transformers, alternative feeding may be necessary. One possible arrangement is to extend the normal feeding by closing the bus section circuit breaker at the $MPSS$. The prospective current levels for faults beyond the $MPSS$ will be much lower than normal

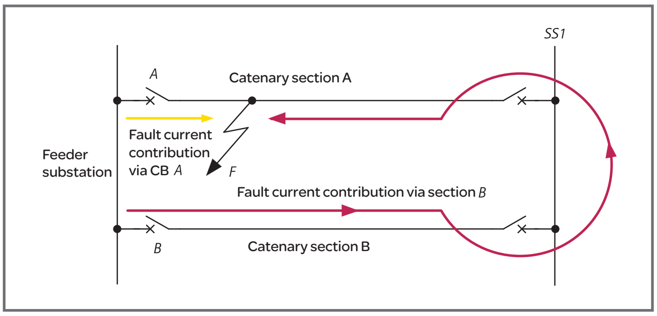

Figure C10.5: 'Hairpin' fault current contribution

Overcurrent protection is detailed in Section 5.

In addition to protection against faults, thermal protection of the catenary is required to prevent excessive contact wire sag, leading to possible dewirements. Section 4 details the principles of catenary thermal protection.

Distance protection has been the most proven method of protecting railway catenaries, due to its inherent ability to remain stable for heavy load current, whilst being able to discriminatively trip for quite low levels of fault current. For general details of distance protection, see Chapter [C3: Distance Protection]. Figure C10.5 shows how the fault current generally lags the system voltage by a greater phase angle than is usual under load conditions, and thus the impedance phase angle measurement is an important attribute of distance relays for discriminating between minimum load impedance and maximum remote fault impedance.

3.3 Distance protection zone reaches

Distance relays applied to a classical single-phase electrified railway system have two measurement inputs:

a. a catenary to rail voltage signal derived from a line or busbar connected voltage transformer

b. a track feeder current signal derived from a current transformer for the circuit breaker feeding the protected section

3. Classical single-phase feeding

Distance relays perform a vector division of voltage by current to determine the protected circuit loop impedance (Z). Typical relay characteristics are shown in the $R + jX$ impedance diagram, Figure C10.6.

Solid faults on the catenary will present impedances to the relay along the dotted line in Figure C10.6. The illustrated quadrilateral distance relay operating zones have been set with characteristic angles to match the catenary solid-fault impedance angle, which is usually 70 to 75 degrees. Two of the zones of operation have been set as directional, with the third being semi-directional to provide back-up protection. The measured fault impedance will be lower for a fault closer to the relay location, and the relay makes a trip decision when the measured fault impedance falls within its tripping zones. Three zones of protection (shown as $Z1$, $Z2$, $Z3$) are commonly applied. For each zone, the forward and resistive impedance reach settings must be optimised to avoid tripping for load current, but to offer the required catenary fault coverage. All fault impedance reaches for distance zones are calculated in polar form, $Z\angle\theta$, where Z is the reach in ohms, and θ is the line angle setting in degrees. For railway systems, where all catenaries have a similar fault impedance angle, it is often convenient to add and subtract section impedances algebraically and treat Z as a scalar quantity.

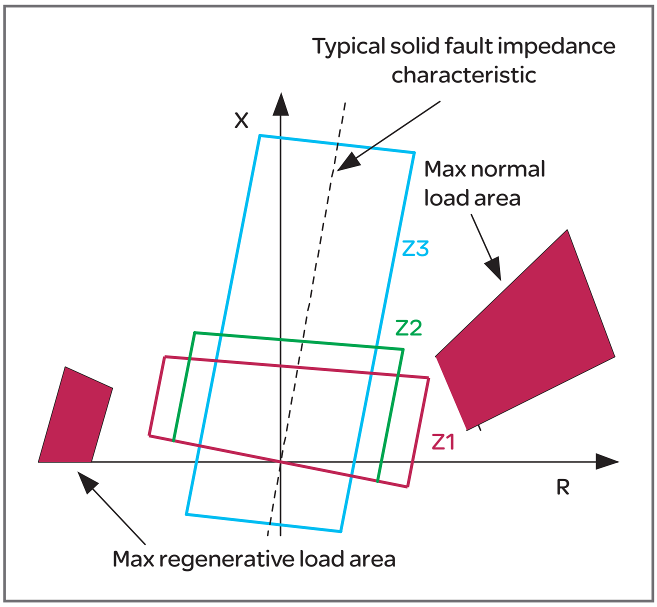

Figure C10.6:
Polar impedance plot of typical trip characteristics

Relays at all of the track sectioning substations ($SS1$, etc.) will see the reverse-looking load and regeneration areas in addition to those in the forward direction shown in Figure C10.6. The reverse-looking zones, which are mirror images of the forward-looking zones, have been omitted from the diagram for clarity.

3.3.1 Zone 1

The Zone 1 element of a distance relay is usually set to protect as much of the immediate catenary section as possible, without picking-up for faults that lie outside of the section. In such applications Zone 1 tripping does not need to be time-graded with the operation of other protection, as the Zone 1 reach ($Z1$) cannot respond to faults beyond the protected catenary section. Zone 1 tripping can be instantaneous (i.e. no intentional time delay). For an under-reaching application, the Zone 1 reach must therefore be set to account for any possible overreaching errors. These errors come from the relay, the VTs and CTs and inaccurate catenary impedance data. It is therefore recommended that the reach of the Zone 1 element is restricted to 85% of the protected catenary impedance, with the Zone 2 element set to cover the final 15%.

3.3.2 Zone 2

To allow for under-reaching errors, the Zone 2 reach ($Z2$) should be set to a minimum of 115% of the protected catenary impedance for all fault conditions. This is to guarantee coverage of the remote end not covered by Zone 1. It is often beneficial to set Zone 2 to reach further than this minimum, in order to provide faster back-up protection for uncleared downstream faults. A constraining requirement is that Zone 2 does not reach beyond the Zone 1 reach of downstream catenary protection. This principle is illustrated in Figure C10.7, for a four-track system, where the local breaker for section H has failed to trip.

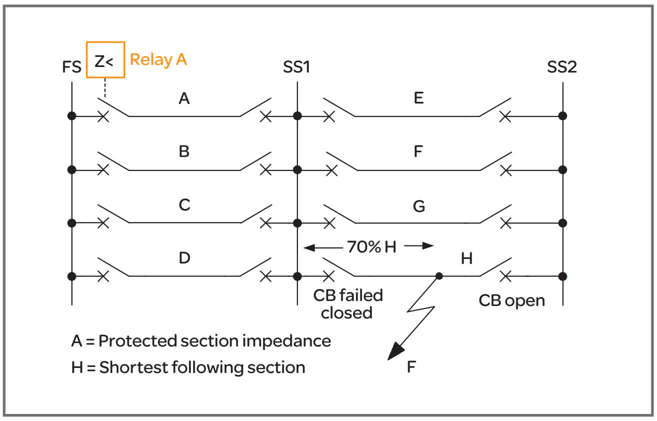

Figure C10.7:
Fault scenario for Zone 2 reach constraint (normal feeding)

In order to calculate $Z2$ for the FS circuit breaker of protected catenary 'A', a fault is imagined to occur at 70% of the shortest following section. This is the closest location that unwanted overlap could occur with $Z2$ main protection for catenary H. The value of 70% is determined by subtracting a suitable margin for measurement errors (15%) from the nominal 85% $Z1$ reach for catenary H protection.

3. Classical single-phase feeding

The apparent impedance of the fault, as viewed from relay A at location FS is then calculated, noting that any fault impedance beyond $SS1$ appears to be approximately four times its actual ohmic impedance, due to the fault current parallelling along four adjacent tracks. The setting applied to the relay is the result of this calculation, with a further 15% subtracted to allow for accommodation of any measurement errors at relay A location.

The equation for the maximum Zone 2 reach becomes:

$$Z2 = \frac{\left((Z + 0.7H) \times \frac{(A + R)}{R} \right)}{1.15} \quad \text{...Equation C10.1}$$

where:

H = impedance of shortest following section

A = impedance of protected section

R = impedance of sections B, C, D in parallel

Z = impedance of sections A, B, C, D in parallel

The possibility of current following out and back along a hairpin path to a fault has already been discussed and it is essential that the relay does not overreach under these conditions. The feeding scenario is shown in Figure C10.8.

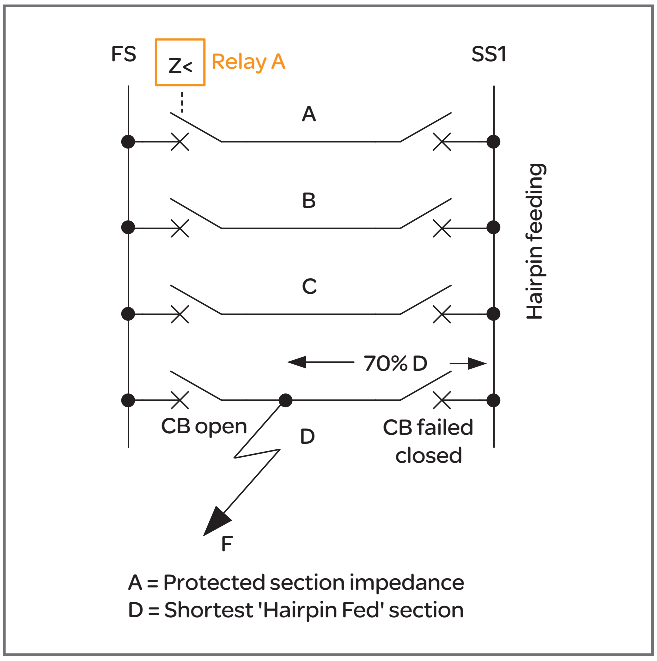

Figure C10.8:
Fault scenario for maximum Zone 2 reach (hairpin feeding)

Figure C10.8 depicts a fault that has been cleared at one end only, with the remote end breaker for section D failing to trip. The fault is assumed to be on the lowest impedance catenary, which is an important consideration when there are more than two tracks. In a four-track system, it is usual for mutual induction to cause inner (middle) track catenaries to have a characteristic impedance that is 13% higher than for the outside tracks.

The calculation principle is similar to that for normal feeding, except that now the fault current is parallelling along three (= number of tracks minus one) adjacent tracks. The three catenaries concerned are the protected catenary A, and the remainder of the healthy catenaries (R), i.e. catenaries B and C.

The equation for the maximum hairpin Zone 2 reach becomes:

$$Z2 = \frac{\left((Z + 0.7D) \times \frac{(A + R)}{R} \right)}{1.15} \quad \text{...Equation C10.2}$$

where:

D = impedance of shortest hairpin fed section

A = impedance of protected section

R = impedance of sections B and C in parallel

Z = impedance of sections A, B, C in parallel

To avoid overreaching for both normal feeding and hairpin fed faults, the lower of the two calculated impedances is used as the Zone 2 reach setting.

3.3.3 Zone 3

The Zone 3 element would usually be used to provide overall back-up protection for downstream catenary sections. The Zone 3 reach ($Z3$) should typically be set to at least 115% of the combined apparent impedance of the protected catenary plus the longest downstream catenary. Figure C10.9 shows the feeding considered:

The equation for the minimum Zone 3 reach (normal feeding) for Relay A becomes:

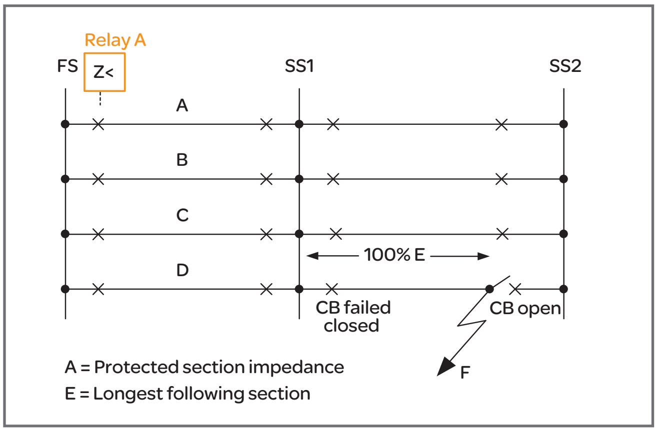

Figure C10.9:
Fault scenario for Zone 3 minimum reach (normal feeding)

$$Z3 = 1.15 \times (Z + E) \times \left(\frac{(A + R)}{R} \right) \quad \text{...Equation C10.3}$$

where:

E = impedance of longest following section

A = impedance of protected section

R = impedance of sections B, C, D in parallel

Z = impedance of sections A, B, C, D in parallel

It can be appreciated that hairpin feeding scenarios too must be considered, and this is depicted in Figure C10.10: The equation for the minimum Zone 3 reach (hairpin feeding) becomes:

$$Z3 = 1.15 \times (Z + D) \times \left(\frac{(A + R)}{R} \right) \quad \text{...Equation C10.4}$$

where:

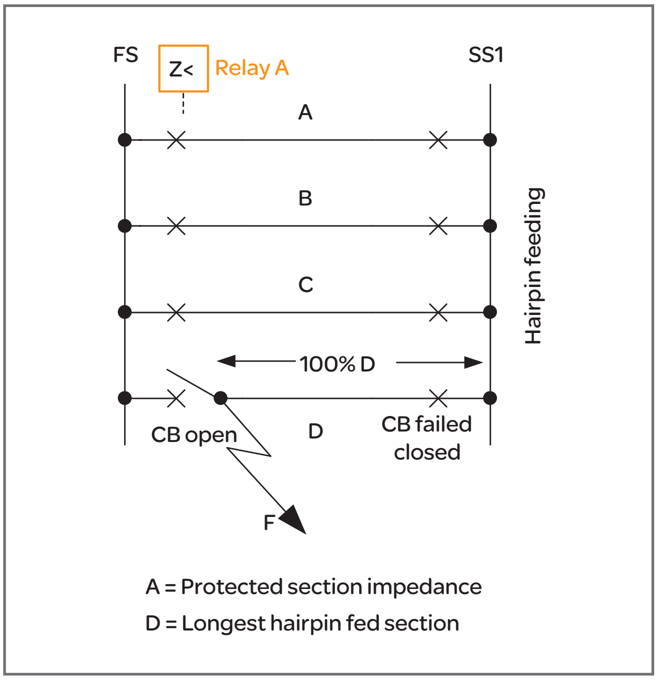

Figure C10.10:
Fault scenario for Zone 3 minimum reach (hairpin feeding)

D = impedance of longest hairpin fed section

A = impedance of protected section

R = impedance of sections B and C in parallel

Z = impedance of sections A, B, C, D in parallel

To avoid under-reaching for both normal feeding and hairpin fed faults, the higher of the two calculated impedances is used as the Zone 3 reach setting. Occasionally the Zone 3 reach requirement may be raised further, to offset the effects of trains with regenerative braking, which would provide an additional current infeed to the fault. An additional 5% reach increase would generally be sufficient to allow for regenerative under-reach.

3.3.4 Reverse reaching zones

An impedance measurement zone with reverse reach is typically applied to provide back-up protection for the local busbar at a paralleling/sectionalising substation. A typical reverse reach is 25% of the Zone 1 reach of the relay. Typically Zone 3 is set with a reverse offset to provide this protection and also so that the Zone 3 element will satisfy the requirement for Switch-on-to Fault (SOTF) protection.

3.3.5 Distance zone time delay settings

The Zone 1 time delay ($tZ1$) is generally set to zero, giving instantaneous operation.

The Zone 2 time delay ($tZ2$) should be set to co-ordinate with Zone 1 fault clearance time for downstream catenaries.

The total fault clearance time will consist of the downstream Zone 1 operating time plus the associated breaker operating time. Allowance must also be made for the Zone 2 elements to reset following clearance of an adjacent line fault and also for a safety margin. A typical minimum Zone 2 time delay is of the order of 150-200ms. This time may have to be adjusted where the relay is required to grade with other Zone 2 protection or slower forms of back-up protection for downstream circuits.

The Zone 3 time delay ($tZ3$) is typically set with the same considerations made for the Zone 2 time delay, except that the delay needs to co-ordinate with the downstream Zone 2 fault clearance. A typical minimum Zone 3 operating time would be in the region of 400ms. Again, this may need to be modified to co-ordinate with slower forms of back-up protection for adjacent circuits.

3.4 Load avoidance

Figure C10.4 shows how the distance relay trip characteristics must avoid regions of the polar plot where the traction load may be present. This has historically been achieved by using shaped trip characteristics, such as the lenticular characteristic. Commencing around 1990, the benefits of applying quadrilateral characteristics were realised with the introduction of integrated circuit relays.

A quadrilateral characteristic permits the resistive reach to be set independently of the required forward zone reach, which determines the position of the top line of the quadrilateral element. The resistive reach setting is then set merely to avoid the traction load impedance by a safe margin and to provide acceptable resistive fault coverage. Figure C10.11 shows how the resistive reach settings are determined.

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3. Classical single-phase feeding

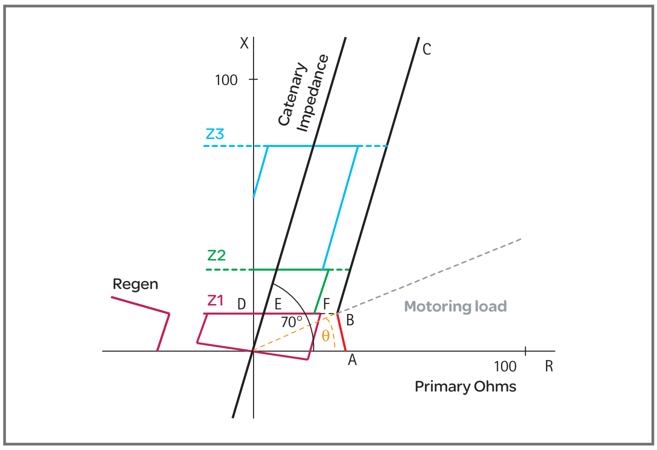

Figure C10.11:
Resistive reach settings for load avoidance

For all quadrilateral characteristics, impedance point B is the critical loading to avoid. The magnitude of the impedance is calculated from $Z=V/I$ taking the minimum operational catenary voltage and the maximum short-term catenary current. The catenary voltage is permitted to fall to 80% of nominal or less at the train location under normal operating conditions, and the short term current loading to rise to 160% of nominal – these worst-case measured values should be used when aiming to find the lowest load impedance.

The phase angle of point B with respect to the resistive axis is determined as:

$\theta = COS^{-1}$ (max lagging power factor)

The diagram shows how resistive reach E-F for Zone 1 has been chosen to avoid the worst-case loading by a suitable margin of 10%-20%. Zones 2 and 3 reach further, thus the effect of any angular errors introduced by CTs, VTs etc. will be more pronounced. It is therefore common to set the resistive reaches progressively marginally smaller for zones with longer reaches.

A practical setting constraint to ensure that zones with long reaches are not too narrow, and not overly affected by angle measurement tolerances, is for the resistive reach not to be less than 14% of the zone reach.

3.5 Enhanced modern relay characteristics

Figure C10.12 illustrates the polygonal distance relay characteristics of a modern numerical railway distance relay. Introduction of a γ setting modifies the basic quadrilateral characteristic into a polygonal one, in order to optimise fault impedance coverage and load avoidance for modern railway applications.

The use of the γ setting allows a load avoidance notch to be placed within the right-hand resistive reach line of the quadrilateral. γ is chosen to be around 10 degrees greater than the worst-case power factor load angle, limiting the resistive reach to R_g to avoid all load impedances. For impedance angles greater than γ, the zone resistive reach R applies, and the fault arc resistive coverage is improved. This is especially beneficial for Zone 3 back-up protection of adjacent catenaries, where the apparent level of arc resistance will be raised through the effect of parallel circuit infeeds at the intervening substation.

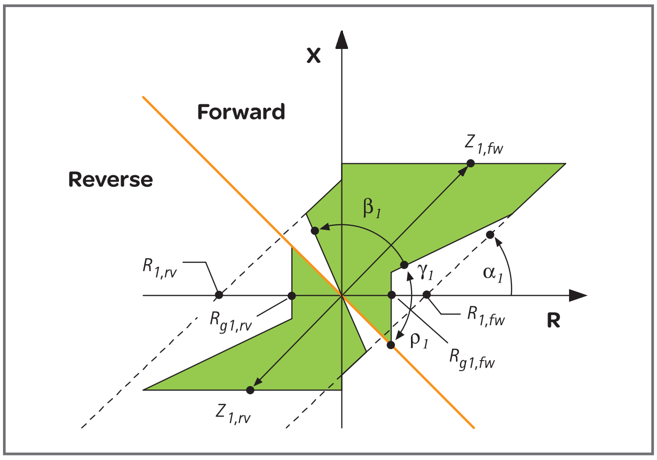

Figure C10.12:
Polygon distance characteristics

3.6 Impact of trains with regenerative braking

It is common for the Zone 1 characteristic to apply to the forward direction only. However, other zones may be set to have a reverse reach – see Section 3.3.4 for details. Another case where reverse- reaching zones may be required is where trains having regenerative braking are used.

Such trains usually regenerate at a leading power factor to avoid the creation of overvoltages on the catenary. Where a regenerating train contributes to fault current, the fault impedance measured by distance relays may shift up to 10° greater than α . Some railway administrations require that the fault impedance remains within the trip characteristic, and does not stray outside the top left hand resistive boundary of the polygon. This can be obtained by setting the reverse resistive reach (R_{rv}) to be greater than the forward resistive reach (R_{fw}).

3.7 Other relay characteristics

Recent relay technology developments also allow the use of detectors for rate of change of current and voltage (di/dt and dv/dt). These detectors are used to control the time delays associated with time-delayed Zones 2 and 3, and hence obtain better discrimination between load and fault impedances. The technique is still in its infancy, but shows significant potential for the future.

4. Catenary thermal protection

It is essential that railway catenaries remain in the correct position relative to the track, thus ensuring good current collection by train pantographs. The catenary is designed to operate continuously at a temperature corresponding to its full load rating, where heat generated is balanced with heat dissipated by radiation etc. Overtemperature conditions therefore occur when currents in excess of rating are allowed to flow for a period of time. Economic catenary design demands that the catenary rating be that of the maximum average continuous load expected. Peaks in loading due to peak-hour timetables, or trains starting or accelerating simultaneously are accommodated using the thermal capacity of the catenary - in much the same way as use is made of transformer overload capacity to cater for peak loading.

It can be shown that the temperatures during heating follow exponential time constants and a similar exponential decrease of temperature occurs during cooling. It is important that the catenary is not allowed to overheat, as this will lead to contact wire supporting arms moving beyond acceptable limits, and loss of the correct alignment with respect to the track. The period of time for which the catenary can be overloaded is therefore a function of thermal history of the catenary, degree of overload, and ambient temperature with cooling conditions.

The tension in the catenary is often maintained by balance weights, suspended at each end of tension lengths of contact wire. Overthermal temperature will cause the catenary to stretch, with the balance weights eventually touching the ground. Further heating will then result in a loss of contact wire tension, and excessive sagging of the contact wire. To provide protection against such conditions, catenary thermal protection is provided.

4.1 Catenary thermal protection method

Catenary thermal protection typically uses a current based thermal replica, using load current to model heating and cooling of the protected catenary. The element can be set with both alarm (warning) and trip stages.

The heat generated within the catenary is the resistive loss ($I^2R \times t$). Thus, the thermal time characteristic used in the relay is therefore based on current squared, integrated over time. The heating leads to a temperature rise above ambient temperature, so in order to calculate the actual catenary temperature, the relay must know the ambient temperature along its' length. This can be either set as an assumed 'default' ambient temperature, or measured, typically using a temperature probe mounted externally to the substation building. However, the tension length of a contact wire may be over 1km, and traverse cuttings and tunnels - with resulting significant changes in the local ambient temperature. Therefore, the probe should ideally be mounted in a location that most accurately models the coolant air around the catenary for the majority of the protected section:

a. if exposed to direct sunlight, then the probe should be mounted to face the sun

b. if shaded from sunlight, such as running in a tunnel, then the probe should be mounted on an exterior wall facing away from the sun

c. if running in a cutting, shielded from wind, the probe should be mounted in the lee of the substation

d. if exposed to the wind, the probe should also be mounted on an exposed wall

It is virtually impossible to site the probe such as to exactly model the ambient conditions along the protected section, and thus a typical error in the allowable temperature rise of between 1°C and 3°C will result (for well-sited and poorly-sited probes, respectively). RTD and CT errors, along with relay tolerances may also introduce further errors of up to 1°C in the thermal model. Overall, the error in the temperature reading above the 20°C rated ambient could be 4°C. Therefore, relays may have a setting to compensate for such measurement tolerances, to ensure that the trip will not occur too late to prevent mechanical damage. Some relays may have an option to express the above tolerance as a percentage of the temperature at which a trip is required, rather than in absolute terms.

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5. Catenary backup protection

Railway systems often use overcurrent protection as time-delayed back-up protection for the main distance protection. Two different philosophies for overcurrent protection are typical:

a. definite-time overcurrent protection (DTOC)

b. back-up overcurrent protection (BUOC)

5.1 Definite-time overcurrent protection (DTOC)

This form of protection is continually in service, in parallel to the distance relay elements, either included within the same relay as the distance function, or as a separate relay. The latter approach is currently more common for installations at Feeder Stations. This is due to the perceived increase in security and reliability obtained from the redundancy of separate devices. However, the trends evident in other protection applications to provide more functionality within a single relay will in time surely apply to this area as well.

It operates on the basis of conventional definite-time overcurrent protection, as described in Chapter [C1: Overcurrent Protection for Phase and Earth Faults]. The time settings are chosen to ensure that the distance relay elements should operate first, thus the overcurrent elements only operate if the distance elements fail, or if they are out of service for some reason.

5.2 Back-up overcurrent protection (BUOC)

This form of back-up protection is switched in service only during periods when the distance protection is out of service. A typical example is where VT supervision or a measuring circuit monitoring function detects a blown VT fuse or an MCB trip. In such instances the distance protection is automatically blocked, and the BUOC elements are automatically brought into service, such that catenary protection is not lost.

Methods of setting overcurrent protection are covered in Chapter [C1: Overcurrent Protection for Phase and Earth Faults]. An example of using overcurrent protection is given in Section 8.

6. Auto-transformer feeding

High-speed rail lines, with maximum speeds in excess of 200km/h (125mph) have much higher traction power demands. This is not only to cope with the peak power required for rapid acceleration to high speed, but also to cope with the steeper gradients that are commonly encountered along such routes. The total traction power per train may amount to 12-16MW, comprising two or more power cars per unit and often two units coupled together to form a complete train. The heavy load currents drawn may cause significant voltage drops across the catenary feeding impedance with a classical feeding arrangement – depending on the section length being fed and the traffic frequency (in both directions). To avoid a decrease in train performance, feeder stations and parallelling substations for classical systems would have to be sited at prohibitively short intervals. In such circumstances, especially where the route involves new construction, auto-transformer feeding is normally favoured.

6.1 Description of auto-transformer feeding

Auto-transformer feeding uses a high voltage system comprising of a centre-tapped supply transformer, catenary wire and a feeder wire. The feeder wire is aerially mounted on insulators along the back of the overhead line masts. The running rails are connected to the centre tap of the supply transformer, and hence a train sees only half of the system voltage. Auto-transformers located at intervals along the tracks ensure division of load current between catenary and feeder wires that minimises the voltage drop between the supply transformer and the train. Figure C10.13 shows auto-transformer feeding for the typical 25-0-25kV system found in Western Europe.

The use of auto-transformers (AT) results in distribution losses that are lower than for classical 25kV feeding, and therefore can support the use of high power 25kV traction units. Feeder substation spacing can also be much greater than if a classical feeding system is used. Fewer substations means less maintenance and reduced operating costs. Two-pole switchgear is normally used to isolate both the feeder and catenary wires in the event of a fault on either wire.

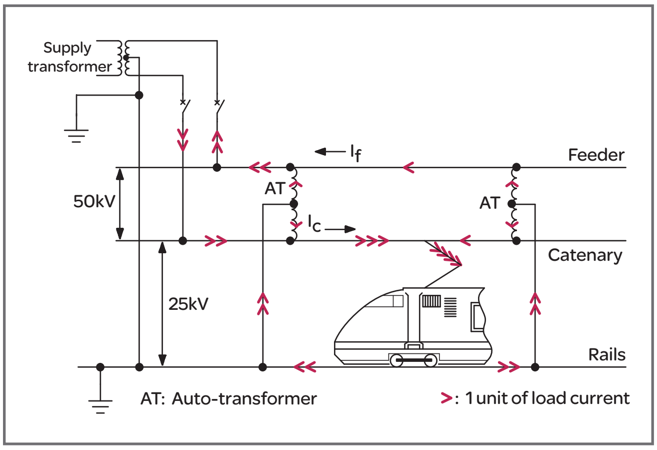

Figure C10.13:
25-0-25kV auto-transformer feeding

6. Auto-transformer feeding

However, some auto-transformer systems allow single wire tripping, where separate distance protection is provided for each wire. The protection would then monitor the two 'halves' of the system independently, with Protection Zones 1 and 2 typically set to 85% and 120% of the protected impedance - similar to the protection of a classical catenary system. Figure C10.13 also illustrates the distribution of load current for a train situated midway between AT locations.

The topology of the AT system is often similar to the classical system shown in Figure C10.4, except that the grid supply transformer 50kV secondary winding is wound as a centre-tapped AT winding, and ATs are connected catenary-rail-feeder at each downstream substation and at intervening locations.

Figure C10.14 shows a typical protection one-line diagram for an auto-transformer-fed system, while Figure C10.15 shows the construction of the catenary system.

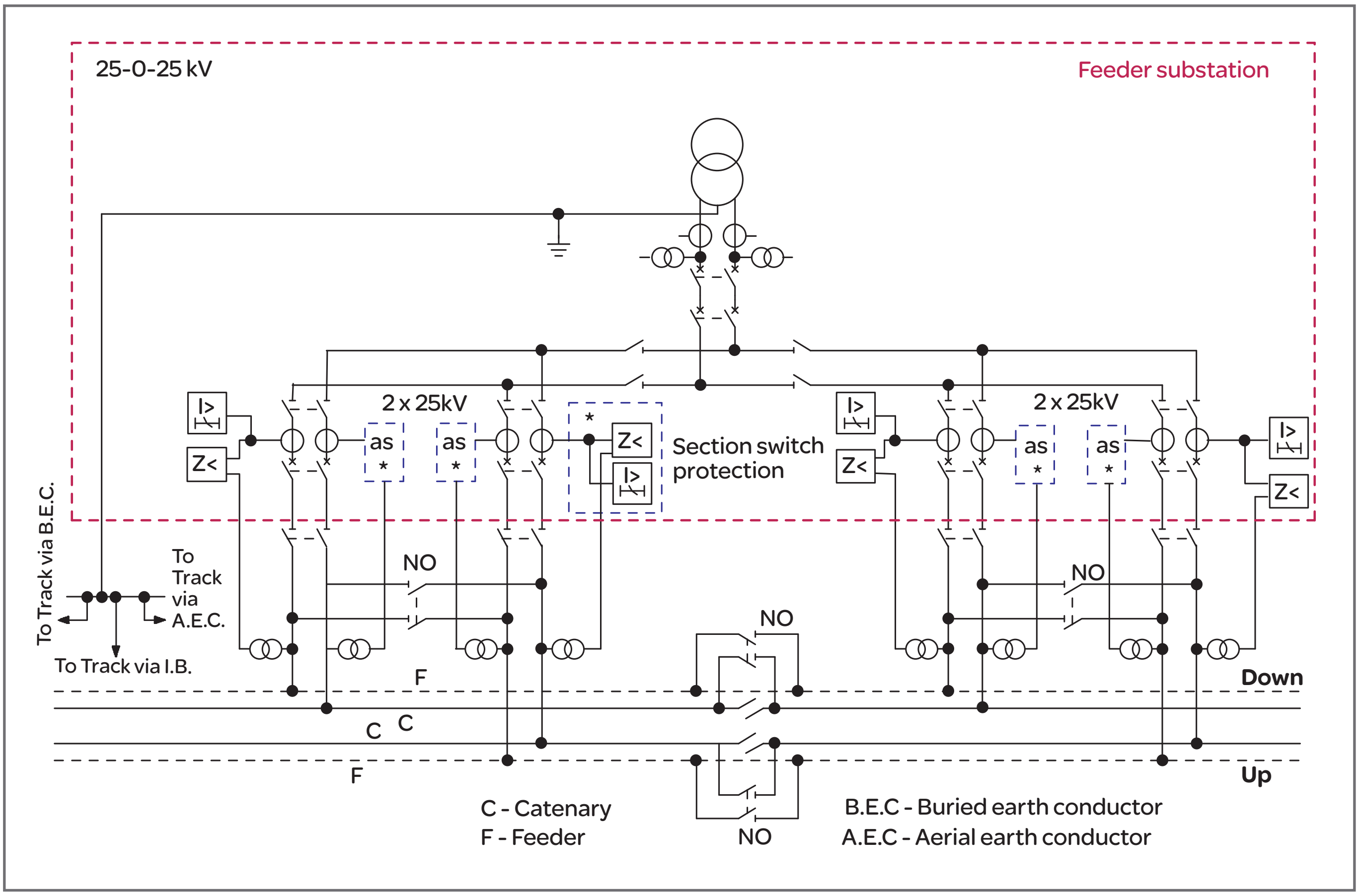

Figure C10.14:
Auto-transformer-fed system one-line diagram showing protection

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6. Auto-transformer feeding

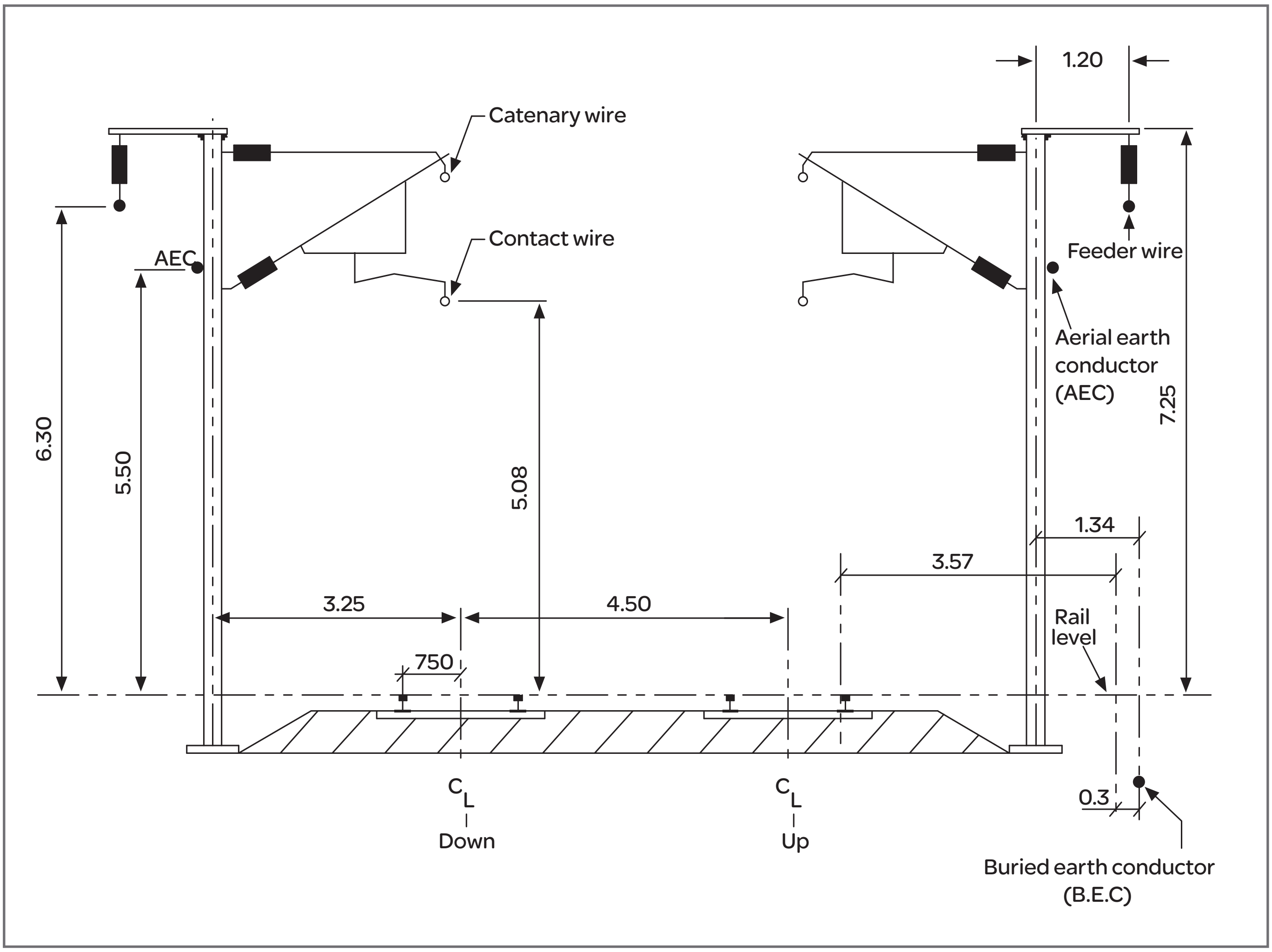

Figure C10.15:
Typical auto-transformer–fed catenary layout

6.2 Auto-transformer system protection philosophy

From Figure C10.13 it can be seen that the summation $(I_e - I_f)$ at any location will be equal to the downstream traction load current. The same is true for fault current, and so physically performing this current summation, through the parallel connection of feeder and catenary CT secondary windings, or mathematically summating within a protection relay, can be the basis for auto-transformer circuit protection.

To discriminate between normal load current and feeder wire or catenary faults, distance protection is commonly applied, with $(I_c - I_f)$ being the measured current. The measured voltage is generally the catenary to rail voltage. The relatively low reactance of the ATs – typically 1% on a 10MVA base – ensures that any fault voltage drop on the catenary will be proportional to the feeder wire voltage drop.

When applying zones of distance protection to AT systems, with double-pole tripping, it should be appreciated that it is not usually possible to provide fully discriminative protection. When the catenary and feeder currents are combined, the relationship between impedance and distance-to-fault is non-linear.

Consequently, it is more difficult to set Zone 1 to be under-reaching and Zone 2 to be overreaching in the normal manner. The approach that is normally adopted is to set the Feeder Station distance protection to detect all faults along any track, up to, but not beyond, the Mid-Point Substation. It can be arranged that operation of any distance relay will trip all Feeder Station breakers. In the event of any fault up to the $MPSS$, simultaneous tripping of all the track feeder circuit breakers at the FS will cut supplies to all tracks. Where this scheme is adopted, the application of auto-reclosing is essential to restore supplies to all but the permanently faulted section of catenary and feeder. The momentum of moving trains will ensure that little speed is lost during the dead time of the auto-reclose sequences. Considerations relating to the application of auto-reclosure are detailed in Section 5.5. With high speed lines generally being better fenced, and having fewer overbridges and greater electrical clearances compared to classical systems, the infrequent losses of supply cause few operational problems. As tripping of circuit breakers at the FS isolates all line faults, there is then no need to have switchgear at downstream substations rated to interrupt fault current. For economy, load-breaking switches are used instead of breakers at $SS1$ and $SS2$ in Figure C10.4.

6.3 Distance protection zone reaches

Figure C10.16 illustrates the typical locus of impedance measured at the FS, for a catenary-to-earth fault, at a variable location upstream of $SS2$, for any one track.

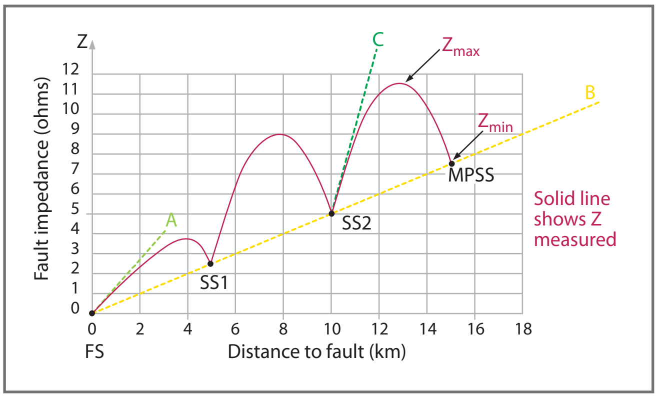

Figure C10.16:
Variation of impedance measurement with fault location along track

While a similar effect exists for classically-fed systems, it is small by comparison and normally ignored. The impedance measured is defined as:

$$Z = \frac{V_{catenary}}{\left(I_{catenary} - I_{feeder}\right)}$$

For clarity, only the impedances measured for a catenary-to-earth fault located upstream of $SS2$ are plotted. The hump-like impedance locus in Figure C10.16 has a number of identifiable trends:

a. the initial slope of the locus, in Ω/km, shown as line 'A'. This is according to the catenary-to-rail loop impedance (the 25kV loop in Figure C10.13), since the fault current flows almost entirely in the catenary-rail loop for faults close to a feeding point

b. at AT locations, slope 'B' shows how the effective ohms/km trend is less than half the catenary-to-feeder loop impedance (the 50kV loop in Figure C10.13) due to the method of impedance measurement and due to the fault current distribution. For a catenary-earth fault located at an auto-transformer, the fault current will circulate almost entirely in the catenary-feeder loop rather than in the catenary-rail loop. Additionally, the impedance of the catenary-feeder loop is lower than that of the catenary-rail loop, as the feeder cable is a better conductor than the rails

c. beyond $SS1$, the effect of parallel feeding from other circuits between the FS and $SS1$ means that slope 'B' for a single circuit beyond $SS1$ is greater than slope 'A'. With reference to Figure C10.7, the system simulated is four track, thus the gradient of 'C' will be approximately four times that of 'A' (marginally higher than four for the inner tracks, and less than four for outer tracks)

Considerations for the setting of distance relay reaches are detailed in the following sections.

6.3.1 Zone 1

The Zone 1 elements of any FS distance relay should not overreach and trip for faults beyond the $MPSS$, when the mid-point bus section breaker is closed. If it is known that the $MPSS$ is definitely open, then there is no real reach constraint for distance protection. However, if the mid-point breaker is closed, or no status information is communicated to the protection to control overreach, through reversion to an alternative setting group, then the relay must not trip for the lowest impedance for a fault at the $MPSS$ busbar. Referring to Figure C10.16, this fault impedance would be Z_{min} along slope B (to 15km and 7.5 Ω). The applied Zone 1 setting should be restricted to 85% of this impedance, to allow for all measurement and impedance data tolerances.

A lower reach setting might be necessary to prevent unwanted tripping with aggregate magnetising inrush currents following circuit energisation. This will depend on the response of the relay elements to inrush current and to the number of ATs applied. For relays that have magnetising inrush restraint or some means of providing immunity or reduced sensitivity to inrush currents such a constraint may not apply.

6.3.2 Zone 2

Allowing for under-reaching errors, the Zone 2 reach ($Z2$) should be set in excess of 115% of the protected line impedance for all fault conditions. The relevant impedance in Figure C10.16 would be the Z_{max} peak between $SS2$ and $MPSS$. A typical value of Z_{max} would be approximately 11.5 Ω at 13km distance from the feeder station.

If trains with regenerative braking are in service along the protected track a 20% additional reach margin would typically be applied.

With the stated Zone 1 and Zone 2 setting policy, relays at the Feeder Station provide complete track protection up to the $MPSS$.

6. Auto-transformer feeding

6.3.3 Zone 3

Zone 3 may be applied to provide remote back-up protection for faults beyond the $MPSS$, or with a longer reach to cover instances where ATs are switched out of service, such that the effective normal feeding impedance becomes higher.

6.4 Distance zone time delay settings and load avoidance

The principles used are identical to those for classical feeding, with one exception. A short time delay of the order of 50ms may be used with the Zone 1 element if a relay without magnetising inrush restraint is used.

The relay uses (I_e-I_f), which is measuring the combined load current of all trains at their pantographs. Therefore, the load impedance to avoid is that measured from catenary to rail (the '25kV' impedance in Figure C10.11).

6.5 Implications of using two-pole switching and auto-reclosure

A full discussion of operational implications is beyond the scope of this chapter, thus only the important points are listed:

a. it is usual to remove all parallelling between tracks prior to any breaker reclosing. This avoids repetitive re-tripping of healthy catenary sections as multiple track feeder circuit breakers are being reclosed after clearance of a fault on one feeder. Paralleling is removed by opening the motorised isolators at all SS and $MPSS$ locations. Following feeder breaker reclosure, the tracks will be radially fed. A persistent fault would only result in re-tripping of the faulted track circuit breakers

b. in the period where tracks are being radially-fed, the relays at the FS should only trip their own track circuit breakers. Cross-tripping of parallel track circuit breakers should be inhibited

c. protection at the FS can trip for an AT fault. Since there would typically be no circuit breakers at the SS and $MPSS$ auto-transformer locations, AT protection should wait for loss of line voltage during the dead time of FS circuit breakers before initiating the opening of a local motorised disconnector switch. This action should take place within the dead time so that the faulted AT will have been disconnected before reclosure of the FS breakers

d. with radially fed tracks, multiple shot auto-reclosing is often applied to dislodge any debris (wildlife or other stray material) that may have caused a semi-permanent fault. Before the last auto-reclose shot, it is common to disconnect all ATs downstream of the FS. With all ATs and paralleling removed the faulted circuit distance relays would then see a linear relationship between the impedance measured and the distance to fault. The results obtained from conventional, integral fault location algorithms would then offer rectification crews a fairly accurate estimate of where the permanent fault might be located

e. it may be necessary to automatically increase the Zone reaches of distance relay elements before the final auto-reclose attempt to allow for the higher catenary-to-rail fault loop impedance up to the $MPSS$ rather than the lower catenary-feeder loop impedance. This may be achieved by switching to an alternative setting group with $Z2$ set higher than previously

6.6 Backup protection

Backup protection considerations for auto-transformer fed systems are similar, in principle, to those for classical systems, as described in Section 5.

7. Feeder substation protection

Each feeder substation comprises transformers, busbars, cables, switchgear, etc. All of these items require protection. Due to the much higher frequency of faults on the catenary system, special attention must be given to ensuring that the substation protection remains stable for catenary faults, whilst offering dependable protection for substation faults.

Other than this, there are no special requirements for the protection of feeder substation equipment and the forms of protection detailed in Chapters [C1: Overcurrent Protection for Phase and Earth Faults] and [C7: Transformer and Transformer-Feeder Protection] are directly applicable, on a single phase basis.

8. Delta function

A significant new protection feature is the Delta function for 1 AC and 2 AC contact line systems which is intended to detect high resistance earth faults with minimal time delay. As a basis an expanded harmonic supervision algorithm is required, monitoring the 3rd and 5th harmonics.

AC traction load conditions are distinctly different to industrial medium-voltage applications. Due to the structure of contact lines, the traffic situation and environment, a rapid and frequent variation in load and the occasional overload condition must be taken into account. In addition to the varying load conditions, fault scenarios must also be accurately detected. While the magnitude of fault current may vary from 40 % to 100 % of the short circuit capacity, the frequency of fault inception coupled with the high tension in the contact wire makes fast fault clearance the ultimate requirement for the protection device.

At times the short-circuit scenarios may not be fulfilled, especially in the case of high impedance faults caused by wildlife, vegetation or bond open earth faults causing low return current. The resultant fault current magnitudes can be similar to expected operating loads in such cases. In these circumstances, distance protection devices have difficulty detecting such faults.

Modern electrified locomotives for heavy load and high-speed passenger trains are provided with three-phase technologies for the traction motors which make use of static converters for onboard drives. This energy conversion produces a significant proportion of harmonics, particularly odd numbered harmonics. Typical percentage levels of harmonics, evaluated in 50 Hz contact lines, are provided in Table C10.2.

Harmonics	Frequency	Percentage
Third harmonics	150 Hz	~ 20%
Fifth harmonics	250 Hz	~ 10 %
Others	-	~ 8 %

Table C10.2:
Mean harmonic content, generated by engines

As indicated, the majority of the rolling stock loads introduce significant third or fifth harmonic levels into the AC power system, generated by the locomotive converters. AC traction systems experience inrush current when inductive loads such as auto-transformers or track switch heating or the electrical rolling stock themselves are energised. These inrush currents, high in second harmonic components, are also present when electric locomotives pass through neutral sections.

Load currents in contact lines are characterised by a substantial amount of measurable harmonic content. In contrast, short circuit fault currents are mostly sine wave current at fundamental frequency and contain little harmonic content. Harmonic levels are an important characteristic of the current profile that can be utilised to distinguish between load and fault conditions.

Detection of high impedance faults is based on the fact that fast current changes, or jumps, without a significant harmonic content, e. g third harmonic, are indicative of fault conditions. This fact is well known and has been used in protection applications for many years.

For fault detection, the following elements must be securely fulfilled:

a. Minimum base current available

b. Current jump ΔI detected

c. No inrush blocking

d. Harmonic supervision of third harmonic not started

Supervision of the third harmonic level can be used for both blocking and stabilisation functionality. When the stabilisation function is activated, a multiplying factor is used to dynamically increase the current jump threshold if harmonics due to load are detected in the system.

The application may be viewed graphically as shown in Figure C10.17.

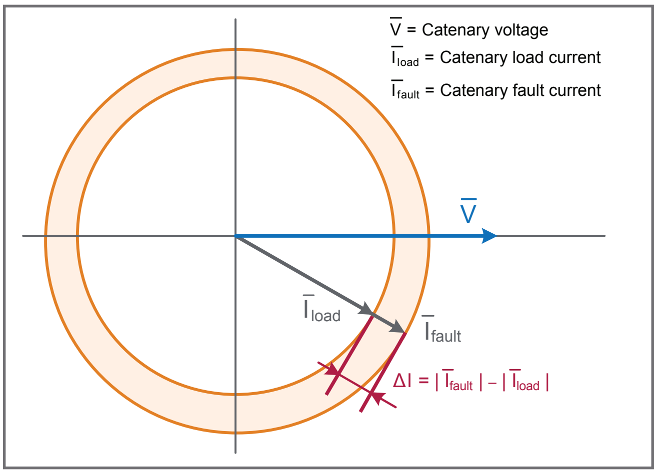

Figure C10.17:
Basic function ΔI

A fault condition is detected by a current jump ΔI when a minimum current level is exceeded at the same time. Inrush conditions, due to second harmonic detection, will block the complete function during the inrush event. Depending on the operating mode for the harmonic supervision, the ΔI criteria will be blocked or stabilised with a detected high third harmonic content.

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8. Delta function

In addition to the elements described for the basic application, enhanced applications make use of one or more additional elements to provide added reliability and enhanced discrimination between load and fault conditions.

The following additional elements must be fulfilled securely, if enabled:

a. Current angle change $\Delta\varphi$ detected

b. Reactance supervision criteria

c. Enhanced harmonic supervision of third and fifth harmonic not started

d. No functional blocking by the auxiliary contact of the circuit breaker

The current angle change and reactance supervision elements make use of voltage signals to provide added stability and discrimination. A minimum angle change criteria ensures the current change is due to the onset of a fault, rather than load, while reactance supervision may be enabled to restrict the zone of operation to the immediate line section and avoid the need to time grade with downstream devices. Should failure of the voltage transformer circuits occur, the function can revert to the basic application or it may be blocked, if stability is no longer maintained.

Harmonic supervision may be expanded to include the fifth harmonic as well. This allows further flexibility to provide expanded stabilisation for the use of lower harmonic values for fault discrimination.

The application may be viewed graphically as shown in Figure C10.18.

A fault condition is detected by a ΔI value, stabilised by a current angle change $\Delta\varphi$, when a minimum current level is exceeded at the same time. Depending on the operating mode for harmonic supervision the ΔI criteria will be blocked or stabilised with a detected high third or fifth harmonic component. The inrush detection function works as described in the basic application.

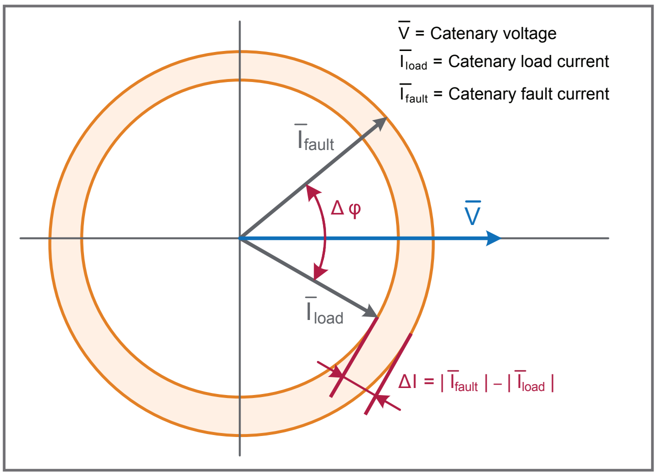

Figure C10.18:
Basic function ΔI with additional stabilisation $\Delta\varphi$

The implementation for high impedance fault detection performs a significant additional function in the protection of a.c. railway contact lines for many rail network operators. In addition to the main distance and backup over-current protection devices, a third device for high impedance fault detection was used in the past in many countries. By integrating all three protection elements and combining this with additional automation, supervision and self-monitoring, a modern multifunctional railway protection device with comprehensive functionality provides a cost-optimised solution for all a.c. railway contact line installations.

9. Example of classical system protection

Figure C10.19 depicts a typical 25kV system, where the settings for the relay protecting track feeder $TF\text{-}1$ at Substation $S1$ are to be calculated. The inputs to the relay are derived from the track feeder CT adjacent to the circuit breaker, and from a section busbar VT at busbar $S1$ (a catenary-side VT would be equally suitable). The system data is given in Table C10.3. A MiCOM P438 relay is used in the example.

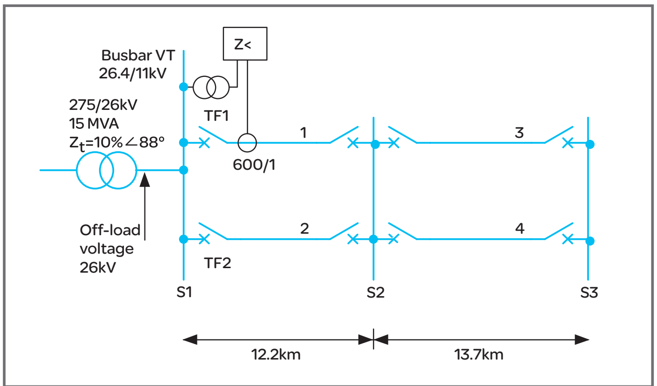

Figure C10.19:
Network diagram – Example calculation

Catenary thermal protection	Data
Catenary impedance	0.26 + j0.68 Ω/km
Booster transformer impedance	0.051 + j0.21 Ω
Booster transformer spacing	Every 3km
Maximum load current	900A
CB type	Vacuum
CB trip time	0.065 s
Max zone 1 protection trip time	0.045 s
Catenary design temperature range for correct tension	-18°C to 38°C
Typical assumed max. winter temperature (610A rating)	10°C
Typical assumed max. spring/autumn temperature (540A rating)	20°C
Typical assumed summer temperature (515A rating)	23°C
Worst-case assumed hottest ambient	28°C
Temperature for balance weights to touch ground	38°C
Temperature at which 20% loss of tension, train speeds must be restricted	48°C
Temperature at which possible damage due to clashing of supports at overlaps occurs	56°C
Heating time constant - daytime	5 mins
Cooling time constant - nightime	7 mins

Table C10.3:
Electrified railway system data

9.1 Section impedance data

The first step is to calculate the primary impedance for the catenary sections to be protected. Zone 1 for the relay associated with feeder $TF\text{-}1$ protects section 1, however the backup protection offered by Zones 2 and 3 must discriminate with downstream relays and so the impedance of sections 2, 3 and 4 needs to be calculated too. In this example each pair of catenaries runs between the common substations, and so the impedance of adjacent sections will be identical. There are situations where this is not the case, of which:

a. the sections to be protected consist of four tracks

b. the two tracks follow different routes due to the geography of the route and hence may not be of the same length

c. if there is a junction within a section

are three examples.

The equivalent section impedance per kilometer is given by the formula:

$$Z_{sect} / \text{km} = \text{line impedance / km} + \left(\frac{BT\ impedance}{BT\ spacing}\right)$$

$$(0.26 + j0.68) + \left(\frac{(0.051 + j0.21)}{3}\right)$$

$$= 0.277 + j0.75\Omega/\ km$$

$$= 0.8\angle\ 69.7°\Omega/\ km$$

This will be rounded up to 70° as the nearest settable value of the common characteristic line angle of the relay, α.

Distance protection relays are often set and injection-tested in terms of the impedance on the secondary side of the CTs/VTs used. Therefore, it is helpful for testing if the primary impedances on the system are converted to secondary quantities. The equation to be used is:

$$Z'_{sect} = Z_{sect} \times \frac{CT\ ratio}{VT\ ratio}$$

where:

Z_{sect} = system impedance referred to primary

Z'_{sect} = system impedance referred to secondary

Hence,

$$Z'_{sect} = Z_{sect} \times \frac{600/1}{26400/110}$$

$$= Z_{sect} \times 2.5$$

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9. Example of classical system protection

9.2 Section impedance calculations

The section impedances can be calculated as follows:

9.2.1 Sections 1 and 2

The impedances for sections 1 and 2 are:

$$Z_{sect} = 12.2 \times 0.8 = 9.76\Omega$$

$$Z'_{sect} = 9.76 \times 2.5 = 24.4\Omega$$

9.2.2 Sections 3 and 4

The impedances for sections 3 and 4 are:

$$Z_{sect} = 13.7 \times 0.8 = 10.96\Omega$$

$$Z'_{sect} = 10.96 \times 2.5 = 27.4\Omega$$

9.3 Zone 1 reach calculation for TF-1

The Zone 1 forward reach is set to be 85% of the section 1 impedance, referred to the secondary of the relay.

Hence, the forward reach is calculated as

$$Z1_{fw} = 24.4 \times 0.85 = 20.75\Omega$$

Zone 1 is not required to operate in the reverse direction, so the setting $Z1_{rv}$ is set to blocked.

9.4 Zone 2 reach calculation for TF-1

Two configurations have to be considered in the setting of the Zone 2 reach. These are:

a. the 'follow-on' configuration of Figure C10.7

b. the 'Hairpin' feeding configuration of Figure C10.8.

The setting required is the lowest of the above two configurations.

9.4.1 'Follow-on' configuration

Figure C10.7 shows the condition to consider, with two track feeding only for the area fed by Substation $S1$. Equation C10.1 is used to calculate the reach:

$$Z2 = \frac{\left((Z + 0.7E) \times \frac{(A + R)}{R} \right)}{1.15}$$

where:

Z = impedance of sections 1 and 2 in parallel

A = the track section of interest, section 1

R = parallel fault current path (section 2)

E = shortest following section (3 or 4)

Hence,

$$Z2 = (12.2 + 0.7 \times 27.4) \times \frac{\left(\frac{24.4 + 24.4}{24.4} \right)}{1.15}$$

$$= (12.2 + 0.7 \times 27.4) \times \frac{2}{1.15}$$

$$= 54.6\Omega$$

Notice how for two track feeding, $(A+R)/R$ above becomes 2, due to a fault current split between two identical parallel paths.

9.4.2 'Hairpin' feeding configuration

Referring to Figure C10.8, it is apparent that with only two tracks, inner tracks B and C are not present. Once circuit breaker $TF\text{-}2$ at substation $S1$ is open, the impedance to the fault is merely 170% times the impedance of track section 1 or 2.

Thus, from Equation C10.2:

$$Z2 = \left(24.4 + \frac{(0.7 \times 24.4)}{1.15} \right)$$

$$= 36.1\Omega$$

For Zone 2 it is always the lower of the two calculated results that is used.

Therefore, use a setting of:

Forward reach $Z2_{fw} = 36.1\Omega$

The Reverse reach, $Z2_{rv}$, is set to blocked, as only forward directional operation is required.

9.5 Zone 3 reach calculation for TF-1

In similar fashion to the Zone 2 reach, the 'follow-on' and 'Hairpin' fault configurations have to be considered. As Zone 3 must tend to overreach rather than underreach, 120% of the fault impedance calculated is used as the setting and the higher of the two possible settings is used.

9.5.1 'Follow-on' fault configuration

Figure C10.9 shows the configuration for a follow-on fault with two tracks: It is apparent that the calculation is exactly as for Zone 2 follow-on, except that the multiplier of 0.7 (70%) is replaced by 1 (100%).

$$Z3 = (12.2 + 27.4) \times 2 \times 1.2 = 95.1\Omega$$

9.5.2 'Hairpin feeding' fault configuration

Repeating the same for hairpin feeding (Figure C10.10, Equation C10.4):

$$Z3 = (24.4 + 24.4) \times 1.2 = 58.6\Omega$$

9. Example of classical system protection

Hence, use a setting of:

Forward reach $Z3_{fw} = 95.1\Omega$

For Zone 3, a reverse reach is required to act a backup to the upstream protection. The usual setting is 25% of the Zone 1 forward reach.

Therefore, use a setting of: Reverse reach

$Z3_{rv} = 0.25 \times 20.75 = 5.2\Omega$

9.6 Zone time delays

The Zone 1 time delay will be set to instantaneous operation ($t1 = 0$) – it is not common practice to time-grade this zone with the primary protection fitted on board the trains.

Zone 2 ($t2$) should be delayed as follows:

$t2 = CB\ max\ trip\ time + Relay\ max\ trip\ time + 50ms\ margin$

Hence,

$t2 = 65 + 45 + 50 = 160ms$

As all of the protection and circuit breakers are identical, this value can be used for $t2$. If the downstream relays were electromechanical (typically 40-70ms slower than numerical), or the circuit breakers were oil insulated (OCBs, typically 40 to 60ms slower than VCBs), then the $t2$ delay would need to be extended accordingly. The 50ms margin allows for the reset time of the $Z2$ element.

The Zone 3 time delay can typically be set double the minimum calculated above.

However, as Zone 3 is often most at risk of unwanted pickup due to train starting currents or momentary overloads, a longer setting of $t3 = 500ms$ is applied.

9.7 Overcurrent protection

Overcurrent protection can be applied to the 25kV system in Figure C10.19. For railway applications, non-directional overcurrent protection is normal. The simplest application is for track feeders at Feeder Stations, such as $TF\text{-}1$. At this location and with normal feeding, any fault current will naturally be flowing away from the busbar, and so no reverse operation can occur. At downstream substations it will not be possible to apply overcurrent protection in a similar way, and any elements enabled would tend to be set with long time delays to ensure that all of the distance protection zones are given sufficient time to trip beforehand.

9.7.1 Back-up overcurrent (BUOC) at feeder stations

Should the distance protection be out of service, two BUOC overcurrent elements could be set. Firstly a high set overcurrent element is set to underreach the protected section, mimicking Zone 1 operation. This can be set for instantaneous tripping. Secondly, a lower-set overcurrent element can be applied to complete protection for the $TB\text{-}1$ section, to overreach the end of the protected section at $S2$. The overcurrent element of the relay would be set accordingly and with a definite time delay.

9.7.2 Calculation of fault current

In order to determine the overcurrent settings, the fault current measured by $TF\text{-}1$ CT for a fault adjacent to the $S2$ busbar needs to be calculated. There are two possible configurations to consider:

a. fault current for a fault at the end of section 1, with two tracks in-service

b. current for a fault at the end of section 1, with section 2 isolated for maintenance

For the first configuration, the fault current per track can be calculated as

$$I_{f1} = \frac{E}{2+\left(Z_t+Z_{sp}\right)}$$

where:

E = source voltage = $26.4kV$

Z_t = transformer impedance = $4.5 \angle 88°\Omega$

Z_{sp} = parallel impedance of sections 1 and 2

= $9.76 \angle 70°\Omega/ 2$

Note that the fault current splits into two parallel paths, fed via $TF\text{-}1$ and $TF\text{-}2$. Hence, the division by 2 in the equation for calculating the per-track current measured by the protection.

Hence,

$I_{f1} = 1.4kA$

For the second configuration,

$$I_{f2} = \frac{E}{\left(Z_t+Z_{s1}\right)}$$

where:

Z_{s1} = impedance of section 1

Hence,

$I_{f2} = 1.84kA$

9.7.3 Overcurrent setting for BUOC instantaneous stage

To prevent overreach, set at least 20% above the higher of the two fault scenarios:

$I_{inst} = 1840 \times 1.2 = 2200A$

The secondary current setting on the relay is found by dividing by the CT ratio:

$$I'_{inst} = \frac{2200}{600} = 3.68A$$

9. Example of classical system protection

9.7.4 Overcurrent setting for BUOC definite-time delayed stage

To ensure complete cover for short circuits in the protected section, the setting should be no greater than 80% of the lower of the two fault scenarios:

$$I_{oc} \leq 1400 \times 0.8 = 1100A$$

In terms of secondary quantities,

$$I_{oc} \leq 1400 \times 0.8 = 1100A$$

$$I'_{oc} = \frac{1100}{600} = 1.86A$$

A time setting no less than the Zone 2 distance time delay would be used, so tI'_{oc} = 250ms is suitable.

All overcurrent protection must have a pickup in excess of the maximum expected load current. Assuming that the maximum overloading would never exceed 150% of CT rating, the I'_{inst} and I'_{oc} settings are acceptable.

9.7.5 Definite time overcurrent (DTOC)

It is not general practice to set instantaneous protection elements that are running in parallel to the distance zones. Thus often just one definite time delayed stage is used. This setting can be applied at all locations, and must be in excess of the maximum load and overload current expected.

$$I_{dtinst} \geq 1.5 \times I_{flc}$$

where:

I_{flc} = full load current of feeder

Hence,

$$I_{dtinst} = 1.5 \times 600 = 900A$$

Referred to the secondary side of the CT,

$$I'_{dtinst} = \frac{900}{600} = 1.5A$$

The time delay applied must be longer than the $t3$ distance zone delay, so tI'_{dtinst} would be acceptable.

9.8 Thermal protection

The thermal data for the catenary are also given in Table C10.3. The calculation of the thermal protection settings is given in the following sections.

9.8.1 Thermal reference current/ temperature

The P438 requires a thermal rated current or reference current, I_{ref}, to be set that corresponds to full load current. The ambient temperature at which this applies qualifies this rated current. The reference current referred to the CT primary is given in Table C10.3 as:

$$I_{refp} = 540A$$

The relay setting is in terms of the secondary current. Hence, the secondary current setting on the relay is found by dividing by the CT ratio:

$$I'_{refs} = \frac{540}{600} = 0.9A$$

The ambient temperature t_{amb} at which I_{refp} occurs is set at 20°C.

9.8.2 Mechanical damage protection

The catenary temperature at which mechanical damage may begin to occur is 56°C. This must correspond to the MiCOM P438 thermal trip command, and so:

$$t_{catmax} = 56°C$$

Account must be taken of the measurement errors described in Section 4.1. The MiCOM P438 relay setting, θ_{trip}, must allow for these errors, which are taken to be 4°C. Hence,

$$\theta_{trip} = (56 - 4)°C = 52°C$$

To avoid chattering of contacts when the load current is close to the trip threshold, a hysteresis setting is provided on reset. Typically the hysteresis is set to 2%, such that following a trip, the thermal model must cool by 2% before the trip contacts will reset.

9.8.3 Dewirement protection

An alarm should be issued to warn the rail operator when speed restrictions are necessary, to avoid the risk of dewirements. From Table C10.3, the catenary temperature at which there is a danger of dewirement is 48°C. The same measurement errors apply as for the trip setting. Hence the relay setting, $\theta_{warning}$, is:

$$\theta_{warning} = (48 - 4) = 44°C$$

9.8.4 Maximum ambient temperature

It is possible to place a limit on the maximum ambient temperature that will be used by the thermal model, to avoid over-restrictive loading constraints being imposed.

From Table C10.3:

$$t_{ambmax} = 28°C$$

9.8.5 Default ambient temperature

If ambient temperature compensation is not being used, an assumed default coolant temperature ambient must be chosen. The default ambient temperature must be chosen to be sufficiently high to minimise the danger of undetected problems occurring on hot days, when the ambient temperature is well in excess of the default value. Similarly, it must not be so high that alarms and/or trips occur unnecessarily. A default ambient temperature (t_{ambdef}) of 20°C, would provide adequate protection, except for a calculated risk on certain hot summer days. Note that the rated thermal current at this ambient is I_{refs}.

9. Example of classical system protection

9.8.6 Thermal time constants

The catenary thermal model requires heating and cooling time constants to be specified. For most catenaries, the heating and cooling time constants would be expected to be equal. However, this may not always be the case, for example the cooling time constant at night may be longer than that applicable during the day. The relay can accommodate different settings where required. Conservative settings that assume the worst case time constants for heating (τ_h) and cooling (τ_c) would be to assume a day time heating time constant and night time cooling time constant.

Hence:

τ_h = 5min

τ_c = 7min

The MiCOM P438 also allows the thermal rating of the protection to be modified, based on signals from opto inputs. However, this facility is not used in this example.

9.9 Summary of catenary protection settings

The protection calculations for the catenary are now complete. The relay settings are summarised in Table C10.4.

Parameter	Symbol	Value
Zone 1 forward reach	$Z1_{fw}$	20.75 Ω
Zone 1 backward reach	$Z1_{rv}$	Blocked
Zone 2 forward reach	$Z2_{fw}$	36.1 Ω
Zone 2 backward reach	$Z2_{rv}$	Blocked
Zone 3 forward reach	$Z3_{fw}$	95.1 Ω
Zone 3 backward reach	$Z3_{rv}$	5.2 Ω
Zone 1 time delay	t_1	0s
Zone 2 time delay	t_2	160ms
Zone 3 time delay	t_3	500ms
Back-up overcurrent Instantaneous current setting	I'_{inst}	3.68A
Back-up overcurrent IDMT current setting	I'_{oc}	1.86A
Back-up overcurrent IDMT time delay setting	tI'_{oc}	250ms
Definite time overcurrent protection current setting	I'_{dtinst}	1.5A
Definite time overcurrent protection time delay setting	tI'_{dtinst}	800ms
Thermal protection reference current	I_{refs}	0.9A
Ambient temperature reference	t_{amb}	20°C
Thermal trip temperature	θ_{trip}	52°C
Thermal warning temperature	$\theta_{warning}$	44°C
Maximum ambient temperature	t_{ambmax}	28°C
Default ambient temperature	t_{ambdef}	20°C
Heating time constant - daytime	τ_h	5 min
Cooling time constant - nightime	τ_c	7 min

Table C10.4:
Electrified railway system example-relay settings

C11 Arc Protection

Network Protection & Automation Guide

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Chapter C11

Arc Protection

C11

1. Introduction

High power arc faults in switchgear are rare events but their consequences can be extremely severe. They can be characterised as electrical explosions. Personnel may be seriously affected by the radiation, heat, pressure wave, and flying particles associated with the arc flash. These impacts can also devastate the switchgear and cause substantial economic losses either directly by destroying components of the system or indirectly by causing process outages or medical and legal expenses. Traditional overcurrent protection is inefficient in the detection of arcing faults because it is too slow. Faster protection methods are needed in order to significantly reduce the released energy.

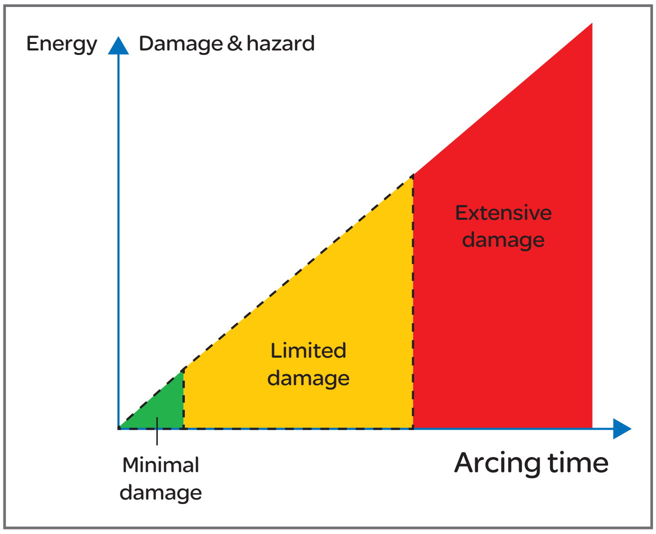

Figure C11.1:
Damage level dependent on the arcing time

This chapter describes the state-of-the-art arc protection technology which is based on minimisation of arcing time by very fast arc detection and elimination. By using simultaneous detection of fault arc light and overcurrent it is possible to reliably detect the arc within 2ms and phase-to-phase faults within 1ms. The principle of this protection method and the associated sensors, devices and systems are explained and clarified by typical application examples. Figure C11.1 illustrates that limitation of the arcing time is an efficient way to mitigate damages on arc faults. Figure C11.2a and C11.2b show the results of a 50kA 3 phase internal arc test with short and long arcing time.

Figure C11.2a:
Arcing time 47ms - Minor damage

Figure C11.2b:
Arcing time 500 ms - Copper busbars have evaporated

2. Arc flash phenomenon

An electric arc is a luminous discharge short circuit through dielectric gas or fluid.

Arcs can be categorised as useful arcs (welding), breaking arcs (in switching devices), and fault arcs. Fault arcs can further be divided into low power arcs and high power arcs. Examples of low power arc faults are series faults in power systems (e.g. loose connections) and arcs in photovoltaic low voltage systems. These arcs release very limited amount of energy compared with high power arc faults.

This chapter is focused on high power arcs in gases where the fault arc is formed between two or more conductive parts of a power system, most commonly between two or more phases or between phase and earth. The emphasis is in high power fault arcs in air insulated switchgear. An arc fault in switchgear is a short circuit through ionised gas (normally air) between live parts or between one live part and earth. It is very different from a bolted fault with a solid connection.

Air-insulated switchgear is commonly used, since dry air in normal temperature is a reasonably good insulator. However, when the temperature of the air is very high, more than 2000 K, thermal ionisation makes air conductive. The ionised air and the ionised material from the electrodes form a conductive plasma channel between the electrodes. The plasma consists mainly of nitrogen and oxygen molecules, atoms and ions of N and O, electrode material and electrons. The plasma is very hot, temperatures as high as 20000 K have been reported, and it radiates light. The light comes from hot particles and from electrons returning from high energy states to lower states.

In a high power arc fault very high amounts of electrical energy turns into radiation and thermal energy extremely rapidly. Due to the light and the high temperature with the associated pressure wave and possible flying particles, arc faults can be characterised as electrical explosions (see Figure C11.3).

Figure C11.3: [Photo: J.Vogler]: Electrical explosions as result of an arc fault

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3. Causes of arc faults in switchgear

Internal arc faults in switchgear are caused by something that leads to a failure in the insulation. Many arc faults are caused by direct human errors, such as forgotten tools, forgotten earthing connections or errors while working on equipment. Loose connection, vibration, insufficient mechanical dimensioning and overvoltage can also lead to an arc fault. Animals, contamination, dirt, moisture, ageing of insulation, corrosion and maloperation of switching devices are also possible causes of arcs. Many arc faults start as single phase faults and then rapidly escalate into three-phase faults.

IEC Standard 62271-200 provides a good overview of possible locations and causes of internal arc faults as shown in Table C11.1.

Locations where internal arc faults are most likely to occur (1)	Possible causes of internal arc faults (2)	Examples of possible preventive measures (3)
Connection compartments	Inadequate design	• Selection of adequate dimensions • Use of appropriate materials
	Faulty installation	• Avoidance of crossed cables connections • Checking of workmanship on site • Correct torque
	Failure of solid or liquid insulation (defective or missing)	• Checking of workmanship and/or dielectric test on site • Regular checking of liquid levels, where applicable
Disconnectors Switches Earthing switches	Maloperation	• Interlocks • Delayed reopening • Independent manual operation • Making capacity for switches and earthing switches • Instructions to personnel
Bolted connections and contacts	Corrosion	• Use of corrosion inhibiting coating and/or greases • Use of plating • Encapsulation, where possible • Supplemental heating to prevent condensation
	Faulty assembly	• Checking of workmanship by suitable means • Correct torque • Adequate locking means
	During racking-in or racking-out of withdrawable parts E.g. due to dielectric change of state in combination with damage or distortion of the plugging contacts and/or shutters	• Checking of workmanship at site
Instrument transformers	Ferro-resonance	• Avoidance of these electrical influences by suitable design of the circuit
	Short circuit on low-voltage side for VTs	• Avoid short circuit by proper means for example, protection cover, low-voltage fuses
Circuit-breakers	Insufficient maintenance	• Regular programmed maintenance • Instructions to personnel
All locations	Error by personnel	• Limitation of access by compartmentalisation • Insulation of embedded live parts • Instructions to personnel
	Ageing under electric stresses	• Partial discharge routine tests
	Pollution, moisture ingress of dust, vermin, etc	• Measures to ensure that the specified service conditions are achieved • Use of gas filled compartments
	Overvoltages	• Surge protection • Adequate insulation co-ordination • Dielectric tests on site

Table C11.1:
Locations, causes and examples of measures to decrease the probability of internal arc faults [IEC Standard 62271-200]

4. Impacts and consequences of arc faults

Figure C11.4 illustrates the impacts and consequences of arc faults.

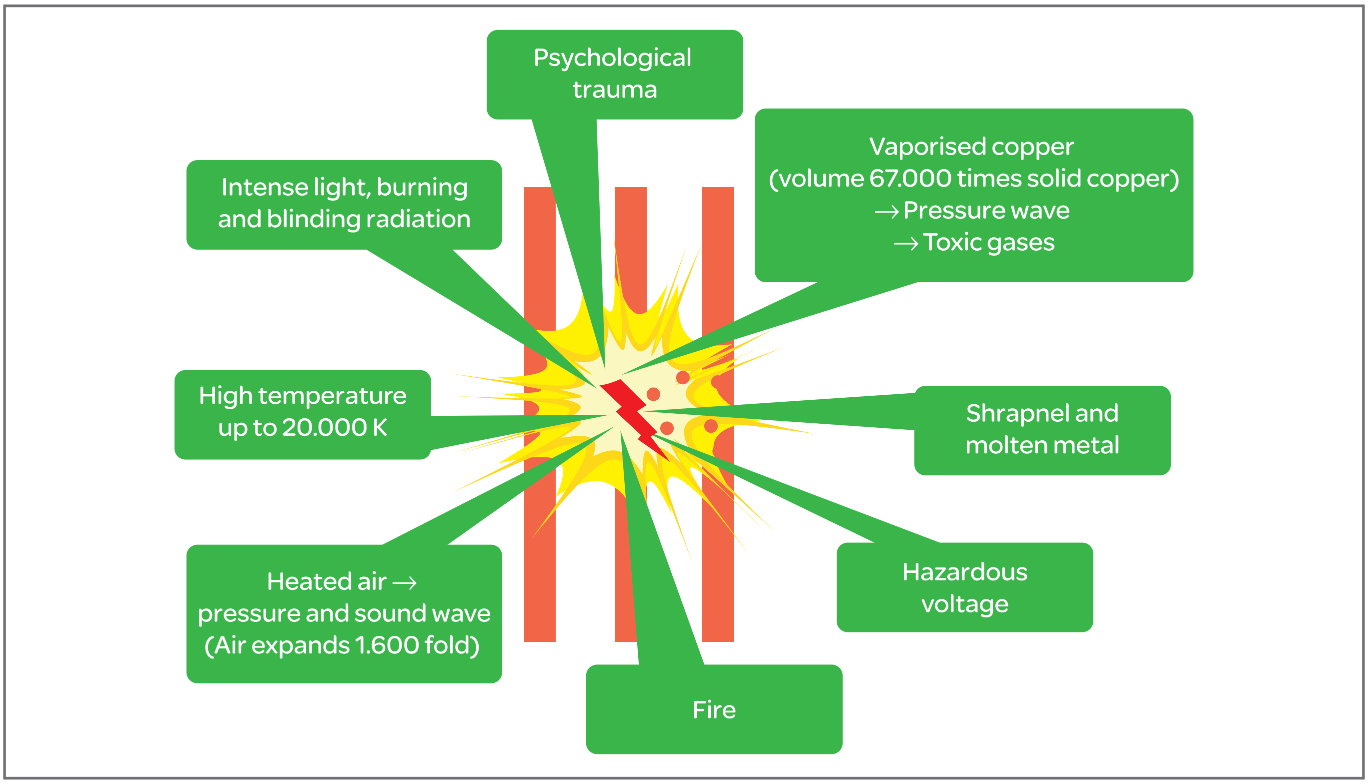

Figure C11.4:
Consequences of arc faults

In a high power arc fault incident huge amounts of electrical energy are converted into radiation and thermal energy. The radiation includes visible light. The very intense light of the arc flash can cause eye damage and it also plays a part in the burning impact of the arc (see Figure C11.5a to C11.5c).

Figure C11.5a, 5b, 5c: Light arcing flash

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4. Impacts and consequences of arc faults

Most of the burning effect comes from the thermal energy which in fact has many impacts. The high temperature heats up the air, and it vaporises the metal of the busbars. The hot plasma and the convection of the hot gases can cause serious arc burns to personnel.

Serious damage to equipment is also possible. If the arcing time is high the busbars can be totally destroyed, and the arc can burn holes to the switchgear housing.

Since arcs can ignite fire, additional damage to switchgear or substations is possible. Personnel's clothes may catch fire and increase the risk of burns. Additional safety hazard comes from toxic gases, due to evaporation of metal parts. Humans nearby are also vulnerable to hazardous voltage caused by the fault, and an arc fault may cause subsequent psychological trauma.

When the temperature of the air rises the volume of the air increases. Furthermore, when metals evaporate, they expand dramatically (see Figure C11.6a and C11.6b). For example when copper evaporates its volume is 67000 times as large as in the solid form. This instantaneous expansion creates another major impact of the arc, the pressure wave. The pressure wave, often called the arc blast, is dangerous to humans. In addition to ear damage and lung collapse, it can throw humans against walls or to the floor causing bone fractures or more serious injuries. Additional injuries can be caused by flying particles and molten metal from the damaged busbar and assembly.

Figure C11.6a:
Damage after an arc fault

Figure C11.6b:
Damage after an arc fault

Arc blast gives arc fault incidents an explosive nature. Since the peak value of the pressure, measured at the compartment walls, is normally reached 4-15ms after the ignition of the fault (peak pressure buildup time is relative to volume), mitigation of the pressure impact requires either efficient arc containment, redirection of the arc blast or high speed mitigation of the arc.

The above mentioned consequences, serious safety hazard and significant damage to equipment are not the only risks caused by arc faults. Injury or even death of humans may lead to substantial medical and legal expenses. When it comes to equipment, indirect costs are possible as well. Prolonged power and process outages due to the destroyed equipment are possible and in process industries particularly the interruption costs can be very high.

5. Arc protection related standards

In some countries arc protection based on simultaneous detection of light and overcurrent is a 'de facto' standard which means that practically all new industrial switchgear and primary substations of the utilities are equipped with the technology. However, currently in 2015, there are no international standards directly standardising methodology or equipment for arc protection.

Currently available standards concerning arc fault issues are the following:

a. IEC 62271-200, High-voltage switchgear and controlgear - Part 200: AC metal-enclosed switchgear and controlgear for rated voltages above 1 kV and up to and including 52 kV, known as the international switchgear standard

b. IEC 60364 Low-voltage electrical installations

c. IEEE Std 1584™-2002, IEEE Guide for Performing Arc-Flash Hazard Calculations

d. NFPA 70E®, Standard for Electrical Safety in the Workplace, 2015 Edition, NFPA (National Fire Protection Association)

IEC 62271-200 (Edition 2.0, 2011) is a MV switchgear standard and it "specifies requirements for prefabricated metal-enclosed switchgear and controlgear for alternating current of rated voltages above 1 kV and up to and including 52 kV for indoor and outdoor installation and for service frequencies up to and including 60 Hz. Enclosures may include fixed and removable components and may be filled with fluid (liquid or gas) to provide insulation." Arc faults are briefly discussed in the standard.

The standard aims at preventing the occurrence of internal arc faults. It gives a good list of locations where faults are most likely to occur, and explains causes of failure and possible measures to decrease the probability of faults. Additionally IEC 62271-200 gives examples of supplementary measures - in practice arc protection technologies - to provide protection to persons:

a. rapid fault clearance times initiated by detectors sensitive to light, pressure or heat or by a differential busbar protection

b. application of suitable fuses in combination with switching devices to limit the let-through current and fault duration

c. fast elimination of arc by diverting it to metallic short circuit by means of fast-sensing and fast-closing devices

d. remote operation instead of operation in front of the switchgear and controlgear

e. pressure-relief device

f. transfer of a withdrawable part to or from the service position only when the front door is closed

IEC 62271-200 recognises two important ratings of the arc fault currents: a) three-phase arc fault current and b) single phase-to earth arc fault current.

IEEE Std 1584™-2002, IEEE Guide for Performing Arc-Flash Hazard Calculations, is a safety oriented guide. It provides techniques to apply in determining the **arc-flash hazard distance** and the **incident energy** to which employees could be exposed during their work on or near electrical equipment. Its applications cover an empirically derived model including enclosed equipment and open lines for voltages from 208 V to 15 kV, and a theoretically derived model applicable for any voltage. The standard also provides a good list of arc fault related definitions.

One of the most central definitions is the concept of incident energy: The amount of energy impressed on a surface, a certain distance from the source, generated during an electrical arc event. Incident energy is measured in joules per centimetre squared (J/cm²). The incident energy concept is used for developing strategies to minimise burn injuries.

The guide is based upon testing and analysis of the hazards presented by incident energy. It provides a detailed step-by-step process for arc flash analysis. This analysis ends up with determining the incident energy level and the flash-protection boundary (The distance from live parts that are uninsulated or exposed within which a person could receive a second degree burn) based on incident energy of 5.0 J/cm². One should note that the analysis only covers the thermal impact of the arc fault, not the pressure related impact for example.

The standard is well known but mostly utilised in North America. Although incident energy levels are seldom calculated in Europe, incident energy calculations are a useful tool when comparing the effectiveness of different arc protection methods. Because the incident energy level depends on four key parameters: the arcing current, the voltage, the working distance and the arcing time, it is relatively easy to see that normally the most practical factors in the mitigation of the thermal impacts of arc faults are the arcing time and the arcing current.

IEEE Std 1584™-2002 includes reporting of the tests carried out with current-limiting fuses. The published figures confirm the risk related to current-limiting fuses: high incident energy levels occur when the fault current is low, and the fuse is not in its intended range of operation.

NFPA 70E, Standard for Electrical Safety in the Workplace® by National Fire Protection Association addresses electrical safety-related work practices, safety-related maintenance requirements and other administrative controls for the practical safeguarding of employees. It has some links to arc protection and it provides some commonly used arc fault related definitions, such as:

a. Arc Flash Boundary: When an arc flash hazard exists, the distance from a prospective arc source at which a person could receive a second degree burn if an electrical arc flash were to occur. (A second degree burn is possible

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5. Arc protection related standards

by an exposure of unprotected skin to an electric arc flash above the incident energy level of 5 J/cm²

b. Arc-Resistant Switchgear: Equipment designed to withstand the effects of an internal arcing fault and that directs the internally released energy away from the employee

NFPA 70E includes an informative annex giving guidance on selection of arc-rated clothing and other PPE (Personal Protective Equipment) when it is not practical to eliminate exposure to incident energy.

6. Arc protection and mitigation methods

Naturally the primary goal is to prevent arc faults by, for example, careful design, education of personnel and adequate maintenance of equipment. In some cases early detection of developing faults is possible by special monitoring equipment. However, it is very difficult to totally eliminate arc faults in distribution systems.

As shown previously, the incident energy depends on the voltage, working distance, arc current and arc duration. From an arc protection point of view it is normally not possible to effect the applied voltage. The working distance is only related to humans working on the equipment, and it is often difficult to increase this distance. In practice there are two major approaches for decreasing the released energy: limitation of the arc current or reduction of the arc time.

Incident energy calculations, based on testing, show that the released energy is proportional to the arc time. When traditional overcurrent protection is applied, the arc time is normally some hundreds of milliseconds. This leads to extensive damage and a serious safety hazard. This is why several different arc fault mitigation approaches have been introduced, that are much more efficient than overcurrent protection.

The following Table C11.2 presents evaluation of some well known arc mitigation methods.

Method	Benefits	Drawbacks
Arc-resistant switchgear Equipment designed to withstand the effects of an internal arc fault and that directs the internally released energy away from the employee	• Good protection for personnel at least when the doors are closed • Provides protection against the pressure impact • Gives very good protection if used in combination with fast protection	• If used as the only arc mitigation approach, provides no protection to the equipment in the enclosure
Maintenance switch A switch that when turned on (during maintenance at a substation) makes circuit breakers operate without any intentional delay	• Rather good protection of personnel	• Effective only during maintenance
Zone-selective interlocking	• Rather simple, relatively low costs	• Not very fast
Current-limiting fuses	• Very fast operation and good protection if the fault current is in the operation range of the fuse • Limits both current and arc time	• When fault current is low (as it can be for various reasons) the arc time and the incident energy are high
Current-limiting reactors	• Limit fault current	• Increase cost and losses • Limited effect
Busbar differential protection	• Fast protection	• Complicated settings • Requires careful CT selection • Does not operate in cable terminal faults

Table C11.2:
Comparison of mitigation methods

7. The principle of arc protection based on simultaneous detection of light and overcurrent

The leading method in arc protection is based on simultaneous very fast detection of light and overcurrent as shown in Figure C11.7. This approach can be divided into two parts: Arc detection and Arc mitigation. The arc can be detected within <1 milliseconds which is outstanding performance compared with conventional protection technology. The arc time varies according to the elimination technology. When applying conventional circuit breakers the arc time is some tens of milliseconds. If a short-circuit device is applied, the arcing time is less than half cycle.

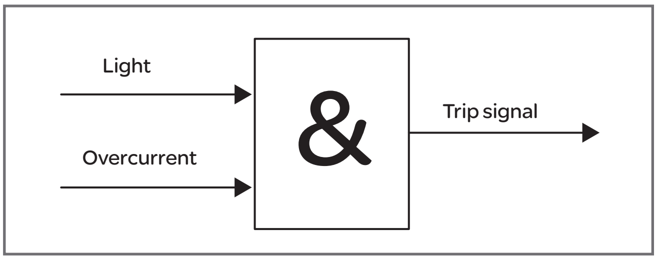

Figure C11.7:
Modern arc protection logic

Normally the overcurrent condition increases costs only a little since existing current transformers can be used. However, there are applications where "light only" based arc detection can be applied. For example, if the probability of intense external light can be practically closed out, measurement of current would be very difficult, or where low cost is essential the "light only" condition can be justified.

7.1 Fast optical detection of light

There is a strong correlation between the power of the arc and the intensity of the observed light. Fault arcs can be detected practically immediately by using light sensitive sensors, such as photodiode (point type of sensor) or optical fibre (loop or point type of sensor).

There is not an exact universal sensitivity threshold value which could always differentiate between light emanating from arc faults and the light coming from other sources. Practical experience has shown that sensitivity of approximately 10000 lux (visible light) gives excellent results. Sensors with the sensitivity of 10000 lux are very likely to detect the light in all relevant arc fault situations with metal-enclosed switchgear while at the same time the risk of false activation is low. This is true especially in the cases where the detection of the arc is confirmed by the simultaneous detection of overcurrent.

Point type of sensors (Figure C11.8) enable more selective protection than fibre loop sensors, identifying the location of the arc more accurately. Loop sensors (Figure C11.9) are a cost effective solution for applications where protection selectivity is not a critical.

Figure C11.8:
Point type of optical sensor

Figure C11.9:
Fibre type of optical sensor

7.2 Fast detection of overcurrent

In order to minimise the possible nuisance tripping caused by external light, an overcurrent condition, i.e. detection of overcurrent (secondary sensor) is often required in parallel with the detection of light (primary sensor). The current can be measured with normal (existing) current transformers. In arc protection applications it is however necessary to minimise the operation time and special methods are used to enable the rapid detection of the overcurrent. Very fast (less than 1ms) detection of overcurrent is possible by applying an analogue comparator. The method is illustrated in Figure C11.10.

Because many arc faults start as single-phase faults, it is justified to detect phase-to-earth faults as well. If the arc is detected and eliminated before it escalates into high-power three-phase fault, the damage will be lower. The detection of phase-to-earth arc fault is normally based on simultaneous detection of light and zero-sequence overcurrent, but zero sequence voltage can be utilised as well.

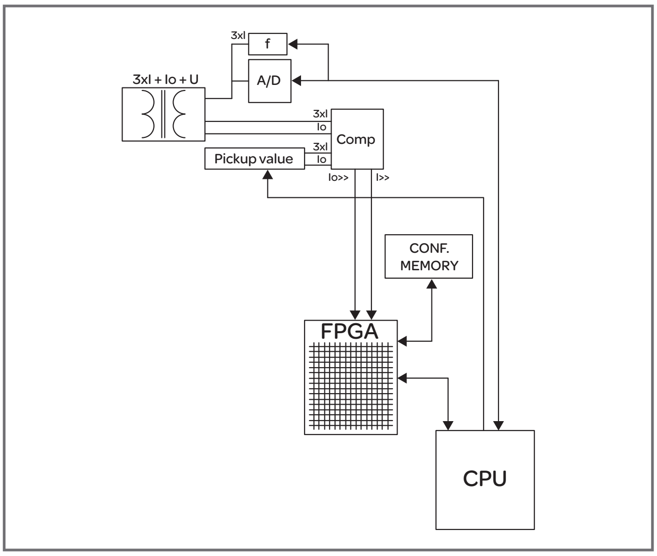

Figure C11.10:
A method for very fast detection of overcurrent, utilising an analogue comparator

8. How to avoid nuisance tripping caused by switching arcs

In almost all cases, both in medium voltage (MV) and low voltage (LV) systems, the trip condition of simultaneous detection of light and overcurrent has proven to be successful. However, some low voltage circuit breakers (air-magnetic type) emit light and other type of pollution while operating. This problem can be mitigated by using special types of light sensors, less sensitive or designed for limited wavelength ranges or by applying pressure sensors.

9. Arc protection systems

9.1 Stand-alone arc protection systems

The simplest arc protection solutions can be based on stand-alone devices (Figure C11.11). When "light only" detection criteria is applied, all that is required is the optical sensors, and a device that collects the information from the sensors and sends the trip command to the appropriate circuit breaker. Some wind power applications, secondary substations and limited low voltage switchboards are examples of possible application areas for stand-alone devices.

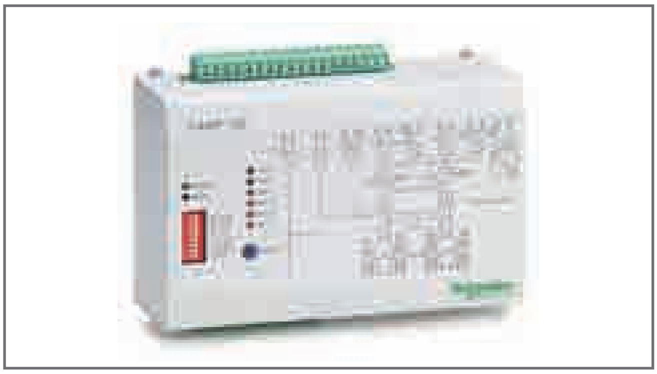

Figure C11.11:
Stand alone arc protection system

9.2 Arc protection integrated in numerical protection relays

Another cost effective and very widely applied solution is to integrate arc protection into normal protection devices (Figure C11.12). Because most relays already include current measurement, it is relatively easy to add the input for light sensors to achieve the light and overcurrent based trip condition. However, the overcurrent detection must be very fast.

When the relays are equipped with communication and several light sensor inputs, selective arc protection can be provided.

An example of applications is a primary substation (HV/MV) where arc faults can be selectively tripped . e.g. in cable terminations of outgoing feeders - a typical location of arc faults.

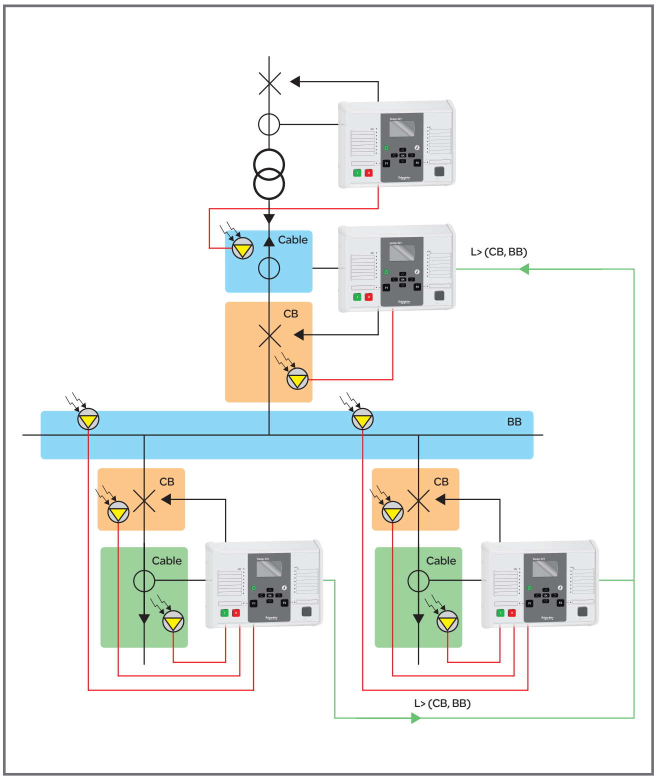

Figure C11.12:
Integrated arc protection function in a protection device

9.3 Dedicated arc protection systems

Arc protection is most often implemented by a separate system using arc flash detectors connected to dedicated arc protection relays (Figure C11.13). Overcurrent and earth-fault protection is carried out by other relays. A comprehensive, selective arc protection system comprises of optical sensors, current transformers (normally no additional CTs are needed), I/O units collecting data from the sensors and CTs, communication cabling, and a master unit or several master units for final collection of all the sensor data. The master unit(s) are measuring the current and tripping the appropriate circuit breakers, if both light and overcurrent are detected. Very high speed communication between the components is an essential feature of the system, transmitting information on detected light, detected overcurrent, addresses (location) of detection, and trip commands.

A separate system enables large installations with selective protection and multiple protection zones. It provides very high speed protection and can also provide some protection redundancy.

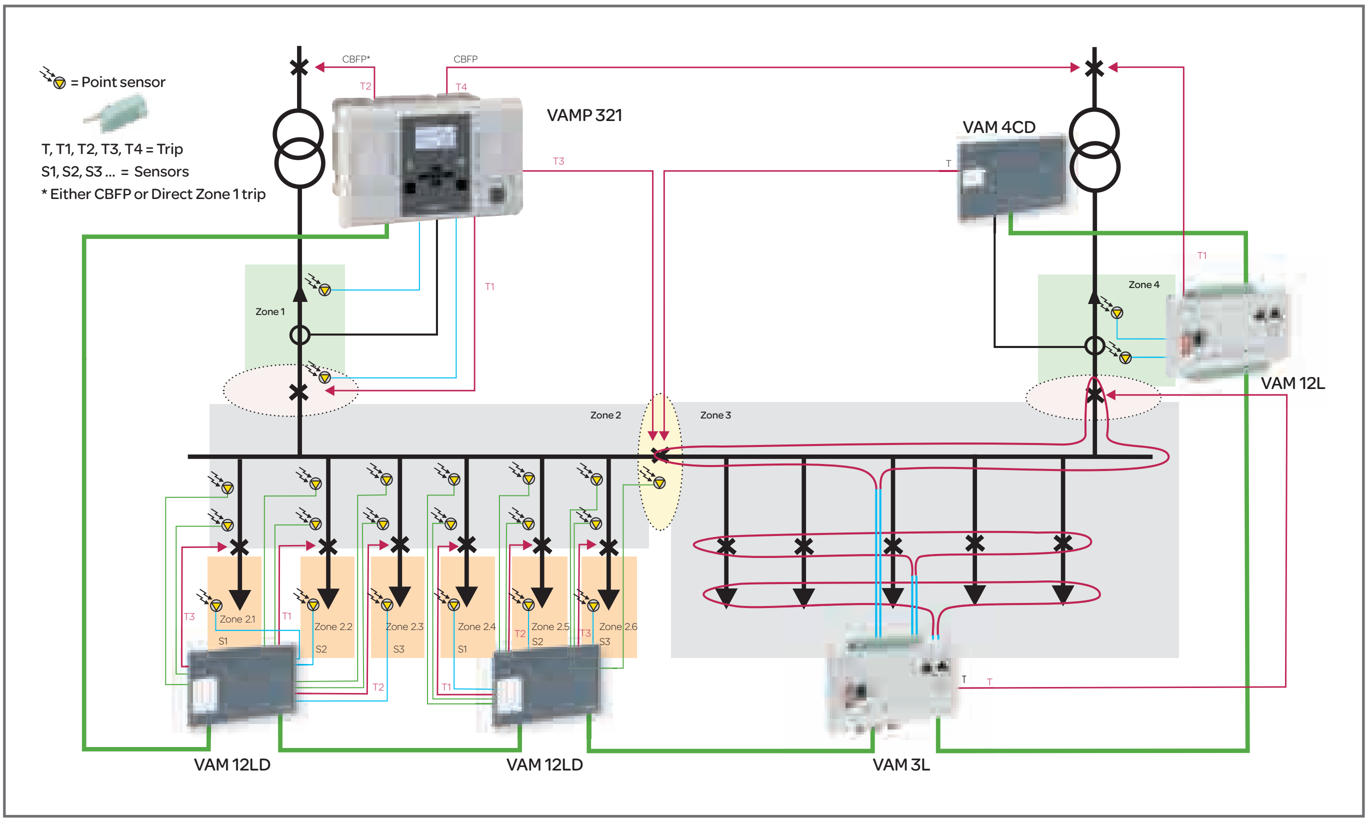

Figure C11.13:
Dedicated arc protection system

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10. Elimination of the arc fault

10.1 The importance of the arc elimination time

The incident energy is proportional to the arcing time. From a protection point of view the arcing time consists of two components: arc detection time and arc elimination time. By applying arc detection methods described above, minimal arc detection time can be achieved. The arcing time then depends almost entirely on arc elimination time.

10.2 Circuit breakers

In most applications arc protection relays send the trip signal to appropriate circuit breakers which then open the circuit and extinguish the fault arc. In MV applications using arc protection relays and CBs the total arcing time is in the order of 60ms, consisting of 1ms detection time and <60ms CB operation time. The operating times of LV CBs are usually shorter than MV CBs' operation times. When total arcing time is in only a few tens of milliseconds, the thermal impacts of faults arcs are efficiently mitigated (see Figure C11.14).

Figure C11.14:
Low impact on an arc fault with fast arc protection trip

10.3 Short-circuit devices (arc eliminators)

Arc eliminating by means of a short-circuit device (crowbar unit, arc quencher or high speed earthing device) is recognised by IEC Standard 62271-200 as an option to provide the highest possible level of protection to personnel in case of an internal arc in MV switchgear. When using a short-circuit device the arc protection systems sends trip commands to both the arc eliminator and the appropriate circuit breakers. The short-circuit device will create an intentional high speed short circuit in the system so that the voltage collapses and the arc is extinguished. The short-circuit current is then eliminated by the circuit breaker within a few cycles.

Fast communication between the arc protection relay and the short-circuit device is vital. The combination of optical arc detection and a short-circuit device provides extremely fast and efficient protection. The arcing time is only a few milliseconds. The thermal impact of the fault is minimal, and the pressure impact is significantly mitigated.

10.4 Current-limiting fuses

The use of current-limiting fuses in arc protection requires good product and system knowledge otherwise the protection level may be much lower than expected. CL fuses can be very efficient in both limiting the current and reducing the arc time. When the fault current is in the current-limiting range, the fuse is able to break the current very rapidly, and also reduce the peak current. The reduction of the peak current is a benefit, because high current causes mechanical forces that are detrimental to transformers feeding the current. Figure C11.15 below illustrates the current-limiting impact of a CL fuse.

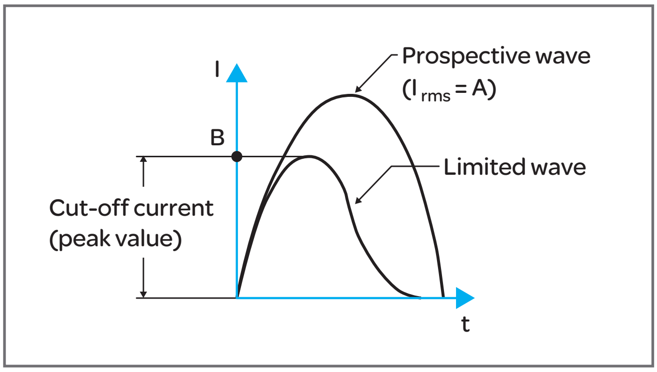

Figure C11.15:
Current-limitation of a CL fuse

Current-limiting fuses are not a perfect solution. They are very effective in limiting the released energy only if they are in their current-limiting range. Particularly in low voltage applications it is difficult to determine the arc fault current level. The current can be as low as 20-40 % of the bolted fault current. Low fault current can lead to prolonged arc times and thus higher released energy and greater damage.

11.1 Single main application

The following Figure C11.16 gives an overview of a single main application.

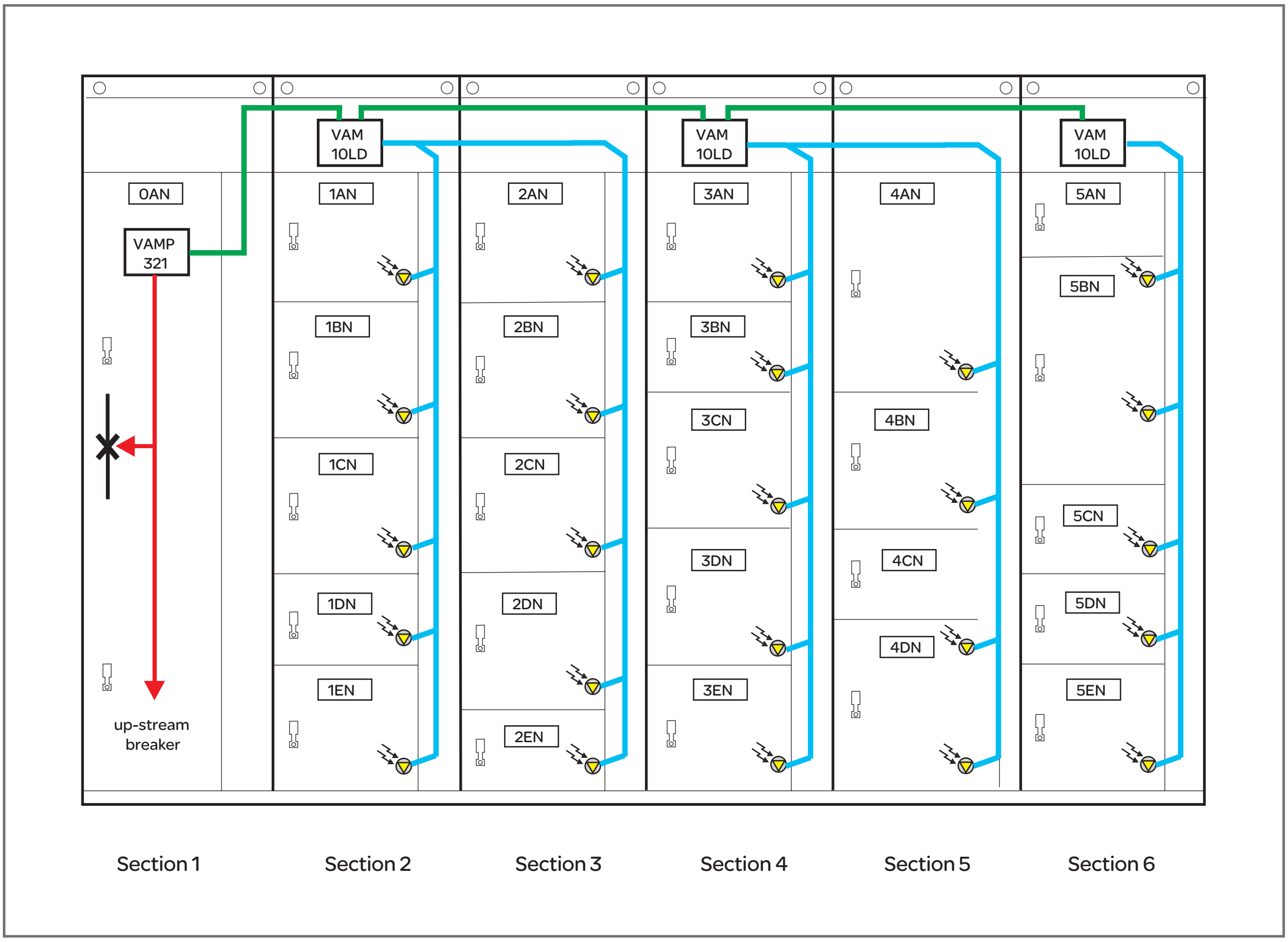

Figure C11.16:
Single main application

Every compartment is equipped with an arc sensor. The trip output relay of AFS units control the incomer breakers. Any of the point sensors will cause a trip of the main breaker to mitigate the arc fault. Additionally overcurrent measurement is taken account if the application requires a minimisation of the possible nuisance tripping caused by external light.

11. Typical application examples

11.2 Main tie main application + CBF (circuit breaker failure)

The following Figure C11.17 gives an overview of a main tie main application with circuit breaker failure.

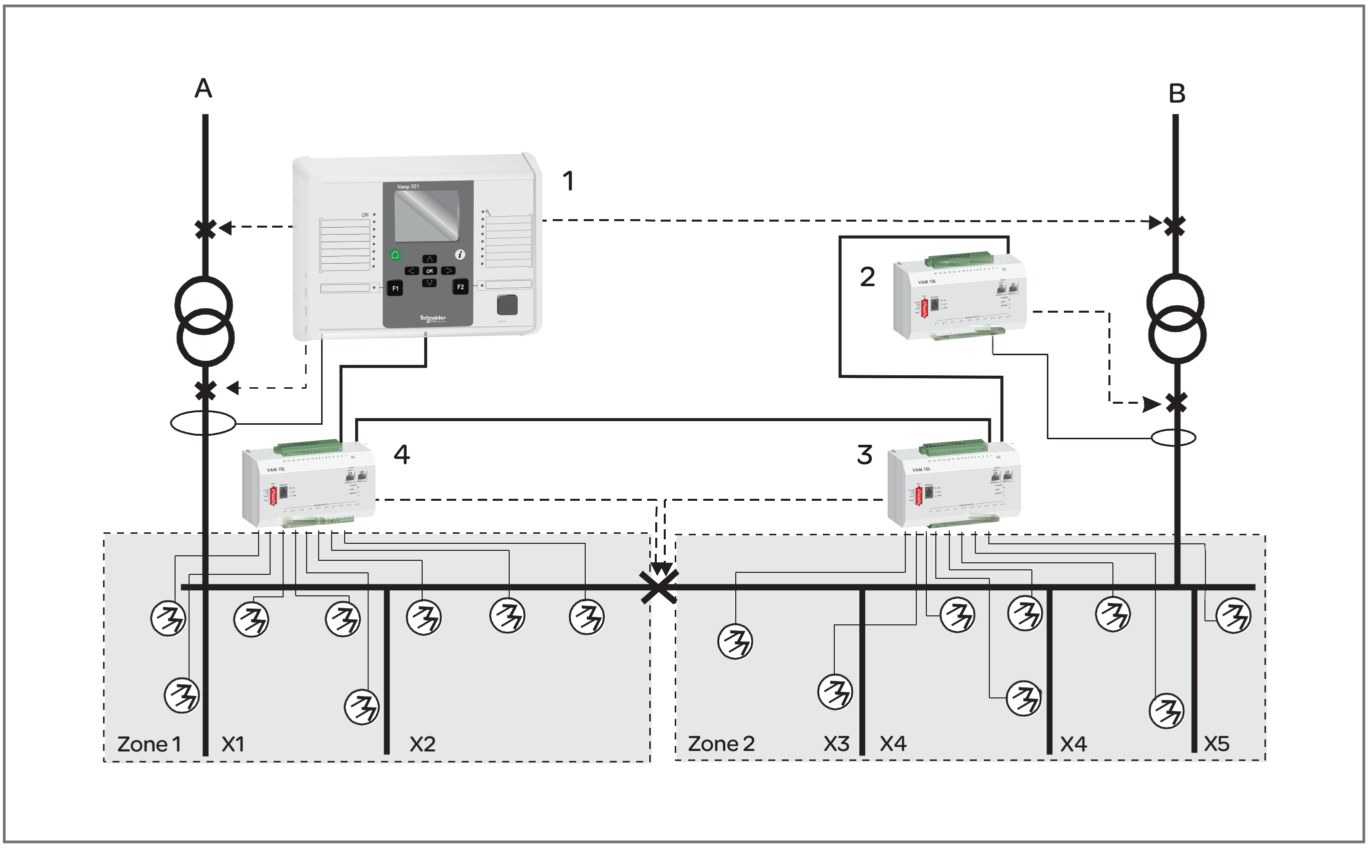

Figure C11.17:
Main tie main application

The protected target is a medium voltage enclosure with two separate incomers. The enclosure has a longitudinal busbar between the incomers. To minimise the fault zone, the enclosure is divided into two separate protection zones.

The different zones are divided by a bus-coupler circuit breaker and monitored by light sensors connected to the light detecting units (3 & 4). The system receives current criteria from the main unit(1) and current measurement unit (2), which have been installed on incomers.

The CBFP (circuit breaker failure protection) contacts have been wired to the HV side of the supply transformer for enclosure backup detection. When defining the CBFP delay time, the standard break-time of the feeder circuit breaker of the enclosure must be taken into account.

The main unit and extension units serve as trip units. The main unit (1) trips its own feeder circuit breaker in zone 1 faults and serves as CBFP in zone 1 and 2 faults. The arc sensor units (3 and 4) trip the bus-coupler circuit breaker between zones 1 and 2 in faults in their own zone. The zone 2 light detecting unit (3) trips its own bus-coupler circuit breaker.

11.3 Feeder selective multiple busbar application

The following Figure C11.18 gives an overview of a feeder selective multiple busbar application.

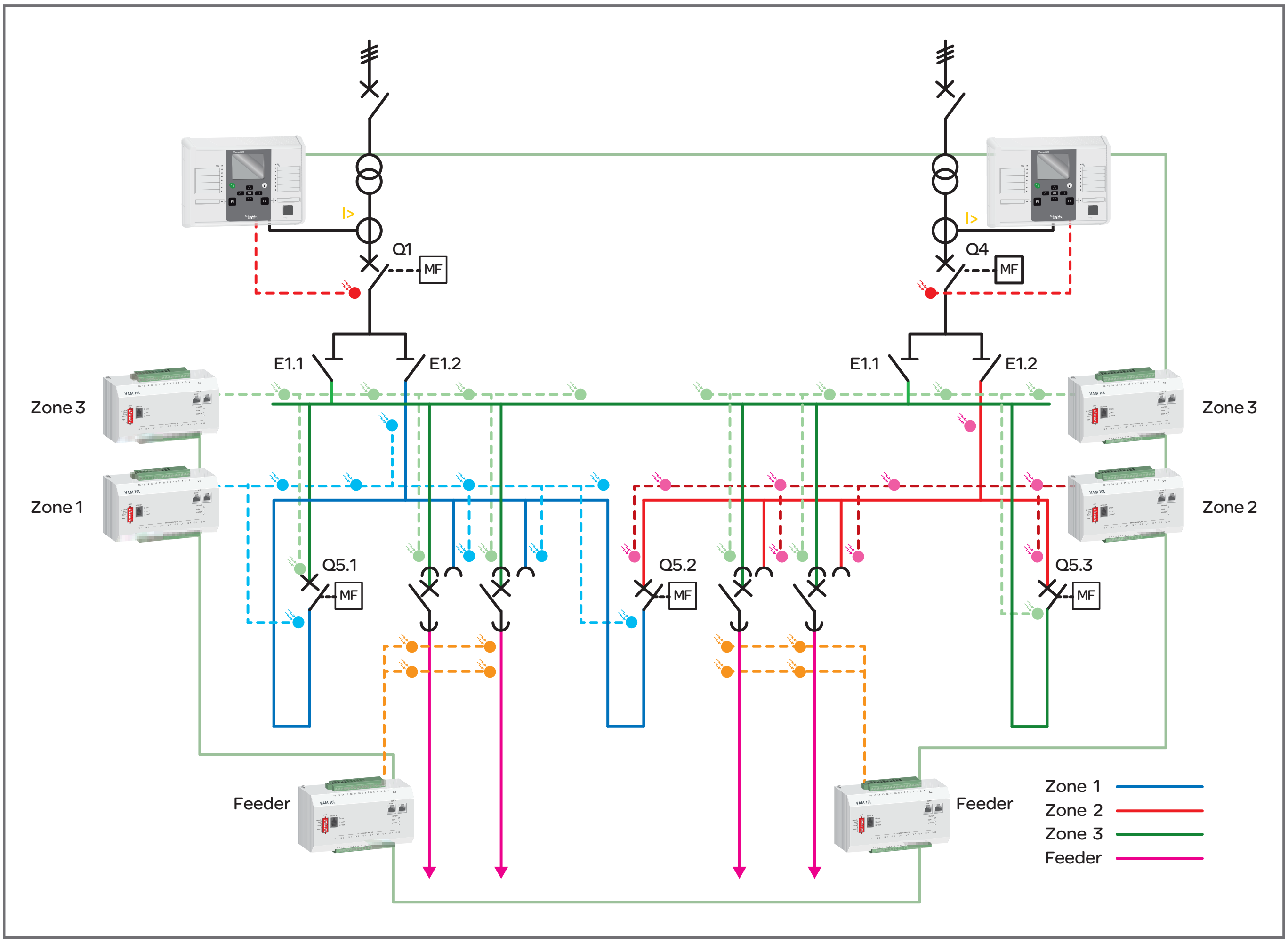

Figure C11.18:
Multiple busbar application

The protected target is a medium voltage enclosure with multiple separate incomers. The enclosure has a longitudinal busbar between the incomers. To minimise the fault zone, the enclosure is divided into four separate protection zones (zone1, 2, 3 and Feeder). The different zones are divided by bus-coupler circuit breakers and monitored by light sensors connected to the light detecting units in zones 1, 2,3 and feeder. The detection system receives current criteria from the main units, which are installed on incomers.

The main units and extension units serve as trip units. The main units trip their own feeder circuit breaker for internal arc faults when a fault is fed from their own incomer. The arc sensor units in zones 1, 2 and 3 trip the bus-coupler circuit breaker between different zone faults in their own zone. The outgoing feeder zone light detecting units trips their own feeder circuit breakers.

Selective tripping schemes on main units automatically adjust according to incomer disconnector positions (E1.x and E2.x) and changes the tripping logic accordingly. This will allow arc flash protection to fullfill full selective protection.

The outgoing feeder section is protected by using dedicated light detecting units. These individially trip the corresponding feeder circuit breaker to limit the impact without shutting down the entire busbar in the system e.g. cable fault.

D1

Auto-Reclosing

Network Protection & Automation Guide

Life Is On

Schneider Electric

Chapter D1

Auto-Reclosing

D1

1. Introduction

Faults on overhead lines fall into one of three categories:

a. transient

b. semi-permanent

c. permanent

80-90% of faults on any overhead line network are transient in nature. The remaining 10%-20% of faults are either semi-permanent or permanent.

Transient faults are commonly caused by lightning and temporary contact with foreign objects. The immediate tripping of one or more circuit breakers clears the fault. Subsequent re-energisation of the line is usually successful.

A small tree branch falling on the line could cause a semi-permanent fault. The cause of the fault would not be removed by the immediate tripping of the circuit, but could be burnt away during a time-delayed trip. HV overhead lines in forest areas are prone to this type of fault. Permanent faults, such as broken conductors, and faults on underground cable sections, must be located and repaired before the supply can be restored.

Use of an auto-reclose scheme to re-energise the line after a fault trip permits successful re-energisation of the line. Sufficient time must be allowed after tripping for the fault arc to de-energise prior to reclosing otherwise the arc will re-strike. Such schemes have been the cause of a substantial improvement in continuity of supply. A further benefit, particularly to EHV systems, is the maintenance of system stability and synchronism.

A typical single-shot auto-reclose scheme is shown in Figures D1.1 and D1.2. Figure D1.1 shows a successful reclosure in the event of a transient fault, and Figure D1.2 an unsuccessful reclosure followed by lockout of the circuit breaker if the fault is permanent.

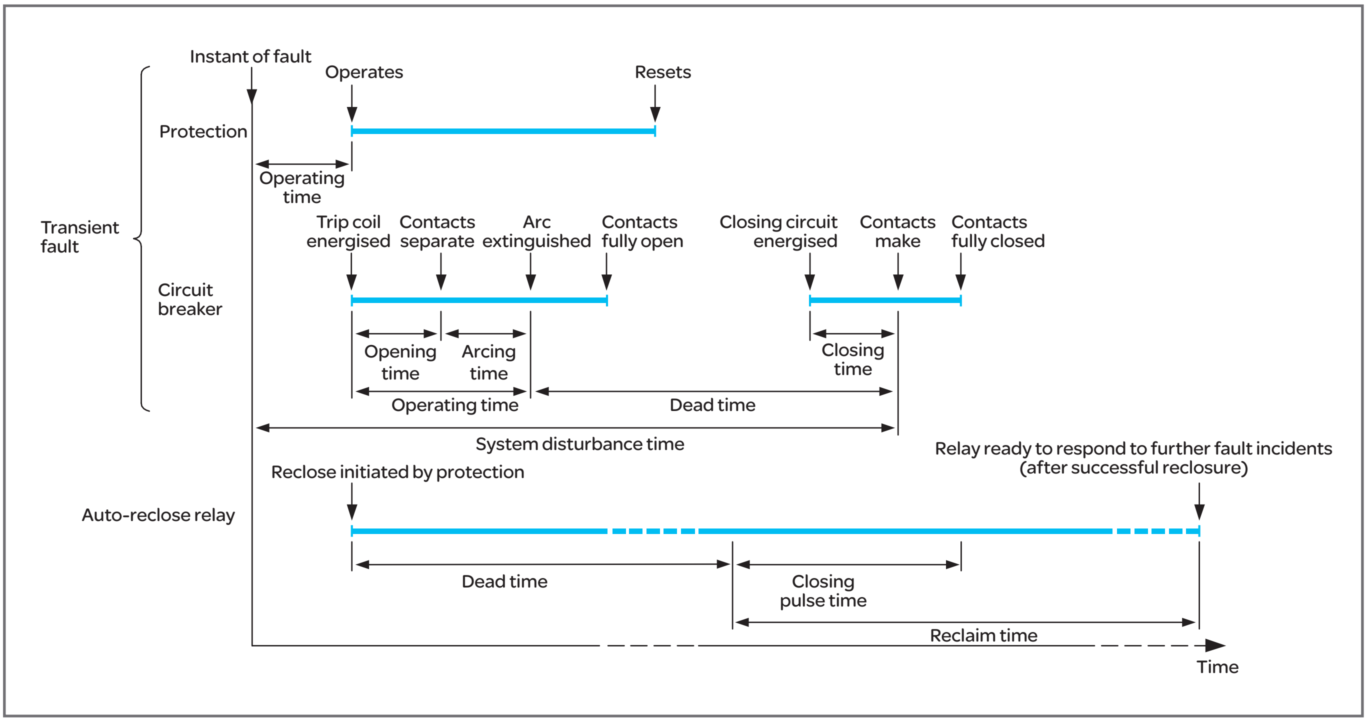

Figure D1.1:
Single-shot auto-reclose scheme operation for a transient fault

1. Introduction

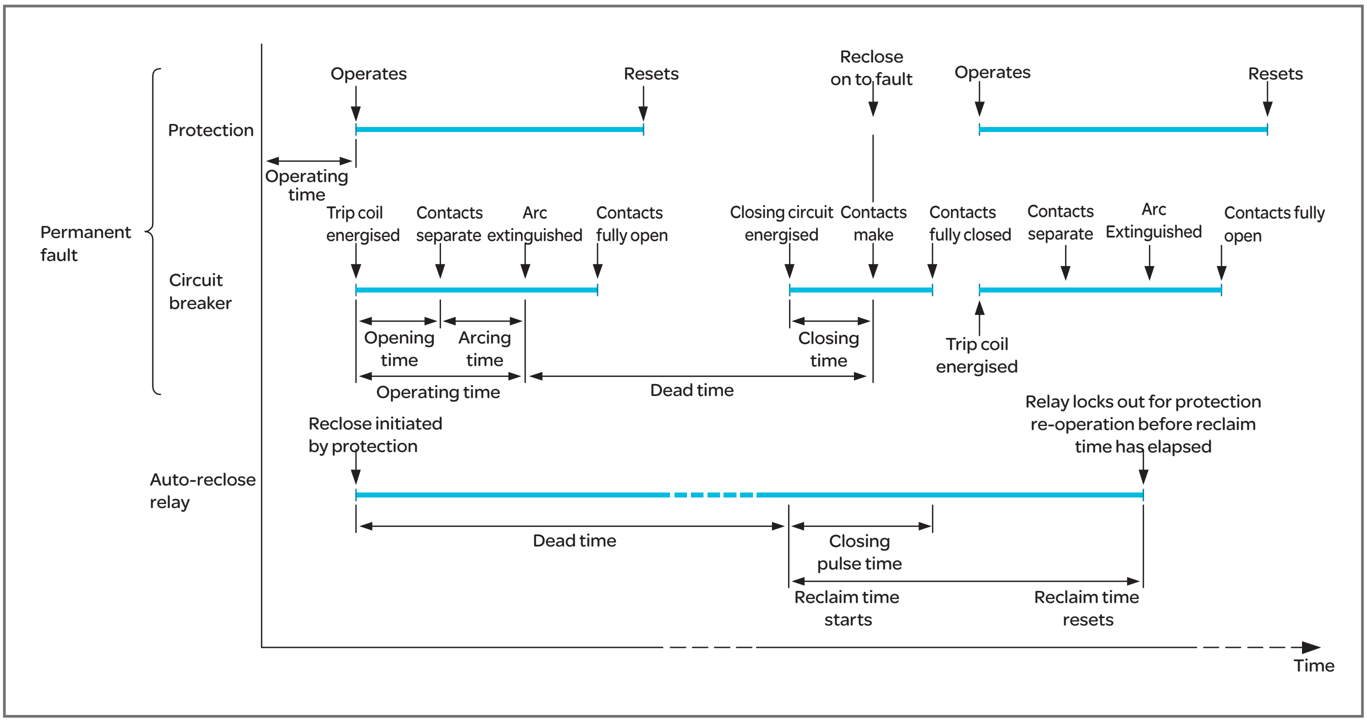

Figure D1.2:
Operation of single-shot auto-reclose scheme on a permanent fault

2. Application of auto-reclosing

The most important parameters of an auto-reclose scheme are:

a. dead time

b. reclaim time

c. single or multi-shot

These parameters are influenced by:

a. type of protection

b. type of switchgear

c. possible stability problems

d. effects on the various types of consumer loads

e. Type of fault, Phase to Phase or Phase to Ground

The weighting given to the above factors is different for HV distribution networks and EHV transmission systems and therefore it is convenient to discuss them under separate headings. Sections 3 and 4 cover the application of auto-reclosing to HV distribution networks while Sections 5 - 9 cover EHV schemes.

The rapid expansion in the use of auto-reclosing has led to the existence of a variety of different control schemes. The various features in common use are discussed in Section 10. The related subject of auto-closing, that is, the automatic closing of normally open circuit breakers, is dealt with in Section 11.

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3. Auto-reclosing on HV distribution networks

On HV distribution networks, auto-reclosing is applied mainly to radial feeders where problems of system stability do not arise, and the main advantages to be derived from its use can be summarised as follows:

a. reduction to a minimum of the interruptions of supply to the consumer

b. instantaneous fault clearance can be introduced, with the accompanying benefits of shorter fault duration, less fault damage, and fewer permanent faults

As 80% of overhead line faults are transient, elimination of loss of supply from this cause by the introduction of auto-reclosing gives obvious benefits through:

a. improved supply continuity

b. reduction of substation visits

Instantaneous tripping reduces the duration of the power arc resulting from an overhead line fault to a minimum. The chance of permanent damage occurring to the line is reduced. The application of instantaneous protection may result in non-selective tripping of a number of circuit breakers and an ensuing loss of supply to a number of healthy sections. Auto-reclosing allows these circuit breakers to be reclosed within a few seconds. With transient faults, the overall effect would be loss of supply for a very short time but affecting a larger number of consumers. If only time-graded protection without auto-reclose was used, a smaller number of consumers might be affected, but for a longer time period.

When instantaneous protection is used with auto-reclosing, the scheme is normally arranged to inhibit the instantaneous protection after the first trip. For a permanent fault, the time-graded protection will give discriminative tripping after reclosure, resulting in the isolation of the faulted section. Some schemes allow a number of reclosures and time-graded trips after the first instantaneous trip, which may result in the burning out and clearance of semi-permanent faults. A further benefit of instantaneous tripping is a reduction in circuit breaker maintenance by reducing pre-arc heating when clearing transient faults.

When considering feeders that are partly overhead line and partly underground cable, any decision to install auto-reclosing would be influenced by any data known on the frequency of transient faults. Where a significant proportion of faults are permanent, the advantages of auto-reclosing are small, particularly since reclosing on to a faulty cable is likely to aggravate the damage.

4. Factors influencing HV auto-reclose schemes

The factors that influence the choice of dead time, reclaim time, and the number of shots are now discussed.

4.1 Dead Time

Several factors affect the selection of system dead time as follows:

a. system stability and synchronism

b. type of load

c. CB characteristics

d. fault path de-ionisation time

e. protection reset time

These factors are discussed in the following sections.

4.1.1 System stability and synchronism

In order to reclose without loss of synchronism after a fault on the interconnecting feeder, the dead time must be kept to the minimum permissible consistent with de-ionisation of the fault arc. Other time delays that contribute to the total system disturbance time must also be kept as short as possible. The problem arises only on distribution networks with more than one power source, where power can be fed into both ends of an inter-connecting line. A typical example is embedded generation (see Chapter [C8: Generator and Generator-Transformer Protection], or where a small centre of population with a local diesel generating plant may be connected to the rest of the supply system by a single tie-line.

The use of high-speed protection, such as unit protection or distance schemes, with operating times of less than 0.05s is essential. The circuit breakers must have very short operation times and then be able to reclose the circuit after a dead time of the order of 0.3s-0.6s to allow for fault-arc de-ionisation.

It may be desirable in some cases to use synchronism check logic, so that auto-reclosing is prevented if the phase angle has moved outside specified limits. The matter is dealt with more fully in Section 9 on EHV systems.

4.1.2 Type of load

On HV systems, the main problem to be considered in relation to dead time is the effect on various types of consumer load.

4. Factors influencing HV auto-reclose schemes

a. industrial consumers

Most industrial consumers operate mixed loads comprising induction motors, lighting, process control and static loads. Synchronous motors may also be used. Dead time has to be long enough to allow motor circuits to trip out on loss of supply. Once the supply is restored, restarting of drives can then occur under direction of the process control system in a safe and programmed manner, and can often be fast enough to ensure no significant loss of production or product quality

b. domestic consumers

It is improbable that expensive processes or dangerous conditions will be involved with domestic consumers and the main consideration is that of inconvenience and compensation for supply interruption. A dead time of seconds or a few minutes is of little importance compared with the loss of cooking facilities, central heating, light and audio/visual entertainment resulting from a longer supply failure that could occur without auto-reclosing

4.1.3 Circuit breaker characteristics

The time delays imposed by the circuit breaker during a tripping and reclosing operation must be taken into consideration, especially when assessing the possibility of applying high speed auto-reclosing.

a. mechanism resetting time

Most circuit breakers are 'trip free', which means that the breaker can be tripped during the closing stroke. After tripping, a time of the order of 0.2s must be allowed for the trip-free mechanism to reset before applying a closing impulse. Where high speed reclosing is required, a latch check interlock is desirable in the reclosing circuit

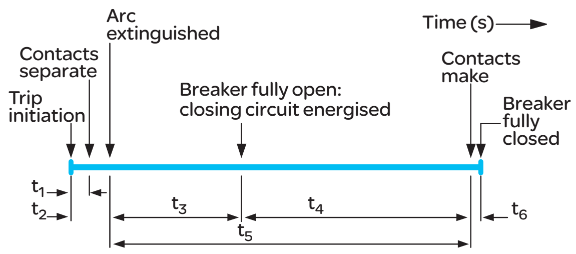
b. closing time

This is the time interval between the energisation of the closing mechanism and the making of the contacts. Owing to the time constant of the solenoid and the inertia of the plunger, a solenoid closing mechanism may take 0.3s to close. A spring-operated breaker, on the other hand, can close in less than 0.2s. Modern vacuum circuit breakers may have a closing time of less than 0.1s

The circuit breaker mechanism imposes a minimum dead time made up from the sum of (a) and (b) above. Figure D1.3 illustrates the performance of modern HV circuit breakers in this respect. Older circuit breakers may require longer times than those shown.

4.1.4 De-ionisation of fault path

As mentioned above, successful high speed reclosure requires the interruption of the fault by the circuit breaker to be followed by a time delay long enough to allow the ionised air to disperse. This time is dependent on the system voltage, cause of fault, weather conditions and so on, but at voltages up to 66kV,



	Oil 11kV	Vacuum 15kV	Oil 132kV	Air 380kV	SF_6 132kV	SF_6 380kV
t_1	0.06	0.038	0.03	0.035	0.04	0.02
t_2	0.1	0.053	0.06	0.045	0.07	0.05
t_3	0.08	0.023	0.2	0.235	0.03	0.01
t_4	0.16	0.048	0.35	0.065	0.08	0.06
t_5	0.24	0.28	0.55	0.3	0.11	0.07
t_6	0.02	0.07	0.01	0.02	0.12	0.04

Note: 380kV data applicable to 400kV also. All times in seconds

Figure D1.3:
Typical circuit breaker trip-close operation times

0.1s-0.2s should be adequate. On HV systems, therefore, fault de-ionisation time is of less importance than circuit breaker time delays.

4.1.5 Protection reset time

If time delayed protection is used, it is essential that the timing device shall fully reset during the dead time, so that correct time discrimination will be maintained after reclosure on to a fault. The reset time of the electromechanical I.D.M.T. relay is 10 seconds or more when on maximum time setting, and dead times of at least this value may be required.

When short dead times are required, the protection relays must reset almost instantaneously, a requirement that is easily met by the use of static, digital and numerical I.D.M.T. relays.

4.2 Reclaim time

Factors affecting the setting of the reclaim time are discussed in the following sections.

4.2.1 Type of protection

The reclaim time must be long enough to allow the protection relays to operate when the circuit breaker is reclosed on to a permanent fault. The most common forms of protection applied to HV lines are I.D.M.T. or definite time over-current and earth-fault relays. The maximum operating time for the former with very low fault levels could be up to 30 seconds, while for fault levels of several times rating the operating time may be 10 seconds or less.

In the case of definite time protection, settings of 3 seconds or less are common, with 10 seconds as an absolute maximum. It has been common practice to use reclaim times of 30 seconds on HV auto-reclose schemes. However, there is a danger with a setting of this length that during a thunderstorm,

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4. Factors influencing HV auto-reclose schemes

when the incidence of transient faults is high, the breaker may reclose successfully after one fault, and then trip and lock out for a second fault within this time. Use of a shorter reclaim time of, say, 15 seconds may enable the second fault to be treated as a separate incident, with a further successful reclosure.

Where fault levels are low, it may be difficult to select I.D.M.T. time settings to give satisfactory grading with an operating time limit of 15 seconds, and the matter becomes a question of selecting a reclaim time compatible with I.D.M.T. requirements.

It is common to fit sensitive earth-fault protection to supplement the normal protection in order to detect high resistance earth faults. This protection cannot possibly be stable on through-faults, and is therefore set to have an operating time longer than that of the main protection. This longer time may have to be taken into consideration when deciding on a reclaim time. A broken overhead conductor in contact with dry ground or a wood fence may cause this type of fault. It is rarely if ever transient and may be a danger to the public. It is therefore common practice to use a contact on the sensitive earth fault relay to block auto-reclosing and lock out the circuit breaker.

Where high-speed protection is used, reclaim times of 1 second or less would be adequate. However, such short times are rarely used in practice, to relieve the duty on the circuit breaker.

4.2.2 Energy recovery time

In all cases the CB trip mechanism will take time to recover enough energy to be able to perform a Close and Trip sequence. The reclaim time should not be set below this value. For a motor wound spring this time could be significant (up to 30 seconds) and therefore be the limiting parameter in setting the reclaim time. For other types of trip mechanism this time could be much smaller, involving the recharging of energy storage capacitors or gas pressure. Here the reclaim time will be governed by other factors.

4.3 Number of Shots

There are no definite rules for defining the number of shots for any particular auto-reclose application, but a number of factors must be taken into account.

4.3.1 Circuit breaker limitations

Important considerations are the ability of the circuit breaker to perform several trip and close operations in quick succession and the effect of these operations on the maintenance period. Maintenance periods vary according to the type of circuit breaker used and the fault current broken when clearing each fault. Use of modern numerical relays can assist, as they often have a CB condition-monitoring feature included that can be arranged to indicate to a Control Centre when maintenance is required. Auto-reclose may then be locked out until maintenance has been carried out.

4.3.2 System conditions

If statistical information on a particular system shows a moderate percentage of semi-permanent faults that could be burned out during 2 or 3 time-delayed trips, a multi-shot scheme may be justified. This is often the case in forest areas. Another situation is where fused ‘tees’ are used and the fault level is low, since the fusing time may not discriminate with the main I.D.M.T. relay. The use of several shots will heat the fuse to such an extent that it would eventually blow before the main protection operated.

5. Auto-reclosing on EHV transmission lines

The most important consideration in the application of auto-reclosing to EHV transmission lines is the maintenance of system stability and synchronism. The problems involved are dependent on whether the transmission system is weak or strong. With a weak system, loss of a transmission link may lead quickly to an excessive phase angle across the CB used for re-closure, thus preventing a successful re-closure. In a relatively strong system, the rate of change of phase angle will be slow, so that delayed auto-reclose can be successfully applied.

An illustration is the interconnector between two power systems as shown in Figure D1.4.

Under healthy conditions, the amount of synchronising power transmitted, P, crosses the power/angle curve OAB at point X, showing that the phase displacement between the two systems is θ_0.

Under fault conditions, the curve OCB is applicable, and the operating point changes to Y. Assuming constant power input to both ends of the line, there is now an accelerating power XY. As a result, the operating point moves to Z, with an increased phase displacement, θ_1, between the two systems. At this point the circuit breakers trip and break the connection. The phase displacement continues to increase at a rate dependent on the inertia of the two power sources. To maintain

5. Auto-reclosing on EHV transmission lines

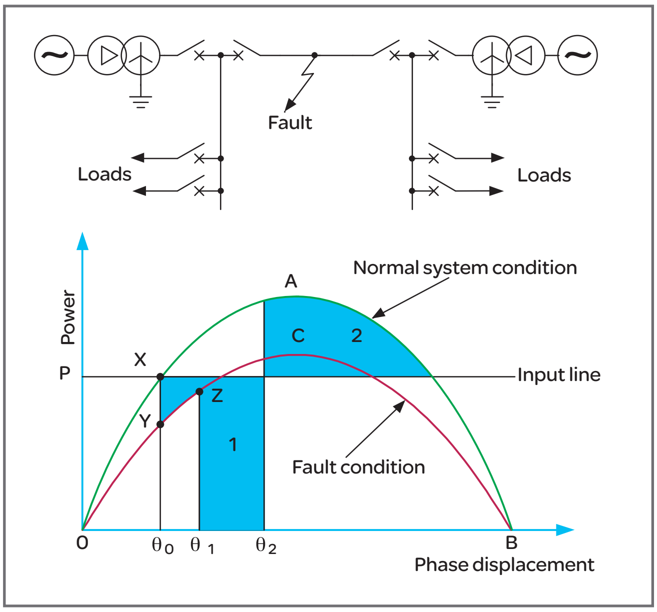

Figure D1.4:
Effect of high-speed three-phase auto-reclosing on system stability for a weak system

synchronism, the circuit breaker must be reclosed in a time short enough to prevent the phase angle exceeding θ_2. This angle is such that the area (2) stays greater than the area (1), which is the condition for maintenance of synchronism.

This example, for a weak system, shows that the successful application of auto-reclosing in such a case needs high-speed protection and circuit breakers, and a short dead time. On strong systems, synchronism is unlikely to be lost by the tripping out of a single line. For such systems, an alternative policy of delayed auto-reclosing may be adopted. This enables the power swings on the system resulting from the fault to decay before reclosure is attempted.

The various factors to be considered when using EHV auto-reclose schemes are now dealt with. High-speed and delayed auto-reclose schemes are discussed separately.

6. High speed auto-reclosing on EHV systems

The first requirement for the application of high-speed auto-reclosing is knowledge of the system disturbance time that can be tolerated without loss of system stability. This will normally require transient stability studies to be conducted for a defined set of power system configurations and fault conditions. With knowledge of protection and circuit breaker operating characteristics and fault arc de-ionisation times, the feasibility of high-speed auto-reclosing can then be assessed. These factors are now discussed.

6.1 Protection characteristics

The use of high-speed protection equipment, such as distance or unit protection schemes, giving operating times of less than 50ms, is essential. In conjunction with fast operating circuit breakers, high-speed protection reduces the duration of the fault arc and thus the total system disturbance time.

It is important that the circuit breakers at both ends of a fault line should be tripped as rapidly as possible. The time that the line is still being fed from one end represents an effective reduction in the dead time, and may well jeopardise the chances of a successful reclosure. When distance protection is used, and the fault occurs near one end of the line, special measures have to be adopted to ensure simultaneous tripping at each end. These are described in Section 8.

6.2 De-Ionisation of fault arc

It is important to know the time that must be allowed for complete de-ionisation of the arc, to prevent the arc restriking when the voltage is re-applied.

The de-ionisation time of an uncontrolled arc, in free air depends on the circuit voltage, conductor spacing, fault currents, fault duration, wind speed and capacitive coupling from adjacent conductors.

Of these, the circuit voltage is the most important, and as a general rule, the higher the voltage the longer the time required for de- ionisation. Typical values are given in Table D1.1.

If single-phase tripping and auto-reclosing is used, capacitive coupling between the healthy phases and the faulty phase tends to maintain the arc and hence extend the dead time required. This is a particular problem on long distance EHV transmission lines.

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6. High speed auto-reclosing on EHV systems

Line voltage (kV)	Minimum de-energisation time (seconds)
66	0.2
110	0.28
132	0.3
220	0.35
275	0.38
40	0.45
525	0.55

Table D1.1:
Fault-arc de-ionisation times

6.3 Circuit breaker characteristics

The high fault levels involved in EHV systems impose a very severe duty on the circuit breakers used in high-speed auto-reclose schemes. The accepted breaker cycle of break-make-break requires the circuit breaker to interrupt the fault current, reclose the circuit after a time delay of upwards of 0.2s and then break the fault current again if the fault persists. The types of circuit breaker commonly used on EHV systems are oil, air blast and SF6 types.

6.3.1 Oil circuit breakers

Oil circuit breakers are used for transmission voltages up to 300kV, and can be subdivided into the two types: 'bulk oil' and 'small oil volume'. The latter is a design aimed at reducing the fire hazard associated with the large volume of oil contained in the bulk oil breaker.

The operating mechanisms of oil circuit breakers are of two types, 'fixed trip' and 'trip free', of which the latter is the most common. With trip-free types, the reclosing cycle must allow time for the mechanism to reset after tripping before applying the closing impulse.

Special means have to be adopted to obtain the short dead times required for high-speed auto-reclosing. Various types of tripping mechanism have been developed to meet this requirement.

The three types of closing mechanism fitted to oil circuit breakers are:

a. solenoid

b. spring

c. pneumatic

CBs with solenoid closing are not suitable for high-speed auto-reclose due to the long time constant involved. Spring, hydraulic or pneumatic closing mechanisms are universal at the upper end of the EHV range and give the fastest closing time. Figure D1.3 shows the operation times for various types of EHV circuit breakers, including the dead time that can be attained.

6.3.2 Air blast circuit breakers

Air blast breakers have been developed for voltages up to the highest at present in use on transmission lines. They fall into two categories:

a. pressurised head circuit breakers

b. non-pressurised head circuit breakers

In pressurised head circuit breakers, compressed air is maintained in the chamber surrounding the main contacts. When a tripping signal is received, an auxiliary air system separates the main contacts and allows compressed air to blast through the gap to the atmosphere, extinguishing the arc. With the contacts fully open, compressed air is maintained in the chamber.

Loss of air pressure could result in the contacts reclosing, or, if a mechanical latch is employed, restriking of the arc in the de-pressurised chamber. For this reason, sequential series isolators, which isolate the main contacts after tripping, are commonly used with air blast breakers. Since these are comparatively slow in opening, their operation must be inhibited when auto-reclosing is required. A contact on the auto-reclose relay is made available for this purpose.

Non-pressurised head circuit breakers are slower in operation than the pressurised head type and are not usually applied in high-speed reclosing schemes.

6.3.3 SF6 circuit breakers

Many EHV circuit breakers are manufactured using SF6 gas as an insulating and arc-quenching medium. The basic design of such circuit breakers is in many ways similar to that of pressurised head air blast circuit breakers, and normally retain all, or almost all, of their voltage withstand capability, even if the SF6 pressure level falls to atmospheric pressure. Sequential series isolators are therefore not normally used, but they are sometimes specified to prevent damage to the circuit breaker in the event of a lightning strike on an open ended conductor. Provision should therefore be made to inhibit sequential series isolation during an auto-reclose cycle.

6.4 Choice of dead time

At voltages of 220kV and above, the de-ionisation time will probably dictate the minimum dead time, rather than any circuit breaker limitations. This can be deduced from Table D1.1. The dead time setting on a high-speed auto-reclose relay should be long enough to ensure complete de-ionisation of the arc. On EHV systems, an unsuccessful reclosure is more detrimental to the system than no reclosure at all.

6. High speed auto-reclosing on EHV systems

6.5 Choice of reclaim time

Where EHV oil circuit breakers are concerned, the reclaim time should take account of the time needed for the closing mechanism to reset ready for the next reclosing operation.

6.6 Number of shots

High-speed auto-reclosing on EHV systems is invariably single shot. Repeated reclosure attempts with high fault levels would have serious effects on system stability, so the circuit breakers are locked out after one unsuccessful attempt. Also, the incidence of semi-permanent faults which can be cleared by repeated reclosures is less likely than on HV systems.

7. Single-phase auto-reclosing

Single phase-to-earth faults account for the majority of overhead line faults. When three-phase auto-reclosing is applied to single circuit interconnectors between two power systems, the tripping of all three phases may cause the two systems to drift apart in phase, as described in Section 5. No interchange of synchronising power can take place during the dead time. If only the faulty phase is tripped, synchronising power can still be interchanged through the healthy phases. Any difference in phase between the two systems will be correspondingly less, leading to a reduction in the disturbance on the system when the circuit breaker recloses.

For single-phase auto-reclosing each circuit breaker pole must be provided with its own closing and tripping mechanism; this is normal with EHV air blast and SF6 breakers. The associated tripping and reclosing circuitry is therefore more complicated, and, except in distance schemes, the protection may need the addition of phase selection logic.

On the occurrence of a phase-earth fault, single-phase auto-reclose schemes trip and reclose only the corresponding pole of the circuit breaker. The auto-reclose function in a relay therefore has three separate elements, one for each phase. Operation of any element energises the corresponding dead timer, which in turn initiates a closing pulse for the appropriate pole of the circuit breaker. A successful reclosure results in the auto-reclose logic resetting at the end of the reclaim time, ready to respond to a further fault incident. If the fault is persistent and reclosure is unsuccessful, it is usual to trip and lock out all three poles of the circuit breaker.

The above describes only one of many variants. Other possibilities are:

a. three-phase trip and lockout for phase-phase or 3-phase faults, or if either of the remaining phases should develop a fault during the dead time

b. use of a selector switch to give a choice of single- or three-phase reclosing

c. combined single- and three-phase auto-reclosing; single phase-to-earth faults initiate single-phase tripping and reclosure, and phase-phase faults initiate three-phase tripping and reclosure

Modern numerical relays often incorporate the logic for all of the above schemes, for the user to select as required. Use can be made of any user-definable logic feature in a numerical relay to implement other schemes that may be required.

The advantages of single-phase auto-reclosing are:

a. the maintenance of system integrity

b. on multiple earth systems, negligible interference with the transmission of load. This is because the current in the faulted phase can flow through earth via the various earthing points until the fault is cleared and the faulty phase restored

The main disadvantage is the longer de-ionisation time resulting from capacitive coupling between the faulty and healthy lines. This leads to a longer dead time being required. Maloperation of earth fault relays on double circuit lines owing to the flow of zero sequence currents may also occur. These are induced by mutual induction between faulty and healthy lines (see Chapter [C5: Protection of Complex Transmission Circuits] for details).

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8. High-speed auto-reclosing on lines employing distance schemes

The importance of rapid tripping of the circuit breakers at each end of a faulted line where high-speed auto-reclosing is employed has already been covered in Section 6. Simple distance protection presents some difficulties in this respect.

Owing to the errors involved in determining the ohmic setting of the distance relays, it is not possible to set Zone 1 of a distance relay to cover 100% of the protected line – see Chapter [C3: Distance Protection] for more details. Zone 1 is set to cover 80-85% of the line length, with the remainder of the line covered by time-delayed Zone 2 protection.

Figure D1.5 illustrates this for a typical three-zone distance scheme covering two transmission lines.

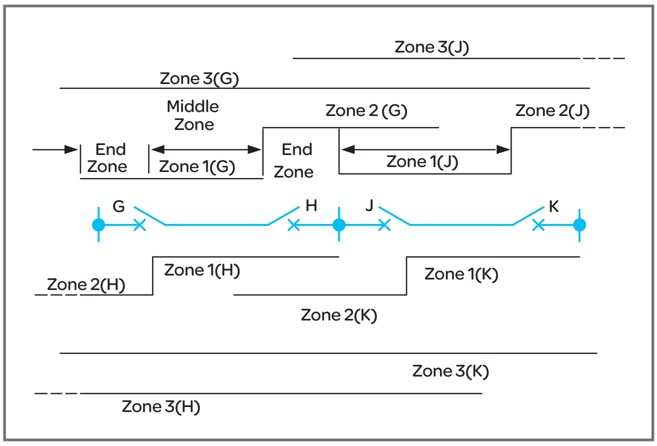

Figure D1.5:
Typical three zone distance scheme

For this reason, a fault occurring in an end zone would be cleared instantaneously, by the protection at one end of the feeder. However, the CB at the other end opens in 0.3-0.4 seconds (Zone 2 time). High-speed auto-reclosing applied to the circuit breakers at each end of the feeder could result either in no dead time or in a dead time insufficient to allow de-ionisation of the fault arc. A transient fault could therefore be seen as a permanent one, resulting in the locking out of both circuit breakers.

Two methods are available for overcoming this difficulty. Firstly, one of the transfer-trip or blocking schemes that involves the use of an intertrip signal between the two ends of the line can be used. Alternatively, a Zone 1 extension scheme may be used to give instantaneous tripping over the whole line length. Further details of these schemes are given in Chapter [C4: Distance Protection Schemes], but a brief description of how they are used in conjunction with an auto-reclose scheme is given below.

8.1 Transfer-trip or blocking schemes

This involves use of a signalling channel between the two ends of the line. Tripping occurs rapidly at both ends of the faulty line, enabling the use of high-speed auto-reclose. Some complication occurs if single-phase auto-reclose is used, as the signalling channel must identify which phase should be tripped, but this problem does not exist if a modern numerical relay is used.

Irrespective of the scheme used, it is customary to provide an auto-reclose blocking relay to prevent the circuit breakers auto-reclosing for faults seen by the distance relay in Zones 2 and 3.

8.2 Zone 1 extension

In this scheme, the reach of Zone 1 is normally extended to 120% of the line length and is reset to 80% when a command from the auto-reclose logic is received. This auto-reclose logic signal should occur before a closing pulse is applied to the circuit breaker and remain operated until the end of the reclaim time. The logic signal should also be present when auto-reclose is out of service.

9. Delayed auto-reclosing on EHV systems

On highly interconnected transmission systems, where the loss of a single line is unlikely to cause two sections of the system to drift apart significantly and lose synchronism, delayed auto-reclosing can be employed. Dead times of the order of 5s-60s are commonly used. No problems are presented by fault arc de-ionisation times and circuit breaker operating characteristics, and power swings on the system decay before reclosing. In addition, all tripping and reclose schemes can be three-phase only, simplifying control circuits in comparison with single-phase schemes. In systems on which delayed auto-reclosing is permissible, the chances of a reclosure being successful are somewhat greater with delayed reclosing than would be the case with high-speed reclosing.

9.1 Scheme operation

The sequence of operations of a delayed auto-reclose scheme can be best understood by reference to Figure D1.6. This shows a transmission line connecting two substations A and B, with the circuit beakers at A and B tripping out in the event of a line fault. Synchronism is unlikely to be lost in a system that employs delayed auto-reclose. However, the transfer of power through the remaining tie-lines on the system could result in the development of an excessive phase difference between the voltages at points A and B. The result, if reclosure takes place, is an unacceptable shock to the system. It is therefore usual practice to incorporate a synchronism check relay into the reclosing system to determine whether auto-reclosing should take place.

After tripping on a fault, it is normal procedure to reclose the breaker at one end first, a process known as ‘live bus/dead line charging’. Reclosing at the other and is then under the control of a synchronism check relay element for what is known as bus/live line reclosing’.

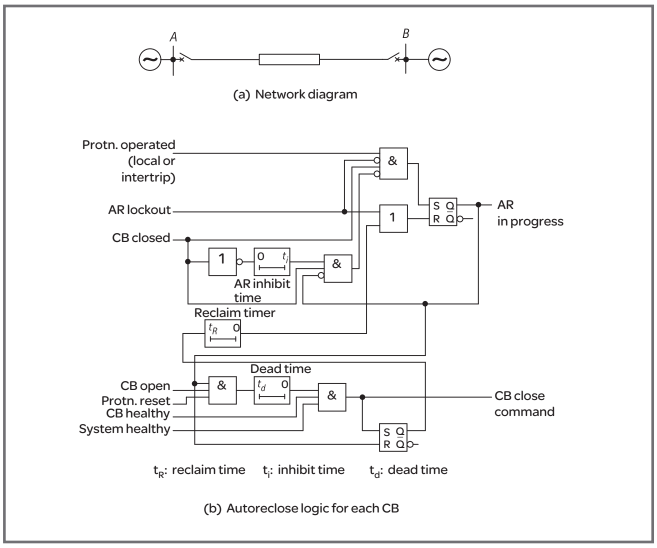

Figure D1.6:
Delayed auto-reclose scheme logic

For example, if it were decided to charge the line initially from station A, the dead time in the auto-reclose relay at A would be set at, say, 5 seconds, while the corresponding timer in the auto-reclose relay at B would be set at, say, 15 seconds. The circuit breaker at A would then reclose after 5 seconds provided that voltage monitoring relays at A indicated that the busbars were alive and the line dead. With the line recharged, the circuit breaker at B would then reclose with a synchronism check, after a 2 second delay imposed by the synchronism check relay element.

If for any reason the line fails to ‘dead line charge’ from end A, reclosure from end B would take place after 15 seconds. The circuit breaker at A would then be given the opportunity to reclose with a synchronism check.

9.2 Synchronism check relays

The synchronism check relay element commonly provides a three-fold check:

a. phase angle difference

b. voltage

c. frequency difference

The phase angle setting is usually set to between 20°– 45°, and reclosure is inhibited if the phase difference exceeds this value. The scheme waits for a reclosing opportunity with the phase angle within the set value, but locks out if reclosure does not occur within a defined period, typically 5s.

A voltage check is incorporated to prevent reclosure under various circumstances. A number of different modes may be available. These are typically undervoltage on either of the two measured voltages, differential voltage, or both of these conditions.

The logic also incorporates a frequency difference check, either by direct measurement or by using a timer in conjunction with the phase angle check. In the latter case, if a 2 second timer is employed, the logic gives an output only if the phase difference does not exceed the phase angle setting over a period of 2 seconds. This limits the frequency difference (in the case of a phase angle setting of 20°) to a maximum of 0.11% of 50Hz, corresponding to a phase swing from +20° to -20° over the measured 2 seconds. While a significant frequency difference is unlikely to arise during a delayed auto-reclose sequence, the time available allows this check to be carried out as an additional safeguard.

As well as ‘live bus/dead line’ and ‘live bus/live line’ reclosing, sometimes ‘live line/dead bus’ reclosing may need to be implemented. A numerical relay will typically allow any combination of these modes to be implemented. The voltage settings for distinguishing between ‘live’ and ‘dead’ conditions must be carefully chosen. In addition, the locations of the VTs must be known and checked so that the correct voltage signals are connected to the ‘line’ and ‘bus’ inputs.

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10. Operating features of auto-reclose schemes

The extensive use of auto-reclosing has resulted in the existence of a wide variety of different control schemes. Some of the more important variations in the features provided are described below.

10.1 Initiation

Modern auto-reclosing schemes are invariably initiated by the tripping command of a protection relay function. Some older schemes may employ a contact on the circuit breaker. Modern digital or numerical relays often incorporate a comprehensive auto-reclose facility within the relay, thus eliminating the need for a separate auto-reclose relay and any starter relays.

10.2 Type of protection

On HV distribution systems, advantage is often taken of auto-reclosing to use instantaneous protection for the first trip, followed by I.D.M.T. for subsequent trips in a single fault incident. In such cases, the auto-reclose relay must provide a means of isolating the instantaneous relay after the first trip. In older schemes, this may be done with a normally closed contact on the auto-reclose starting element wired into the connection between the instantaneous relay contact and the circuit breaker trip coil. With digital or numerical relays with in-built auto-reclose facilities, internal logic facilities will normally be used.

With certain supply authorities, it is the rule to fit tripping relays to every circuit breaker. If auto-reclosing is required, electrically reset tripping relays must be used, and a contact must be provided either in the auto-reclose logic or by a separate trip relay resetting scheme to energise the reset coil before reclosing can take place.

10.3 Dead timer

This will have a range of settings to cover the specified high-speed or delayed reclosing duty. Any interlocks that are needed to hold up reclosing until conditions are suitable can be connected into the dead timer circuit. Section 12.1 provides an example of this applied to transformer feeders.

10.4 Reclosing impulse

The duration of the reclosing impulse must be related to the requirements of the circuit breaker closing mechanism. On auto-reclose schemes using spring-closed breakers, it is sufficient to operate a contact at the end of the dead time to energise the latch release coil on the spring-closing mechanism. A circuit breaker auxiliary switch can be used to cancel the closing pulse and reset the auto-reclose relay. With solenoid operated breakers, it is usual to provide a closing pulse of the order of 1-2 seconds, so as to hold the solenoid energised for a short time after the main contacts have closed. This ensures that the mechanism settles in the fully latched-in position. The pneumatic or hydraulic closing mechanisms fitted to oil, air blast and SF6 circuit breakers use a circuit breaker auxiliary switch for terminating the closing pulse applied by the auto-reclose relay.

10.5 Anti-pumping devices

The function of an anti-pumping device is to prevent the circuit breaker closing and opening several times in quick succession. This might be caused by the application of a closing pulse while the circuit breaker is being tripped via the protection relays. Alternatively, it may occur if the circuit breaker is closed on to a fault and the closing pulse is longer than the sum of protection relay and circuit breaker operating times. Circuit breakers with trip free mechanisms do not require this feature.

10.6 Reclaim timer

Electromechanical, static or software-based timers are used to provide the reclaim time, depending on the relay technology used. If electromechanical timers are used, it is convenient to employ two independently adjustable timed contacts to obtain both the dead time and the reclaim time on one timer. With static and software-based timers, separate timer elements are generally provided.

10.7 CB lockout

If reclosure is unsuccessful the auto-reclose relay locks out the circuit breaker. Some schemes provide a lockout relay with a flag, with provision of a contact for remote alarm. The circuit breaker can then only be closed by hand; this action can be arranged to reset the auto-reclose relay element automatically. Alternatively, most modern relays can be configured such that a lockout condition can be reset only by operator action.

Circuit breaker manufacturers state the maximum number of operations allowed before maintenance is required. A number of schemes provide a fault trip counting function and give a warning when the total approaches the manufacturer's recommendation. These schemes will lock out when the total number of fault trips has reached the maximum value allowed.

10.8 Manual closing

It is undesirable to permit auto-reclosing if circuit breaker closing is manually initiated. Auto-reclose schemes include the facility to inhibit auto-reclose initiation for a set time following manual CB closure. The time is typically in the range of 2-5 seconds.

10.9 Multi-shot schemes

Schemes providing up to three or four shots using timing circuits are often included in an auto-reclose relay to provide different, independently adjustable, dead times for each shot. Instantaneous protection can be used for the first trip, since each scheme provides a signal to inhibit instantaneous tripping after a set number of trips and selects I.D.M.T. protection for subsequent ones. The scheme resets if reclosure is successful within the chosen number of shots, ready to respond to further fault incidents.

11. Auto-close circuits

Auto-close schemes are employed to close automatically circuit breakers that are normally open when the supply network is healthy. This may occur for a variety of reasons, for instance the fault level may be excessive if the CBs were normally closed. The circuits involved are very similar to those used for auto-reclosing. Two typical applications are described in the following sections.

11.1 Standby transformers

Figure D1.7 shows a busbar station fed by three transformers, $T1$, $T2$, and $T3$. The loss of one transformer might cause serious overloading of the remaining two. However, connection of a further transformer to overcome this may increase the fault level to an unacceptable value.

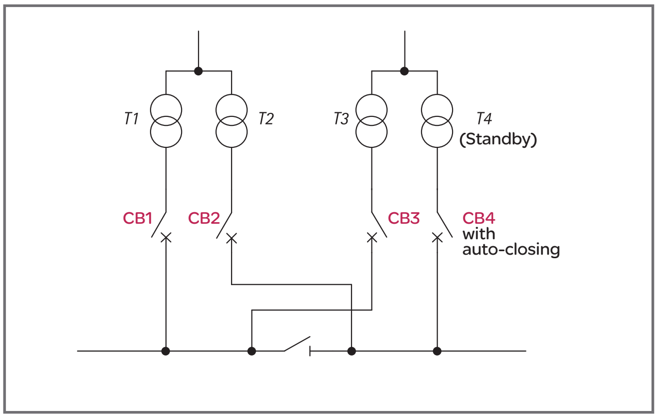


Figure D1.7:
Standby transformer with auto-closing

The solution is to have a standby transformer $T4$ permanently energised from the primary side and arranged to be switched into service if one of the others trips on fault.

The starting circuits for breaker $CB4$ monitor the operation of transformer protection on any of the transformers $T1$, $T2$, and $T3$ together with the tripping of an associated circuit breaker $CB1$-$CB3$. In the event of a fault, the auto-close circuit is initiated and circuit breaker $CB4$ closes, after a short time delay, to switch in the standby transformer. Some schemes employ an auto-tripping relay, so that when the faulty transformer is returned to service, the standby is automatically disconnected.

11.2 Bus coupler or bus section breaker

If all four power transformers are normally in service for the system of Figure D1.7, and the bus sections are interconnected by a normally-open bus section breaker instead of the isolator, the bus section breaker should be auto-closed in the event of the loss of one transformer, to spread the load over the remaining transformers. This, of course, is subject to the fault level being acceptable with the bus-section breaker closed.

Starting and auto-trip circuits are employed as in the stand-by scheme. The auto-close relay used in practice is a variant of one of the standard auto-reclose relays.

12. Examples of auto-reclose applications

Auto-reclose facilities in common use for a number of standard substation configurations are described in the following sections.

12.1 Double busbar substation

A typical double busbar station is illustrated in Figure D1.8. Each of the six EHV transmission lines brought into the station is under the control of a circuit breaker, $CB1$ to $CB6$ inclusive, and each transmission line can be connected either to the main or to the reserve busbars by manually operated isolators.

Bus section isolators enable sections of busbar to be isolated in the event of fault, and bus coupler breaker BC permits sections of main and reserve bars to be interconnected.

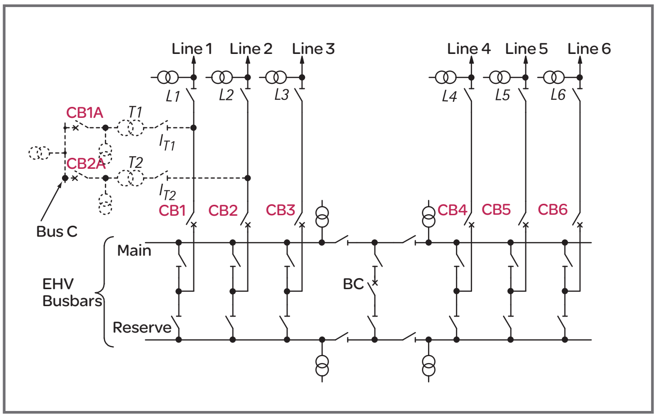


Figure D1.8:
Double busbar substation

D1

12. Examples of auto-reclose applications

12.1.1 Basic scheme – banked transformers omitted

Each line circuit breaker is provided with an auto-reclose relay that recloses the appropriate circuit breakers in the event of a line fault. For a fault on $Line\ 1$, this would require opening of $CB1$ and the corresponding CB at the remote end of the line. The operation of either the busbar protection or a VT Buchholz relay is arranged to lock out the auto-reclosing sequence. In the event of a persistent fault on $Line\ 1$, the line circuit breakers trip and lock out after one attempt at reclosure.

12.1.2 Scheme with banked transformers

Some utilities use a variation of the basic scheme in which Transformers $T1$ and $T2$ are banked off $Lines\ 1$ and 2, as shown in Figure D1.8. This provides some economy in the number of circuit breakers required. The corresponding transformer circuits 1 and 2 are tee'd off $Lines\ 1$ and 2 respectively. The transformer secondaries are connected to a separate HV busbar system via circuit breakers $CB1A$ and $CB2A$.

Auto-reclose facilities can be extended to cover the circuits for banked transformers where these are used.

For example, a fault on $Line\ 1$ would cause the tripping of circuit breakers $CB1$, $CB1A$ and the remote line circuit breaker. When $Line\ 1$ is re-energised, either by auto-reclosure of $CB1$ or by the remote circuit breaker, whichever is set to reclose first, transformer $T1$ is also energised. $CB1A$ will not reclose until the appearance of transformer secondary voltage, as monitored by the secondary VT; it then recloses on to the HV busbars after a short time delay, with a synchronism check if required.

In the event of a fault on transformer $T1$, the local and remote line circuit breakers and breaker $CB1A$ trip to isolate the fault. Automatic opening of the motorised transformer isolator I_{T1} follows this. The line circuit breakers then reclose in the normal manner and circuit breaker $CB1A$ locks out.

A shortcoming of this scheme is that this results in healthy transformer $T1$ being isolated from the system; also, isolator $L1$ must be opened manually before circuit breakers $CB1$ and $CB1A$, can be closed to re-establish supply to the HV busbars via the transformer. A variant of this scheme is designed to instruct isolator $L1$ to open automatically following a persistent fault on $Line\ 1$ and provide a second auto-reclosure of $CB1$ and $CB1A$. The supply to $Bus\ C$ is thereby restored without manual intervention.

12.2 Single switch substation

The arrangement shown in Figure D1.9 consists basically of two transformer feeders interconnected by a single circuit breaker 120. Each transformer therefore has an alternative source of supply in the event of loss of one or other of the feeders.

For example, a transient fault on $Line\ 1$ causes tripping of circuit breakers 120 and $B1$ followed by reclosure of $CB\ 120$. If the reclosure is successful, Transformer $T1$ is re-energised and circuit breaker $B1$ recloses after a short time delay.

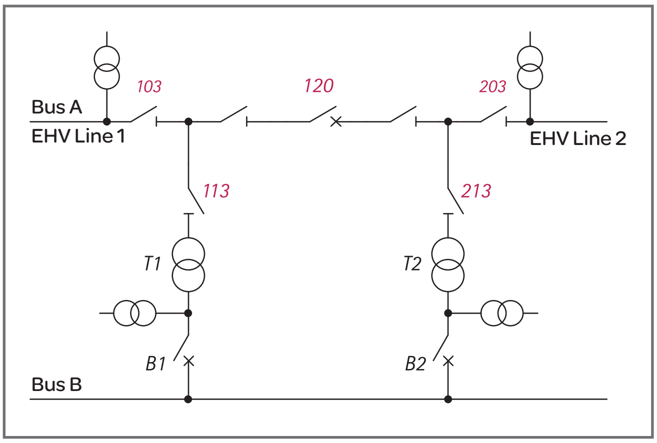


Figure D1.9:
Single switch substation

If the line fault is persistent, 120 trips again and the motorised line isolator 103 is automatically opened. Circuit breaker 120 recloses again, followed by $B1$, so that both transformers $T1$ and $T2$ are then supplied from $Line\ 2$.

A transformer fault causes the automatic opening of the appropriate transformer isolator, lock-out of the transformer secondary circuit breaker and reclosure of circuit breaker 120. Facilities for dead line charging or reclosure with synchronism check are provided for each circuit breaker.

12.3 Four-switch mesh substation

The mesh substation illustrated in Figure D1.10 is extensively used by some utilities, either in full or part. The basic mesh has a feeder at each corner, as shown at mesh corners $MC2$, $MC3$ and $MC4$. One or two transformers may also be banked at a mesh corner, as shown at $MC1$. Mesh corner protection is required if more than one circuit is fed from a mesh corner, irrespective of the CT locations – see Chapter [C6: Busbar Protection] for more details.

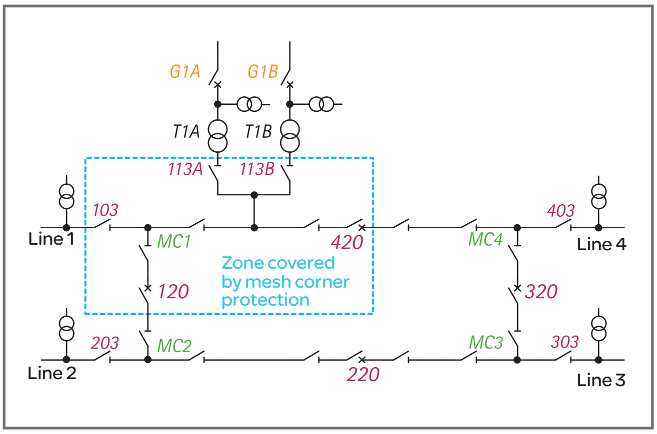


Figure D1.10:
Four-switch mesh substation

12. Examples of auto-reclose applications

Considerable problems can be encountered in the application of auto-reclosing to the mesh substation. For example, circuit breakers 120 and 420 in Figure D1.10 are tripped out for a variety of different types of fault associated with mesh corner 1 ($MC1$), and each requires different treatment as far as auto-reclosing is concerned. Further variations occur if the faults are persistent.

Following normal practice, circuit breakers must be reclosed in sequence, so sequencing circuits are necessary for the four mesh breakers. Closing priority may be in any order, but is normally 120, 220, 320, and 420.

A summary of facilities is now given, based on mesh corner $MC1$ to show the inclusion of banked transformers; facilities at other corners are similar but omit the operation of equipment solely associated with the banked transformers.

12.3.1 Transient fault on Line 1

Tripping of circuit breakers 120, 420, and $G1B$ is followed by reclosure of 120 to give dead line charging of $Line\ 1$. Breaker 420 recloses in sequence, with a synchronism check. Breakers $G1A$, $G1B$ reclose with a synchronism check if necessary.

12.3.2 Persistent fault on Line 1

Circuit breaker 120 trips again after the first reclosure and isolator 103 is automatically opened to isolate the faulted line. Breakers 120, 420, $G1A$ and $G1B$ then reclose in sequence as above.

12.3.3 Transformer fault (local transformer 1A)

Automatic opening of isolator $113A$ to isolate the faulted transformer follows tripping of circuit breakers 120, 420, $G1A$ and $G1B$. Breakers 120, 420 and $G1B$ then reclose in sequence, and breaker $G1A$ is locked out.

12.3.4 Transformer fault (remote transformer)

For a remote transformer fault, an intertrip signal is received at the local station to trip breakers 120, 420, $G1A$ and $G1B$ and inhibit auto-reclosing until the faulted transformer has been isolated at the remote station. If the intertrip persists for 60 seconds it is assumed that the fault cannot be isolated at the remote station. Isolator 103 is then automatically opened and circuit breakers 120, 420, $G1A$ and $G1B$ are reclosed in sequence.

12.3.5 Transient mesh corner fault

Any fault covered by the mesh corner protection zone, shown in Figure D1.10, results in tripping of circuit breakers 120, 420, $G1A$ and $G1B$. These are then reclosed in sequence.

There may be circumstances in which reclosure onto a persistent fault is not permitted – clearly it is not known in advance of reclosure if the fault is persistent or not. In these circumstances, scheme logic inhibits reclosure and locks out the circuit breakers.

12.3.6 Persistent mesh corner fault

The sequence described in Section 12.3.5 is followed initially. When CB 120 is reclosed, it will trip again due to the fault and lock out. At this point, the logic inhibits the reclosure of CBs 420, $G1A$ and $G1B$ and locks out these CBs. Line isolator 103 is automatically opened to isolate the fault from the remote station.

D2

Signalling and Intertripping in Protection Schemes

Network Protection & Automation Guide

Life Is On | Schneider Electric

Chapter

D2

Signalling and Intertripping in Protection Schemes

1. Introduction

Unit protection schemes, formed by a number of relays located remotely from each other, and some distance protection schemes, require some form of communication between each location in order to achieve a unit protection function. This form of communication is known as protection signalling. Additionally communications facilities are also required when remote operation of a circuit breaker is required as a result of a local event. This form of communications is known as intertripping.

The communication messages involved may be quite simple, involving instructions for the receiving device to take some defined action (trip, block, etc.), or it may be the passing of measured data in some form from one device to another (as in a unit protection scheme).

Various types of communication links are available for protection signalling, for example:

a. private pilot wires installed by the power authority

b. pilot wires or channels rented from a communications company

c. carrier channels at high frequencies over the power lines

d. radio channels at very high or ultra high frequencies

e. optical fibres

Whether or not a particular link is used depends on factors such as the availability of an appropriate communication network, the distance between protection relaying points, the terrain over which the power network is constructed, as well as cost.

Protection signalling is used to implement Unit Protection schemes, provide teleprotection commands, or implement intertripping between circuit breakers

2. Unit protection schemes

Phase comparison and current differential schemes use signalling to convey information concerning the relaying quantity - phase angle of current and phase and magnitude of current respectively - between local and remote relaying points. Comparison of local and remote signals provides the basis for both fault detection and discrimination of the schemes.

Details of Unit Protection schemes are given in Chapter [C1: Overcurrent Protection for Phase and Earth Faults].

Communications methods are covered later in this Chapter.

3. Teleprotection commands

Some Distance Protection schemes described in Chapter [C4: Distance Protection Schemes] use signalling to convey a command between local and remote relaying points. Receipt of the information is used to aid or speed up clearance of faults within a protected zone or to prevent tripping from faults outside a protected zone.

Teleprotection systems are often referred to by their mode of operation, or the role of the teleprotection command in the system.

4. Intertripping

Intertripping is the controlled tripping of a circuit breaker so as to complete the isolation of a circuit or piece of apparatus in sympathy with the tripping of other circuit breakers. The main use of such schemes is to ensure that protection at both ends of a faulted circuit will operate to isolate the equipment concerned. Possible circumstances when it may be used are:

a. a feeder with a weak infeed at one end, insufficient to operate the protection for all faults

b. feeder protection applied to transformer-feeder circuits. Faults on the transformer windings may operate the transformer protection but not the feeder protection. Similarly, some earth faults may not be detected due to transformer connections

c. faults between the CB and feeder protection CTs, when these are located on the feeder side of the CB. Bus-zone protection does not result in fault clearance – the fault is still fed from the remote end of the feeder, while feeder unit protection may not operate as the fault is outside the protected zone.

d. some distance protection schemes use intertripping to improve fault clearance times for some kinds of fault – see Chapters [C4: Distance Protection Schemes] and [C5: Protection of Complex Transmission Circuits].

Intertripping schemes use signalling to convey a trip command to remote circuit breakers to isolate circuits. For high reliability EHV protection schemes, intertripping may be used to give back-up to main protections, or back-tripping in the case of breaker failure. Three types of intertripping are commonly encountered, and are described below.

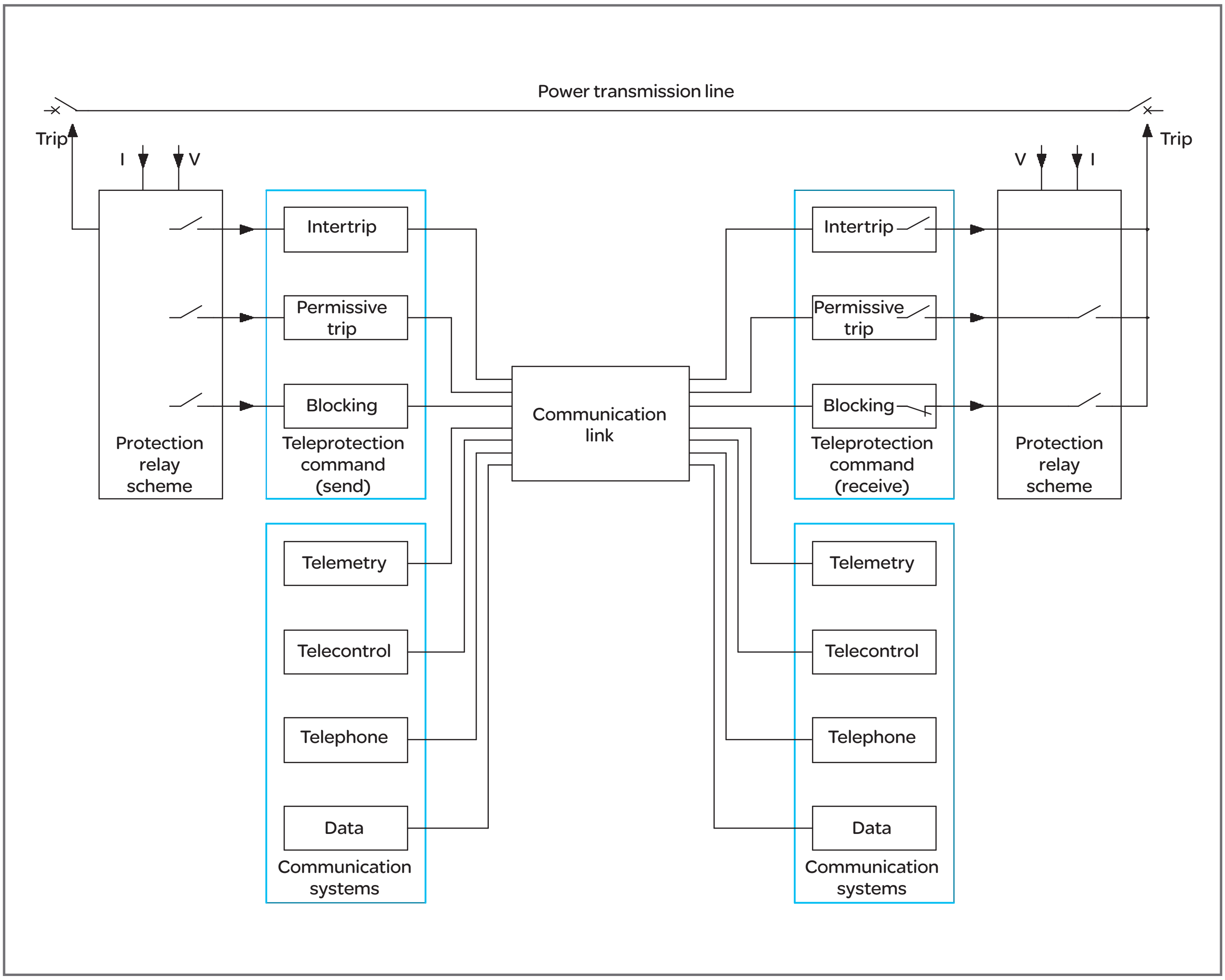


Figure D2.1:
Application of protection signalling and its relationship to other systems using communication (shown as a unidirectional system for simplicity)

D2

4. Intertripping

4.1 Direct tripping

In direct tripping applications, intertrip signals are sent directly to the master trip relay. Receipt of the command causes circuit breaker operation. The method of communication must be reliable and secure because any signal detected at the receiving end will cause a trip of the circuit at that end. The communications system design must be such that interference on the communication circuit does not cause spurious trips. Should a spurious trip occur, considerable unnecessary isolation of the primary system might result, which is at best undesirable and at worst quite unacceptable.

4.2 Permissive tripping

Permissive trip commands are always monitored by a protection relay. The circuit breaker is tripped when receipt of the command coincides with operation of the protection relay at the receiving end responding to a system fault. Requirements for the communications channel are less onerous than for direct tripping schemes, since receipt of an incorrect signal must coincide with operation of the receiving end protection for a trip operation to take place. The intention of these schemes is to speed up tripping for faults occurring within the protected zone.

4.3 Blocking scheme

Blocking commands are initiated by a protection element that detects faults external to the protected zone. Detection of an external fault at the local end of a protected circuit results in a blocking signal being transmitted to the remote end. At the remote end, receipt of the blocking signal prevents the remote end protection operating if it had detected the external fault. Loss of the communications channel is less serious for this scheme than in others as loss of the channel does not result in a failure to trip when required. However, the risk of a spurious trip is higher.

Figure D2.1 shows the typical applications of protection signalling and their relationship to other signalling systems commonly required for control and management of a power system. Of course, not all of the protection signals shown will be required in any particular scheme.

5. Performance requirements

Overall fault clearance time is the sum of:

a. signalling time

b. protection relay operating time

c. trip relay operating time

d. circuit breaker operating time

The overall time must be less than the maximum time for which a fault can remain on the system for minimum plant damage, loss of stability, etc. Fast operation is therefore a pre-requisite of most signalling systems.

Typically the time allowed for the transfer of a command is of the same order as the operating time of the associated protection relays. Typical operating times range from 5 to 40ms dependent on the mode of operation of the teleprotection system.

Protection signals are subjected to the noise and interference associated with each communication medium. If noise reproduces the signal used to convey the command, unwanted commands may be produced, whilst if noise occurs when a command signal is being transmitted, the command may be retarded or missed completely. Performance is expressed in terms of security and dependability. Security is assessed by the probability of an unwanted command occurring, and dependability is assessed by the probability of missing a command. The required degree of security and dependability is related to the mode of operation, the characteristics of the communication medium and the operating standards of the particular power authority.

Typical design objectives for teleprotection systems are not more than one incorrect trip per 500 equipment years and less than one failure to trip in every 1000 attempts, or a delay of more than 50msec should not occur more than once per 10 equipment years. To achieve these objectives, special emphasis may be attached to the security and dependability of the teleprotection command for each mode of operation in the system, as follows.

5.1 Performance requirements - Intertripping

Since any unwanted command causes incorrect tripping, very high security is required at all noise levels up to the maximum that might ever be encountered.

5. Performance requirements

5.2 Performance requirements - Permissive tripping

Security somewhat lower than that required for intertripping is usually satisfactory, since incorrect tripping can occur only if an unwanted command happens to coincide with operation of the protection relay for an out-of-zone fault.

For permissive over-reach schemes, resetting after a command should be highly dependable to avoid any chance of maloperations during current reversals.

5.3 Performance requirements - Blocking schemes

Low security is usually adequate since an unwanted command can never cause an incorrect trip. High dependability is required since absence of the command could cause incorrect tripping if the protection relay operates for an out-of-zone fault.

Typical performance requirements are shown in Figure D2.2.

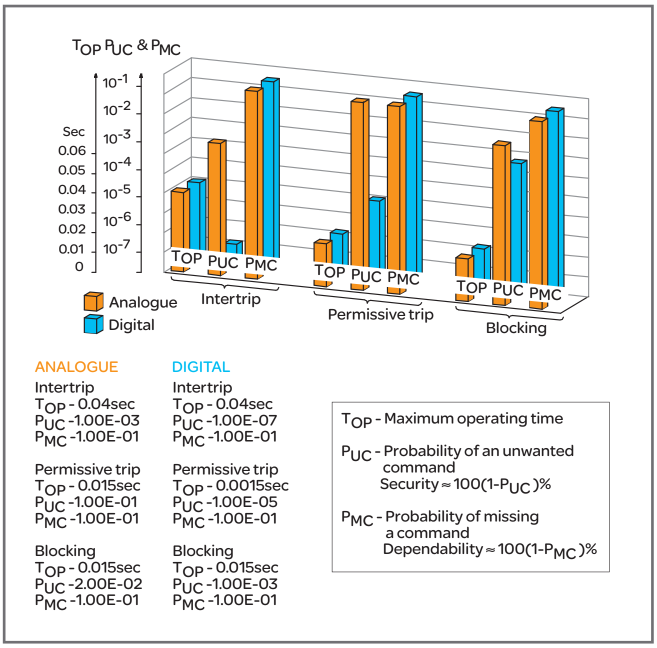


Figure D2.2:
Typical performance requirements for protection signalling when the communication link is subjected to noise

6. Transmission media, interference and noise

The transmission media that provide the communication links involved in protection signalling are:

a. private pilots

b. rented pilots or channels

c. power line carrier

d. radio

e. optical fibres

Historically, pilot wires and channels (discontinuous pilot wires with isolation transformers or repeaters along the route between signalling points) have been the most widely used due to their availability, followed by Power Line Carrier Communications (PLCC) techniques and radio. In recent years, fibre-optic systems have become the usual choice for new installations, primarily due to their complete immunity from electrical interference. The use of fibre-optic cables also greatly increases the number of communication channels available for each physical fibre connection and thus enables more comprehensive protection and monitoring of the power system to be achieved by the provision of a large number of communication channels.

6.1 Private pilot wires and channels

Pilot wires are continuous copper connections between signalling stations, while pilot channels are discontinuous pilot wires with isolation transformers or repeaters along the route between signalling stations. They may be laid in a trench with high voltage cables, laid by a separate route or strung as an open wire on a separate wood pole route.

Distances over which signalling is required vary considerably. At one end of the scale, the distance may be only a few tens of metres, where the devices concerned are located in the same substation. For applications on EHV lines, the distance between devices may be between 10-100km or more. For short distances, no special measures are required against interference, but over longer distances, special send and receive relays may be required to boost signal levels and provide immunity against induced voltages from power circuits, lightning strikes to ground adjacent to the route, etc. Isolation transformers may also have to be provided to guard against rises in substation ground potential due to earth faults.

D2

6. Transmission media, interference and noise

The capacity of a link can be increased if frequency division multiplexing techniques are used to run parallel signalling systems, but some Utilities prefer the link to be used only for protection signalling.

Private pilot wires or channels can be attractive to a Utility running a very dense power system with short distances between stations.

6.2 Rented pilot wires and channels

These are rented from national communication authorities and, apart from the connection from the relaying point to the nearest telephone exchange, the routing will be through cables forming part of the national communication network.

An economic decision has to be made between the use of private or rented pilots. If private pilots are used, the owner has complete control, but bears the cost of installation and maintenance. If rented pilots are used, most of these costs are eliminated, but fees must be paid to the owner of the pilots and the signal path may be changed without warning. This may be a problem in protection applications where signal transmission times are critical.

The chance of voltages being induced in rented pilots is smaller than for private pilots, as the pilot route is normally not related to the route of the power line with which it is associated. However, some degree of security and protection against induced voltages must be built into signalling systems. Electrical interference from other signalling systems, particularly 17, 25 and 50Hz ringing tones up to 150V peak, and from noise generated within the equipment used in the communication network, is a common hazard. Similarly, the signalling system must also be proof against intermittent short and open circuits on the pilot link, incorrect connection of 50 volts d.c. across the pilot link and other similar faults.

Station earth potential rise is a significant factor to be taken into account and isolation must be provided to protect both the personnel and equipment of the communication authority.

The most significant hazard to be withstood by a protection signalling system using this medium arises when a linesman inadvertently connects a low impedance test oscillator across the pilot link that can generate signalling tones. Transmissions by such an oscillator may simulate the operating code or tone sequence that, in the case of direct intertripping schemes, would result in incorrect operation of the circuit breaker.

Communication between relaying points may be over a two-wire or four-wire link. Consequently the effect of a particular human action, for example an incorrect disconnection, may disrupt communication in one direction or both.

The signals transmitted must be limited in both level and bandwidth to avoid interference with other signalling systems. The owner of the pilots will impose standards in this respect that may limit transmission capacity and/or transmission distance.

With a power system operating at, say, 132kV, where relatively long protection signalling times are acceptable, signalling has been achieved above speech together with metering and control signalling on an established control network. Consequently the protection signalling was achieved at very low cost. High voltage systems (220kV and above) have demanded shorter operating times and improved security, which has led to the renting of pilot links exclusively for protection signalling purposes.

6.3 Power line carrier communications techniques

Where long line sections are involved, or if the route involves installation difficulties, the expense of providing physical pilot connections or operational restrictions associated with the route length require that other means of providing signalling facilities are required.

Power Line Carrier Communications (PLCC) is a technique that involves high frequency signal transmission along the overhead power line. It is robust and therefore reliable, constituting a low loss transmission path that is fully controlled by the Utility.

High voltage capacitors are used, along with drainage coils, for the purpose of injecting the signal to and extracting it from the line. Injection can be carried out by impressing the carrier signal voltage between one conductor and earth or between any two phase conductors. The basic units can be built up into a high pass or band pass filter as shown in Figure D2.3.

The high voltage capacitor is tuned by a tuning coil to present a low impedance at the signal frequency; the parallel circuit presents a high impedance at the signal frequency while providing a path for the power frequency currents passed by the capacitor.

The complete arrangement is designed as a balanced or unbalanced half-section band pass filter, according to whether the transmission is phase-phase or phase-earth; the power line characteristic impedance, between 400 and 600 ohms, determines the design impedance of the filter.

It is necessary to minimise the loss of signal into other parts of the power system, to allow the same frequency to be used on another line. This is done with a 'line trap' or 'wave trap', which in its simplest form is a parallel circuit tuned to present a very high impedance to the signal frequency. It is connected in the phase conductor on the station side of the injection equipment. The complete carrier coupling equipment is shown in Figure D2.4.

The single frequency line trap may be treated as an integral part of the complete injection equipment to accommodate two or more carrier systems. However, difficulties may arise in an overall design, as, at certain frequencies, the actual station reactance, which is normally capacitive, will tune with

6. Transmission media, interference and noise

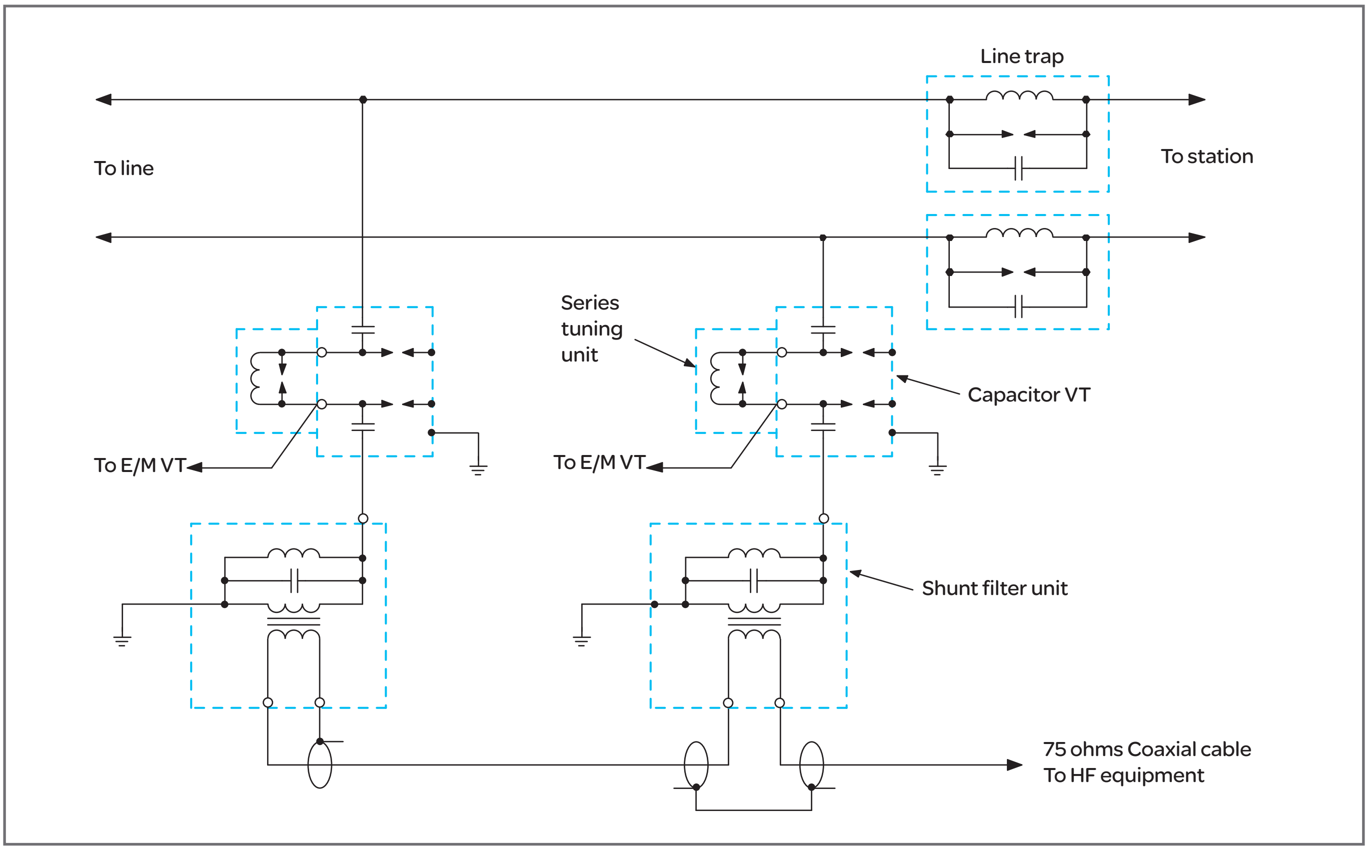


Figure D2.3:
Typical phase-to-phase coupling equipment

the trap, which is inductive below its resonant frequency; the result will be a low impedance across the transmission path, preventing operation at these frequencies. This situation can be avoided by the use of an independent 'double frequency' or 'broad-band' trap.

The coupling filter and the carrier equipment are connected by high frequency cable of preferred characteristic impedance 75 ohms. A matching transformer is incorporated in the line coupling filter to match it to the HF (High Frequency) cable. Surge diverters are fitted to protect the components against transient overvoltages.

The attenuation of a channel is of prime importance in the application of carrier signalling, because it determines the amount of transmitted energy available at the receiving end to overcome noise and interfering voltages. The loss of each line terminal will be 1 to 2dB through the coupling filter, a maximum of 3dB through its broad-band trap and not more than 0.5dB per 100 metres through the high frequency cable.

An installation of PLCC equipment including capacitor voltage transformers and line traps, in a line-to-line injection arrangement, is shown in Figure D2.4.

Figure D2.4:
Carrier coupling equipment

D2

6. Transmission media, interference and noise

The high frequency transmission characteristics of power circuits are good, with losses amounting to 0.02 to 0.2dB per kilometre depending upon line voltage and frequency. Line attenuation is not affected appreciably by rain, but serious increase in loss may occur when the phase conductors are thickly coated with hoar-frost or ice. Attenuations of up to three times the fair weather value have been experienced. Receiving equipment commonly incorporates automatic gain control (AGC) to compensate for variations in attenuation of signals.

High noise levels arise from lightning strikes and system fault inception or clearance. Although these are of short duration, lasting only a few milliseconds at the most, they may cause overloading of power line carrier receiving equipment. Signalling systems used for intertripping in particular must incorporate appropriate security features to avoid maloperation. The most severe noise levels are encountered with operation of the line isolators, and these may last for some seconds. Although maloperation of the associated teleprotection scheme may have little operational significance, since the circuit breaker at one end at least is normally already open, high security is generally required to cater for noise coupled between parallel lines or passed through line traps from adjacent lines.

Signalling for permissive intertrip applications needs special consideration, as this involves signalling through a power system fault. The increase in channel attenuation due to the fault varies according to the type of fault, but most power authorities select a nominal value, usually between 20 and 30dB, as an application guide. A protection signal boost facility can be employed to cater for an increase in attenuation of this order of magnitude, to maintain an acceptable signal-to-noise ratio at the receiving end, so that the performance of the service is not impaired.

Most direct intertrip applications require signalling over a healthy power system, so boosting is not normally needed. In fact, if a voice frequency intertrip system is operating over a carrier bearer channel, the dynamic operating range of the receiver must be increased to accommodate a boosted signal. This makes it less inherently secure in the presence of noise during a quiescent signalling condition.

6.4 Radio channels

At first consideration, the wide bandwidth associated with radio frequency transmissions could allow the use of modems operating at very high data rates. Protection signalling commands could be sent by serial coded messages of sufficient length and complexity to give high security, but still achieve fast operating times. In practice, it is seldom economic to provide radio equipment exclusively for protection signalling, so standard general-purpose telecommunications channel equipment is normally adopted.

Typical radio bearer equipment operates at the microwave frequencies of 0.2 to 10GHz. Because of the relatively short range and directional nature of the transmitter and receiver aerial systems at these frequencies, large bandwidths can be allocated without much chance of mutual interference with other systems.

Multiplexing techniques allow a number of channels to share the common bearer medium and exploit the large bandwidth. In addition to voice frequency channels, wider bandwidth channels or data channels may be available, dependent on the particular system. For instance, in analogue systems using frequency division multiplexing, normally up to 12 voice frequency channels are grouped together in basebands at 12-60kHz or 60-108kHz, but alternatively the baseband may be used as a 48kHz signal channel. Modern digital systems employing pulse code modulation and time division multiplexing usually provide the voice frequency channels by sampling at 8kHz and quantising to 8 bits; alternatively, access may be available for data at 64kbits/s (equivalent to one voice frequency channel) or higher data rates.

Radio systems are well suited to the bulk transmission of information between control centres and are widely used for this. When the route of the trunk data network coincides with that of transmission lines, channels can often be allocated for protection signalling. More generally, radio communication is between major stations rather than the ends of individual lines, because of the need for line-of-sight operation between aerials and other requirements of the network. Roundabout routes involving repeater stations and the addition of pilot channels to interconnect the radio installation and the relay station may be possible, but overall dependability will normally be much lower than for PLCC systems in which the communication is direct from one end of the line to the other.

Radio channels are not affected by increased attenuation due to power system faults, but fading has to be taken into account when the signal-to-noise ratio of a particular installation is being considered.

Most of the noise in such a protection signalling system will be generated within the radio equipment itself.

A polluted atmosphere can cause radio beam refraction that will interfere with efficient signalling. The height of aerial tower should be limited, so that winds and temperature changes have the minimum effect on their position.

6.5 Optical fibre channels

Optical fibres are fine strands of glass, which behave as wave guides for light. This ability to transmit light over considerable distances can be used to provide optical communication links with enormous information carrying capacity and an inherent immunity to electromagnetic interference.

A practical optical cable consists of a central optical fibre which comprises core, cladding and protective buffer coating surrounded by a protective plastic oversheath containing strength members which, in some cases, are enclosed by a layer of armouring.

6. Transmission media, interference and noise

To communicate information a beam of light is modulated in accordance with the signal to be transmitted. This modulated beam travels along the optical fibre and is subsequently decoded at the remote terminal into the received signal. On/off modulation of the light source is normally preferred to linear modulation since the distortion caused by non-linearities in the light source and detectors, as well as variations in received light power, are largely avoided.

The light transmitter and receiver are usually laser or LED devices capable of emitting and detecting narrow beams of light at selected frequencies in the low attenuation 850, 1300 and 1550 nanometre spectral windows. The distance over which effective communications can be established depends on the attenuation and dispersion of the communication link and this depends on the type and quality of the fibre and the wavelength of the optical source. Within the fibre there are many modes of propagation with different optical paths that cause dispersion of the light signal and result in pulse broadening.

The degrading of the signal in this way can be reduced by the use of 'graded index' fibres that cause the various modes to follow nearly equal paths. The distance over which signals can be transmitted is significantly increased by the use of 'monomode' fibres that support only one mode of propagation.

With optical fibre channels, communication at data rates of hundreds of megahertz is achievable over a few tens of kilometres, whilst greater distances require the use of repeaters. An optical fibre can be used as a dedicated link between two terminal equipments, or as a multiplexed link that carries all communication traffic such as voice, telecontrol and protection signalling. In the latter case the available bandwidth of a link is divided by means of time division multiplexing (T.D.M.) techniques into a number of channels, each of 64kbits/s (equivalent to one voice frequency channel which typically uses an 8-bit analogue-to-digital conversion at a sampling rate of 8kHz). A number of Utilities sell surplus capacity on their links to telecommunications operators. The trend of using rented pilot circuits is therefore being reversed, with the Utilities moving back towards ownership of the communication circuits that carry protection signalling.

The equipments that carry out this multiplexing at each end of a line are known as 'Pulse Code Modulation' (P.C.M.) terminal equipments. This approach is the one adopted by telecommunications authorities and some Utilities favour its adoption on their private systems, for economic considerations.

Optical fibre communications are well established in the electrical supply industry. They are the preferred means for the communications link between a substation and a telephone exchange when rented circuits are used, as trials have shown that this link is particularly susceptible to interference from power system faults if copper conductors are used. Whilst such fibres can be laid in cable trenches, there is a strong trend to associate them with the conductors themselves by producing composite cables comprising optical fibres embedded within the conductors, either earth or phase. For overhead lines use of OPGW (Optical Ground Wire) earth conductors is very common, while an alternative is to wrap the optical cable helically around a phase or earth conductor. This latter technique can be used without restringing of the line.

D2

7. Signalling methods

Various methods are used in protection signalling; not all need be suited to every transmission medium. The methods to be considered briefly are:

a. D.C. voltage step or d.c. voltage reversals

b. plain tone keyed signals at high and voice frequencies

c. frequency shift keyed signals involving two or more tones at high and voice frequencies

General purpose telecommunications equipment operating over power line carrier, radio or optical fibre media incorporate frequency translating or multiplexing techniques to provide the user with standardised communication channels. They have a nominal bandwidth/channel of 4kHz and are often referred to as voice frequency (vf) channels. Protection signalling equipments operating at voice frequencies exploit the standardisation of the communication interface. Where voice frequency channels are not available or suitable, protection signalling may make use of a medium or specialised equipment dedicated entirely to the signalling requirements.

Figure D2.5 illustrates the communication arrangements commonly encountered in protection signalling.

7.1 D.C. voltage signalling

A d.c. voltage step or d.c. voltage reversals may be used to convey a signalling instruction between protection relaying points in a power system, but these are suited only to private pilot wires, where low speed signalling is acceptable, with its inherent security.

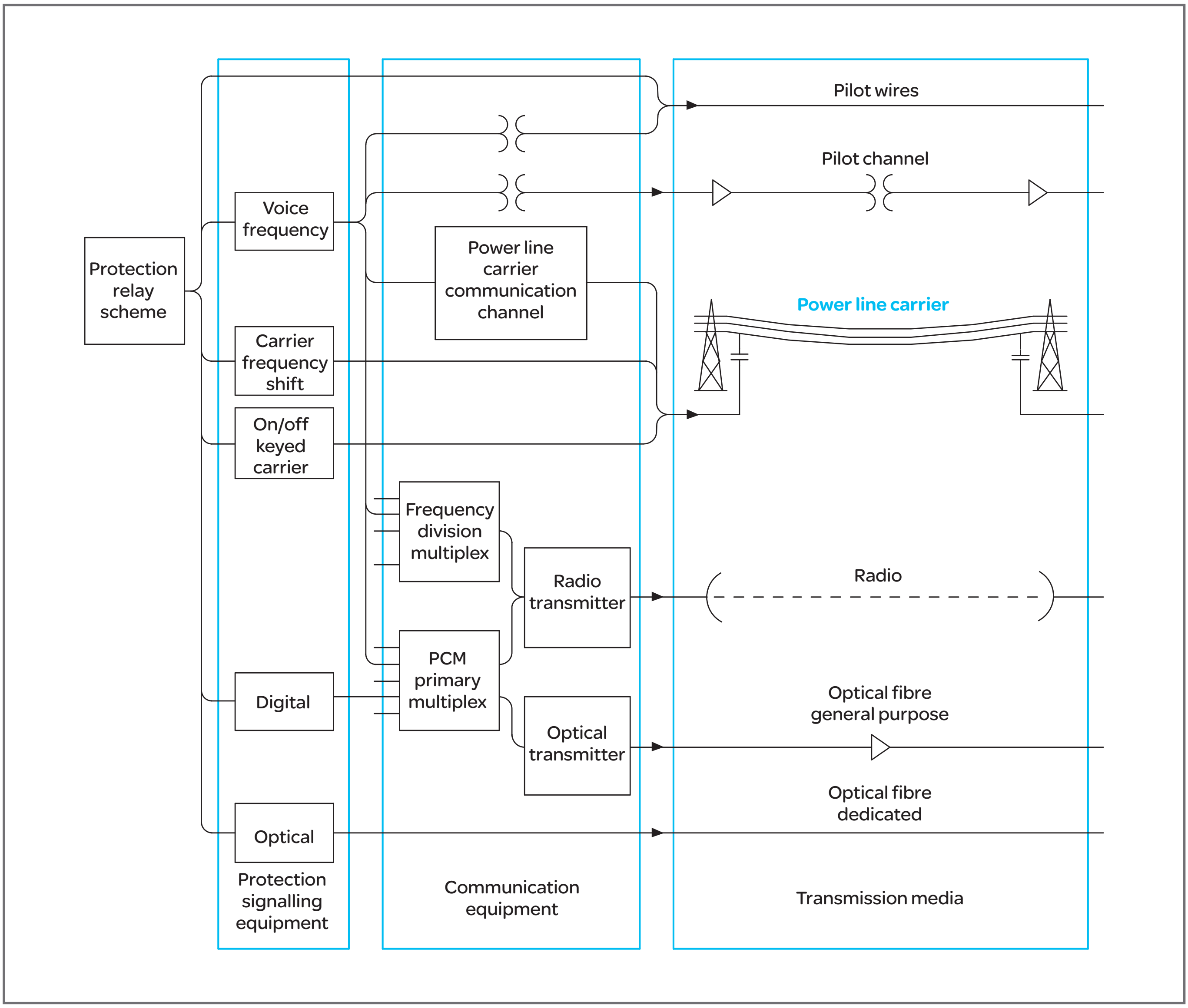


Figure D2.5:
Communication arrangements commonly encountered in protection signalling

7. Signalling methods

7.2 Plain tone signals

Plain high frequency signals can be used successfully for the signalling of blocking information over a power line. A normally quiescent power line carrier equipment can be dedicated entirely to the transfer to teleprotection blocking commands. Phase comparison power line carrier unit protection schemes often use such equipment and take advantage of the very high speed and dependability of the signalling system. The special characteristics of dedicated 'on/off' keyed carrier systems are discussed later. A relatively insensitive receiver is used to discriminate against noise on an amplitude basis, and for some applications the security may be satisfactory for permissive tripping, particularly if the normal high-speed operation of about 6ms is sacrificed by the addition of delays. The need for regular reflex testing of a normally quiescent channel usually precludes any use for intertripping.

Plain tone power line carrier signalling systems are particularly suited to providing the blocking commands often associated with the protection of multi-ended feeders, as described in Chapter [C5: Protection of Complex Transmission Circuits]. A blocking command sent from one end can be received simultaneously at all the other ends using a single power line carrier channel. Other signalling systems usually require discrete communication channels between each of the ends or involve repeaters, leading to decreased dependability of the blocking command.

Plain voice frequency signals can be used for blocking, permissive intertrip and direct intertrip applications for all transmission media but operation is at such a low signal level that security from maloperation is not very good. Operation in the 'tone on' to 'tone off' mode gives the best channel monitoring, but offers little security; to obtain a satisfactory performance the output must be delayed. This results in relatively slow operation: 70 milliseconds for permissive intertripping, and 180 milliseconds for direct intertripping.

7.3 Frequency shift keyed signals

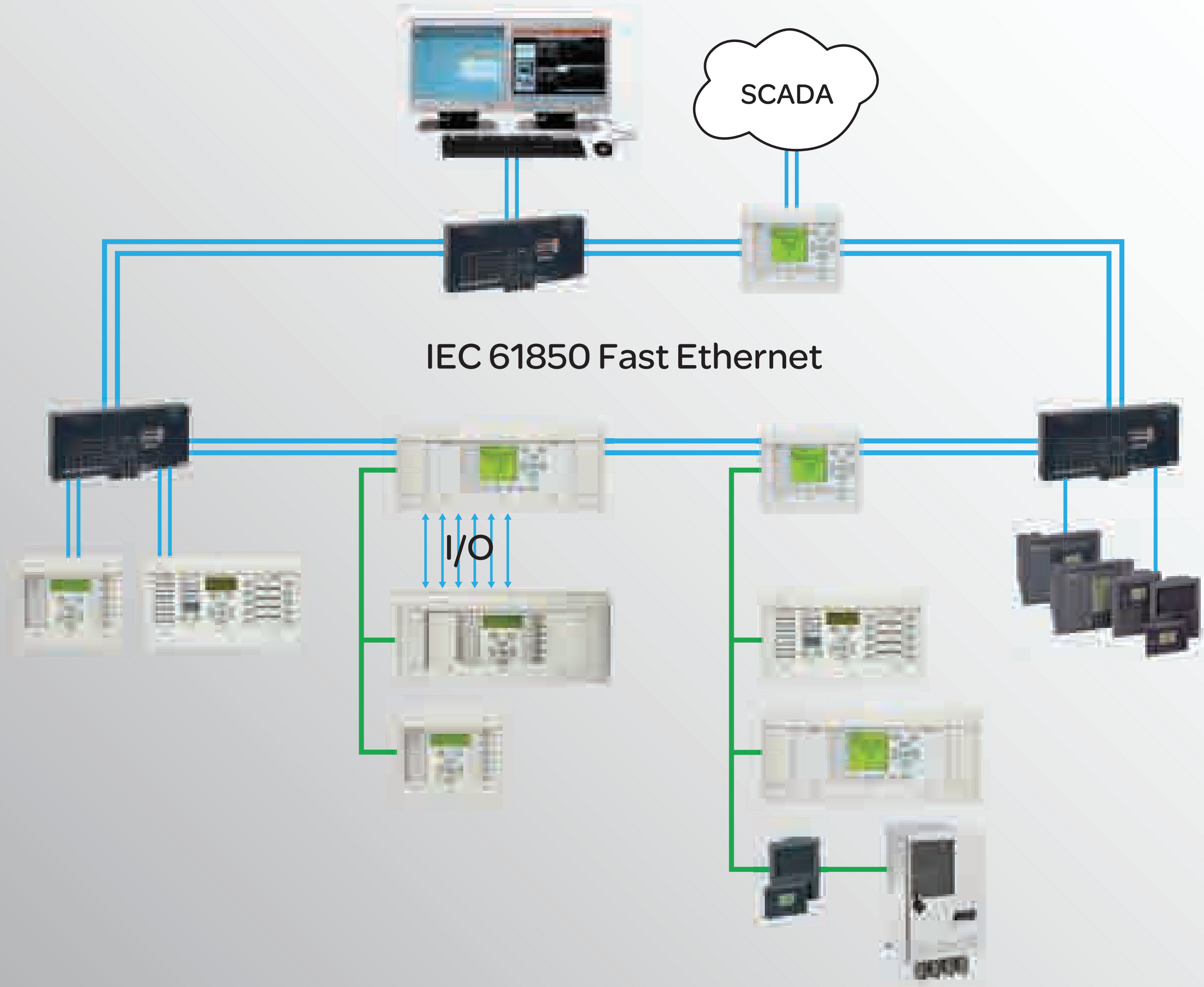
Frequency shift keyed high frequency signals can be used over a power line carrier link to give short operating times (15 milliseconds for blocking and permissive intertripping, 20 milliseconds for direct intertripping) for all applications of protection signalling. The required amount of security can be achieved by using a broadband noise detector to monitor the actual operational signalling equipment.

Frequency shift keyed voice frequency signals can be used for all protection signalling applications over all transmission media. Frequency modulation techniques make possible an improvement in performance, because amplitude limiting rejects the amplitude modulation component of noise, leaving only the phase modulation components to be detected.

The operational protection signal may consist of tone sequence codes with, say, three tones, or a multi-bit code using two discrete tones for successive bits, or of a single frequency shift.

Modern high-speed systems use multi-bit code or single frequency shift techniques. Complex codes are used to give the required degree of security in direct intertrip schemes: the short operating times needed may result in uneconomical use of the available voice frequency spectrum, particularly if the channel is not exclusively employed for protection signalling. As noise power is directly proportional to bandwidth, a large bandwidth causes an increase in the noise level admitted to the detector, making operation in the presence of noise more difficult. So, again, it is difficult to obtain both high dependability and high security.

The signal frequency shift technique has advantages where fast signalling is needed for blocked distance and permissive intertrip applications. It has little inherent security, but additional circuits responsive to every type of interference can give acceptable security. This system does not require a channel capable of high transmission rates, as the frequency changes once only; the bandwidth can therefore be narrower than in coded systems, giving better noise rejection as well as being advantageous if the channel is shared with telemetry and control signalling, which will inevitably be the case if a power line carrier bearer is employed.



D3

IEC 61850 and Applications

Network Protection & Automation Guide

Life Is On | Schneider Electric

Chapter D3

IEC 61850 and Applications

D3

1. Introduction

IEC 61850 is the international standard for the communication networks and systems for power utility automation. It allows the implementation of distributed application functions, based on Intelligent Electronic Devices (IEDs) from different manufacturers. Initially dedicated to communication inside substations, IEC 61850 is now the one central communication standard of the Smart Grid IEC reference architecture as shown in Figure D3.1.

This chapter presents an overview of IEC 61850 and shows practical applications of this standard in the protective relays domain. A further chapter outlines typical network architecture solutions and related redundancy concepts for Ethernet solutions selected by IEC 61850 as the communication layer.

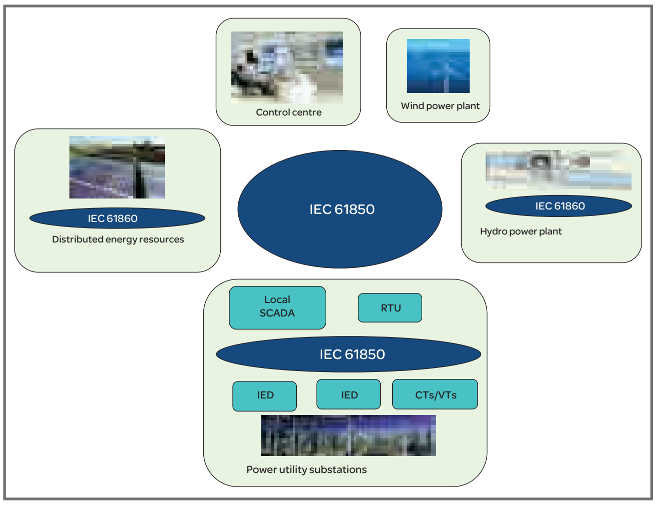


Figure D3.1:
IEC 61850 Smartgrid Architecture

1.1 What is IEC 61850?

The objective of the IEC 61850 standard is to offer a way of exchanging meaningful information between field level devices coming from different vendors in the context of electric utility energy automation.

But IEC 61850 is much more than just a communication protocol. It aims to offer ways to seamlessly and efficiently design an automation system from the very upstream specification part, down to commissioning, operation and maintenance. It has been designed to specifically address the specifics of electricity transmission and distribution such as:

a. The reaction speed: a few milliseconds reaction time is achievable

b. Multicast capabilities: information can be sent by the producer to a group of connected devices

c. EMC performance level: matching the specific electrical environment

The flexible design of the standard allows it to support evolution coping with technology evolutions and domain extensions.

IEC 61850 is based on 3 pillars:

a. A set of dictionaries: the information modelling or data model

b. A set of communication services available on several communication layers

c. A configuration language: the backbone of the engineering workflow.

1.1.1 IEC 61850 as a set of dictionaries

When a device receives an IEC 61850 data item there is no ambiguity in the meaning of this information as it is clearly defined in the dictionary. Every IEC 61850 domain (substation, hydro etc.) shares a common dictionary. But also each IEC 61850 domain can own a specific dictionary for its own definition. The link of data definition is done to create functional bricks used to model typical electrical and non-electrical functions used in an application model.

1.1.2 IEC 61850 as a communication protocol

The communication services have been defined in a generic way in IEC 61850 through an Abstract Communication Service interface (ACSI).

ACSI is independent of any communication method but provides basic functions such as read/write, browsing, event, setting, control, file transfer etc.

This abstract specification is mapped on communication technologies such as:

a. Client-Server over MMS/IP (most common)

b. Client-Server over web services

c. Multicast on Ethernet (most common)

d. Multicast on IP

1.1.3 IEC 61850 as a configuration language

The configuration language defines the structure of the configuration files used by the engineering workflow. This XML based schema (named SCL for System Configuration Language) supports many activities:

a. Specifying system requirements in terms of topology, primary devices and functions

b. Describing a complete system, following the life cycle of this system

c. Describing the functional capabilities of devices (through its communication interface)

The different actors of the engineering workflow exchange data using files based on SCL. These kinds of files are also standardised for specific usage, depending on the associated workflow state. This allows engineering tools to be interoperable regarding system configuration process.

1.2 Why choose IEC 61850?

IEC 61850 seeks to overcome the problem of multiple vendors using multiple protocols or different solutions based on the same protocol to convey essentially the same information.

This is one of the key drivers, however there are many other features and benefits that provide the user with more control and better visibility of the system, maintenance and process:

a. A single configuration file is used to define the system

b. Direct, high speed, peer to peer communications simplifies or replaces wiring schemes (GOOSE)

c. Common data models provide an interoperable solution for data description between vendors

d. The inbuilt engineering process provides standardisation and common structures

e. Cost and delivery can be controlled and long term maintenance is simplified

f. Data integrity built in means that the user understands the status of his communication network and can be assured that only valid signals are acted upon

g. Contextual data allows for more and more automated solutions with products self identifying and describing

h. An open protocol that allows future extensions.

1.3 History of IEC 61850

Development of Substation Automation Systems has been very rapid in the last few decades because of major advances in communication and microprocessor technologies.

In the 1980s, utilities and manufacturers started developing private communication protocols. Rapidly, the lack of compatibility led to the necessity for an international standardisation with the effort to ensure interoperability. Utilities were frustrated with the cost of supporting many device protocols and with the lack of freedom in choosing components within a solution. End-users complained that products and systems were not interoperable and that maintenance, installation and engineering costs were getting higher and higher.

IEC 61850 has been elaborated by the IEC technical committee 57 by merging concepts coming from two preceding standards: UCA2 from Electric Power Research Institute (EPRI) and the IEC 60870-5.

Starting in 2002, IEC has published a list of separate consistent documents establishing the Edition 1 of IEC 61850. Since the introduction of this new standard several thousands of substations were installed all over the world according to this Edition.

The main benefits are not only interoperability, but also a reduction in hardware equipment and its wiring thanks to the substitution by a single Ethernet cable, an enhancement of the maintainability by the increased system observability, an easier way to diagnose and repair and finally an agility increase, so that installations can more easily cope with new functional requirements.

But nevertheless, as usual for such a complex standard, this first version did not solve all potential interoperability problems in one go. Issues have been registered in a web database (http://tissue.iec61850.com/) and solved by extensions or corrections of the standard.

Edition 2 of IEC 61850 was published in 2009. Previous parts have been improved by adding more precise descriptions of ambiguous points and fixing errors. IEC 61850 foundations have been strengthened by various updates.

New parts have been added, so that the scope of the standard is no longer limited to substations, it now includes inter-substation communication, wind farm systems, control centres, distributed energy resources (DER), wide area measurement and protection automation control systems, hydro power systems and power quality.

The standard is giving clear rules using so called “name space” extensions to add manufacturer or domain specific data without a risk of collision or interoperability break.

In addition secured communication over WAN, high availability seamless redundancy protocols (HSR/PRP), mapping IEC 61850/IEC 850-1-101/104 and mapping IEC 61850/DNP3 (IEEE 1815) are now defined to support this standard.

1.4 Evolution of IEC 61850

Evolutions of IEC 61850 will not stop with the Edition 2. On the contrary, IEC 61850 will play a major role in the scope of the smart grid. In 2015, IEC should release an amendment named Ed2.1. The scope and the quality of IEC 61850 quality shall be improved again.

A maintenance process is setup to handle technical issues (called TISSUES) raised after publication. Two categories of TISSUES are defined. The first one, the most critical, called “IntOp” TISSUES must be handled by a vendor as soon as a proposed fix is provided by the IEC committee. TISSUES of the second category are improvement proposals. They are taken into account for future versions of the standard.

The Ed2.1 standard itself will be auto-generated from a database, avoiding any typing or format mistakes. A machine readable data model will be available for engineering tools usage. A web-access will be provided through the IEC web site in future.

New parts are under development to extend the coverage to new actors: feeder automation, power supply, battery storage, FACTS (Flexible Alternative Current Transmission System) etc.

New parts, related to new communication and configuration technologies are also under development: use of wide area networks, use of web services, logic modelling, and statistical calculation capabilities.

D3

2. General philosophy

This chapter covers the main aspect of IEC 61850. The first section gives an overview of the IEC 61850 series, thereby one can go directly to the part of interest. The last three sections explain the three foundations of IEC 61850: the data model, the communication services and the configuration process.

2.1 Global approach

To achieve interoperability between IEDs from different manufacturers, the standard has to specify a very precise definition of both the functions and the communication services, without compromising the needed flexibility.

A function can be defined as a task which has to be performed by the electric utility automation system. A function has a well defined purpose, inputs and outputs. The standard defines many basic functions, named **Logical Node (LN)**. Collectively, LNs define the behaviour of the system. At the end, the real processing is done in physical devices. To achieve flexibility, the standard allows the free allocation of a LN to the physical devices, taking into account availability requirements, performance requirements, cost constraint, and device capabilities etc. Communications services allow exchange of data between LNs which are not located in the same physical devices.

Figure D3.2 shows 4 IEDs that each contain one or more LNs (PTOC, PDIS, PTRC, XCBR). The red lines represent the communication services between IEDs. The black lines represent communications between LNs inside some IEDs, but they are private to the IED and not defined by the standard.

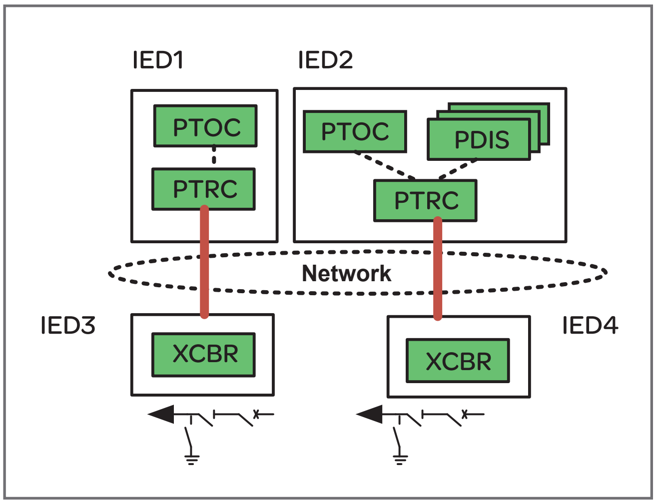


Figure D3.2:
IEC 61850 smartgrid architecture

2.2 Parts of the standard

2.2.1 Documentation structure

IEC 61850 documentation is quite extensive. The documentation is split into several parts. Some of them are normative (International Standard). Others are only informative and can be used as a guideline or overview (for instance part 7-5). Let's describe briefly the documentation structure.

Parts 1 to 5 cover general requirements.

Parts 7-3, 7-4, 7-4xx, describe the set of dictionaries (the first pillar as introduced earlier).

Parts 7-2, 8-1, 9-2 focus on communication services (the second pillar).

Part 6 deals with the configuration language (the third pillar)

Finally, **part 10** specifies the test cases which have to be performed to ensure the conformance of the implementation.

As a summary, the documentation defines how IEDs must be implemented, provides general information and guidelines and specifies how a manufacturer can obtain an IEC 61850 conformance certificate.

The following Figure D3.3 outlines the structure of the documentation with the three pillars. The following Table D3.1 lists the official IEC 61850 parts as of June 2015 (In Pink: Dictionaries, Orange: Communication Protocols, Green: Configuration language).

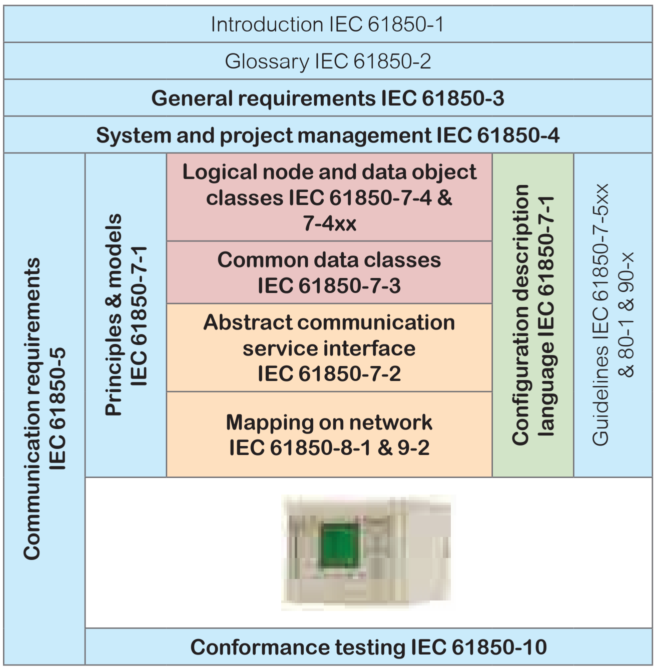


Figure D3.3:
IEC 61850 standard parts overview

2. General philosophy

Part	Title	Latest	Previous
1	Introduction and overview	ed2.0_2013-03	ed1.0_2003-04
2	Glossary	ed1.0_2003-08	
3	**General requirements**	ed2.0_2013-12	ed1.0_2002-02
4	**System and project management**	ed2.0_2011-04	ed1.0_2002-01
5	**Communication requirements for functions and device models**	ed2.0_2013-01	ed1.0_2003-07
6	**Configuration language for communication in electrical substations relate**	ed2.0_2009-12	ed1.0_2004-03
	Basic communication structure		
7-1	**Principles and models**	ed2.0_2011-07	ed1.0_2003-07
7-2	**Abstract communication service interface (ACSI)**	ed2.0_2010-08	ed1.0_2003-05
7-3	**Common Data Classes**	ed2.0_2010-12	ed1.0_2003-05
7-4	**Compatible logical node classes and data classes**	ed2.0_2010-03	ed1.0_2003-05
7-410	Hydroelectric power plants - Communication for monitoring end control	ed2.0_2012-10	ed1.0_2007-08
7-420	Distributed energy resources logical nodes	ed1.0_2009-03	
7-510	Hydroelectric power plants - Modelling concepts and guidelines	ed1.0_2012-03	
	Specific communication service mapping (SCSM)		
8-1	**Mappings to MMS (ISO/IEC9506-1 and ISO/IEC 9506-2)**	ed2.0_2011-06	ed1.0_2004-05
9-1	*Sampled values over serial unidirectional multidrop point to point link*	*withdraw*	*ed1.0_2003-05*
9-2	**Sampled values over ISO/IEC 8802-3**	ed2.0_2011-09	ed1.0_2004-04
10	**Conformance testing**	ed2.0_2012-12	ed1.0_2005-05
80-1	Guideline to exchanging information from a CDC-based data model using IEC 60870-5-101 or IEC 60870-5-104	ed1.0_2008-12	
90-1	Use of IEC 61850 for the communication between substations	ed1.0_2010-03	
90-4	Network engineering guidelines	ed1.0_2013-08	
90-5	Use of IEC 61850 to transmit synchrophasor information according to IEEE C37.118	ed1.0_2012-05	
90-7	Object models for power converters in distributed energy resources (DER) system	ed1.0_2013-02	

Table D3.1:
List of IEC 61850 standard parts (published until the 30.04.2015)

If relevant, the reference of the previous version is also mentioned. Some parts are still in the first edition. You will notice that IEC has decided to withdraw the **part 9-1**.

New parts of IEC 61850 are regularly published because of the inclusion of new domains or methods of communication or guidelines.

The main parts are: **6, 7-2, 7-3, 7-4, 8-1, 9-2** and **10** because they provide the foundation of the interoperability characteristic of IEC 61850.

2.2.2 General requirements

IEC 61850-1 provides an introduction and an overview of IEC 61850.

IEC 61850-2 lists a collection of terminology and definitions used within the various part of the standard.

IEC 61850-3 provides general requirements: quality requirements (reliability, maintainability etc.), environmental conditions.

IEC 61850-4 describes the system lifecycle, the engineering requirements and the quality assurance.

IEC 61850-5 defines the communication requirements for functions. Part 5 decomposes the whole system behaviour into the smallest functions, called **Logical Nodes**. All of them are documented and categorised.

2.2.3 Parts linked to data model definition

IEC 61850-7-4 specifies the information model of devices and functions generally related to power utility automation. It also contains the information model of devices and function-related applications in a substation.

IEC 61850-7-410 and **IEC 61850-7-420** have the same part 7-4 objective, but are dedicated respectively to distributed energy resources and hydroelectric power plants.

IEC 61850-7-3 is applicable to the description of device models and functions of substations and feeder equipment.

2. General philosophy

It has a list of commonly used information that is referenced in part 7-4 and 7-4xx. In particular, it specifies common basic information (named Common Data Class or **CDC**) for status, measurement, control, setting and description.

2.2.4 Parts linked to communication services definition

IEC 61850-7-2 applies to the ACSI communication for energy systems providing the following abstract communication service interfaces:

a. Abstract interface describing communications between a client and a remote server

b. Abstract interface for fast and reliable system-wide event distribution between an application in one device and many remote applications in different devices (publisher/subscriber)

c. Abstract interface for transmission of sampled measured values (publisher/subscriber).

IEC 61850-8-1 specifies a method of exchanging time-critical and non-time-critical data through local-area networks according to the abstract specification in IEC 61850-7-2 by mapping ACSI to MMS and ISO/IEC 8802-3 frames. This is often referred to as “System Bus”.

IEC 61850-9-2 defines the specific communication service mapping for the transmission of sampled values according to the abstract specification in IEC 61850-7-2. It defines the concrete means to communicate samples values from sensors to IEDs. This is often referred to as “Process Bus”.

2.2.5 Part linked to the definition of substation communication language

IEC 61850-6 specifies a file format describing communication-related configurations and IED parameters, communication system configurations, switch yard (function) structures, and the relations between them. The main purpose of this format is to exchange IED capability descriptions and SA system descriptions between IED and system engineering tools of different manufacturers in a compatible way. This part also defines the engineering process cycle with tool roles and different file types to reflect the different process phases to be done.

2.2.6 Parts linked to the definition of conformance testing

IEC 61850-10 specifies test-cases which must be passed to prove a certain level of interoperability. It applies both to IEDs and tools. It excludes functional testing. UCA/IEC international users group uses this part as a foundation to establish a conformance test procedure. This allows products to be tested in a uniform way and to obtain a certificate of conformance to the standard.

2.2.7 Guideline parts

IEC 61850-7-1 explains the general concepts and can be used as a tutorial. It’s a good means to acquire a global understanding of the standard.

IEC 61850-7-510 explains the modelling of hydroelectric power plants. There are other parts planned in this area as following:

a. 7-5: Application guide

b. 7-500: Use of logical nodes for modelling applications and related concepts and guidelines for substations.

IEC 61850-80-x and **IEC 61850-90-x** series deal with communication mapping with other technologies. The parts **80-x** are mainly “Technical Specifications” (**TS**) which are used as amendments to the IEC 61850 standard, e.g. mapping of other standards like IEC 60870 series/DNP3/Modbus/web protocols or IEEE C34.94). The parts **90-x** are used for “Technical Reports” (**TR**), which are mostly definitions of new features which could be integrated in any future major edition of the standard (like communication between Substations, Substations and Network Centres, LAN (Local Area Network) and WAN (Wide Area Network) etc.). These parts can be seen as extensions to the standard with all requirements to be added in each pillar of the IEC 61850.

2.3 Abstract service interface

To prepare the standard for future usage, the part IEC 61850-7-2 defines an abstract communication service interface (ACSI) for the link between the communication hardware and driver software to the application. Figure D3.4 illustrates the principle based on the OSI (Open Systems Interconnection) communication layer model.

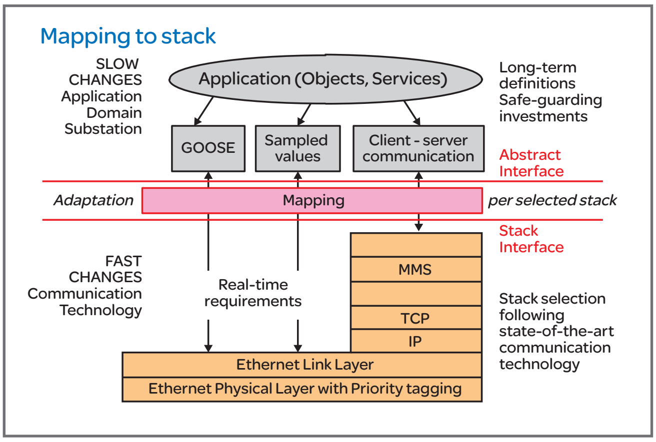


Figure D3.4:
Abstract communication interface

The ACSI allows the development of hardware independent software structures at the application level. This is done by using a communication stack for the connection to the hardware technology selected. As it is expected that the hardware technology is continuously changing in future, e.g. from today’s 100MBit Ethernet to e.g. 1GBit Ethernet, the software part can be kept unchanged as the adaptation to the new hardware is managed by a new or updated communication stack. The stack software itself has to provide an interface to different layers and protocols to support the different services used for IEC 61850. IEC 61850-8-1 and IEC 61850-9-2 currently define the communication media (Hardware level). Table D3.2 details the selected protocols for each category of service with standard part name.

Sampled values	GOOSE	Time synchronisation	Client/server services	Category
IEC 61850 -9-2	IEC 61850-8-1			Standard
SV	GOOSE	Time sync (SNTP)	MMS protocol suite	Application, presentation, session layers
		UPD/IP	TCP/IP T-PROFILE	Transport network, data link layers
SMV	GOOSE			
HSR/PRP (optional)				
802.1Q		802.1Q (optional)		
1 Gb fibre	100 Mb fibre or copper			Physical layer

Table D3.2:
Network mapping for IEC 61850

For "Sampled Values" (see section 3.4) according to part 9-2 and "GOOSE communication" (see section 3.3) according to part 8-1, the data is transported on a low communication layer as multicast on the MAC address level with its own defined data structure and content.

Time Synchronisation is managed by SNTP (Simple Network Time Protocol). IEEE Std1588:2009 can also be used when higher precision is required.

For "Client-Server communication", MMS (Manufacturing Messaging Specification) is used. It was initially designed for the manufacturing industry and it has been chosen, because it is able to support the complex naming and service model of IEC 61850 and the event reporting mechanism. Mapping of the Client-Server services from part 7-2 onto MMS is relatively straightforward. TCP/IP is not the only transport option, but today every device uses it.

A mapping of Client-Server services of part 7-2 using Web-Services is coming and foreseen as the future part 8-2.

2.4 Data modelling

Data modelling allows real world objects to be represented in a virtual world, allowing information to be exchanged digitally. Data is grouped in a structured way allowing a semantic to be applied to give a strong meaning to their virtual representation. The semantic is represented by standardised names listed in part 7-2, 7-3,7-4 and 7-4xx series of the IEC 61850 standard.

The data model of a device is the description of all of its data and their organisation. There is a minimum of 5 nested layers used to define the structure of a data model of the device. All upper levels are used to structure the information and as a container for data of a lower level. Figure D3.5 illustrates this principle. At the lowest level, the data values are managed by Data Attributes (DA). Those are grouped to build Data Objects (DO). At the next level DO are also grouped to build Logical Nodes (LN). LN again are grouped to Logical Devices (LD) and LD to Physical devices. The standard allows two levels of DO or several levels of DA. These sub level elements are named as SDO (Sub Data Object) and SDA (Sub Data Attribute). They are used when the element needs a deeper, more detailed differentiation.

The standard defines the most typical objects which could be added to the data model. Nevertheless this collection of standard objects cannot contain elements for all available information provided by the functionality of an IED. By adding private elements to the data model, it can be extended so that manufacturer specific data can be included as manufacturer specific LN or DO at the right level, without breaking the interoperability.

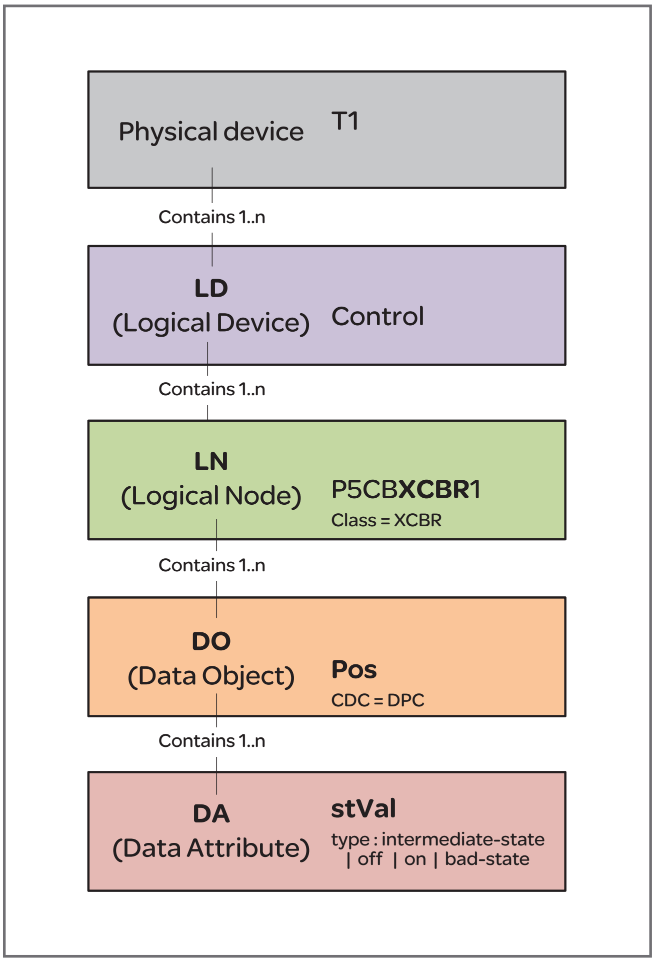


Figure D3.5:
Hierarchy of data model objects

D3

2. General philosophy

2.4.1 Logical devices

A physical device is split into several **Logical Devices (LD)** to allow the structuring of different independent functional groups of functions. A typical bay unit could contain a LD for protection, control or measurements. The grouping and structure depends strongly on the applications for which the physical device is made. An IED hosts one or multiple communication access points and related communication services with one or multiple LDs inside. With Edition 2 of the standard it is also possible to cascade multiple levels of LD.

2.4.2 Logical nodes

Each LD is a collection of **Logical Nodes (LN)**. Each LN is an instance of a Logical Nodes class. Logical Node classes are defined in part 7-4 or part 7-4xx. A Logical Node class represents a well defined autonomous function. For example, class XCBR always represents a circuit breaker and class PDIS a single zone element of the distance protection. LN class names are always built with 4 letters. This first letter is used to categorise the LN class. For example, **P**TOC, **P**DIS, **P**TRC are all LN classes related to protection functions. Table D3.3 shows the different categories available. The standard gives a specific LN class for each dedicated type of application function to define its mandatory or optional DOs. All LNs instantiated from a given Logical Node class are not necessarily identical in terms of DO composition. The presence of some DOs is mandatory. For others, the presence is optional or depends on a set of well defined rules. That means that two LNs built upon the same LN class can be composed of two different DO sets. LNs can exchange information to each other by using embedded DOs or DAs.

2.4.3 Data objects

Each DO is an instance of a **Common Data Class (CDC)**. CDCs are defined in part 7-3. Table D3.4 shows all the available CDCs. CDCs are categorised into 7 categories: status information, measured information, controls, status settings, analogue settings, description information and service tracking. A CDC is a defined class for a DO to list all data attributes required to support all access services. Similar to LN, DO instantiated from a given CDC can be different when additional DA gets added to the collection of DA given by the template.

An example of a DO in LN class XCBR is the DO “Pos”, which contains mainly the DA “stVal” for the position of the circuit breaker, the “t” for the timestamp and the “q” for quality. DA “stVal” is an enumeration with the four states “on”, “off”, “intermediate-state” and “bad state”. “Pos” is based on the CDC class “DPC” which can be controlled and monitored. This is based on the two wires used for the control and two others for the status of a switching device.

The distance LN PDIS itself contains a DO “Str” for the starting information and an “Op” for the trip (Operate) information for the distance element. The DO “Str” and “Op” are based on CDC “SPS” as binary “Single Pole Status”.

LN class first letter / Category	
A	Automatic control
C	Supervisory control
D	Distributed energy resources
F	Functional blocks
G	Generic function references
H	Hydro power
I	Interfacing and archiving
K	Mechanical and non-electrical primary equipment
L	System logical nodes
M	Metering and measurement
P	Protection functions
Q	Power quality events detection related
R	Protection related functions
S	Supervision and monitoring
T	Instrument transformer and sensors
W	Wind power
X	Switchgear
Y	Power transformer and related functions
Z	Further (power system) equipment

Table D3.3:
LN class categories overview

Category	
Status information	SPS,DPS,INS,ENS,ACT,ACD,SEC,BCR,HST, VSS
Measured information	MV,CMV,SAV,WYE,DEL,SEQ,HMV,HWYE,HDEL
Controls	SPC,DPC,INC,ENC,BSC,ISC,APC,BAC
Status settings	SPG,ING,ENG,ORG,TSG,CUG,VSG
Analogue settings	ASG,CURVE,CSG
Description information	DPL,LPL,CSD
Service tracking	CST,BTS,UTS,LTS,GTS,MTS,NTS,STS,CTS,OT, VSD

Table D3.4:
CDC class overview

2.4.4 Data attributes

Each DO is a collection of **Data Attributes (DA)**. A DA is linked to each single information element of the DO and provides information such as the value, its time stamp, its quality and other required information defined for each DO. DA definition can be retrieved by looking inside the CDC definition linked to the DO. DA is mainly defined by its standardised name and its type. The type of DA can by basic (integer, float, string etc.) or already structured (Quality, Range, Unit, Vector etc.). Basic types are defined in part 7-2. Structured types are named ‘Constructed attribute classes’ and defined in part 7-3. Also standardised enumerations are defined in 7-3 and 7-4. They make use of standardised names.

2.4.5 Data reference

All data owned by a given device has a standardised reference: a name built according to a rule and with standardised names. Physical Device, LD, LN, DO and DA build together as string to create a unique reference. Table D3.5 shows several examples of DA references. For the DO and SDO part, the associated CDC is mentioned. For the DA and SDA, the associated format type is also mentioned.

In example Ex1 (see 1st column in Table D3.5), **T1Control/P5CBXCMB1.Pos.stVal** represents the position of the breaker. Example Ex2 is more complex. It involves 3 levels of DA.

T1Measurement/P5VECAMMXU1.A.phsA.cVal.mag.f represents the current measurement of the Phase A of a measurement unit.

The last example Ex3 represents a setting of an overcurrent protection. **T1Protection/P5PHPTOC1.OpDlTmms.setVal** represents the Operate delay time duration.

The value **T1Protection/P5PHPTOC1.OpDlTmms.units.multiplier** makes it possible to know if the value is in seconds, in milliseconds, or in any other unit.

2.4.6 Communication modelling

The LD/LN/DO/DA hierarchy isn’t sufficient to model objects for use by communication services. This section goes deeper into the data model description, so that communication services can be more easily understood.

From a network communication point of view, a system is a set of communicating physical devices connected together using communication networks. IEC 61850 models the system using “Sub Network” and “Access Point” entities.

Sub Network is a logical, visible subdivision of an IP network. Each device on the subnet has a common subnet IP address allowing simple segregation by creating a subnet mask to isolate specific devices assigned.

Access Point represents a network interface of a physical device connected to one as used above to highlight that it is a special expression “Sub Network”.

IEC 61850 reference for DA										
	LDName		LNName			DataName[.DataName[. ...]]				
	IEDname (Physical Device Name)	**Ldinst**	**LN Prefix**	**LN Class** defined in part 7-4	**LN Suffix**	**DO** defined in part 7-3	**SDO** defined in part 7-3	**DA** defined in part 7-3	**SDA** defined in part 7-3	**SDA** defined in part 7-3
Ext1	T1	Control	P5CB	XCMB	1	Pos CDC: DPC		stVal Type : intermediate-state | off | on | bad-state		
Ext2	T1	Measurement	P5VECA	MMXU	1	A CDC: WYE	phsA CDC: CMV	cVal Type: Vector	mag Type : AnalogueValue	f Type: float
Ext3	T1	Protection	P5PH	PTOC	1	OpDlTmms CDC: ING		units Type:Unit	multiplier Type: enum	

Table D3.5:
Reference overview for DA

D3

2. General philosophy

Server is the logical grouping of Logical Devices. It controls the access to the whole set of data exposed by a given physical device through a given Access Point. Dedicated Authentication mechanisms could be described at that level. Server is the owner of the data. A physical device can own several access points and so it can communicate on several networks. Facilities are provided, so that the same Server is exposed to manage this multiple network access. Figure D3.6 outlines all entities required for communication purpose. The picture introduces the new "Control Block", "Data Set" and "LOG" entities.

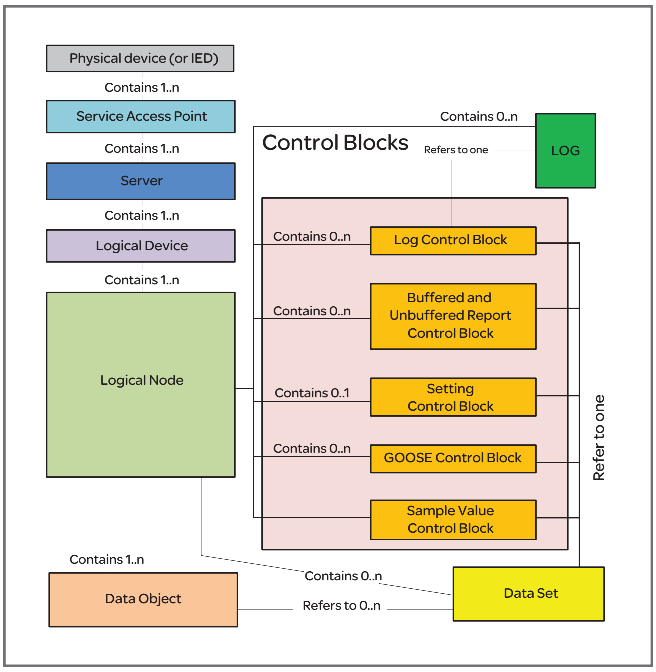


Figure D3.6:
Data model for communication services

A Data Set is an ordered group of DO and DA references called the members of the data set. The membership and order of the references in a data set shall be known to both the client/subscriber and the server/publisher, therefore it is included as a list in the data model and the ICD file. This capability avoids the transmission of many references in the messages and permits more efficient use of the communications bandwidth. Data Set can be usually pre-defined at configuration, but can also be dynamically created or modified using a dedicated communication services model. This feature provides a lot of flexibility.

Control blocks are used for Logging, Reporting, Setting Group management, GOOSE and Sampled Values services to configure the transmission networks. Facilities are provided, so that the same Server is exposed to work on several networks.

LOG is the data base where events are stored. The client can later retrieve them by using the logging services.

Figure D3.6 outlines all entities required for communication purpose with properties and runtime behaviour of the associated communication services. For the data transmission each control block gets a data set assigned defining the data content behind it. When an event-triggered transmission for the control block is configured, a report will only happen, when one of the references in the assigned Data Set has changed its status. Similarly to data set, control blocks can be defined dynamically (during operation).

2.5 Engineering process

2.5.1 Substation configuration language

Based on the very widely used **eXtensible Markup Language** (**XML**) as the exchange data format, IEC 61850 provides a configuration language, the **System Configuration Language** (**SCL**). SCL defines how the data is structured inside the file to allow an interoperable way to import and export data between the different tools from possibly different vendors.

The SCL is used to store all relevant information objects such as the data model, the supported services and the communication parameters of an IED in one common file. Secondly at a higher hierarchy level, an SCL file is used to describe the whole substation system with all its primary and secondary equipment. It contains the collection of IEDs including the links between them and the primary equipment.

SCL is defined in IEC 61850-6. SCL benefits from the XML format as it allows a deep control of the content through a normalised schema definition file (XSD files) specifically for IEC 61850.

The SCL file contains the following sub-sections:

a. The definition of the primary power system structure (transformers, breakers, etc.) and how the apparatus is connected. The functional specification of the power system switchyard equipment, and how it relates to the communication system and IEDs

b. The communication system: how IEDs are connected to networks and sub-networks, the IP addresses, multicast addresses, VLAN definition and other communication network parameters

c. For each IED: the logical devices configured on the IED, the logical nodes, off-line configuration values, the configuration of control blocks and data sets, supported ACSI services

d. A Data Type Template section with definition of LN, DO, DA types and used format (e.g. list of enumeration types)

Subsection (**a**) helps LNs to perform their processing. Subsection (**b**) allows the binding to the network. With the contents of subsection (**c**) and (**d**) the IED can build and initialise its runtime data model.

All this information is stored in various types of file with different subsets of data, described in Table D3.6.

2. General philosophy

SCL file	File extension	Description
IED capability description	ICD	The ICD contains a description of the functional capabilities of a specific IED type. It acts as an un-configured template to be configured in a System or IED Configuration Tool.
Instantiated IED description	IID	The IID contains a configured instance for a single IED for a specific IED of a project. It may have some components already configured such as project addresses or data sets. This data can be imported to a System Configuration Tool.
System specification description	SSD	The SSD describes the system specification including the single line diagram of the substation, the required substation switchyard equipment, their functions and all its required Logical Nodes. It can also contain specification of virtual IEDs which can be used to adapt the modelling to a profile.
Substation configuration description	SCD	The SCD contains the complete system configuration including the substation specification, all configured IED instances and the communication configurations.
Configured IED description	CID	The CID file is meant to be sent directly to the IED for configuration. It contains information related to configuring the communications for a specific IED. It can contain standardised or private data in an interoperable description.
System exchange description	SED	The SED describes interfaces for data that needs to be exchanged between different systems or projects. The SED gets exchanged between different System Configuration Tools (SCT) or different projects managed by the same SCT.

Table D3.6:
File types according IEC 61850-6

All these files allow data transfer between different engineering tools and devices independent of vendor. This eliminates some of the intermediate steps that are required when using more traditional tools for substation engineering in projects and helps to maintain data consistency.

2.5.2 The engineering cycle

The IEC 61850 standard defines a methodology for engineering a substation automation system in an object-oriented, multi-vendor environment. Two main tools are used to achieve the configuration process.

The **System Specification Tool** (**SST**) is used to specify a system with all primary and secondary equipment of the substation on the basis of the functional topology and required logical nodes. The tool is able to:

a. Model a substation

b. Export an SSD file with the substation specification

The **System Configuration Tool** (**SCT**) is an IED independent tool to specify a system. The tool is able to:

a. Import an ICD/IID files for the various IEDs used in the system

b. Configure communication parameters and dataflow (configuration, data sets, control blocks, external references etc.,) for IEDs

c. Export an SCD file with the modelling of the whole substation and used IEDs

d. Import a specification by mean of an SSD

e. Exchange with other system configuration tools by import/export an SED (optional)

The **IED Configuration Tool** (**IET**) is a manufacturer specific or at least IED specific tool. It is able to:

a. Create an ICD file as IED template

b. Configure a linked IED using private means

c. import an SCD file to get data for an IED from the SCT

d. Export (IID) SCL files

e. Export a CID file or any other manufacturer specific format to configure the real IED (CID capability is not mandatory)

Figure D3.7 shows the data flow for a usual "Top Down configuration process". The following list gives the detailed description for each step marked with a number, the red and green colour shows the engineering for two different vendor IEDs:

1 Availability of ICD or IID files

Most organisations have a process to choose the standard IEDs used in their substations, based on their specific protection and control philosophies and the required logical nodes for their power system. This allows a pre-selection of the ICD files required for the system configuration.

Native IED configuration tools contain a mechanism to export ICD files which act as a template for a specific IED containing the logical nodes supported by the device and its capabilities. In some cases, an organisation may have standardised configuration parameters such as network addresses or preconfigured data sets. In this case an IID file can be used. The IID file would contain the same data as the ICD file, plus it would also contain additional parameters regarding the configuration for a specific IED. The objects in an IID can already be reduced to those ones used in the dedicated substation system.

D3

2. General philosophy

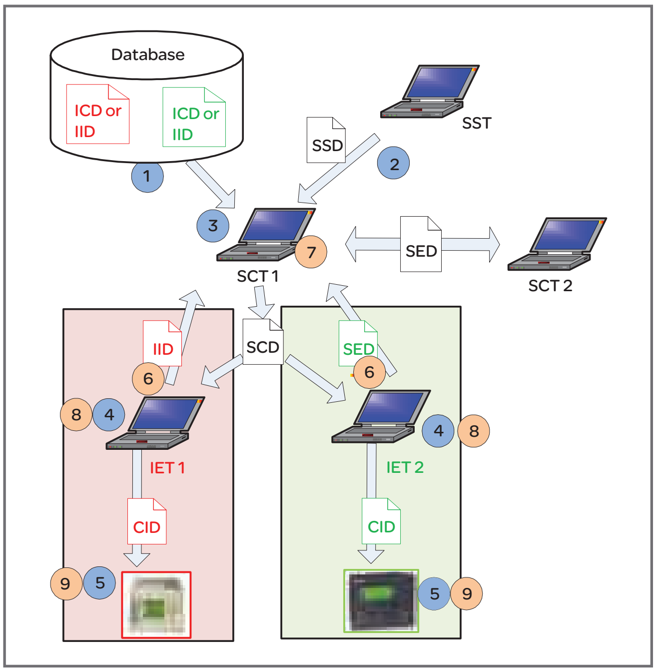


Figure D3.7:
Top Down Cycle

2 SSD file setup

In parallel, substation engineers define the substation specification based on their operating methodologies. This includes defining the primary switchyard equipment, their functions, the single line diagram and choosing the necessary logical nodes. This data contains a substation section of the project.

3 System engineering

Once the group of IEDs and the system specification have been defined, they can be imported into a system configuration tool. Within the system configuration tool the engineer can define specific instances from the different IED templates and link them to the electrical process. The engineer can then define project-specific addressing and configure the data model by defining the data sets for Reporting and GOOSE publishing/subscribing amongst the various IEDs. The complete substation description, all IEDs and communications configuration can be exported then as an SCD file.

4 IED configuration level engineering

The SCD file can be imported to various vendor specific ICTs to complete the protection, control, and device-specific configuration. The IED configuration tool is fully aware of the data available to it from the system and can make use of this data in the protection logic.

5 IED download of configuration file

When the IED specific configuration is completed, the configuration can be downloaded to the IED through a proprietary way or by transferring a CID file with standardised objects to the IED. In real life, this Top Down configuration process is not sufficient. Often, during the process, changes are made at the communication level. A further "Round Trip" of the configuration process needs to be performed.

6 The impacted **IED configurator exports** its IID files for a next "Round Trip" cycle.

7 System configurator import

An SCD file is rebuilt by importing the IID file back into the system configuration tool. All related IED sections at the substation level will be updated accordingly. A further repeat of the top down cycle (steps 4 & 5) ensures that any IEDs impacted by the IID are updated with new information.

8 Repetition of step 4 (2nd loop of the Top Down Cycle)

9 Repetition of step 5 (2nd loop of the Top Down Cycle)

Several further cycles could be required to complete the configuration process ending up at system configuration level as final system documentation.

2.6 Documentation

For the engineering and testing of IEDs the user needs sufficient documentation of the supported services and data. The standard specifies the IED file described in the engineering process in section 2.5. This file contains the whole data model and object classes in a structured ASCII format. In addition the standard specifies the following text files which each vendor has to provide on request to the user:

A "Protocol Implementation Conformance Statement" **(PICS)** lists all supported services with Yes/No statements so that a user or tester understands the IED capabilities.

A "Model Implementation Conformance Statement" **(MICS** lists all used object classes which are given in the ICD file in the type template section.

A "Protocol Implementation eXtra Information for Testing" **(PIXIT)** provides additional information on possible restrictions and predetermined boundary conditions of the IED on the supported services and available data which is relevant for the conformance testing (e.g. a functional limitation or a remark to a special setting or configuration).

A "Technical Issue Conformance Statement" **(TICS)** provides a statement to each Tissue raised at the standardisation committee, if the IED already supports the corrected subject of the standard or not. With each new conformity test this document has to be updated to include all Tissues known at the moment of testing. For Tissues with relevance to the interoperability, it is essential for the conformity tester to evaluate the impact when the IED is not designed according the latest definitions.

All these documents are mandatory for a vendor IED to get a conformity certificate by any test institute.

2. General philosophy

2.7 Interoperability vs. interchangeability

One of the main disadvantages of conventional communication standards was always the limitations on the compatibility between devices from different vendors to provide sufficient system functionality by exchanging data in the right form and content and to use similar procedures to transmit them. The IEC 61850 standard has addressed this topic as a central requirement under the heading of "Interoperability".

Interoperability is the ability of two or more intelligent electronic devices from the same vendor, or different vendors, to exchange information and to use that information for correct co-operation.

To achieve this goal the standard provides the following key elements:

a. Open modelling method to describe each possible data object in its functional context in such a way that each tool and component in the system can understand and process this data

b. Standardised file format to exchange the data description and device capabilities between tools of different vendors without limitations

c. Standardised communication procedures called "services" to allow system wide interaction between components of different vendors as a complete system

d. Standardised mapping on a network to use unique communication and hardware layers

e. Test method definition to confirm interoperable behaviour of all system components

For the last topic part 10 called "Conformance Testing" was added to ensure that each vendor or third party can execute a test of a product or system component to confirm its level of interoperability to the standard. The main topic of the defined testing is the proof of the correct implementation of data modelling, services, description files and documentation. This testing only proves that there is no inconsistency between the data model, description file and documentation.

For the services all the different procedures and their use cases including fault reaction behaviour are validated.

The validation of which functional objects are modelled and how they are structured is out of scope of this conformance testing. This can lead to differences between the communication partners and results in an issue around the "interchangeability".

Interchangeability is the possibility to replace one intelligent electronic device by another one without additional modifications of the equipment around it. This possibility is normally only given when the same type of IED or system component from the same vendor on the same product platform is used as a replacement.

In terms of a communication protocol, it can only be said that full interchangeability occurs when the IEDs or system components from different vendors can provide the full collection of services and similar data content for the specific substation in which it is installed. As the standard offers a very flexible way of data modelling and a lot of space for interpretation of it, the data modelling for each vendor IED is quite different. The related data model of an IED is known in IEC 61850 as "Product Naming".

Product Naming (PN) is the fixed or default data model of the IED reflecting the complete hierarchy/structure of the functions inside an IED. IEC 61850 also provides a user view looking more from the substation and primary equipment side called "Functional Naming".

Functional Naming (FN) is the reflection of the functional application view (like in a substation) in the naming of the structural elements of an IED data model as LDname (IEDname+LDInst) and LN pre/suffix. To reach any kind of interchangeability, it is required to modify the data model in the IED in such a way, that all data exchanged has the same naming with same function behind it. IEDs that provide this capability provide "Flexible Product Naming" functionality.

Flexible Product Naming (fPN) allows the data model of an IED to be modified to reflect the hierarchy/structure defined by the overall scheme. This means that, from the communication point of view, any IED can be remodelled to comply with the overall substation control scheme structure and thus the IED data definition can become vendor independent. Figures D3.8 and D3.9 show two examples for the fPN remodelling.

There are of course other criteria for the interchangeability such as the different hardware solutions, e.g. case and mounting, power supply, wiring for CT/VT and I/O will be different as well as the tools used for its configuration. Therefore a communication standard can only provide a general basis to reach compatibility without standardisation of the products and system components.

FN - Functional naming (Customer substation view)

Station	Vtg Lvl	Bay	Function	IED	Subf	LN	Suffix	DO	DA
IEDName (Server)			PROT		Prefix	LN	Suffix	DO Name	DA Name
Frankfurt	110 kV	E2	Protection	1	Dtoc	PTOC	2	Str	stVal

PN - Fix product naming (IED address mapping for device "P139")

Station	Vlt Lvl	Bay	Function	Subf	Prefix	LN	Suffix	DO	DA
IEDName (Server)			LDinst		Präfix	LN	Suffix	DO Name	DA Name
P139			Protection		DtpPhs	PTOC	1	Str	stVal

fPN - Flexible product naming (After remodelling by an IED configurator)

Station	Vtg Lvl	Bay	Function	IED	Subf	LN	Suffix	DO	DA
IEDName (Server)			LDinst		Prefix	LN	Suffix	DO Name	DA Name
Frankfurt	110 kV	E2	Protection	1	Dtoc	PTOC	2	Str	stVal

Figure D3.8:
Example for fPN on protection elements

D3

2. General philosophy

FN - Functional naming (Customer substation view)

Station	Vtg Lvl	Bay	Function	IED	Subf	LN	Suffix	DO	DA
IEDName (Server)			PROT		Prefix	LN	Suffix	DO Name	DA Name
Frankfurt	110 kV	E2	Control	1	QA1	XCBR	1	Pos	stVal

PN - Fix product naming (IED address mapping for device "P139")

Station	Vlt Lvl	Bay	Function	Subf	Prefix	LN	Suffix	DO	DA
IEDName (Server)		LDinst			Präfix	LN	Suffix	DO Name	DA Name
P139			Control			XCBR	1	Str	stVal

fPN - Flexible product naming (After remodelling by an IED configurator)

Station	Vtg Lvl	Bay	Function	IED	Subf	LN	Suffix	DO	DA
IEDName (Server)			LDinst		Prefix	LN	Suffix	DO Name	DA Name
Frankfurt	110 kV	E2	Control	1	QA1	XCBR	1	Pos	stVal

Figure D3.9:
Example for fPN on control elements

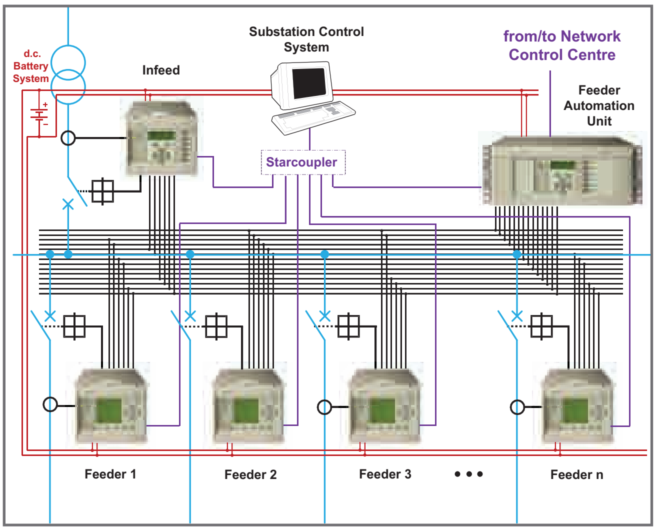


Figure D3.10:
Conventional I/O wiring with feeder automation unit and serial bus system

2.8 Advantages vs. conventional hard-wiring

IEC 61850 provides a lot of areas for optimisation. One specific area is the concept to use one single bus system, such as the Ethernet protocol and related network equipment, to communicate between IEDs and all other system components in a substation and beyond. In parallel with conventional protocol links there are conventionally a considerable amount of electrical wires installed in a substation to exchange binary signals between all IEDs and system components. IEC 61850 provides the opportunity to save cost by the reduction of the required amount of wiring, binary inputs and outputs in the IED. It can do this by the use of client-server or GOOSE communication, which supports the high speed exchange of binary data equivalent to the hardwire signals. By using GOOSE the system is not only cheaper to install but it facilitates testing, post design modifications and commissioning.

For illustration Figure D3.10 shows a typical wiring plan for a complete substation with related I/O wiring. Here we show a bay unit and feeder automation units collecting all signals and providing them to the network control system using a conventional 60870-5-103 bus in star whereas Figure D3.11 shows the optimised solution with an Ethernet redundant ring and Gateway to the network control system.

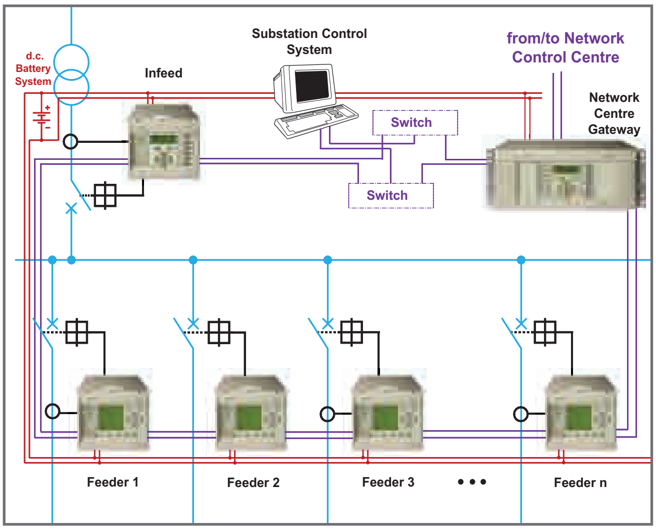


Figure D3.11:
Modern redundant ethernet installation

3. Communication services

This section describes the fundamental "Substation Communication Architecture", which outlines the usage of four communication models. The second section follows with the Client-Server related communication services. The last three sections deal with GOOSE, Sampled Values and finally the Time Synchronisation.

Part 7-2 defines an abstract communication services interface (ACSI) for a compatible exchange of information among all available communication partners and IEDs in a substation. The standard offers the following four types of communication models:

a. Classical Client-Server services model

b. GOOSE (Generic Object Oriented Substation Event) communication with fast and reliable distribution of DO and DA references based on Communication Publisher/Subscriber model

c. Sampled values distribution model based on Communication Publisher/Subscriber model

d. Time synchronisation protocols

3.1 General communication architectures

Today, three communication levels are considered in IEC 61850: "station level", "bay level" and "process level". Figure D3.12 shows the related substation network architecture.

The Station Bus is dedicated to a substation, or power system or more globally, management system for control and protection. The communication at this level is a mix of fast data exchange for protection and automation and of data reporting with less time constraints but with more detailed information flow.

On the lower level, the "Process Bus" is dedicated to the exchange of data between primary devices and the control and protection IEDs.

(1) Represents substation data exchange between the bay units at bay level and the substation control equipment at station level. The criticality of the data allows usage of the Client-Server service model (green marked lines). The same applies for data exchange within the station level **(2)**.

(3) and **(4)** shows the data exchange within the bay level between the bay units (so called "IED to IED communication"). GOOSE is used for that purpose (blue marked lines).

From the bay level down to the process bus level **(5)**, control-data is sent from bay units to the process using GOOSE. Often hardwires are still used here instead of a real process bus (dotted black lines on the right bay level part).

(6) represents the exchange of instantaneous data from the process to the bay level, e.g. analogue values from current and voltage transformers or status of sensors or switches.

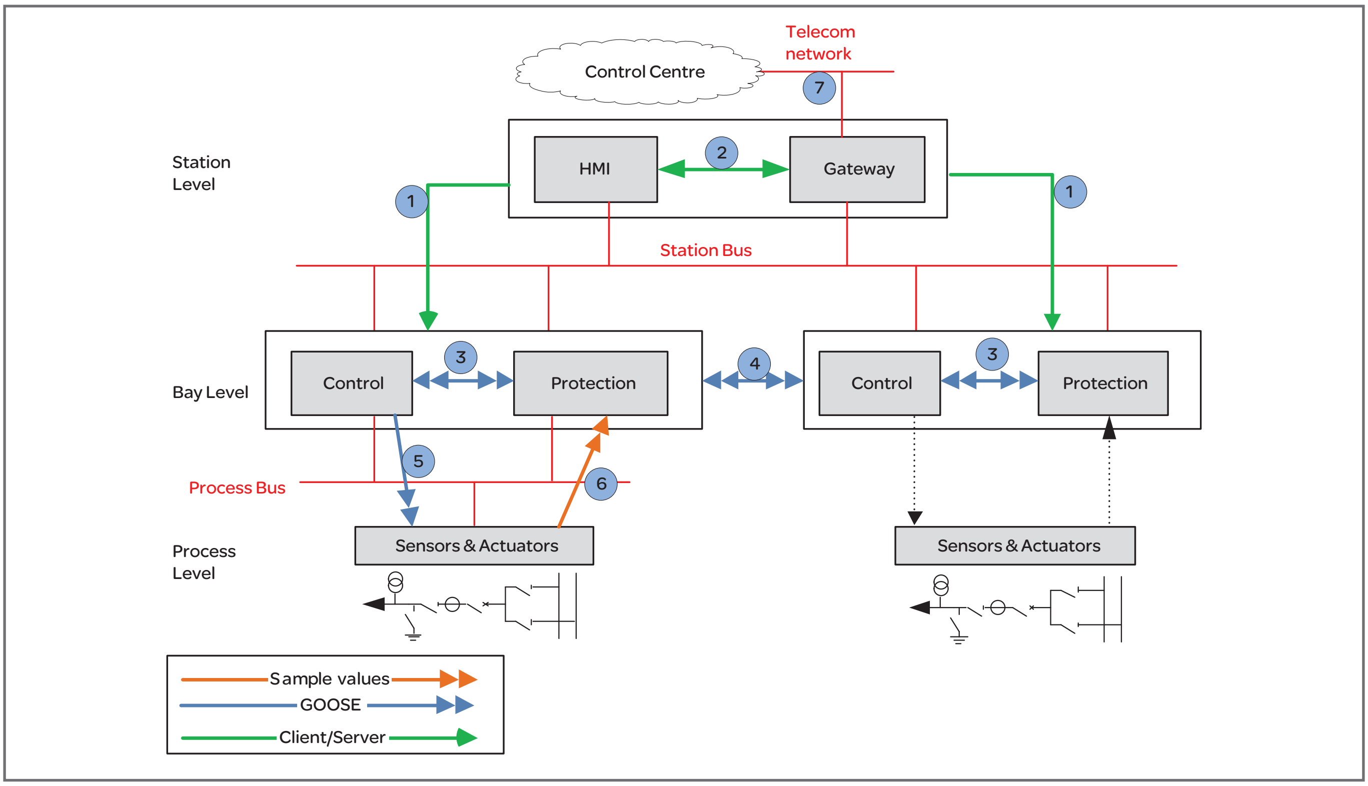


Figure D3.12: Communication architecture

3. Communication services

Analogue values are time critical and they need to be transferred in a precise and chronological order. Sampled values distribution model is used (orange marked lines). For the binary information the usage of GOOSE is usual.

The telecontrol network is used to report data from the substation to other network systems. Traditionally, this level **(7)** is based on SCADA protocols like DNP3, T101 or T104. Part 90-2 is under preparation to define the link between a station bus and a control centre using IEC 61850 services.

The Station and Process Bus shown in Figure D3.12 can be carried out as a separate physical network or on basis of the same physical network by using virtual addressing to filter and separate data at the network switch level.

3.2 Client-server communication

In software engineering a server is an entity that provides information to other communication partners. All entities who are interested in receiving this information are called clients. Each client can request the server to open a continuous connection to subscribe information. During the startup of the connection the client can configure how the information has to be transmitted. When a connection has been established, the server sends all upcoming information to the client and handles and responds to the requests from all the clients connected to it. A server can manage simultaneous connections to several clients as shown in Figure D3.13. A client can also connect to several servers.

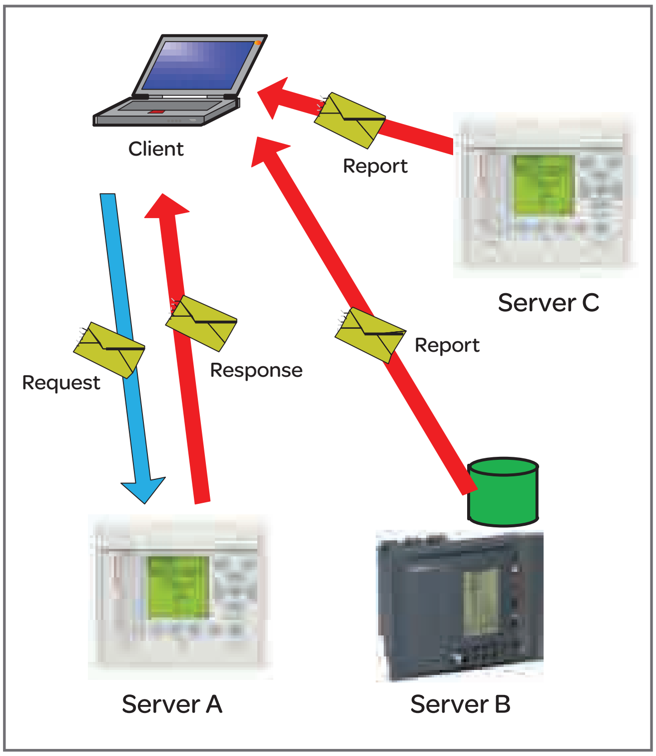


Figure D3.13:
Client-Server communication

Figure D3.14 illustrates the basics of the Client-Server communication services. The communication starts by the establishment of a connection using the "Associate" service. The Associate request message is sent by the client to the server and contains input parameters. The response message is sent by the server to the client and contains output parameters. Often a Control Block or LN, DO or DA reference is used as input or output parameter, just to identify which part of the model the service acts upon. The response message contains the result of the processing of the input parameters. This can be an error code if a failure occurs, the requested information for a simple reading request or simply an acknowledgement of the right command execution.

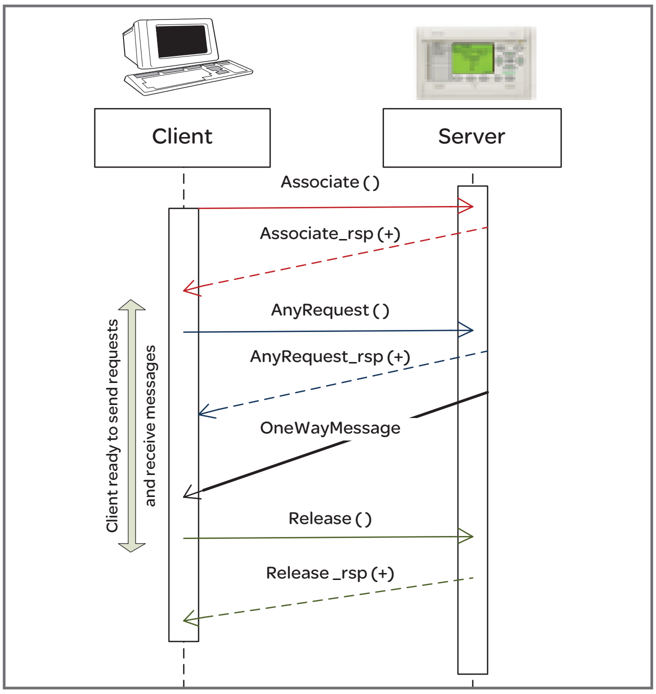


Figure D3.14:
Procedures for Client-Server communication

Two communication services are unidirectional, that means a message is sent, but no response is expected. One is the "Command Termination" service used in the "control model". Second is the "Report" service defined in the information "Report model". Finally, the client ends the data exchange with the server by using a "Release" communication service.

3.2.1 Self-description of device

To work properly, clients e.g. a Human Machine Interface (HMI) need to be configured by an ICD file, to understand and visualise all information received by the servers. During the opening of the connection the client often sends a self-description service, to check that his configuration is in line with the server data model.

Some clients, for example Operating or Test Software, can perform tasks without any pre-configuration. In this case, self-description services are used to acquire the server data model to understand the available services and information.

3.2.2 Real-time data access and retrieval

The data provided by a Server can be static with no change expected during operation (e.g. a serial number) or change slowly or rarely, dependent on the process behind it. Real-time data access and retrieval services deal with data that is static or is changing slowly or not time-critical. The client can read this data from time to time to get an update by "Polling". The data object retrieval services shall be used only when the data change isn't time-critical for the client. If a fast data update is required, the client has to use the event reporting services described in the next section. The typical service used to read data from a server is "GetDataValues". Figure D3.15 illustrates how a client retrieves information about the vendor and software version of an IED. Reading DA NamPlt in the LN LLN0 of the LD Measurement.

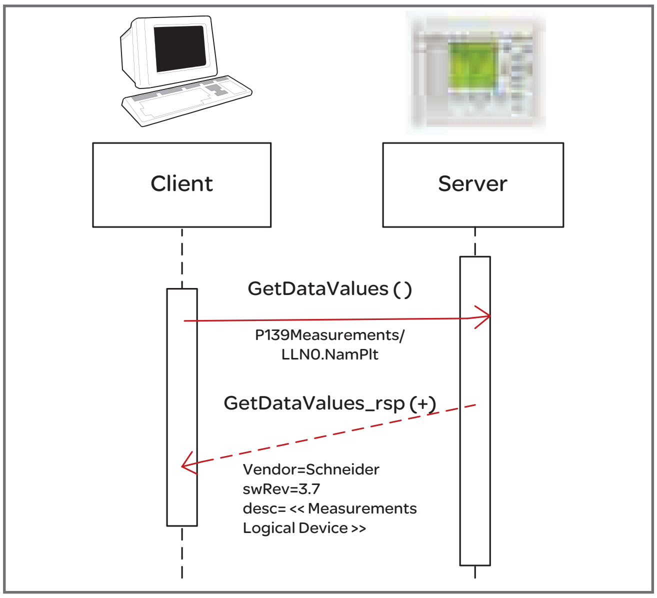


Figure D3.15:
GetDataValues service

Using the service "SetDataValues", a client can overwrite the value of a data object on server side, when this capability is offered by the server. This is described in the IED configuration file (ICD/IID).

3.2.3 Event reporting and logging

The "Reporting" services are used to fulfill the requirement of event-driven information exchange. Event reporting is useful to save network bandwidth and is much more efficient in comparison to the traditional "Polling" procedure reading cyclic data. As long as no data change happens, no data transmission takes place. When one or multiple data objects are changing their value and/or quality status, a report is sent by the server using the service "Reporting", to update all clients subscribing to the related data objects.

The "Logging" services are provided when the event reporting is not required as the information is not time-critical, but the changes should be traced and no data change should be lost. The client can request the data from time to time to collect in a central long term storage.

Reports and logs are both controlled by a control block linked to a Data Set. The data management behind both is very similar. When a data change occurs, each active report or log control block evaluates if the change must generate an event based on its current configuration.

Two kinds of reports are available, the "Unbuffered Reports" and the "Buffered Reports". Related control blocks are named as URCB (Unbuffered Report Control Block) and BRCB (Buffered Report Control Block). With an Unbuffered Report a data change will get lost by a client, if the change happens when the link is disconnected. In the case of Buffered Reports, the server keeps a queue of the events. After a link recovery, the affected client is able to retrieve older events from this data queue.

Report control blocks provide a lot of flexibility with configuration parameters to define the content of the sending message, sending cycle, deadbands for measurements, behaviour during integrity scan or general interrogation.

Figure D3.16 illustrates the basic usage of event reporting services with buffered reports. Behind the pre-configuration by the service "SetBRCBValues" the server is starting to send reports in a pre-defined sending cycle. Other services are for example "GetURCBValues" to read a control block configuration or "QueryLogAfter" to get data from the Logging queue.

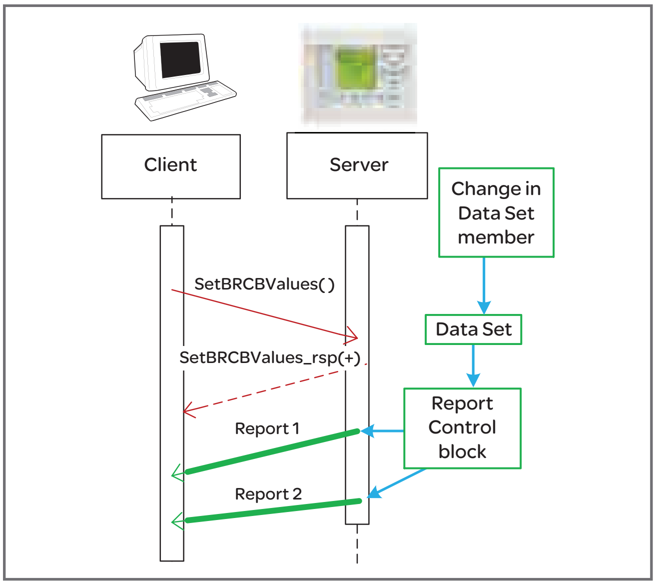


Figure D3.16:
Procedure for reporting

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3. Communication services

3.2.4 Device control

For control the following services are available:

a. Direct control with normal security

b. Direct control with enhanced security

c. SBO control with normal security

d. SBO control with enhanced security

e. Status-only (for manual operation) only

"Direct control" is used when no pre-selection of the equipment is required, whereas "SBO control" require operator to first select a control to ensure that no other process will execute the control at the same time. Control with "normal security" does not respond to the client with a value check result after operate. Control "with enhanced security" is always sending a "command termination" at the procedure completion to confirm if the demanded state/position has been reached or not.

For the control of objects in the LN classes, e.g. the control of DO "Mod" to change the operating mode of a logical node, a direct control with normal or enhanced security is usually used.

For the control of switchgear equipment in substations it is strongly recommended to use only the "SBO with enhanced security". The typical sequences for an SBO control with enhanced security are illustrated in Figures D3.17 to D3.20 showing each single process step for understanding.

Figure D3.17 shows the enhanced select and operate procedure with successful termination. At first the client sends a "Select Value Request" for an open (on) or a close (off). When receiving a positive "Select Value Response" back from the IED the same client sends an "Operate Request" for the open/close operation. Now the switch controller sends an "Activate Output Request" to the logical node representing the switching device (XCBR, XSWI). Directly afterwards it responds to the client with a positive "Operate Response" to confirm the start of a switch actuation. While the primary device is moving, the logical node representing the switching device first sends an intermediate-state and then the new on/off position as requested. As soon as the end position gets returned, the switch controller sends a positive "Report Request" independent of the validation followed afterwards.

If the new status value is the one requested by the client, a positive "Command Termination" is sent to close the sequence.

Figure D3.18 shows a select with unsuccessful selection. At first the client sends a "Select Value Request" for on/off. If another device has already been selected or is in operation, the switch controller returns a negative "Select Value Response" to abort the sequence.

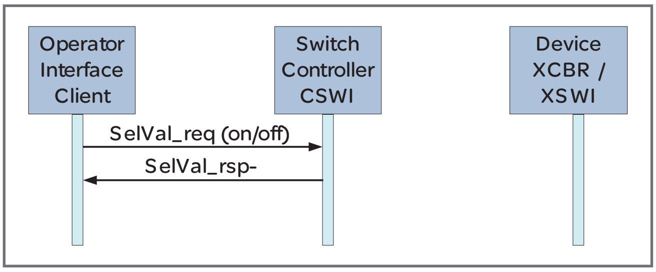

Figure D3.18:
SBO control with enhanced security
Negative select response

Figure D3.19 shows a select and an operate with successful cancellation by the client. At first the client sends a "Select Value Request" for on/off. When receiving a positive "Select Value Response" the same client operator decides that the wrong device has been selected or the switching does not make sense anymore. Then a "Cancel Request" can be sent to stop the procedure. Now the switch controller sends a positive "Cancel Response" to close the sequence.

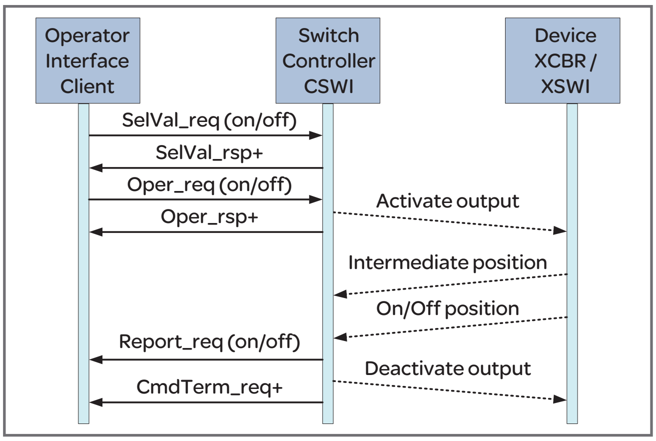

Figure D3.17:
SBO control with enhanced security
Positive command response and termination

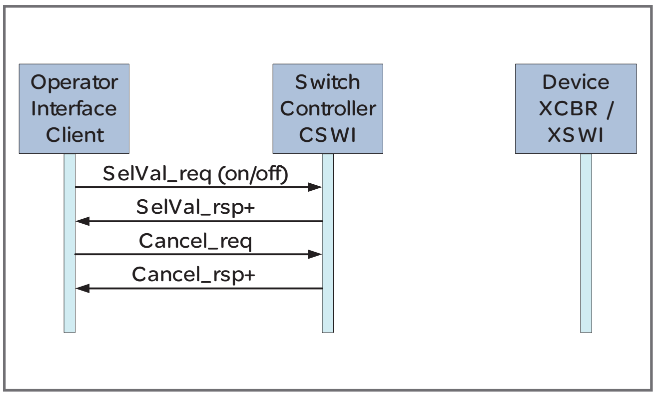

Figure D3.19:
SBO control with enhanced security
Cancel command response

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Figure D3.20 shows a select and operate with time-out. The first part of the sequence is similar to the first case with positive select and operate, but when activating the output, the position signals of the device are not changing. A possible reason for this could be that the switching device did not start to operate or that it did not reach the final position due to a mechanical error. With an expired supervision time the switch controller sends a negative command termination as a result of the validation test.

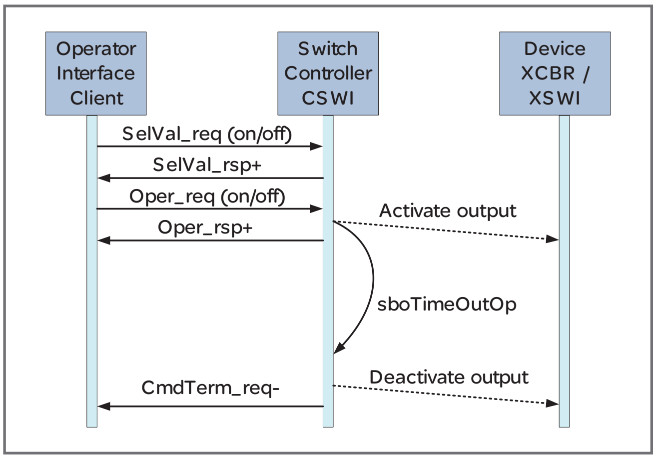

Figure D3.20:
SBO control with enhanced security
Negative command termination

All shown sequences are similar for a direct control procedure except that the select request and response at the beginning are not used.

3.2.5 Setting and setting group management

The initial physical device behaviour is defined by its setting and configuration. During operation it can be useful to allow adjustments of setting and configuration parameters in order to adapt them to changing circumstances. Providing an interoperable changing capability on parameters during operation brings a lot of flexibility. Settings and setting groups are defined in IEC 61850 for that purpose. They offer a standardised way to adjust the behaviour of a device. Adjustments can be done either on a single parameter ("Setting Management") or on sets of parameters ("Setting Group Management"). A given parameter is managed either in standalone or through a set, but not both.

For Setting Management, a client uses the service "SetDataValues" to change parameters one by one. Setting Group Management allows consistent management of a set of parameters. Setting groups are managed using a Setting Group Control Block (SGCB).No data set is needed, because the definition of the set of parameters is defined by the standard as DOs for each LN. The initial values of those parameters are defined during the engineering phase.

During operation a client may use "SetEditSGValue" to change parameters of a setting group during operation or "SelectActiveSG" to switch from a group of parameters to another one. For example, a group of parameters can be used during summer and another during winter.

3.2.6 File transfer

IEC 61850 provides basic file management facilities. A server (IED) has to manage this with a real or virtual file system. File transfer is used to upload files from a client to the server or to download files from the server to the client. Typical files transmitted from the client to the server are configuration or setting files. In the opposite direction recordings, loggings or documentation files can be sent from the server to the client. The services used are "GetFile" for file retrieval as illustrated in Figure D3.21 to retrieve a fault recording. In the opposite direction, the "SetFile" service can be used to send e.g. a CID file for the configuration to the server. Finally, a client can have access to some file attributes using "GetFileAttributeValues" or delete a file using "DeleteFile".

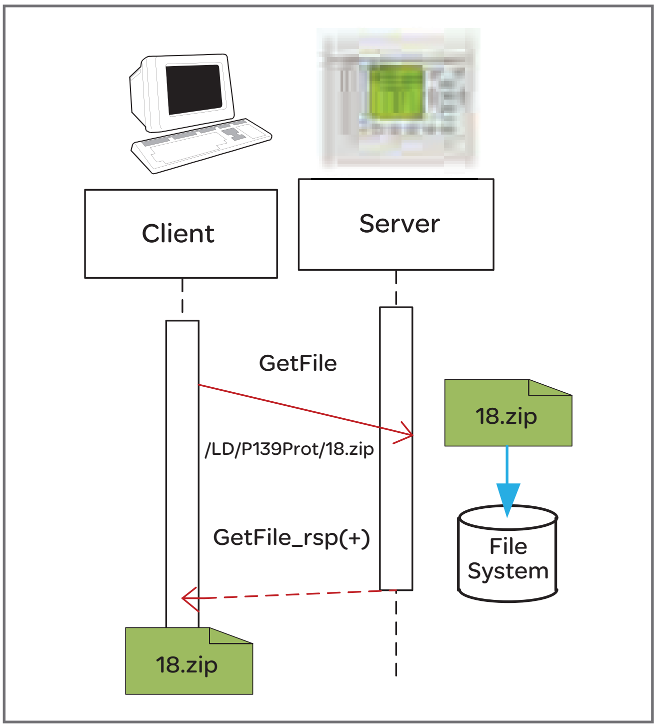

Figure D3.21:
File transfer for fault recording

3.2.7 Substitution

Clients can request the server to replace a process value by a fixed one. It can be useful in case of acquisition failure of external equipment, e.g. a sensor which moves out of order. In IEC 61850, this mechanism to replace a process value for a dedicated time is called 'Substitution'. The service "SetDataValues" is used for that purpose. The substitution

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mechanism is optional and is handled only on server side. The clients handle the 'substituted' process value as a normal value. The only difference is on the quality of the value: a dedicated field indicates that the value has been substituted.

3.3 GOOSE communication

Publish/Subscribe communication is used for the transmission of a "GOOSE" (Generic Object Oriented Substation Event) message. GOOSE communication is used for the fast and reliable distribution of DO or DA reference from one IED to other IEDs. In comparison to Client-Server communication, no dedicated link connection is required. As illustrated in Figure D3.22, a "Publisher" posts a message to all IEDs in the same network using a multicast address as destination address. All subscribers (here "Subscriber A" and "Subscriber B") in the network receive this message and identifies if it contains the same multicast address as if pre-configured in their subscription. If this is the case, the IED processes the data of this GOOSE to its internal function. If not, the message will be ignored.

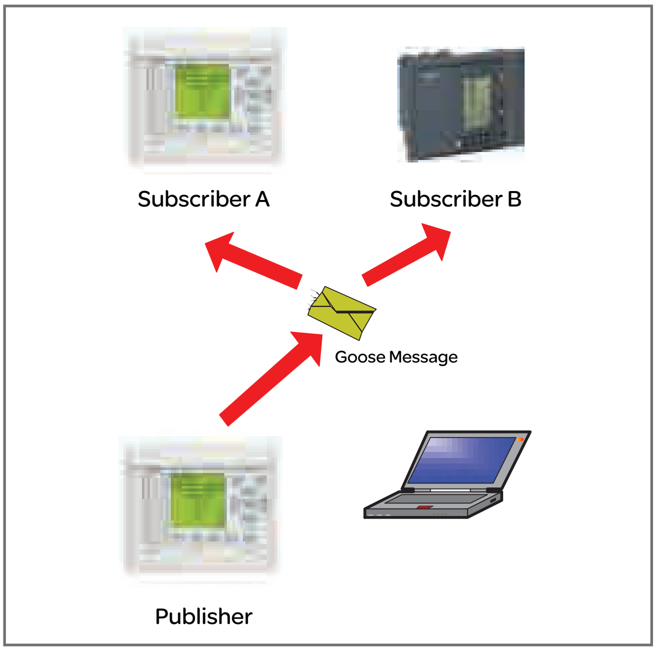

Figure D3.22:
Configuration for GOOSE communication

An IED usually receives GOOSE messages from different IEDs as well as over several different multicast addresses. An example is shown in Figure D3.23, where a "Message A" is received only by "Subcriber2", as "Subscriber1" isn't subscribing to the same multicast address. "MessageB & C" are both received at the same time by both "Subscriber1 and 2". "MessageD"again is received only by "Subscriber1" as it will be ignored by "Subscriber2" due to the unsubscribed multicast address.

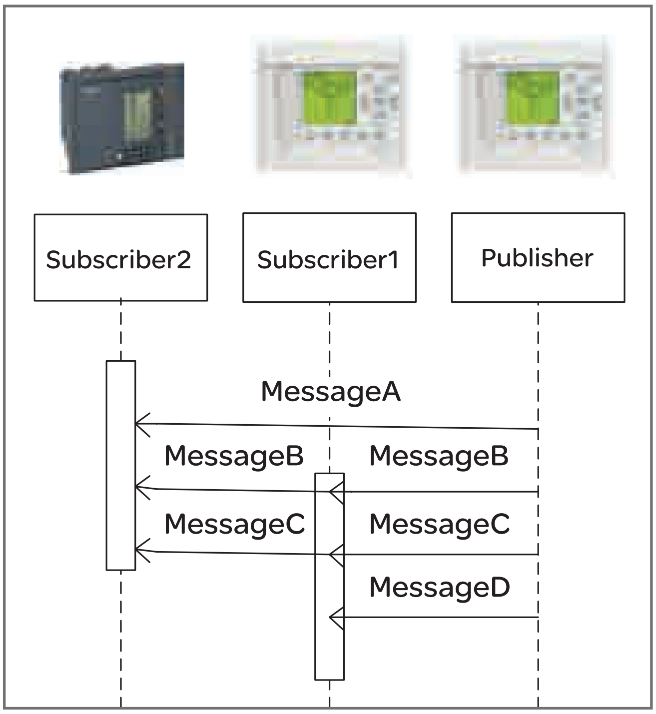

Figure D3.23:
Procedures for GOOSE communication

From a high level perspective, GOOSE fulfills the same requirement as a Report, as it provides an event based distribution of information. As the GOOSE model is designed for high performance, it offers much less flexibility than report mode but can transmit information to other devices in a few milliseconds. To achieve the performance requirements, it is mandatory that the GOOSE message fits inside a single Ethernet frame.

GOOSE behaviour is managed by a GOOSE control block (GCB) and some communication parameters. As for Reporting, a data set is linked to the GCB to list the published and subscribed data.

The GOOSE message includes standard Ethernet fields, VLAN flags (used to virtually isolate part of the communication network), specific GOOSE related fields for identification and timestamp and the values of each member of the data set.

Table D3.7 provides more details on typical GOOSE message with the following colour marking:

a. Green: Identification field to filter on the communication level

b. Purple: Identification field to filter on data model level and other general message information

c. Blue: Data values of DO and DA references

d. Orange: Security or redundancy field

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Field name	Typical value
Multicast MAC address	01:0c:cd:01:00:02
Sender MAC address	00:80:f4:78:88:76
VLAN id and priority	0,4
Ethertype	IEC 61850/GOOSE (0x88b8)
PDU Length	420
APPID	2
Reserved1; Reserved2	Reserve for security
Control block reference	P544System/LLN0GOgcb02
Time allowed to live	2010
Data set reference	P544System/LLN0$DS07
GOOSEID	P544System/LLN0GOgcb02
Event Timestamp	2014-12-18 23:04.8,972000
stNum	10
SqNum	240
Simulation bit	0
Config revision	10
Needs commissioning	FALSE
Number data set entries	15
First data	Depend of data set definition
...	
Last data	Depend of data set definition
Optional security fields	
Optional PRP fields	

Table D3.7:
Structure of a GOOSE frame

Loss of multicast messages can happen on an Ethernet network. Subscribers are able to detect the loss of a message or the whole link because a special repetition mechanism is used as illustrated in Figure D3.24. The message is sent in a slow cycle ("MaxTime"), with each repetition a counter value ("sqNum") gets incremented. The "TimeAllowedToLive" sets the validity time of the last message. If the subscriber receives an invalid "sqNum" or doesn't receive a message before the "TimeAllowedToLive" has expired, the GOOSE monitoring indicates a loss of one of the subscribed message.

When a change occurs in a member of the data set, a new GOOSE message is sent by the Publisher as soon as possible. In this message, "sqNum" is set to zero and "stNum" is incremented. Based on this indication, the subscriber knows that an event has occurred. This message is then repeated again much quicker and several times with increasing cycle time. After several retransmissions, the message is sent again in the "MaxTime" cycle.

There are several other identification elements in addition to the multicast MAC address, to group GOOSE messages. Examples are the VLAN address which can be filtered by the network switches to reduce the traffic or the "AppID" to separate GOOSEs per application.

The GOOSE and Report models are very different but complementary ways to manage events. Depending on the performance or flexibility requirements, either one or other can be chosen.

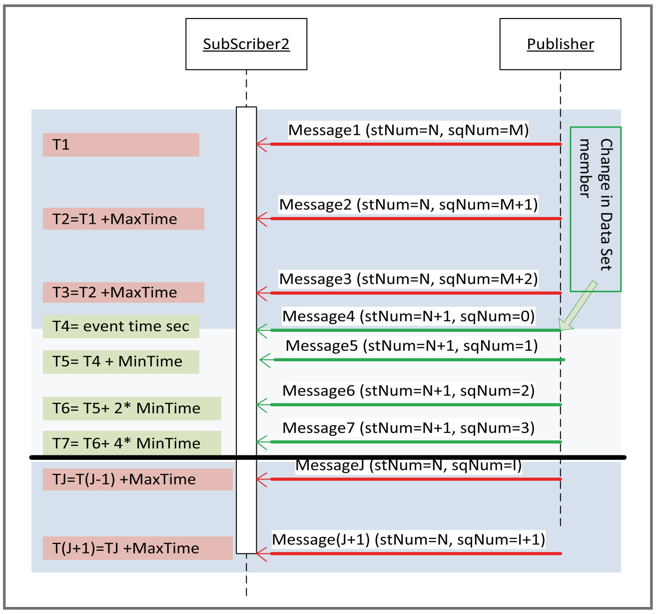

Figure D3.24:
GOOSE publishing mechanism

3.4 Sampled values

Sampled Values (SV) are defined in part 9-2. The goal of SVs is to send sampled Current and Voltage data in a very precise and regular way from an intelligent transformer IED with Ethernet interface called a "Merging Unit" (MU) to other units.

The communication services for SV and GOOSE are very similar. Both use the Publish/Subscribe model and send multicast messages from one publisher MU to one or multiple subscribing IEDs which can use them for further processing. Figure D3.25 illustrates the principle. SV generate a continuous data stream on the Ethernet and consume a significant bandwidth of the network traffic. Especially if multiple MUs are running in the system, it is recommended to use a separate bus system. As the SV are near to the process this separated bus system is called in the standard "Process Bus" as shown in Figure D3.25.

The IEDs themselves no longer need their own CT/VT interface hardware as they receive the sampled data over an Ethernet interface. With respect to the synchronicity and precision of the received sampled data the IED can use them for its protection, control, measurement or power quality purpose. This can reduce the number of transformers and power leading hard-wiring, when the data sent by SV can satisfy the specification of all connected IEDs.

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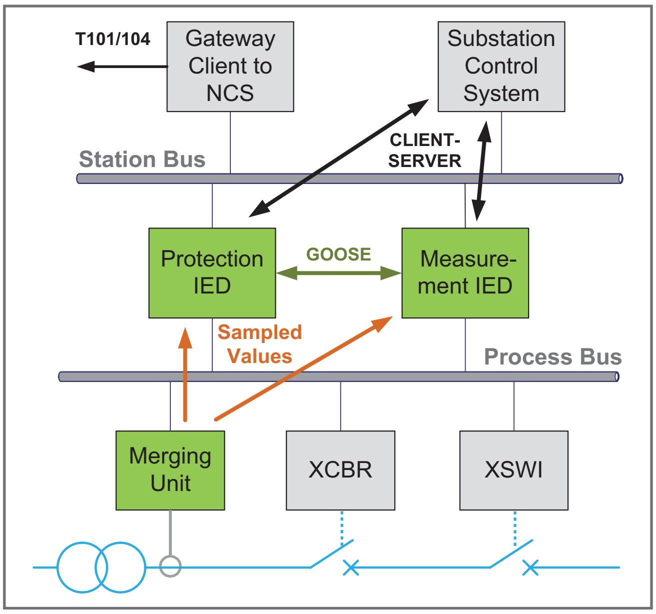

Figure D3.25:
Sampled values via process bus

Typical sampling rates for SV in a 50Hz network:

a. Protection 4 kHz - 80 samples/period

b. Measurement 12.8 kHz - 256 samples/period

A key requirement of the MU is to ensure the synchronisation of the sampling using time synchronisation over IEEE1588. Especially on sampled data for protection devices, a slight slippage in the sampling time leads to a high error on the phase angle between the voltages and currents of the 3 phases. This may have a negative impact to the measurements for the evaluation of the impedance phasors of the distance protection or can generate a delta of the current phasors between the ends of the differential protection.

3.5 Time synchronisation

In IEC 61850 the information data has to be time-stamped when a change occurs. Each device embeds a clock to take the time stamp precisely. To generate a timestamp synchronously to other IEDs, a central time synchronisation of this clock should happen.

IEC 61850 refers to generally available time synchronisation protocols such as the following:

a. 1 PPS

b. IRIG-B

c. SNTP

d. PTP (IEEE1588)

Figure D3.26 shows a classical time synchronisation architecture.

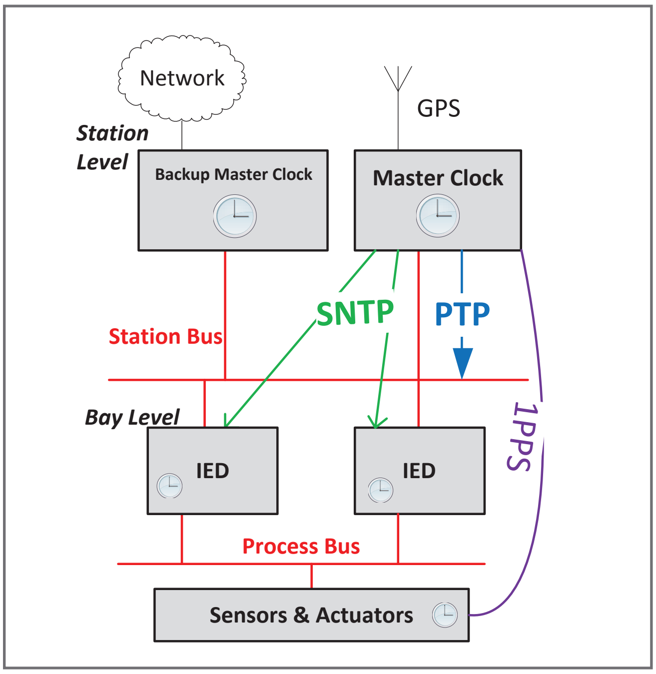

Figure D3.26:
Time synchronisation in IEC 61850

At the top level, a GPS receiver acts as a time server and indicates the absolute time. As time synchronisation is critical, a backup time server should be available, in best case using a different type of media to the first one. It can be based on a network or on a long wave radio (DCF77, MSF-60 etc.). The time server generates a 1 PPS or IRIG-B signal over a dedicated wiring or sends time information on the Ethernet Station Bus using a SNTP or PTP protocol.

1 PPS is referenced by IEC 61850-LE and is mainly used at the merging unit level. Data can be time-stamped with an accuracy of four microseconds. Like 1 PPS, IRIG-B is also based on a pulse, but it also transmits the time data by a real message.

IEC 61850-8.1 specifies SNTP as the synchronisation protocol. SNTP uses a classical Client-Server mechanism. The central time server takes as well the server role for SNTP. All communication devices (IEDs, HMI, Gateway) are working as clients. Each client opens a separate client channel and requests the new time information in a periodic cycle. Devices using SNTP can offer a clock accuracy of about one millisecond.

A new part of IEC 61850 is in progress to define the PTP profile for the substation usage (Part 9-3 - Precision Time Protocol Profile for Power Utility Automation). Contrary to SNTP, PTP acc. IEEE 1588/IEC 61588 relies on the master-slave scheme. The time server broadcasts a sync message periodically containing the reference time. PTP allows much better performance than SNTP with an accuracy in the microsecond area.

4. Typical applications

On applications with normal up to low time requirements the IEC 61850 standard provides the "client-server communication" i.e. the Reporting. The services behind get transported via the MMS stack on a higher application layer. Application examples, where client-server communication is the preferred method for transmission, are following in the next sections 4.1.

On applications with higher time constraints the normal client-server communication over MMS is not fast enough to be usable. For this a dedicated service was foreseen in IEC 61850 which is the GOOSE communication. All information exchanged over GOOSE is transmitted on the TCP Ethernet communication layer. Application examples where GOOSE communication is the main preferred method for transmission follow in section 4.2.

All data objects shown in the several tables of application sections contain only the part of LN/DO/DA information used in the application, the tables cannot be seen as a complete picture of all DO/DA of the related LN classes. The tables include a T/R column which show the direction to (R = Receive) and from (T = Transmit) the IED to the client or other IEDs. The IED name can be found in the related figure of the substation configuration. Names used for "LDInst" in the tables are examples only.

4.1 Applications with client-server communication

4.1.1 Substation control

Controlling of switchgear equipment in an electrical substation is a safety-related operating area. In modern substation control networks there are mostly multiple operator interfaces as communication clients which have the capability and in most cases the authority to control switching devices. To ensure that only one client is able to initiate a control activation at the same time, the IEC 61850 standard provides a well defined "Select-Before-Operate" (SBO) procedure as a common service. SBO allows an exclusive reservation of substation equipment by a pre-selection named in IEC 61850 as "SelectWithValue", before sending the real open or close command as "Operate" to actuate the control action. A second switching command coming from another client will be normally rejected as long as the object is selected, if there is no other principle used to allow multiple switching commands in parallel. The decision on how to handle switching commands in a limited network section or in the entire substation is managed by the "Substation Interlocking" as described in section 1.2.2.

The SBO principle can be explained with help of Figure D3.27. The substation shown has one infeed bay T1 and several feeder bays F1 to Fn. There are two substation control clients S1 & S2 as Operator Interface (OI) from where control commands can be initiated. If OI S1 requests a Select at bay F2 in step "1", feeder bay unit F2 responds to this client with a "switch selected" message in step "2". As soon as the switch of F2 is selected to execute a control command, any further select or operate request will be rejected as shown in step "3".

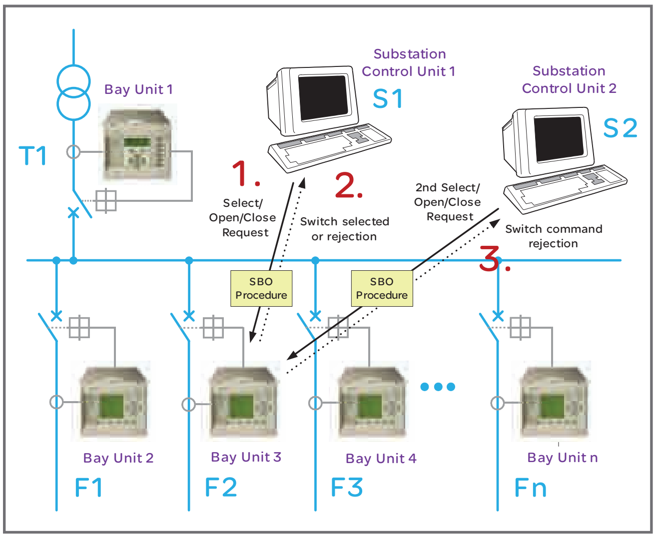

Figure D3.27:
Select-Before-Operate principle in IEC 61850

In IEC 61850 there are several logical nodes defined to model the different functional elements to manage switchgear control. There are two main different kinds of switching devices in a substation:

a. Circuit Breaker with fast switching speed and the capabilities to interrupt load currents and fault currents

b. Disconnector with slow switching speed and low switching capabilities to connect substation parts or to create an earth connection for safety reason during maintenance.

The logical node which is directly connected to the primary process part is called "XCBR" for the circuit breaker and "XSWI" for the disconnector. According to the standard a switchgear position can have four different states for which it is modelled with common data class "Double Pole Control" (DPC) for the control and for the feedback of the state as shown in Table D3.9. Double pole stands here for the 2 wire control of the process, the IED has normally a binary output for the close (switch on) command and a 2nd one for the open (switch off) command. For the feedback of the switch position there are two binary inputs providing the signals from the switch end contact for open and for close ("off" or "on"). If a switch moves from open to close or close to open, there is an "intermediate-state" detectable when both inputs are de-energised as the switch is moving from one end position to the other. When both switch signals are high it is seen as a "bad-state", as it must be an error in the wiring or the position feedback contacts of the switch. In addition, this state is used to indicate that the switch is found in an abnormal status.

In future the Logical Node to represent a circuit breaker or a disconnector can be hosted in an intelligent switch. A further logical node called switch controller "CSWI", is located in the communication server itself, controlling the primary equipment interface nodes XCBR and XSWI. The position signals are

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using the same model. Where the XCBR and the XSWI do provide the actual position signals following the primary equipment, the CSWI may perform a suppression of the intermediate-state, if required. The detailed data information transmitted between client and IED server is shown in Table D3.8 and D3.9. Bay F2 receives a control from the client via CSWI.Pos.ctlVal (LN.DO.DA). The status response is sent using CSWI.Pos.stVal.

T/R	IED	LDInst	LN	DO	DA
->R	F2	Control	CSWI	Pos	ctlVal
T->	F2	Control	CSWI	Pos	stVal, q

Table D3.8:
Transmitted data for substation control

LN	DO	CDC	DA	Values
CSWI	Pos	DPC	ctlVal stVal	0 = intermediate-state 1 = off 2 = on 3 = bad-state
CSWI	Pos	DPC	stSeld	0 = false 1 = true
XCBR XSWI	Pos	DPC	stVal	0 = intermediate state 1 = off 2 = on 3 = bad-state
CILO	EnaOpn	SPS	stVal	0 = false 1 = true
CILO	EnaCls	SPS	stVal	0 = false 1 = true

Table D3.9:
Modelled objects for substation control

For the safe and reliable switching in a bay or entire substation there is a need to realise an interlocking. Most of the switches can be opened or closed only with respect to the positions of other switches. A dedicated logic is built as a control element which is called in IEC 61850 "interlocking" (CILO). See Figure D3.28 for the illustration of all control nodes according to the standard. We distinguish between bay interlocking, which is always part of the bay unit in the communication server, and the system interlocking, which is normally outside the bay equipment, controlling the entire substation or a selected part of it. The CILO manages the monitoring and the release of all controls of switches in the bay, whereas the system interlocking monitors and releases the control of switches. How the substation interlocking works in an IEC 61850 environment is described in section 4.2.2. For the control of switchgear equipment in substations it is strongly recommended to use the service "SBO with enhanced security" only. Refer to section 3.2.4 for detailed description of this service.

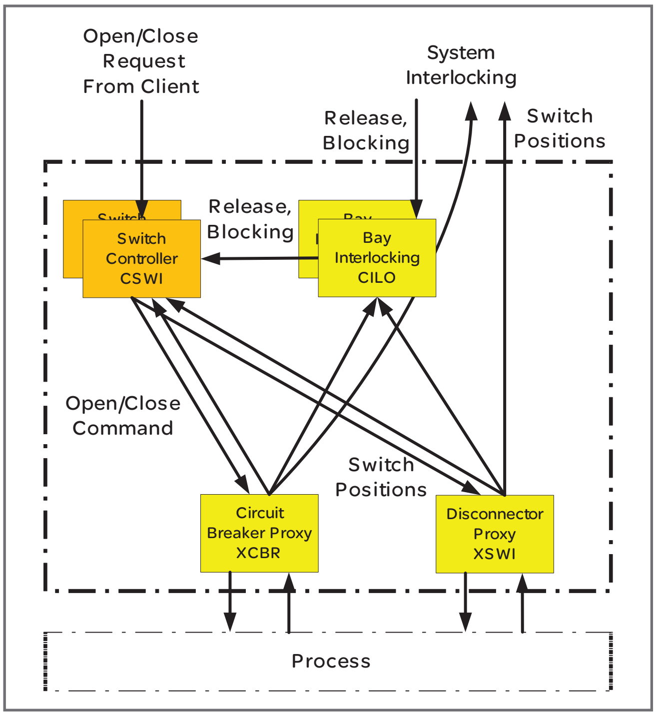

Figure D3.28:
Logical nodes for control in IEC 61850

4.1.2 Local/remote control

Switching devices of a substation as described in the previous section can be controlled from different locations. Each location is assigned a hierarchical level, following the principle 'the closer to the switchgear, the lower the hierarchy'. Typically, "local" is understood if the control happens from the "local" position inside the substation and in front of the control bay unit, and "remote" as issued from a substation control system or a network control centre in another room, floor, building or region. To co-ordinate between control actuations from different sources at the same time, the control device performs a local/remote validation of the control commands against its status before an SBO procedure is accepted. On the bay level, differentiation can be made between controls issued via the Human Machine Interface (HMI) on the front panel of the bay unit and control equipment connected via binary inputs to the bay unit and controls issued directly via push buttons on the switchgear equipment as emergency control without consideration of any interlocking.

Sometimes the local/remote switching is locked by a key switch on the bay unit HMI or by a separate one wired to a binary input of the bay unit. So it is ensured that local control is only activated when the operator with related switch authority uses this key.

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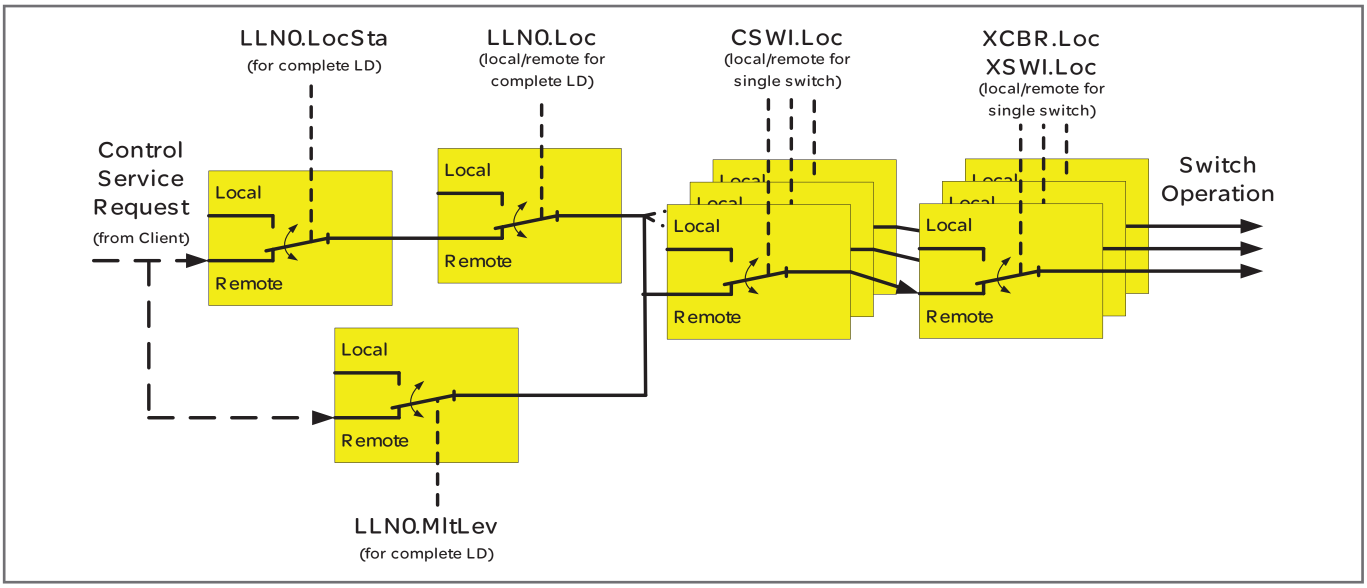

Figure D3.29:
Local/Remote control behaviour

The standard defines a dedicated data object "Loc" on different hierarchical node levels, which each shows the current state and behaviour of the individual switching devices or of the whole logical device or of the bay unit (see Figure D3.29). As the IED cannot know whether a control command received via IEC 61850 is issued from the operator control system location or from the network control centre, all controls which are not issued locally (i.e. from IED level) are dealt with as 'remote'. There is an additional information 'originator.orCat' provided with each control command which helps the IED to decide whether the control hierarchy of the control command received matches the control authority the IED is set to. So, if Loc = false, control commands other than local are rejected. The data object "LocKey" provided on the IED level and with logical nodes hosting controllable objects can be used to set Loc to either 'local' or 'remote'. On the switchgear level, LocKey is typically representing the status of a physical local/remote switch. Another data object object "LocSta" represents the control authority set to substation control system (LocSta = true) or remote via Network Control Centre (LocSta = false). The object "MltLev" defines whether a bay unit will accept a control command from different sources . With MltLev = false the IED only accepts control commands of the given level. With MltLev = true control commands of hierarchical levels closer to the switchgear are also accepted. Table D3.10 and D3.11a summarises all relevant data objects of the local/remote switching.

For safety reasons, a local/remote switchover is always activated via operation at the bay device or at the switchgear via a binary contact and never via communication (therefore SPS, not SPC). For this reason there is no control of any 'Loc' element from an OI client, the various states are only reported from the bay unit to the client when changing.

T/R	IED	LDInst	LN	DO	DA
T->	F2	Control	CSWI	Loc	stVal, q

Table D3.10:
Transmitted data for local/remote control

LN	DO	CDC	DA	Values
LLN0	LocKey	SPS	stVal	0 = false (remote active) 1 = true (local active)
LLN0	Loc	SPS	stVal	0 = false (remote control accepted) 1 = true (local control accepted)
LLN0	LocSta	SPC	stVal	0 = false (remote control from network level accepted) 1 = true (control from station level accepted)
LLN0	MltLev	SPG	stVal	0 = false (single control level acceptable) 1 = true (multiple control levels acceptable)
CSWI	LocKey	SPS	stVal	0 = false (remote active) 1 = true (local active)
CSWI	Loc	SPS	stVal	0 = false (remote control accepted) 1 = true (local control accepted)
CSWI	Pos	DPC	originator	See table D3.11b

Table D3.11a:
Modelled objects for local/remote control

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Each client initiating a control command has to provide his own “originator” information in the control request message. This information comprises the hierarchical level (helping the IED to decide on acceptance), categories of reasons and the name of the issuing client. The bay unit has to copy the originator information into any responses following the control command. As on bay unit level a control command can be created via local HMI, binary input or related communication interface, ‘Originator’ has to be configured for all of these command sources. The possible order categories are shown in Table D3.11b.

LN	DO	CDC	DA	Values
CSWI	Pos	originator	orCat	0 = not supported 1 = bay-control 2 = station-control 3 = remote-control 4 = automatic-bay 5 = automatic-station 6 = automatic-remote 7 = maintenance 8 = process
CSWI	Pos	originator	orIdent	String with control source identification

Table D3.11b:
Originator sub data attributes

4.1.3 Control with synchrocheck

If network areas with different power infeeds have to be connected, an additional function for switchgear control called “synchronism check”, or abbreviated to “synchrocheck”, is used. This function tests before connection if both network sections are synchronous to each other or the deviation is within defined limits. The synchrocheck function measures if the following conditions are met:

a. Difference of voltages $|\Delta U| < \Delta U\ max$

b. Difference of frequencies $\Delta f < \Delta f\ max$

c. Difference of angles $\Delta\alpha < \Delta\alpha\ max$

A closing of the related switch can be only allowed if the limits are not exceeded. The synchrocheck function is sometimes provided by a separate device but very often as an additional function inside a control device.

The synchrocheck can be requested as a first check prior to the decision to do a network connection or directly before the related circuit breaker would be closed. For the second case the request can be combined with the control command of the switch.

The synchrocheck can be managed either centrally or distributed. With the central concept, a dedicated IED performs the synchrocheck for the entire substation. Here a scheme needs to ensure that this IED is provided the necessary measurands. With the distributed concept, the synchrocheck is carried out by each of the bay units where the networks can be connected.

The substation control system uses the client-server communication from IEC 61850 as a service for request and reporting as there are low timing requirements (reaction < 2 seconds). For control commands the typical client supports the differentiation between control modes “with synchrocheck” and “without synchrocheck”. If the control with synchrocheck is selected, the IED performs the check of the network synchronism after having checked the bay and system-wide interlocking. Once the conditions for synchronism have been checked successfully, the close command is released and carried out. If the check fails, the command is blocked and a corresponding message is generated.

The bay unit can report the successful or unsuccessful switch actuation and the measured values for voltage, frequency and phase angle difference, in parallel to the new switch position using the logical Node RSYN for the synchronism check. The detailed data is shown in Tables D3.12 and D3.13. Figure D3.30 illustrates the interactions between the different logical nodes in the bay unit. For the measurement acquisition the nodes TVTR for the voltage transformers are involved to retrieve the required measurement values.

T/R	IED	LDInst	LN	DO	DA
->R	T1	Control	CSWI	Pos	ctlVal check
T->	T1	Control	CSWI	Pos	stVal, q
T->	T1	Control	RSYN	Rel, VInd, AngInd, HzInd	stVal, q
T->	T1	Control	RSYN	DifVClc, DifHzClc, DifAngClc	mag, q

Table D3.12:
Transmitted data for control with synchrocheck

LN	DO	CDC	DA	Values
RSYN	Rel	SPS	stVal	0 = false (blocked) 1 = true (released)
RSYN	VInd	SPS	stVal	0 = false (met) 1 = true (violated)
RSYN	HzInd	SPS	stVal	0 = false (met) 1 = true (violated)
RSYN	AngInd	SPS	stVal	0 = false (met) 1 = true (violated)
CSWI	LocKey	SPS	stVal	0 = false (remote) 1 = true (local)
RSYN	DifVClc	MV	mag	Voltage Difference
RSYN	DifHzClc	MV	mag	Frequency Difference
RSYN	DifAngClc	MV	mag	Angle Difference

Table D3.13:
Used IEC 61850 objects for synchrocheck

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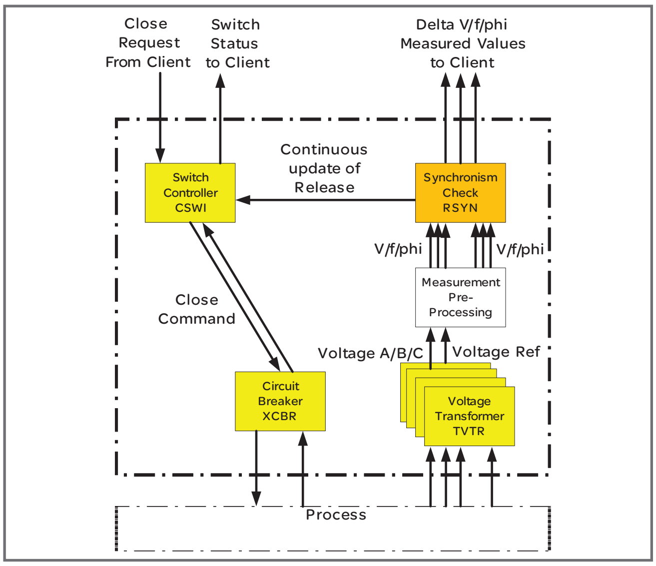

Figure D3.30:
Logical nodes used for synchrocheck

4.1.4 Selection of the parameter subset

In some application cases, the protection settings have to be adjusted when network conditions change during operation. Such a change could happen when additional loads or infeeds are connected, or the settings are changed under different environmental conditions. To satisfy such requirements, modern protection devices offer a certain number of parameter subsets, most of the common protection devices offer 4, 6 or 8 parameter subsets (PS). Typically the first PS considers the normal protection settings, whereas the other ones provide different setting values for the interim network conditions. Parameter subsets can be swapped during operation without interrupting the protection function. The selection of the related PS happens via HMI, binary input or the communication link from the substation control system. Proprietary protocols like IEC 60870-5-103 already provide dedicated definitions to support PS selection with adequate status and control command telegrams. IEC 61850 supports this use case by the services of the Setting Group Control Block (SGCB). The standard defines a control instance SGCB located in the common node LLN0 of a LD, in this example the LD Protection (see Table D3.14, LD name is an example only as it is not defined in the standard). Table D3.15. shows the application relevant attributes of SGCB.

T/R	IED	LDInst	LN	CB	Attribute
->R	F2	Protection	LLN0	SGCB	NumOfSG ActSG LActTm

Table D3.14:
Transmitted data for setting group selection

LN	CB	CDC	Attribute	Values
LLN0	SGCB	INS	NumOfSG	Integer value of max. available SG
LLN0	SGCB	INC	ActSG	Identification number of the active SG
LLN0	SGCB		LActTm	Time of the last SG change

Table D3.15:
Modelled objects for setting group selection

In conformance with the IEC 61850 standard, a client shall use the service SelectActiveSG to activate any of the available PSs. A service request is acknowledged with a positive response (write operation succeeded) if the service was used with valid SGCBReference (System/LLN0.SGCB) and a valid SettingGroupNumber (1 to NumOfSG). The attributes of SGCB are not available for reporting. The identification number of the active PS can be obtained by reading the value of the attribute ActSG or by using a private DO in a data set.

4.1.5 Transmission of disturbance recordings

In cases when a fault occurs in the electrical network, the related protection device detects this fault by its algorithm and clears the fault by issuing a CB trip. A modern protection device generates in parallel to the fault clearance a disturbance recording of the analogue values retrieved during the fault, together with the most important binary signals, to allow a protection engineer to investigate the root cause of the fault afterwards. This disturbance recording can be retrieved from the protection IED in different ways. To simplify the access to disturbance recordings in the devices and to manage an autonomous archiving of all disturbances centrally in a substation, a dedicated disturbance analysis & archiving system can be set up in a communication system. Figure D3.31 illustrates such a disturbance recording system in a typical substation network with file transfer for F2.

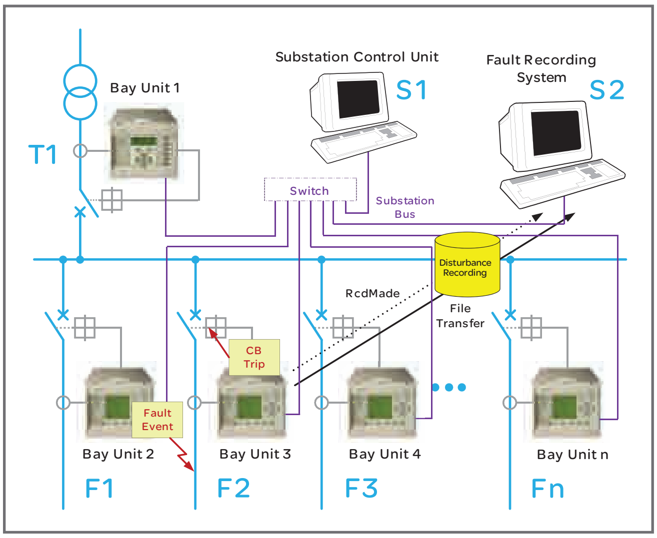

Figure D3.31:
Principle of fault recording retrieval

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By reporting "RcdMade" the protection relay indicates that a disturbance recording was made and that a file can be retrieved. Any subscriber to this information may now use file transfer routines to receive a copy of this file. Proprietary protocols like IEC 60870-5-103 already provide dedicated telegrams to support disturbance recording signalling and download. IEC 61850 supports this use case by file transfer services. The disturbance recording function of an IED is represented by the following LN classes:

a. RDRE – Disturbance recorder function

b. RADR – Disturbance recorder channel analogue

c. RBDR – Disturbance recorder channel binary

RDRE is the function to manage the disturbance recording. The information (header, data values) is stored in a COMTRADE file. Some devices allow to configure whether the COMTRADE file is exposed as ASCII or as binary data. If IEC 61850 is used to configure the disturbance recording function, RADR is the node to configure the analogue channels, RBDR is the node to configure the binary channels. The most important objects required to handle recordings are shown in Tables D3.16 and D3.17. Figure D3.32 illustrates the sequence of messages used to trigger, download and archive the files.

T/R	IED	LDInst	LN	DO	DA
T->	F2	Records	RDRE	RcdStr RcdMade FltNum GriFltNum	stVal, q stVal, q stVal, q stVal, q

Table D3.16:
Transmitted data for fault recordings

LN	DO	CDC	DA	Values
RDRE	RcdStr	SPS	stVal	0 = false (no recording) 1 = true (record started)
RDRE	RcdMade	SPS	stVal	0 = false (no new record) 1 = true (new record made
RDRE	FltNum	INS	stVal	Integer value of fault number
RDRE	GriFltNum	INS	stVal	Integer value of grid fault number

Table D3.17:
Modelled objects for fault recordings

4.1.6 Characteristics switching

For a few applications, the protection functions have to be dynamically adapted to the situation of the electrical network or modus of the electrical objects protected. IEC 61850 provides a couple of different solutions to satisfy this requirement.

One practical example is the distance protection function for an electrical catenary network for railways. Very often the catenary is not organised into one single long feeder line per train direction, but it is a combination of multiple catenary segments for both directions and alternative tracks in parallel, especially near to railway stations. For modern high speed trains there is as well in parallel to the feeder catenary a return conductor to support an auto-transformer solution (see Chapter [C10: A.C. Railway Protection]).

The distance protection device protecting the catenary network is located in each substation over the long railway track between the different railway stations. The protection detects the faults by measuring the impedances of the lines. Dependent on the actual network connections, the impedance changes and the protection has to be adapted to protect the line in the most reliable way.

Figure D3.33 shows an example of the electrical network of a typical railway track under normal conditions. All segments of the catenary are in operation, the distance protection works with an impedance threshold Z1 in both substations.

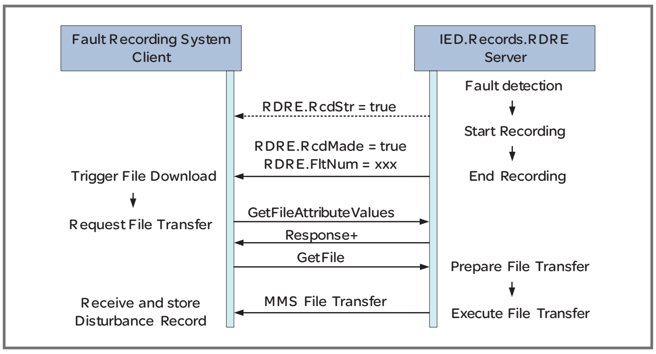

Figure D3.32:
File transfer to download fault records

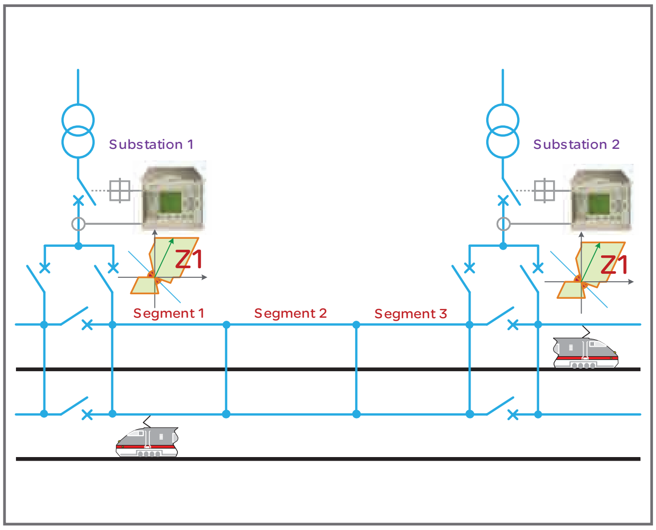

Figure D3.33:
Rail catenary impedance - normal mode

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If one of the catenary segments is now switched off for segment 2, as shown in Figure D3.34, the current flow is different and the impedance of the remaining network system changes. To adapt the protection device to the new arrangement of the catenary the impedance threshold needs to be adjusted to Z1´.

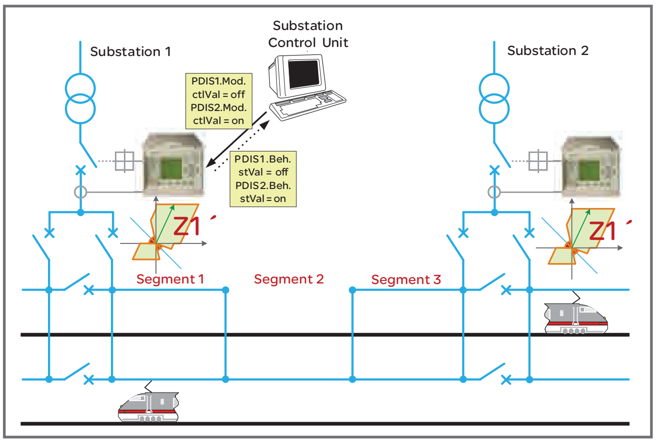

Figure D3.34:
Rail catenary impedance – one segment lost

The change-over is initiated by an operator using the device HMI or via the substation control system, which holds an image of the network configuration. With a switching of a circuit breaker there could be as well an automated change-over made to keep the protection up to date.

The IEC 61850 standard provides two main solutions to manage this kind of application:

a. Selection of the Parameter Subset

b. Enabling/Disabling of Logical Nodes

For the selection of the parameter subset refer to section 4.1.4. Most of the common protection devices offer 4, 6 or 8 parameter subsets. Very often they are already used for other reasons, in the case of the distance for railways for example to manage alternative infeed operation modes and for the adjustment of the impedance levels during train starts or their acceleration. Using the variation of the setting groups for another adaptation, the Enable/ Disable of Logical Nodes is therefore the preferred solution by the railway utility companies.

The timing requirements are not high at all, if the change-over happens in about 1 second, it is sufficient. The selected communication method over IEC 61850 is therefore chosen with client-server communication. The recommended mode is the "Direct control with enhanced security". For the status return it is recommended to use Reporting with spontaneous transmission. For the change of the impedance the substation control system first sends a disable (blocking) of the related distance logical node PDIS1 with impedance threshold value Z1 and directly afterwards an enable of the logical node PDIS2 with impedance threshold value Z1´ to take over. The IED reacts with related response reports to confirm the change of the LN states. The required data element is the data object "Mod" with data attribute "ctlVal" for the control of the LN and the data object "Beh" with the data attribute "stVal" for the status returned (see Table D3.18, D3.19). The disabled LN will be changed to state "off" and the enabled one from "off" to "on". "Beh" represents the real state of the LN. It's computed based on its own Mod value and the Mod of the LLN0 of its LD. If the LLN0 Mod is set to off, all LN of the LD have their Beh also set to off and so, the LNs are disabled by a higher hierarchical level.

T/R	IED	LDInst	LN	DO	DA
->R	S1	Protection	PDIS1 PDIS2	Mod	ctlVal
T->	S1	Protection	PDIS1 PDIS2	Beh	stVal, q

Table D3.18:
Transmitted data for characteristic switching

LN	DO	CDC	DA	Values
PDIS1 PDIS2	Mod	ENC	ctlVal	1 = on 2 = on-blocked 3 = test 4 = test/blocked 5 = off
PDIS1 PDIS2	Beh	ENS	stVal	1 = on 2 = on-blocked 3 = test 4 = test/blocked 5 = off

Table D3.19:
Detailed data for characteristic switching

The IED obviously has to secure that at no time can it happen that both PDIS nodes are in the "on" state at the same time. The best implementation would be to automatically change the one to state "off" when the other is changed to state "on" and vice-versa.

4.2 Applications with GOOSE communication

4.2.1 Reverse interlocking

Reverse interlocking can be used in radial networks with a single infeed, to set up a simple busbar protection scheme. Figure D3.35 shows a simple busbar scheme with a transformer bay T1 as infeed and Feeder bays F1 to Fn for the several outgoing bays in a substation. In our example the highset overcurrent stage I>> of the definite time overcurrent device of T1 is set to a short tripping time of 0.1 seconds. Additionally, this stage is configured to be blocked via a binary input. The first overcurrent

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stage I> of the outgoing feeder bays F1 to Fn are set to a tripping time of 0.3 seconds. The pickup signal of the I> stage or the general pickup signal are configured to a binary output. The binary outputs of all the outgoing protection devices in F1 to Fn are connected as a ring wire to the same blocking input of the infeed protection (see red line in Figure D3.35).

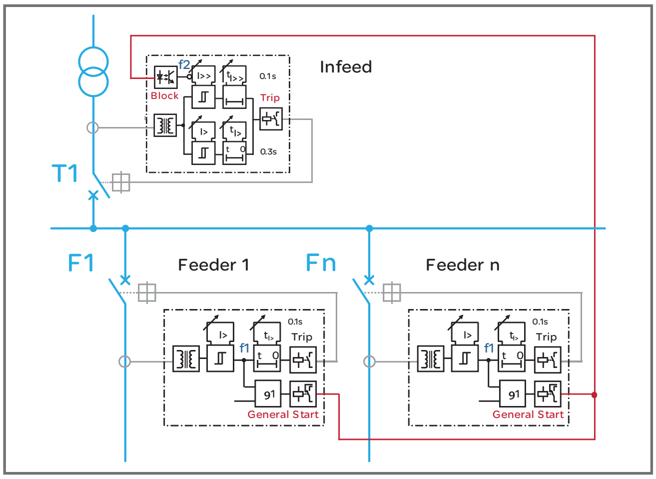

Figure D3.35:
Signal path reverse interlocking by wire

When a fault occurs at one of the outgoing feeders F1 to Fn, the pickup of the protection instantaneously generates a blocking signal to the protection device of the incoming feeder T1 via the configured output and its I>> stage is blocked to prevent a trip condition (e.g. < 0.1 seconds). The outgoing feeder protection in F1 to Fn generates a trip selectively to its circuit breaker which is connected to the faulty outgoing feeder line to clear the fault. The busbar and all other connected loads can remain operational.

When a fault occurs on the busbar itself, the I>> stage of the infeed protection in T1 picks up but none of the outgoing feeder protection units F1 to Fn generate the blocking signal since the affected protection devices of the outgoing feeders do not pick up. Thus, the infeed protection switches off the infeed after 0.1 seconds.

When all protection devices of the busbar are connected via IEC 61850 communication to the Ethernet network of the substation, the GOOSE services can be used to transmit the blocking signals from the feeder bays to the transformer bay without the need of any additional electrical wires. The information is transmitted in one direction only, i.e. to the virtual inputs of the incoming feeder protection (see Figure D3.36).

The use of Ethernet communication thus replaces the ring wire circuits and the required binary outputs of the outgoing feeder protection units and the binary input at the incoming feeder protection unit for blocking the trip. This is saving cost for I/O hardware, wiring and documentation.

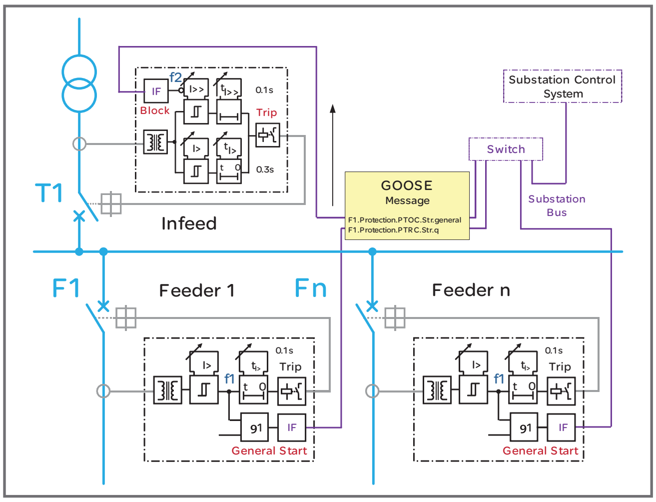

Figure D3.36:
Signal path reverse interlocking by GOOSE

The pickup message of I> as PTOC/Str or the general starting signal as PTRC/Str from the trip Conditioner has to be transmitted by a GOOSE publishing channel from bay F1 to bay T1 (see Figure D3.37). The related IEC 61850 model object is shown in line T-> of Table D3.20. In T1 itself the information out of the subscribed GOOSE messages have to be assigned to the related blocking signal of the I>> stage. The related IEC 61850 model object to indicate that a blocking is affected also is shown in Table D3.20). As IED T1 "collects" all GOOSE information from the different bays F1 to Fn, it has to form a common blocking signal before connecting this to the I>> PTOC function. An internal programming logic is required to combine the virtual inputs by an OR logic. Other possible internal blocking criteria can be integrated as well. The detailed model information is shown in Table D3.21.

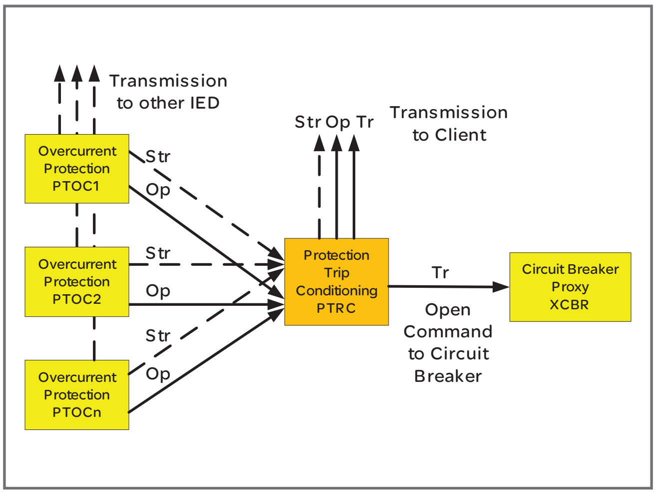

Figure D3.37:
Nodes involved for protection signalling
(Str = Starting, Op = Operate, Tr = Trip)

T/R	IED	LDInst	LN	DO	DA
T->	F1	Protection	PTOC	Str	general, q
T->	F1	Protection	PTRC	Str	general, q
T->	T1	Protection	PTOC	Blk	stVal, q

Table D3.20:
Transmitted data for reverse interlocking

LN	DO	CDC	DA	Values
PTRC	Str	ACD	general	0 = false 1 = true
PTOC	Blk	SPS	stVal	0 = false 1 = true

Table D3.21:
Details on data modelling

For all information submitted via GOOSE, the quality attributes .q have to be transmitted and evaluated on subscriber side to ensure that the blocking is carried out correctly. The blocking may only be activated as long as .q.validity is not marked as “invalid”. The transmission must be completed within less than the set command time tI>> of the incoming feeder protection, which is 0.1 seconds in our example. The time requirement applies here for the transmission path from generation of the pickup $f1$ until the actual blocking takes effect $f2$ (see Figure D3.36) according to IEC 61850 part 5, Edition 2, page 62. The transmission must take place without delay, i.e. a spontaneous transmission is an absolute precondition.

Thus data can be transmitted reliably within a few milliseconds. The reverse interlocking is a part of the protection system and as such is on a high safety level. This is why GOOSE services are especially suitable for this application.

4.2.2 System-wide interlocking

The interlocking function in a substation serves to block the operation of switching devices, if this is hazardous for humans, devices or the whole substation equipment during active service. The decision whether a switchgear actuation is blocked or released requires an evaluation of logical equations from the topological environment of the device in the form of a relevant process information of active and inactive parts of the electrical network. A differentiation is made between the bay-related interlocking and system-wide substation interlocking.

Bay-related interlocking considers the switch positions within in a bay and also the conditions of the switchgear primary equipment such as “spring/drive ready” or “pressure/insulation monitoring” and auxiliary equipment like “MCB Trip”.

System-wide interlocking considers the positions and conditions of all switching devices and their auxiliary equipment within the entire substation or at least a part of it seen as an isolated system.

For a safe system-wide interlocking the following information has to be collected by the interlocking logic:

a. Position indications of all switching devices in the entire substation

b. Warning and alarm messages of the auxiliary equipment (if bay-related interlocking included)

c. Initiation of the interlocking check

d. Release from the interlocking to the IED controlling the switching devices

There are generally three different implementation concepts possible for a substation interlocking as illustrated in Figures D3.38, D3.39, D3.40:

a. Central interlocking by the substation control unit

b. Central interlocking by a dedicated bay unit

c. Distributed interlocking by the bay units

The request for the switching can originally come from the substation control system, the network control centre or locally on the front panel HMI or the binary inputs on the bay unit wired from a remote terminal unit (RTU). The IED can only execute a switching control command when it receives a release by the interlocking unit, otherwise it has to respond to the initiator with a rejection.

The concepts differ depending on which IEDs status indications are exchanged, in which IEDs the interlocking conditions are checked and from where the release signals are generated. If the substation control system is not involved in the interlocking procedure, it only receives updated status information from each IED about the new position of the switching devices.

In the concepts **a** “Central interlocking by the substation control unit” (Figure D3.38) and **b** “Central interlocking by a dedicated bay unit” (Figure D3.39) the interlocking logic is integrated in one central unit. The central unit holds a process image that comprises all information relevant for the all-embracing interlocking conditions.

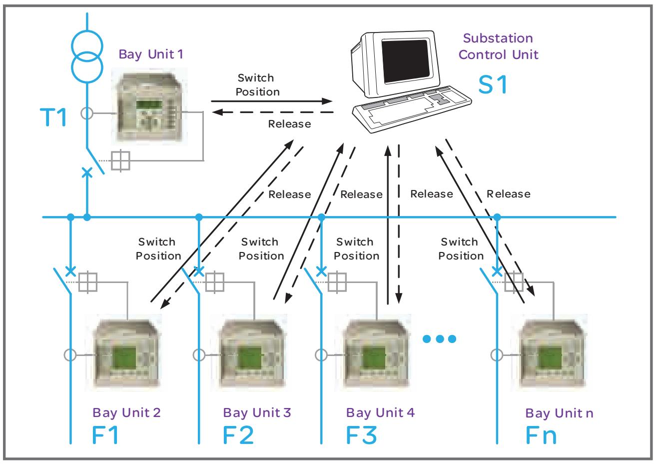

Figure D3.38:
Central interlocking by the substation control unit

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4. Typical applications

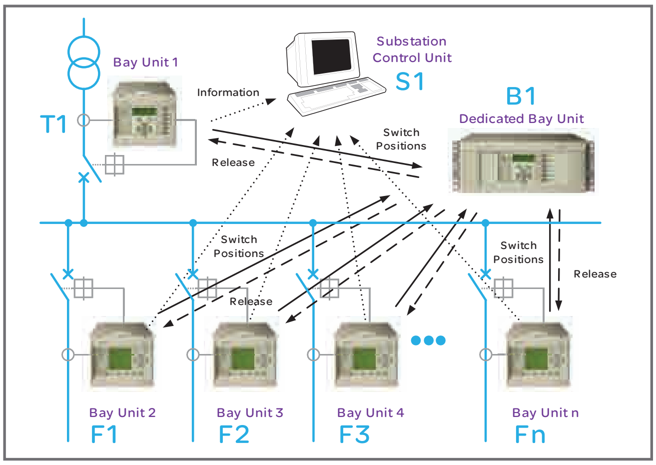

Figure D3.39:
Central interlocking by a dedicated bay unit

All bay units have to transmit the relevant switchgear positions to the central unit either continuously or for each status change. The release information calculated as a result of the central interlocking is sent to the corresponding bay units. This release information is the basis for executing or blocking an open or close control command by the bay units. Additionally it needs to be distinguished whether the interlocking for the bays is integrated in the logic of the central interlocking unit or whether the bay unit manages its own bay-related interlocking. Dependent on this the number of interlocking equations in the central unit may be quite different.

With the concept **c** “Distributed interlocking by the bay units“ (Figure D3.40), the all-embracing interlocking logic is distributed among all participating bay units in the substation. The interlocking logic of each bay unit calculates the interlocking conditions autonomously. Moreover, each bay unit provides the status information required by other bay units for calculating the interlocking conditions in a continuous way.

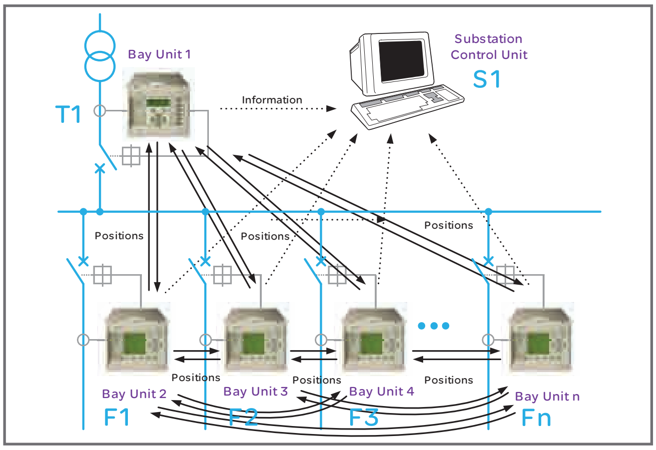

Figure D3.40:
Distributed interlocking by the bay units

With an IEC 61850 network all three concepts can be used. Nevertheless not all concepts can be realised in an interoperable way. For the communication from bay unit to bay unit the GOOSE communication has to be used (so-called “horizontal communication”) which provides a fast transmission time and cyclical status update, whereas the communication between the bay units and the substation control system uses event-triggered reporting via the client-server communication (“vertical communication”). With typically one publishing GOOSE message the bay unit sends a multicast message to all other bays at the same time for subscribing the data. With the client-server reporting the bay sends each data change by a separate message per client connected.

In case of the concept **a** the whole communication would happen via client-server communication as a substation control system has typically no GOOSE subscription capabilities. The status reporting for switching devices is defined in IEC 61850 and this works fully interoperable. But for the send message from the system interlocking to release switch executions, dedicated new procedures and objects have to be defined, as the standard is currently not offering any standardised service. As this extension would be not interoperable, it is not recommended to use the concept **a** for system-wide interlocking. Due to this a further description is not added to this document.

For the two other concepts **b** and **c** the main transmission uses GOOSE communication as bay units typically have no client functionalities. A simple exchange of binary information is made by sending the bay status information and control release information in case of concept **b**. The only case using client-server communication is the status update information to the substation control system, which is unidirectional.

There are arguments in favour of concept **b**:

a. For large substations the number of configurable GOOSE virtual inputs could be exceeded, as each bay unit has to subscribe to the appropriate position signals of other bay units

b. Maintenance of the system interlocking is easier, as not all changes affect all the bay units

In the opposite, the concept **c** provides:

a. The most interoperable solution, as no additional signals need to be defined. Concept **c** is therefore the closest solution to the IEC 61850 standard

b. Testing is much simpler as it is bay-oriented

c. Maintenance is higher than in concept **b** as for each new or changed bay unit the interlocking equations in all other bay units need to be updated

As an example Figure D3.41 shows the communication in the network for concept **b**. For the transmission of the switchgear positions and the open/close release information the horizontal communication via GOOSE is used. Additional reports will be transmitted via vertical client-server communication to update the status in the operator workstation and in the network control centre.

4. Typical applications

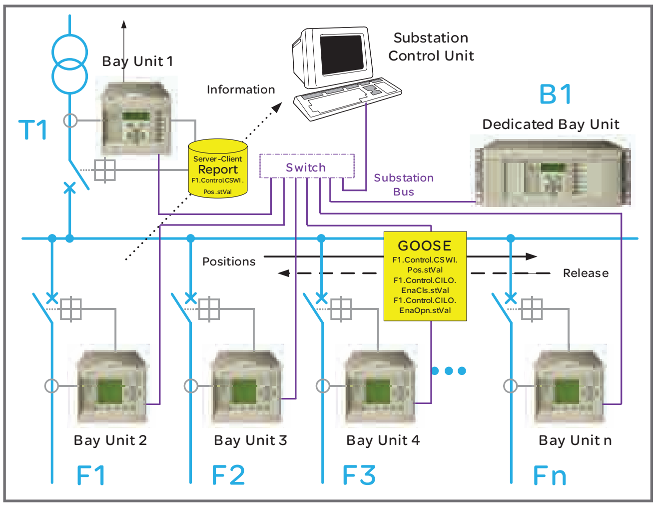

Figure D3.41:
Interlocking communication via IEC 61850

The related objects which are transmitted in concepts **b** and **c** are shown in Tables D3.22 and D3.23. The position indications of the switching devices are modelled in IEC 61850 using the Logical Node (LN) "XCBR" for a circuit breaker and "XSWI" for a disconnector. The data object (DO) "Pos" contains the status information. The position details of a switching device are given by the data attributes (DA) "stVal" for the status value itself and "q" for the quality (e.g. "valid" or "invalid"). As the position

T/R	IED	LDInst	LN	DO	DA
T->	F1	Control	XCBR XSWI	Pos	stVal, q stSeld
T->	F1	Control	CWSI	Pos	stVal, q stSeld
->R	F1	Control	CILO	EnaOpn EnaCls	stVal, q stVal, q

Table D3.22:
Transmitted data for substation interlocking

LN	DO	CDC	DA	Values
XCBR XSWI	Pos	DPC	stVal	0 = intermediate-state 1 = off 2 = on 3 = bad-state
CSWI	Pos	DPC	stSeld	0 = false 1 = true
CILO	EnaOpn	SPS	stVal	0 = false 1 = true
CILO	EnaCls	SPS	stVal	0 = false 1 = true

Table D3.23:
Transmitted data for substation interlocking

status value stVal is a double pole signal, it can take four different values which are "intermediate-state", "off", "on" and "bad-state". For the indication of the switch "selected" state, the switch controller LN CSWI contains the DA "stSeld".

The release signals needed for concept **b** are modelled in the LN CILO (control interlocking logic). The CILO contains DO "EnaOpn" and "EnaCls" to enable (release) or not of the respective open and close controls of the switching device. The internal functional blocks in an IED for control according to IEC 61850 are shown in Figure D3.42.

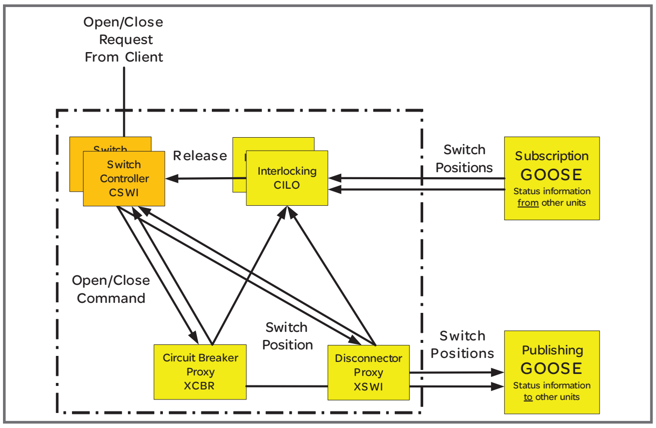

Figure D3.42:
Interaction bay with interlocking unit

For all concepts **a**, **b**, **c** all bay units send their status update via report to the clients connected.

In the case of concept **b** each bay unit continuously sends its switchgear position information and warning GOOSE messages to the interlocking bay unit. The dedicated interlocking bay unit continuously generates the corresponding EnaOpn and EnaCls signals based on the overall substation situation within its interlocking logic and publishes GOOSE messages to return this information to all bay units in charge of their switching devices. If a client requests a select or an operate for a circuit breaker or a disconnector, the corresponding bay unit considers the EnaCls and EnaOpn release status from the interlocking unit in its checks. If the switching control action is permitted, then the command will be executed. If it is not allowed, then the command will not be executed and a rejection message is returned to the client.

In case of concept **c**, each bay unit continuously sends its switchgear position information via a GOOSE message to all other bay units. Each other bay unit has to subscribe to the status GOOSE messages from the other bay units needed for its system-wide interlocking checking. If a client requests a select or an operate for a circuit breaker or a disconnector, the corresponding bay unit when receiving the command initiates an internal interlocking check and evaluates the interlocking status on basis of the received states from the

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4. Typical applications

GOOSEs of other bays involved. If the switching control action is permitted, then the command will be executed. If it is not allowed, then the command will not be executed and a rejection message is returned to the client.

Figure D3.43 and D3.44 illustrate the interaction between the different logical parts for both cases.

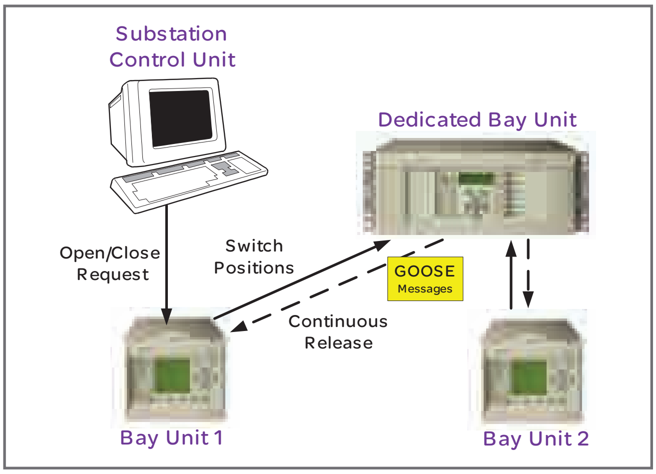

Figure D3.43:
Interaction bay with interlocking unit

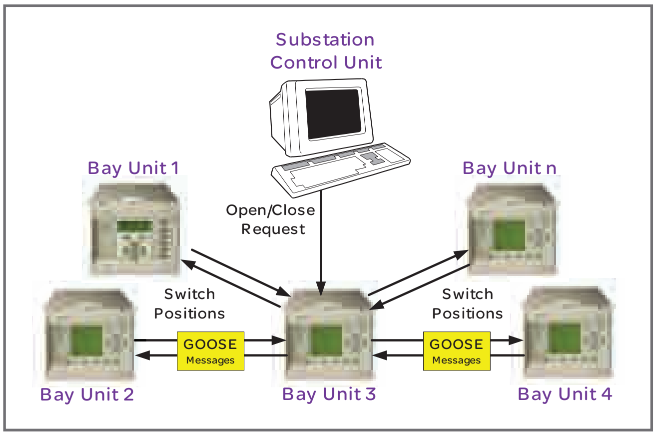

Figure D3.44:
Interaction bay to bay unit

4.2.3 Uniqueness of control

A 1-of-n control logic has to ensure that only one switching control operation can occur at a given time in a pre-defined section of an electrical network. This means that only one switching device (circuit breaker or disconnector) can be opened or closed at the same time. All other switch commands need to be rejected. This function is very important in networks where more than one substation or network control system have the authority to execute operations.

The 1-of-n logic works for a defined substation or network area or possibly a whole substation. The pre-definition of the network sections has to happen at the same time when the concept of the substation interlocking is chosen.

The 1-of-n logic is possible in all three concepts of the system-wide interlocking:

a. Central interlocking by the substation control unit

b. Central interlocking by a dedicated bay unit

c. Distributed interlocking by the bay units

As the concept **a** is currently not feasible in an interoperable way it is not considered in this section.

For the explanation of the 1-of-n logic, the interlocking concept **c** is used. All bay units execute the interlocking by themselves. For that each IED publishes GOOSE messages with the positions of all switching devices. The modelling information transmitted is given in Table D3.24.

LN	DO	CDC	DA	Values
XCBR XSWI	Pos	DPC	stVal	0 = intermediate-state 1 = off 2 = on 3 = bad-state
XCBR XSWI	Pos	DPC	stSeld	0 = false (unselected) 1 = true (selected)

Table D3.24:
Transmitted data for substation interlocking with 1-of-n logic

Each bay unit sends the positions of its primary equipment with the data object “Pos” with an “on”, “off”, “intermediate-state” or “bad-state”. If a switching control operation has been started the position moves from “on” or “off” into the “intermediate-state” until it reaches the opposite state with “off” or “on”. As described in section 4.1.1 “substation control”, the switching control operation is prepared by a “Select” before the real operation.

For the indication that a switch has been selected, an additional status information “stSeld” can be modelled and set from “unselected” to “selected” state. This state will be kept until the final switch position is reached. Adding this object to the GOOSE data set allows other bays to subscribe and to consider it in their bay control logic to be aware of any upcoming and later running switch operations in other bays. The bay control logic of these bays can reject any control request until at least one of the subscribed GOOSE messages from all the other bays signals “Selected” by “stSeld”.

As an example for concept **c** the first step for a close or open command is the operator’s initiation of the operation via the device front panel HMI on bay level or via the Operator Interface (OI) of the substation control system. Figure D3.45 shows in Step “1” a request coming from the OI ‘Select’ as part of an SBO (Select-Before-Operate) command. The control procedure for SBO triggers the interlocking check and responds in Step “2” with a positive confirmation that this switchgear device was now selected. In the next important step “3” in Figure D3.46 the bay unit changes the status of the “stSeld” of the chosen switchgear device to “selected”. If a second control command is initiated during the whole operation by the same or another front panel HMI or by the same or another OI client, in Figure D3.47 shown in Step “4”, the related bay unit can reject the control request directly, in this example by a negative response to the SBO ‘Select’ command to the second OI as illustrated by Step “5”.

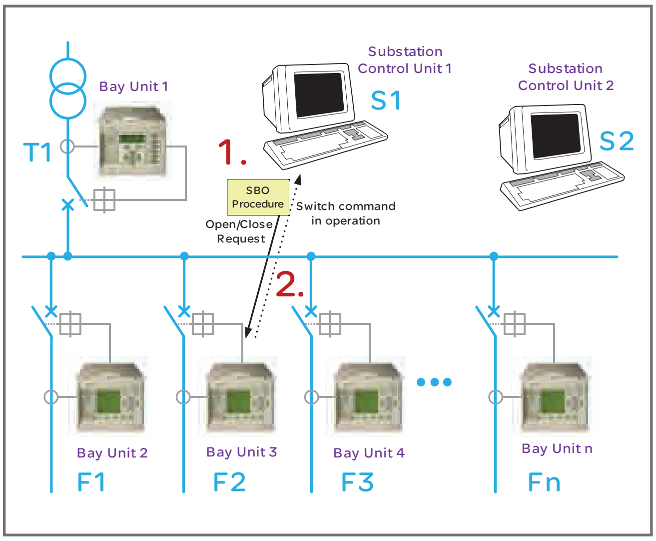

Figure D3.45:
1-of-n logic - step 1 & 2

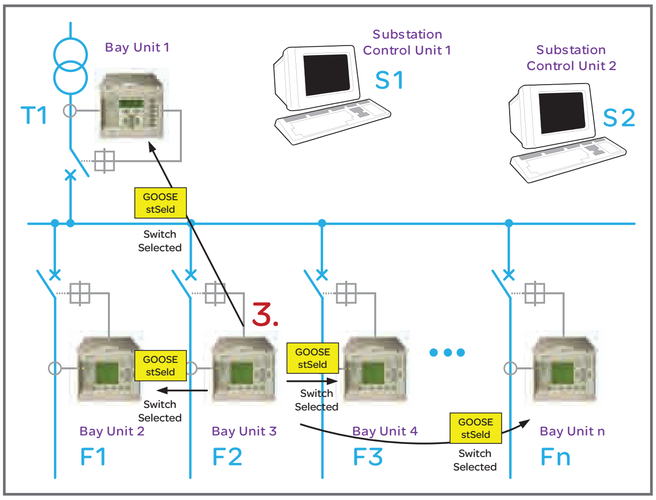

Figure D3.46:
1-of-n logic - step 3

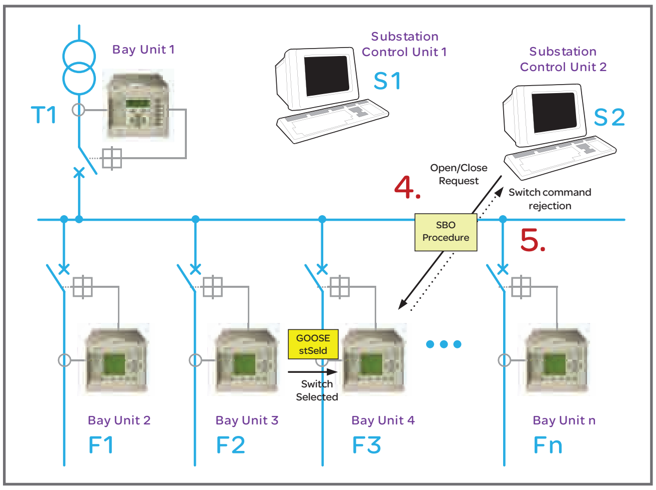

Figure D3.47:
1-of-n logic - step 4 & 5

Figure D3.48 shows the example for concept **b** for the data flow which is much simpler in terms of configuration. The operator initiates a switching control via the Operator Interface (OI) of the substation control system. As shown in Step “1” a SBO request is transmitted from the OI to the bay unit F3. The control procedure for SBO reacts by performing a system-wide interlocking check and responds in Step “2” with a positive confirmation that a switch is now selected. In the next step “3” the bay unit changes the status of the “stSeld” of the chosen switch as “selected” and updates immediately the GOOSE content to the interlocking bay unit. The interlocking bay unit reacts with an immediate update on the release GOOSE messages back to all bay units of the affected system to block further switching operations by setting CILO EnaCls and EnaOpn signals for all other switches to false state (see Table D3.25).

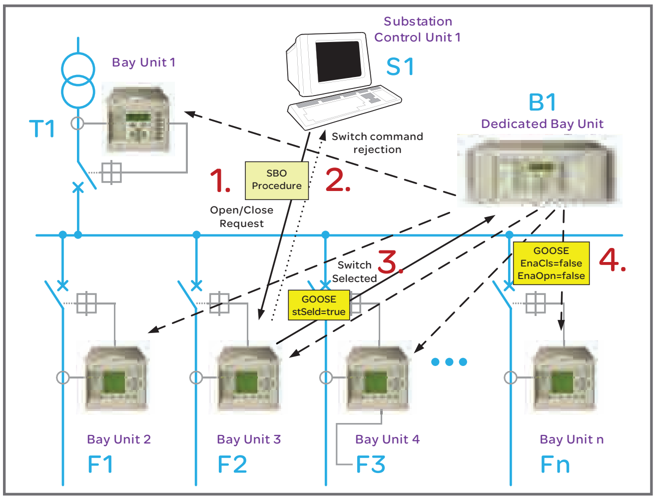

Figure D3.48:
1-of-n logic with dedicated interlocking unit

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4. Typical applications

LN	DO	CDC	DA	Values
XCBR XSWI	Pos	DPC	stVal	0 = intermediate-state 1 = off 2 = on 3 = bad-state
XCBR XSWI	Pos	DPC	stSeld	0 = false 1 = true
CILO	EnaOpn	SPS	stVal	0 = false 1 = true
CILO	EnaCls	SPS	stVal	0 = false 1 = true

Table D3.25:
Transmitted data for substation interlocking

If a second control command is initiated during the whole switch operation time by the HMI or a second OI client, the related bay unit can directly reject the control request, as the incoming system-wide interlocking GOOSE from the dedicated interlocking bay unit is blocking it by false states of the related EnaOpn and EnaCls signals.

For the 1-of-n control logic application the same recommendations related to communication interruptions are valid as mentioned in section 4.2.1 “Reverse Interlocking”. Dependent on the location of the interruption, a control command can be executed without problem or will be rejected. The most critical case is when a bay unit no longer receives any release signals from the dedicated interlocking bay unit (concept **b**) while a system OI still receives updates over client-server communication. Dependent on the GOOSE default definitions it could happen that a second bay unit accepts a switching command in parallel when not receiving the stSeld information (concept **c**) or EnaOpn/ EnaCls information (concept **b**). To prevent this case, it would be useful to report GOOSE error information using LN LGOS to each OI to signify that the system-wide interlocking is not fully operational. For further consideration of fault conditions refer to section 4.2.5 “General Requirements”.

4.2.4 Bay unit testing

Before the first operation of a bay unit in a substation, or at regular intervals after commissioning, the functionality of that bay unit needs to be validated. During such tests the system and operators need to be aware that testing is in progress or test actions need to masked from the operators as not relevant information.

As an example a substation control log should not include test messages and test values as they are not relevant for the normal operation. On the other hand, it is important to block commands from external communications during the ongoing testing if they are not sent specifically for testing purposes.

Conventional serial standard protocols like IEC60870-5-103 provide a solution “monitor direction blocked” to satisfy this requirement. Such a solution cannot be used in the scope of IEC 61850 since there are typically not just two communication partners (in -103 master and slave) but rather a larger number of controlling and monitoring communication clients that can have access to the bay units as servers.

While testing a protection and/or control bay unit in a system environment, a test engineer may have to test one or more functions, an IED or an application scheme. Dependent on the scope of work, the test engineer has to define the structure of functions which have to be put in functional isolation. Resulting from this definition one or more Logical Nodes (LN), one or more Logical Devices (LD), one IED or a number of IEDs must be set to test mode. The strict subordination of the behaviour of Logical Nodes under the behaviour of Logical Devices allows a structured intervention into the IED concerning the LN mode:

a. One or more LN:
access of LNxx.Mod controls this LN

b. One or more LD:
access of LDxx.LLN0.Mod controls all subordinate LD and LN (LLN0 is the central LN of each LD)

c. One complete IED:
access of LD0.LLN0.Mod controls all LD of this IED (Remark: LD0 is the central Logical Device for non-functional LN of a Physical Device, if it exists)

The most common way of testing today is to set a complete bay unit to the test mode. Because of that further description is given for this use case only. If the feature is supported in the IED, the activation of the test mode can be triggered by a binary input stimulated from the insertion of the test plug into the secondary circuits. It is very usual to set the IED into test mode directly via front panel or the operating program.

In a substation which is usually kept in operation during bay unit testing, the IED becomes isolated. This means that some analogue and binary inputs and outputs have to be disconnected or changed over to safe state values to have no negative influence to the other equipment remaining in active operation. On the communication link to the substation control system or network control centre a dedicated message has to be communicated to inform about the unavailability for normal operation. Figure D3.49 illustrates how this information is provided in the client-server communication. In IEC 61850 the test mode information is included in the data object “Beh” of each logical node, including LLN0 which represents the global state of the parent logical device. Tables D3.26 and D3.27 show the details of the related data object which changes its status for IED F2. The data attribute “stVal”, normally in “on” state, changes to the state “test”, if the binary outputs are still connected during the testing to the primary equipment. If they are isolated for the testing which is very usual, the state changes to the “test/blocked” mode accordingly. If the output isolation and test mode changes in two individual steps, the mode first moves from “on” to “on-blocked” and then to “test/blocked” or from “on” to “test” and then to “test/blocked”.

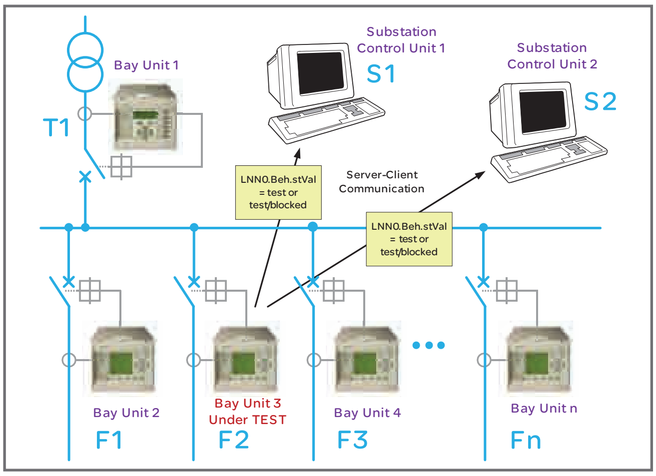

Figure D3.49:
IED in test mode with related indication to the outside equipment in a substation

T/R	IED	LDInst	LN	DO	DA
T->	F2	Various	LLN0 others	Beh	stVal, q

Table D3.26:
Transmitted data for signalling test mode

LN	DO	CDC	DA	Values
LLN0 Others e.g. CSWI PTOC	Beh	ENS	stVal	1 = on 2 = on-blocked 3 = test 4 = test/blocked 5 = off

Table D3.27:
Detailed data for signalling test mode

For each LD the central node "LLN0" changes "Beh" when its state gets modified by the "Mod", to signal the state change for the LD itself. If so, each LN in this LD, e.g. CSWI for control or PTOC for protection, will change the state of "Beh" as well. As this information is usually an element of all data sets, spontaneous reports of all related nodes, which change their states to test mode, are sent to all clients accordingly. This and all further reports to these clients will have data marked as produced while in test mode (data attribute .q as shown in Table D3.28 and D3.29).

T/R	IED	LDInst	LN	DO	DA
T->	F2	Control	CSWI	Pos	q

Table D3.28:
Signalling of messages for testing

LN	DO	CDC	DA	SDA	Values
CSWI	Pos	DPC	q	test	0 = false (off) 1 = true (on)

Table D3.29:
Client message with marking of test mode

The connected clients of the substation and network control system have to react by highlighting this state change of the IED to test mode on their Operator Interface. Furthermore they may ignore all further incoming messages from the IED under test to avoid misinterpretation or malfunction of the equipment not considered as in test mode.

In the opposite case, a client could be used to support the testing by generating special control commands to the IED. In IEC 61850 such test commands are sent with a dedicated marking "Test" in each message to this IED. The IED itself must react only to those messages which are sent with marking "Test".

When a bay unit is placed in Test mode then each of its GOOSE messages must also reflect this by modifying DA. This marking uses the quality DA .q.test = true similar to that used for reporting. The subscribing IED has to react by considering the received data as no longer relevant for its operation whilst the publisher remains in test mode. The detection is only possible when the quality DA for each signal is configured to the GOOSE data set. See also the section 4.2.5 "General Requirements" describing a concept to handle this use case. Figure D3.50 illustrates the example of an IED F2 under test in a complete substation sending its "test mode" information to the other IEDs. The annex of part 7-4 defines how each communication partner should handle each kind of element in test or normal mode.

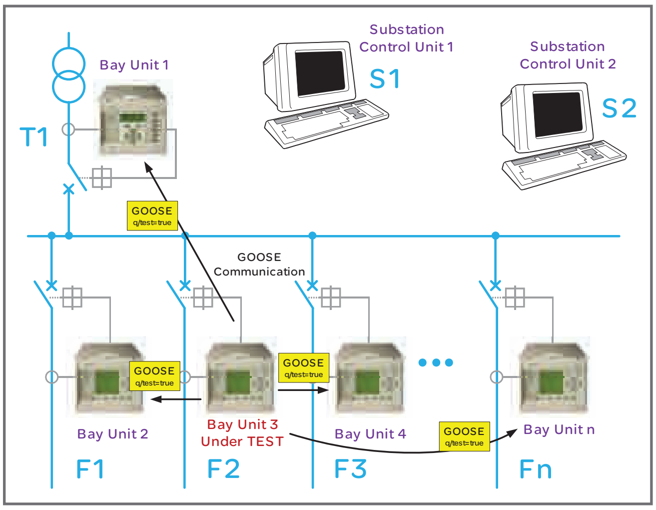

Figure D3.50:
IED in test mode with related indication to the outside equipment in a substation

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4. Typical applications

There are several functions of a bay unit to be tested in a substation, the most common test cases are:

a. Primary switchgear testing

b. Isolated protection function testing of a bay unit

c. Isolated control function testing of a bay unit with or without switchgear consideration

d. Client-server communication testing of a bay unit to the substation control system

e. GOOSE communication testing of a bay unit

f. Protection scheme testing of multiple bay units with or without GOOSE communication

For the primary switchgear testing it makes sense to switch the related bay unit to test mode beforehand. Then the operator is informed that a test is ongoing. An IED which is set to test mode is still connected to the primary equipment and thus the control testing typically is made directly via front panel HMI of the bay unit.

For the isolated protection function testing the entire device has to be switched into "test/blocked" mode. Normally a test plug is used to disconnect the CT/VT and to short-circuit the CT connections to the primary substation transformers and to connect the analogue inputs and some of the binary in/outputs to a secondary injection test set.

For the isolated control function testing the IED is set into the same mode as for the protection testing ("test/blocked"). To test the whole chain of control function, a test client is required to send control commands with the test attribute activated. If the connection to the switchgear has to be included in the testing, the binary control outputs have to be kept connected to the primary to initiate a real circuit breaker or disconnector activation ("test"only).

To test the client-server communication to a client, the bay unit should be switched to the "test-blocked" mode and the affected clients to a dedicated test mode. From then on, each message sent from or to the bay unit is then only to be used for testing. In principle a client could possibly work for equipment under test and equipment in operation marking its controls with or without test information. However for unintentional wrong actions during testing it might be in too dangerous in practice.

For the GOOSE communication testing more and more test equipment provides test features over Ethernet. Testing is facilitated for instance by simulating the GOOSE messages published by other IEDs or by checking the content of the GOOSE received which is marked with test attributes. IEDs which support the simulation functionality indicate this with the DO "Sim" in the LN "LPHD" of related LD.

To test a complete application of multiple bay units using GOOSE, all affected IEDs have to be switched into the "test" mode. Dependent on the test attribute received, the subscriber can differentiate between GOOSE messages coming from IEDs in test mode and from those which remain in normal operation. Once this complex testing is made, the communication loss test (fall-back to a default value) should also be tested to check the right behaviour in a complex network.

The testing capabilities in an IEC 61850 network environment are manifold as the standard provides a comprehensive functionality around this. This can be seen as one of the key advantages of this standard. At least when the bay units work on sampled values over Ethernet from Merging Units transformers, the testing equipment can simulate every analogue signal over the same Ethernet as the Merging Units. Only the 'Sim' indication is recognized by the IED under test which analogue values have to be processed. If all binary inputs and outputs are processed by GOOSE messages, the data exchange with information marked 'test' prevents misinterpretation. When switching an IED to the test mode, no test plug is required, as all information goes over Ethernet and all the partners know which information is based on test and which on operation. Testing equipment installed at a central place where it is connected to the substation Ethernet will make it perfect. The user will benefit from accessing all devices from one workplace, saving the time to move from one device to the other. Figure D3.51 illustrates this highly sophisticated test method of the future.

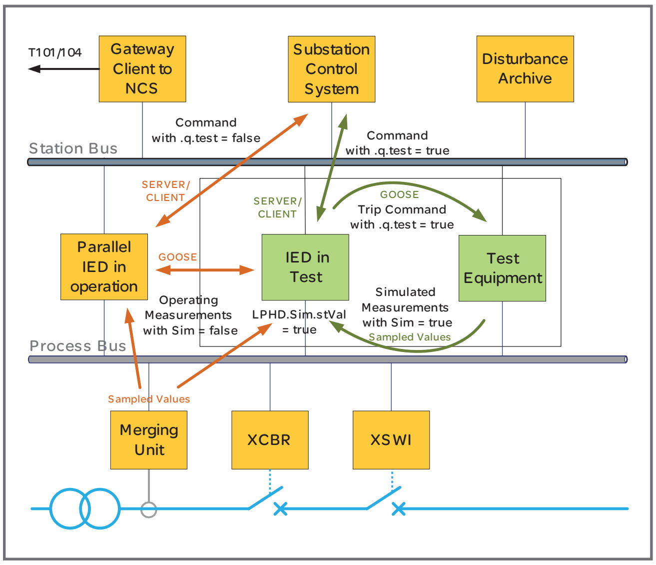

Figure D3.51:
IED in test mode with related indication to the outside equipment in a substation

4. Typical applications

4.2.5 General requirements

When using GOOSE for data transmission, the quality attribute shall be always evaluated. The possibilty to convey information about the data quality of each information value is a key feature of IEC 61850. On the publisher side it has to be assured that each information value is accompanied by its data attribute ‘q’, to allow the subscriber run a data quality dependent processing. The GOOSE monitoring on the subscriber side must inform the processing functions whether the information received can be used for processing. In case of missing GOOSE messages, the subscriber may modify the data quality attributes of each affected piece of information. In devices which support the change-over to default value/quality upon the detection of the loss of a GOOSE message the subscriber function can substitute the last received information by pre-configured values and qualities. (see example for a system-wide interlocking logic in Figure D3.52). These defaults should be defined carefully to prevent malfunctions in the application. The data evaluated is shown in Table D3.30 and D3.31. IED F2 continuously receives GOOSE messages from IEDs T1 and F1 containing their switch positions, for an interlocking logic. If the data attribute “q” shows e.g. a validity of “invalid”, the latest received switch position can no more be used.

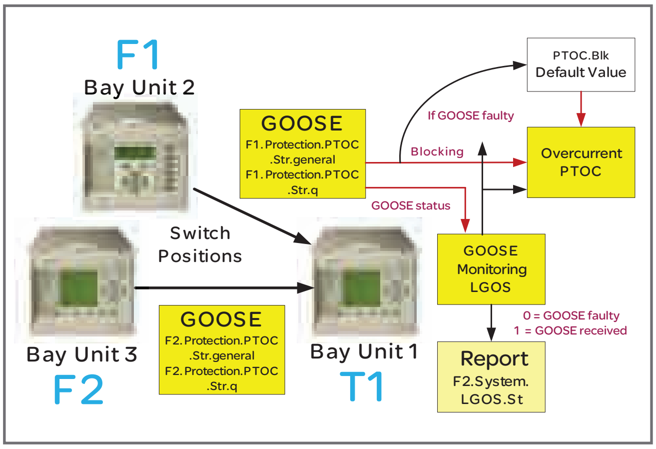

Figure D3.52:
GOOSE monitoring with LGOS

T/R	IED	LDInst	LN	DO	DA
->R	F2	Control	XCBR XSWI	Pos	stVal, q
T->	F2	System	LGOS	St	stVal, q

Table D3.30:
Transmitted data for GOOSE monitoring

LN	DO	CDC	DA	SDA	Values
XCBR XSWI	Pos	DPC	q	validity test	0 = good 1 = invalid 2 = reserved 3 = questionable 0 = false (off) 1 = true (on)
LGOS	St	SPS	stVal		0 = GOOSE inactive 1 = GOOSE active

Table D3.31:
Transmitted data for GOOSE monitoring

Another use case is the activation of the test mode of a publishing IED described in section 4.2.4 “Bay Unit Test”. In this case the quality sub attribute “test” should be evaluated as not relevant for the normal operation if the subscribing IED is not in test mode as well.

To prevent data being lost when (due to frame collisions in the Ethernet network), a GOOSE message is repeated subsequently in increasing time intervals until its normal slow sending cycle (without status change) has been restored. To detect a GOOSE communication interrupt, the IED should provide a monitoring function. The standard provides a dedicated Logical Node LGOS with a status value “St” for the indication of the communication status (see Figure D3.52). The data transmitted is shown in Table D3.30 and D3.31.

The number of GOOSE messages or sampled values in the affected network should not become too high (-> e.g. no merging unit on the same bus as substation control system) to ensure the high demands on the transmission time.

A significant improvement of the GOOSE transmission time can be achieved if all network components (IEDS and switches) support ‘VLAN’ so that GOOSE messages can be prioritised. If such a method is required due to the network load conditions, all corresponding IEDs have to provide this configuration capability - which might not be the case as this is an optional function in IEC 61850.

Using redundancy protocols to improve the availability and reliability of the communication links is very useful. But for protection applications special attention has to be paid. Protocols like RSTP e.g. are not recommended, as the reconfiguration time for the network after any failure in the system takes up to several seconds, which means that applications such as reverse interlocking are not operable during this interruption time. There are other protocols to choose from, like HSR or PRP, which are able to manage a reconfiguration in a few milliseconds.

D4

Frequency and Load Shedding

Network Protection & Automation Guide

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Chapter

D4

Frequency and Load Shedding

D4

1. Introduction

Generation plant normally operates reliably within a defined frequency band around nominal frequency. However, it can only tolerate short time operation at frequencies outside the nominal range without sustaining damage. This consideration also applies to some types of load. Conditions which can affect the generation frequency include overloads caused by a sudden increase in load (e.g. switching on a motor) or loss of a generator set or sudden loss of load due to a downstream fault. Frequency protection is generally used to protect against the overload conditions in generator protection as described in the Generator Protection part of this manual. Fast-acting current-based protection is generally used to clear short circuit faults.

Generation and utilisation need to be well balanced in any industrial, distribution or transmission network. As load increases, the generation needs to be correspondingly increased to maintain the frequency of the supply because there are many types of frequency-sensitive electrical apparatus that can be damaged when network frequency departs from the allowed band for safe operation. At times, when sudden overloads occur, the frequency drops at a rate decided by the system inertia constant, magnitude of overload, system damping constant and various other parameters. Unless corrective measures are taken at the appropriate time, frequency decay can go beyond the point of no return and cause widespread network collapse. In a wider scenario, this can result in “Blackouts”.

To put the network back into a healthy state, considerable amount of time and effort is required to re-synchronise and re-energise the system, potentially involving an expert team of power system protection and control engineers. If recovering from a blackout also “black start capable” power plants might be needed (e.g. pump storage).

Protective relays that can detect a low frequency condition are generally used in such cases to automatically disconnect unimportant loads (also called loadshedding) in order to save the network, by re-establishing the balance of the “generation-load equation”. However, with such devices, the action is initiated only after the event and whilst some salvaging of the situation can be achieved, this form of corrective action may not be effective enough and cannot cope with sudden load increases, causing large frequency decays in very short times. In such cases a device that can anticipate the severity of frequency decay and act to disconnect loads before the frequency actually reaches dangerously low levels, can become very effective in containing damage.

During severe disturbances, the frequency of the power system oscillates as various generators try to synchronise on to a common frequency. The measurement of instantaneous rate of change of frequency can be misleading during such a disturbance. The frequency decay needs to be monitored over a longer period of time to make the correct decision for load shedding.

Normally, generators are rated for a lifetime operation in a particular band of frequency and operation outside this band can cause mechanical damage to the turbine blades. Protection against such out-of-band operation is required when the frequency does not improve, even after load shedding measures have been taken, to trip the turbine. Faster turbine trip clearance times are required for lower system frequency, as in case of severe frequency decay.

Whilst load shedding leads to an improvement in the system frequency, the disconnected loads do need to be reconnected after the system has become stable again. Loads should only be restored if the frequency remains stable, above a defined restoration level, for a set period of time. Minor frequency excursions below the restoration level, of short time duration, can be tolerated during the restoration process, but longer term excursions will cause restoration to be abandoned. The number of load restoration steps is normally less than the number of load shedding steps to reduce repeated disturbances while restoring load.

The amount of load to be shed in such emergency situations is typically defined in Grid Codes [Ref D4.1: Continental Europe Operational Handbook Appendix].

2. Frequency protection

Protective relays that provide frequency protection require a voltage input in order to provide accurate voltage and frequency measurements. Additionally, accurate rate of change of frequency measurement is required for advanced types of frequency protection. The ability of the frequency and df/dt measurements to track with real power system frequency profiles (e.g. in frequency decay or oscillating scenarios) is required to ensure correct operation of the protection. Also, these measurements should be immune to harmonics or noise spikes on the voltage inputs which can cause problems with zero-crossing based techniques.

Generally all types of frequency protection include the capability of being optionally blocked by an undervoltage condition. This ensures that the voltage has not collapsed due to a fault condition and avoids unnecessary load shedding actions.

2.1 Underfrequency 81U

Frequency variations on a power system are an indication that the power balance between generation and load has been lost. In particular, an under-frequency condition implies that the net load is in excess of the available generation. Such a condition can arise, when an interconnected system splits, and the load left connected to one of the subsystems is in excess of the capacity of the generators in that particular subsystem. Industrial plants that are dependent on utilities to supply part of their loads will experience under-frequency conditions when the incoming lines are lost.

An under-frequency condition at nominal voltage can result in over-fluxing of generators and transformers and many types of industrial loads have limited tolerances on the operating frequency and running speeds e.g. synchronous motors. Sustained under-frequency has implications on the stability of the system, whereby any subsequent disturbance may lead to damage to frequency sensitive equipment and even blackouts, if the under-frequency condition is not corrected sufficiently quickly.

Under-frequency protection operates if the input frequency is less than a set underfrequency threshold and usually includes a definite time operate delay. It is often used as a basis for initiating load shedding.

2.2 Overfrequency 81O

Over-frequency running of a generator arises when the mechanical power input to the machine exceeds the electrical output. This could happen, for instance, when there is a sudden loss of load due to tripping of an outgoing feeder from the plant to a load centre. Under such overspeed conditions, the governor should respond quickly so as to obtain a balance between the mechanical input and electrical output, thereby restoring normal frequency. Over-frequency protection is required as a back-up to cater for slow response of frequency control equipment.

Over-frequency protection operates if the input frequency is greater than a set overfrequency threshold and usually includes a definite time operate delay. It is often used as a basis for initiating load restoration.

2.3 ROCOF 81R

As mentioned in earlier sections, conditions involving very large load - generation imbalances may occur, accompanied by rapid decline in system frequency. This corresponds to a high negative rate of change of frequency where the df/dt value provides indication of the mismatch between generation and load, i.e. how much load should be shed. If the discrepancy is large, then shedding of one or two stages of load may be insufficient to stop the decline in frequency. In such a situation, it is advantageous to have an element that identifies the high rate of decline of frequency, and adapts the load shedding scheme accordingly.

Since the rate of change monitoring is independent of frequency, the element can identify frequency variations occurring close to nominal frequency and thus provide early warning to the operator on a developing frequency problem. Additionally, the element could also be used as an alarm to warn operators of unusually high system frequency variations.

Rate of change of frequency (ROCOF) protection often has different operating modes where it can be set to operate for only negative rate of change, or positive rate of change, or either. It usually includes a definite time operate delay.

In load shedding applications, it is usually set for negative df/dt operation. It is often used in conjunction with under-frequency protection in these applications to provide extra flexibility in dealing with severe load to generation imbalances.

In a Chinese application, df/dt is used to block 81U if df/dt exceeds the related setting. This is done to differentiate between system faults and the deficit of active power. Typically, 2 stages of 81U are employed, one set to 49.25 Hz with time delay 20 s and one set to 48.5 Hz with time delay 0.1 s with a df/dt> inhibit set to 5 Hz/s. The df/dt> inhibit of 5 Hz/s is typical for large power systems, however, no df/dt inhibit is used for small systems (such as DG).

Considerable care should be taken when setting this element because it is not supervised by a frequency setting. Setting of the time delay or increasing the number of df/dt averaging cycles will lead to a more stable element, but this should be considered against the loss of fast tripping capability as the tripping time is extended. Stability under oscillating frequency conditions should also be considered, for instance when generators are synchronising or power swings occur.

2.4 Supervised ROCOF 81RF

Conditions may arise in an electrical network where the load to generation imbalance is considerable and this may result in relatively rapid changes of the system frequency. In such a case, maintaining the system stability is an onerous task, and calls for quick corrective action.

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2. Frequency protection

High speed load shedding cannot be achieved by monitoring the system frequency alone and the rate of change of system frequency becomes an equally critical parameter to use.

In the load shedding scheme as shown in Figure D4.1, it is assumed under falling frequency conditions that by shedding a stage of load, the system can be stabilised at frequency f2. For slow rates of decay, this can be achieved using the under-frequency protection element set at frequency f1 with a suitable time delay. However, if the generation deficit is substantial, the frequency will rapidly decrease and it is possible that the time delay imposed by the under-frequency protection will not allow for frequency stabilisation. In this case, the chance of system recovery will be enhanced by disconnecting the load stage based upon a measurement of rate of change of frequency and bypassing the time delay.

Frequency supervised rate of change of frequency protection operates when the frequency is below a set value and the rate of change of frequency exceeds a set value and usually includes a define time operate delay. It is often used in conjunction with under-frequency protection in load shedding applications.

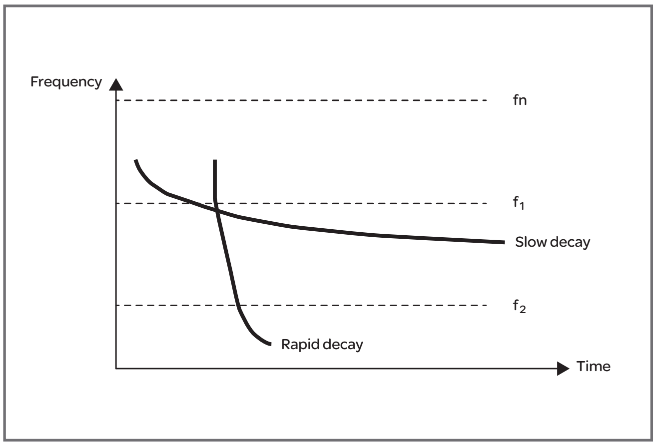

Figure D4.1:
Frequency supervised ROCOF protection

2.5 Average ROCOF 81RAV

Owing to the complex dynamics of power systems, variations in frequency during times of generation - load imbalance do not follow any regular patterns and are highly non-linear.

Oscillations will occur as the system seeks to address the imbalance, resulting in frequency oscillations typically in the order of 0.1 Hz (inter area oscillations) to 1 Hz (local generators), in addition to the basic change in frequency. Due to the oscillatory nature of frequency excursions, the instantaneous measurement value for df/dt can sometimes be misleading, either causing unexpected operation or excessive stability.

For this reason, some relays also provide an element for monitoring the longer term frequency trend, thereby reducing the effects of non-linearities in the system and providing increased security to the rate of change of frequency decision.

The average rate of change of frequency element is initiated when the measured frequency crosses the supervising frequency threshold and a timer is started. As shown in Figure D4.2, at the end of the set time period Δt, the frequency difference ΔF, is evaluated and if this exceeds the setting, a trip output is given.

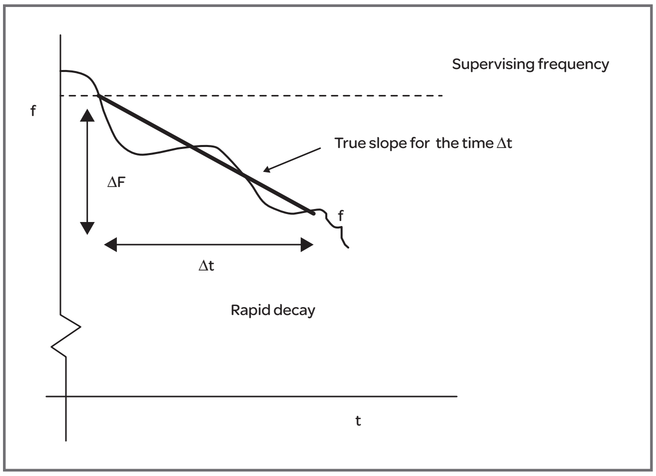

Figure D4.2:
Average rate of change of frequency protection

3. Load shedding

Automatic under-frequency load shedding may be used in extreme conditions to stabilise the balance between generation and load after an electrical island has been formed, dropping enough load to allow the frequency to stabilise in the island.

The required amount of load to be shed is usually defined in grid codes [Ref D4.1: Continental Europe Operational Handbook Appendix]. For entso-e grid Figure D4.3 applies.

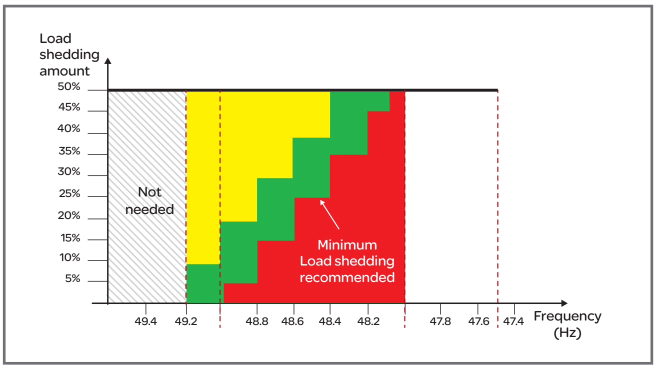

Figure D4.3:
Recommended load shedding according to entso-e

Automatic undervoltage load shedding responds directly to voltage conditions in a local area. Load is shed in stages to restore reactive power relative to demand in order to contain a voltage collapse problem.

Load shedding could be initiated in situations where two transformers are normally connected in parallel, but one is lost due to a fault. Here the transformer protection or supervision device can detect a transformer overload condition and initiate an Overload Alarm which then results in load shedding.

3.1 Frequency-based

Frequency-based load shedding is usually applied as a number of stages or levels where each level corresponds to a frequency value below nominal and is associated with a certain value of load. The levels are organised into a series of descending frequency steps. Usually, the loads which are shed are prioritised, such that non-essential loads will be shed first. The loads associated with loadshed levels can be modified by the user to take account of factors such as night or day or summer or winter or tariff-based peak lopping.

Several protection functions may be associated with each loadshed level, such as time delayed underfrequency protection and frequency supervised rate of change protection. The actual suite of protections used will depend on analysis of the given network to be protected to ensure that damage does not occur to generation and load. Also, if there is embedded generation associated with the load, it is recommended that active power protection is used to take account of the direction of flow of active power, since the embedded generation will be supporting the overall generation.

3.2 Frequency-based theory

In the event of severe system overload or loss of generation conditions, the system frequency will decline exponentially to a new reduced value below the nominal frequency. The time constant of the exponential decay as well as the new frequency level is governed by certain parameters such as the system inertia constant, system damping constant, etc.

The following formula gives the rate of change of frequency for a particular system contingency.

Assuming that the standing load and generation remain constant as the frequency changes, the instantaneous rate of change of frequency at the time of an overload is given by:

Instantaneous rate of change of frequency, $df/dt = -\dfrac{\Delta P \, x \, f_n}{2H}$

Where:

ΔP = overload in per unit

$$= \frac{Connected\ load - Available\ generation}{Available\ generation}$$

f_n = nominal system frequency (in Hz)

H = combined inertia constant of the power system (MWsec/MVA)

$$= \left(\frac{H_1 MVA_1 + \ldots + H_n MVA_n}{MVA_1 + \ldots + MVA_n} \right)$$

where n subscripts 1, 2, ..., n refer to individual generating units

The inertia constant H used in the formula above is essentially a measure of the kinetic energy in a generator rotor. For some types of large steam generator sets, the inertia constant can be as high as 10, however, a value below 5 is more typical especially when considering other types of generator. Lower values tend to dominate with smaller rotor masses e.g. wind turbines, and can make the power system more prone to serious frequency disturbances for sudden load changes. Typically, values between 2 and 5 may be used as defaults if no other knowledge is available.

Real loads, particularly motor loads, do vary with frequency and have a tendency to decrease as frequency reduces. This will have some beneficial effect on system stability and will reduce the effects of the overload condition. Taking this load reduction factor into account, the frequency deviation from nominal is given by:

Frequency deviation from nominal, $\Delta f = \dfrac{\Delta P \, x \, f_n}{d} \left(1 - e^{-\left(td/2H \right)} \right)$

where:

d = load reduction (or damping) factor

$$= \frac{Percentage\ change\ in\ load}{Percentage\ change\ in\ frequency}$$

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3. Load shedding

The above equations are a result of vast simplifications. The actual frequency change will be influenced by governor droop characteristics, load dynamics, interconnections between various generators, system stabilisers etc. However, the frequency deviations calculated in the formulae described may be a good measure of the rate of change of frequency for the purpose of setting the relay.

3.3 Active power dependent

Due to the increasing distributed generation in distribution networks, see Chapter [C8: Generator and Generator-Transformer Protection, Section 20], it is necessary to distinguish between pure load feeders and feeders with generation (and loads) connected. It is advantageous not to disconnect feeders with active power feed to the electrical network in case of underfrequency events.

By evaluating the direction of active power flow the blocking area of UFLS is determined (Figure D4.4).

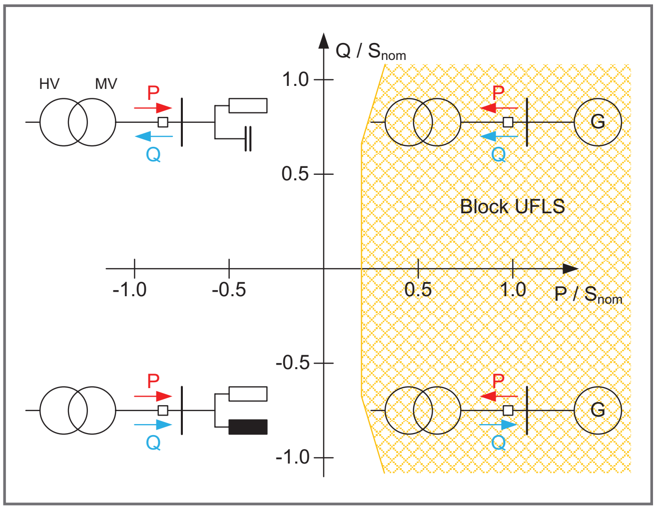

Figure D4.4:
Blocking area for UFLS in the generator reference arrow system (GRAS)

For equal treatment of all customers connected to an electrical grid using underfrequency load shedding, the relay should be able to switch between the predefined frequency levels on request. This can be done locally (e.g. binary inputs, function keys) or by communication protocols.

3.4 Undervoltage-based

Some load shedding schemes are based on undervoltage protection, for instance, in applications where there are small air conditioning motor loads which are susceptible to stalling when subjected to voltage dips. Motor loads are essentially constant kVA devices, which means that a voltage dip causes a corresponding increase in current which increases the need for local reactive power support.

Loadshed levels correspond to voltage levels below nominal, prioritised in a set of descending steps.

Where there is embedded generation associated with the load, it is recommended that reactive power protection is used to take account of the direction of flow of reactive power since the embedded generation will be supporting the overall generation.

3.5 Fast load shedding

Most power systems run on an N-1 basis for the majority of the network to ensure the loss of any plant will not affect the generation/load balance. This rule can be ignored if the loss of plant will have no impact on the system stability, for example, where the plant is only a few percent of the total system. N-1 may still be employed for small plant but this is done for reliability rather than stability.

There are, however, situations where the system is run without N-1 for major items of plant. This allows a greater utilisation of assets but means that the loss of generation, lines or load could cause a system blackout. In this situation a fast load shedding (FLS) or special protection scheme is employed. These schemes rebalance the system before the critical clearance time is exceeded, ensuring the system remains stable.

A FLS scheme constantly monitors the generation/load balance and, considering the system topology, continuously determines what balancing action would be required for any loss of plant. A typical critical clearance time for such a system would be a few hundred milliseconds. Since this includes breaker operating time and, in the worst case CB fail operating time, the FLS operating time is typically less than 100 ms and sometimes less than 50 ms. The majority of this time is taken transferring the trip information to remote plant.

Considering acquisition and processing times it is not possible to collect and process this data in real time and respond within the required time to a loss of plant. Instead FLS schemes consider the current generation, load, spinning reserve and system topology and pre-determine the required trip response to any loss. This is typically refreshed every few seconds. The response needs to consider priorities of different loads when load shedding. Since there is very little commonality between such applications the FLS is usually custom engineered. These schemes can become very complex with thousands of loads, user prioritising and operational restrictions complicating the solutions. Therefore they are only applied when N-1 is prohibitively expensive.

A typical FLS has the following components:

Acquisition

The system needs to know the system power flow and sometimes the reactive power flow as well as equipment status. There is a trade-off between data volume and usability. For example acquiring the power from the substation incomer

3. Load shedding

allows less data to be used but limits all feeders within that substation to the same priority. Accessing data from further into the system will be more costly since either more acquisition units will be needed or data accessed from more IEDs. These IEDs may not have the same communications protocols requiring more integration engineering. Once the acquisition points have been determined the data needs to be sent to the main FLS computer. For power flow this transfer needs to occur within a few seconds and therefore may travel by a traditional SCADA network providing it has adequate performance. Alternatively it can travel via a dedicated FLS network. Loss of generation or load is detected by plant status and therefore this information needs to be transferred very quickly which is usually done via a dedicated FLS network.

Computation

Due to the volume of information that needs consideration, a centralised computer is normally used to perform the FLS calculations. In some applications such as parallel line overrating the operation is fixed and does not require any user inputs. Other applications such as isolated oil and gas networks may require operator inputs to adjust load shed priorities. In these cases the centralised computer will need to either provide a dedicated HMI or interface with the normal SCADA. The role of the centralised computer is to transfer the power and plant status information into trip commands. These trip commands can take the form of contact outputs or communications signals.

Tripping

A network must be provided to convert the trip information provided by the FLS computer to the breakers required to trip. This network may consist of fibre optics, microwave, radio or PLC to transmit this information to remote sites. To meet the low clearance times a dedicated network is usually provided which will have a dedicated receiver for each breaker which requires tripping. A balance between cost and flexibility must be achieved. This is usually done by providing tripping for generators individually and loads in groups. The grouping of loads reduces the cost of tripping equipment but impacts on the FLS Computer engineering as it affects priorities.

Fast load shedding of specific equipment is required when it becomes faulty. This can be achieved by the equipment providing a status output which is detected by a supervisory system to initiate fast load shedding.

The main consideration of these schemes is security. Since their main function is to trip plant, any maloperation could lead to false trips, risking system blackouts and negating the value of the system. To improve system security critical parts of the FLS are often measured independently (such as breaker status) to avoid reliance on existing plant and ensure secure acquisition. The FLS computer is often duplicated and used with 2 of 2 logic. For the tripping equipment high reliability equipment with added message security is also used. These measures obviously increase the cost of FLS schemes.

4. Load restoration

Following a load shed event, measures should be taken to reinstate load following system recovery, which may be facilitated by providing additional generation. Dependent upon the severity of the load shed event, an expert team may be involved with restoration in accordance with an agreed recovery plan. Recovery is then based on manual (local and remote) reconnection and synchronisation of items of plant in the network.

4.1 Automatic restoration

Following a small scale underfrequency-based load shed event, typically in an industrial application, it may be acceptable to automatically restore loads. The load shed event will initiate a time window during which the system frequency should recover to a level that restoration can be undertaken, otherwise restoration is abandoned. The monitoring of the power system frequency is performed by an overfrequency protection element, where the restoration delay is given by the set operate delay (see Figure D4.5). Operation of the protection results in a pulse output used to reconnect the load.

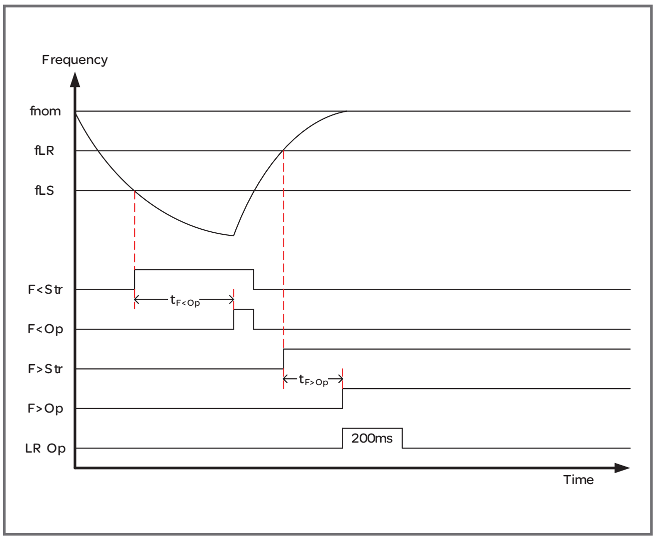

Figure D4.5:
Automatic restoration based on overfrequency

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4. Load restoration

The restoration function will tolerate short term frequency excursions below the restoration level, however, longer term excursions will result in the automatic restoration attempt being abandoned (see Figure D4.6).

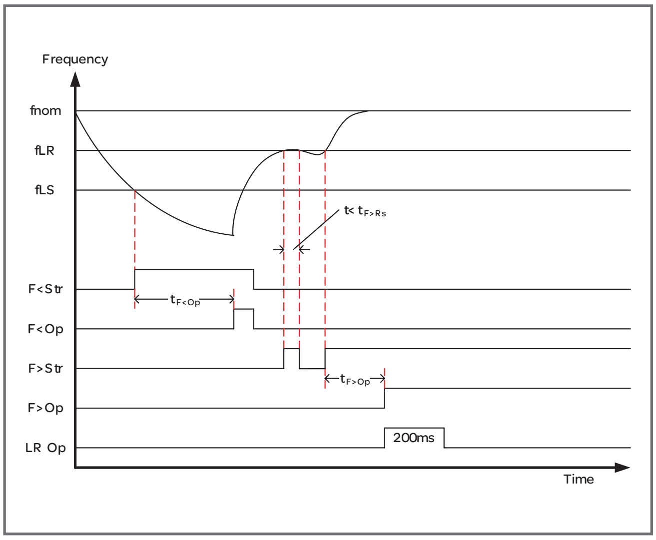


Figure D4.6:
Automatic restoration with short term frequency excursion

5. Turbine abnormal

Turbine abnormal frequency protection 81AB is provided to protect the turbine blade from potential damage due to prolonged under/overfrequency operation of the generator. Typically there are up to six frequency bands which can be programmed, each having an integrating timer to record the time spent within the band as shown in Figure D4.7. Each frequency band includes a user settable operate time setting and provides start and operate digital outputs.

It is recommended that this protection is in service when the generator is synchronised to the system or when separated from the system but supplying auxiliary load.

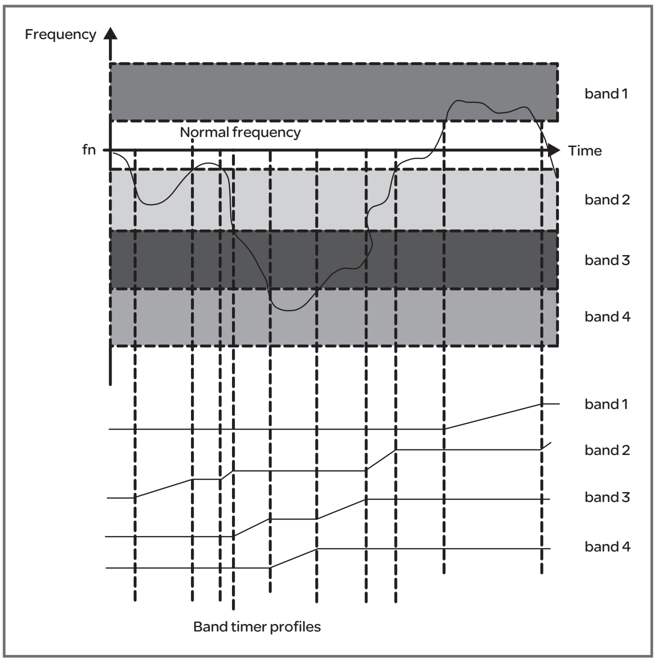
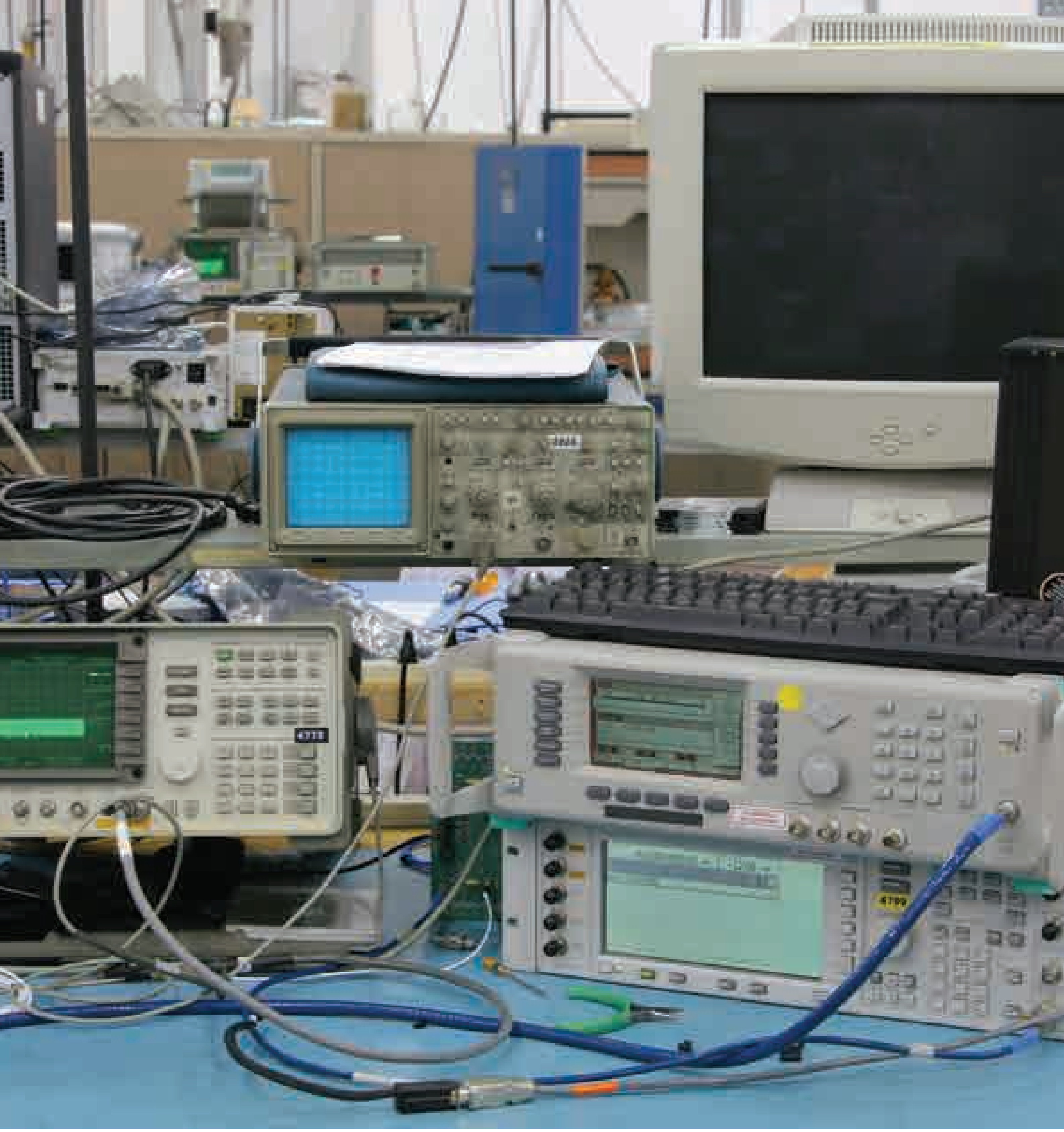


Figure D4.7:
Generator turbine abnormal frequency protection

6. References

[D4.1] Continental Europe Operational Handbook Appendix
- Policy 5: Emergency Operations. entso-e, 2010



E1

Type Testing, Offer Safety and Reliability

Network Protection & Automation Guide

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Chapter E1

Type Testing, Offer Safety and Reliability

1. Introduction

The testing of protection equipment schemes presents a number of problems. This is because the main function of protection equipment is solely concerned with operation under system fault conditions, and cannot readily be tested under normal system operating conditions. This situation is aggravated by the increasing complexity of protection schemes and use of relays containing software.

The testing of protection equipment may be divided into four stages:

a. type tests according reference standards
b. routine factory production tests
c. commissioning tests
d. periodic maintenance tests

1.1 Reference standards

Measuring and protection relays must be compliant with the standard IEC 60255-1. This is the standard of reference for protection relays, which cover, through different chapters, common requirements of use (i.e. rated values, burden, accuracy, etc.), environmental requirements (mechanical, climatic), electro-magnetic compatibility and protection functional requirements. Some definitions and tests are described in more detail in specific chapters. It is particularly the case for functional tests (IEC 60255-1xx), for product safety (IEC 60255-27), for environmental tests (IEC 60068-2-xx) and electromagnetic compatibility requirements (IEC 60255-26). For this specific chapter, the different levels of immunity are in conformity with the standard IEC 61000-6-5 which describes the immunity for power station and substation environments including protection relays.

Local requirements or specific application requirements and recommendation can be specified for the product, for example:

IACS – Specific recommendations for marine,
ATEX for explosive environments,
ANSI/IEEE standards and particularly **IEEE C37.90.1, IEEE C37.90.2, IEEE C37.90.3** for North America,
GOST for Russia, **ENA** for UK, **CEI 016**, for Italy, etc.

Some specific logos are applied on the products as a proof of compliance to some directives and recommendations. Examples include ATEX for explosive atmospheres, CE for European directives, cUL or UL marking for North American market, GOST for Russia, EAC for Eurasian conformity, see Figure E1.1.

1.2 Type tests

Type tests are required to prove that a relay meets the published specification and complies with all relevant standards. Since the principal function of a protection relay is to operate correctly under abnormal power conditions, it is essential that the performance be assessed under such conditions. Comprehensive type tests simulating the operational conditions are therefore conducted at the manufacturer's works during the development and certification of the equipment.

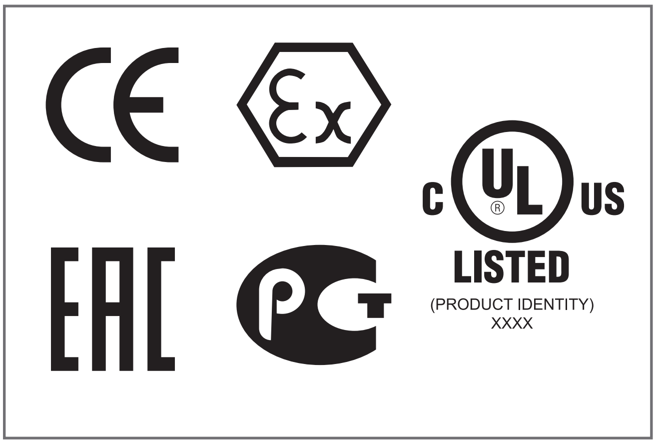

Figure E1.1:
Example of marking on products

The standards that cover most aspects of relay performance are IEC 60255 and ANSI C37.90. However, compliance may also involve consideration of the requirements of IEC 61000, 60068 and 60529, while products intended for use in the EEC also have to comply with the requirements of Directives 2004/108/EC and 2006/95/EC. Since type testing of a digital or numerical relay involves testing of software as well as hardware, the type testing process is very complicated and more involved than a static or electromechanical relay.

1.3 Routine factory production tests

These are conducted to prove that relays are free from defects during manufacture. Testing will take place at several stages during manufacture, to ensure problems are discovered at the earliest possible time and hence minimise remedial work. The extent of testing will be determined by the complexity of the relay and past manufacturing experience.

1.4 Commissioning tests

These tests are designed to prove that a particular protection scheme has been installed correctly prior to setting to work. All aspects of the scheme are thoroughly checked, from installation of the correct equipment through wiring checks and operation checks of the individual items of equipment, finishing with testing of the complete scheme.

1.5 Periodic maintenance checks

These are required to identify equipment failures and degradation in service, so that corrective action can be taken. Because a protection scheme only operates under fault conditions, defects may not be revealed for a significant period of time, until a fault occurs. Regular testing assists in detecting faults that would otherwise remain undetected until a fault occurs.

1.6 Type test reports

The type test reports are considered as a part of the documentation of the digital and numerical protection relays. They give proof that the device is compliant with its specification as it is claimed in it documentation according the IEC 60255-1 standard. They can be provided to the customer on request. A test report can contain the results according to one standard or several standards.

According the IEC 60255-1 standard, type testing a product which is part of a product family shall be considered sufficient to cover the entire product family provided a documented risk assessment is carried out to determine which type tests are valid and which tests need to be repeated on the rest of the product family.

All tests can be in one or several tests reports at the convenience of the manufacturer. Regarding the evolution of the products, some tests can be done at different periods, and some of them not performed. It depends on the impact of the evolution of the product. For example, there is no need to re-perform some mechanical tests if the evolution is only on some electronic components. Some tests reports can be several years old and some of them very recent.

The test report report collection should include the following results:

a. product safety requirements (including thermal short time rating)

b. EMC requirements as well as for emissions and immunity

c. energising quantities including rated burden, voltage dips and change of auxiliary energising quantity

d. digital outputs contact performance

e. communication requirements (e.g. IEC 61850 certificates, etc.)

f. climatic environmental requirements (cold, dry heat, change of temperature, damp heat)

g. mechanical requirements (vibration, shock, bump, seismic)

h. enclosure protection

i. functional requirements (steady-state simulation, dynamic simulation, etc.)

According to specific applications of the protection relay, some other test reports can be provided to the customer (e.g. salt mist, corrosion, etc.)

Each test report includes at least the following basic information:

a. the name(s), function(s) and signature(s) or equivalent identification of person(s) authorising the test report

b. the name and address of the laboratory, and the location where the tests are carried out

c. the name and address of the requester (e.g. a manufacturer or a customer)

d. an unambiguous identification of the equipment: model reference at least

e. the date(s) of performance of the test

f. a statement of what tests are performed and to what international standards, including the dates

g. the acceptance criteria used

h. the tools and instrumentation used

i. the test conditions and method

j. the test results and, when relevant, a statement to the effect that the results relate only to the equipment tested and possibly a product family

k. the test conclusion (pass/fail) and when appropriate and needed, opinions and interpretations from laboratory experts

1.7 Accredited laboratories

To give confidence to the customer, the type test report can be issued by an accredited laboratory to be sure the test has been performed according the standard.

1.7.1 Accreditation

The accreditation of a laboratory is delivered according to ISO/IEC 17025 standard which guarantees the level of competency of the laboratory to perform some tests, the independency and integrity of the laboratory in terms of test results.

The accreditation defines a list of standards for which the laboratory has competency and capability to perform the tests.

The International Laboratory Accreditation Cooperation (ILAC) denotes the collaboration of accreditation bodies that registers calibration laboratories, testing laboratories and/or inspection bodies. Examples of accredited laboratories are shown in Figure E1.2.

Figure E1.2:
Example of logos of different National Accreditation Services

E1

1. Introduction

The accreditation is delivered by a governmental body which is listed to the ILAC (International Laboratory Accreditation Cooperation). An in-house laboratory of a manufacturer or a third party laboratory follows exactly the same rules. The accreditation is regularly reviewed and confirmed by the local governmental accreditation service.

1.7.2 Accredited type test reports

To recognise that a test report is issued from an accredited laboratory, the logo of a governmental accreditation body should be clearly readable on the test report. For ILAC registered laboratories the ILAC logo is often visible on the test report as shown in Figure E1.3.

Figure E1.3: ILAC logo

The accredited test report is archived by the accredited laboratory and cannot be communicated without the authorisation of the test report requester.

1.8 IEC 61850 communication testing

1.8.1 IEC 61850 accreditation and recognition

IEC 61850 international standards is dedicated for communication networks and systems for Power Utilities Automation. The part 10 of IEC 61850 specifies standard techniques for testing of conformance of client or server, as well as specific measurement techniques to be applied when declaring performance parameters. The use of these techniques will enhance the ability of the system integrator to integrate IEDs easily, operate IEDs correctly, and support the applications as intended. The role of the test facilities for conformance testing and certifying the results are beyond the scope of this part of IEC 61850.

The UCA® International Users Group (logo shown in Figure E1.4) is a corporation consisting of utility user and supplier companies that is dedicated to promoting the integration and interoperability of electric/gas/water utility systems through the use of international standards-based technology. It is a User Group for IEC 61850 standard.

Figure E1.4: UCA® International Usergroup

UCA® International Users Group is the only corporation which delivers lab accreditation and recognition for conformance testing for IED servers, clients and network devices.

The certification laboratories contribute to the specification for the test bench and the improvement of the working procedure for IEC 61850 conformance testing execution and approval.

There are two kinds of certification laboratories qualified by UCA® International Users Group:

a. a level A laboratory is an independent third-party test centre (and certified ISO 9001 or ISO/IEC 17025 Quality System by local bodies)

b. a level B laboratory is a test centre which can subordinate to IEC 61850 server or client supplier (certified ISO 9001 or ISO/IEC 17025 Quality System)

The accreditation is delivered by UCA® International Users Group for server or client devices. Level A and level B labs use the test procedures published by the UCA® International Users Group. Their test report must be reviewed by UCA® for acceptance and the IEC 61850 certificate is stamped with UCA® International Users Group.

1.8.2 IEC 61850 certificate and report accredited

IEC 61850 certificate test procedure is published and maintained by UCA® International Users Group as shown in Figure E1.5. When an accredited laboratory completes the certification tests according to the test procedure strictly without issues, the test report and test logs are sent to UCA® International Users Group for review. If the UCA® International Users Group accept the test report and test logs, the accredited laboratory can issue the certificate with the UCA® International User Group stamp. The certificate will be posted in the UCA® International Users Group website http://www.ucaiug.org/.

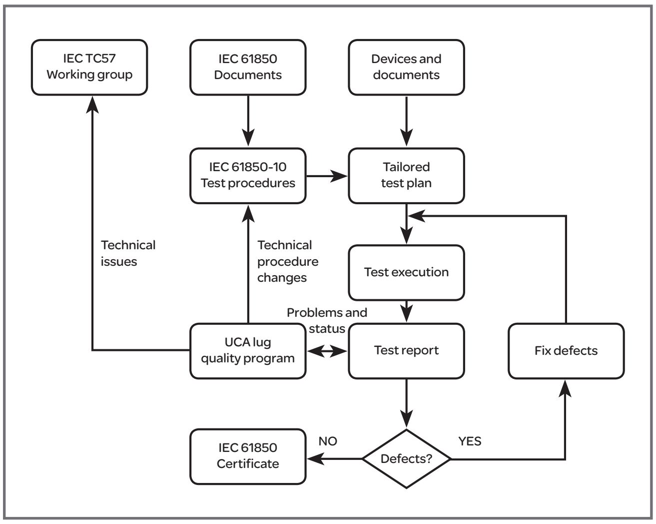

Figure E1.5: Interfaces between IEC working group, UCA Iug and laboratories

2. Functional tests

The functional tests consist of applying the appropriate inputs to the relay under test and measuring the performance to determine if it meets the specification. They are usually carried out under controlled environmental conditions. The testing may be extensive, even where only a simple relay function is being tested, as can be realised by considering the simple overcurrent relay element of Table E1.1.

To determine compliance with the specification, the tests listed in Table E1.2 are required to be carried out. This is an expensive and time consuming task, involving many engineers and technicians.

When a numerical relay with many functions is considered, each of which has to be type-tested, the functional type-testing involved is a major issue. In the case of a recent relay development project, it was calculated that if one person had to do all the work, it would take 4 years to write the functional type-test specifications, 30 years to perform the tests and several years to write the test reports that result. Automated techniques/ equipment are clearly required, and are covered in Section 7.

Element	Range	Step size
Is>	0.05 - 4In (IDMT)	0.01 In
	0.05 - 40In (DT)	0.01 In
Directionality	Forward/reverse/non-directional	
RCA	-95° to + 95°	1°
Characteristic	DT/IDMT	
Definite time delay	0 - 300 s	0.01 s
IEC IDMT time delay	IEC standard inverse	
	IEC very inverse	
	IEC extremely inverse	
	UK long time inverse	
Time multiplier setting (TMS)	0.01 - 15	0.01
IEEE IDMT time delay	IEEE moderately inverse	
	IEEE very inverse	
	IEEE extremely inverse	
	US-CO8 inverse	
	US-CO2 short time inverse	
Time dial (TD)	0.5 - 15	0.1
IEC reset time (DT only)	0 - 100 s	0.01 s
IEEE reset time	IDMT/DT	
IEEE DT reset time	0 - 100 s	0.01 s
IEEE IDMT reset time	IEEE moderately inverse	
	IEEE very inverse	
	IEEE extremely inverse	
	US-CO8 inverse	
	US-CO2 short time inverse	

Table E1.1:
Overcurrent relay element features

Test 1	Three phase non-directional pick up and drop off accuracy over complete current setting range for both stages
Test 2	Three phase directional pick up and drop off accuracy over complete RCA setting range in the forward direction, current angle sweep
Test 3	Three phase directional pick up and drop off accuracy over complete RCA setting range in the reverse direction, current angle sweep
Test 4	Three phase directional pick up and drop off accuracy over complete RCA setting range in the forward direction, voltage angle sweep
Test 5	Three phase directional pick up and drop off accuracy over complete RCA setting range in the reverse direction voltage angle sweep
Test 6	Three phase polarising voltage threshold test
Test 7	Accuracy of DT timer over complete setting range
Test 8	Accuracy of IDMT curves over claimed accuracy range
Test 9	Accuracy of IDMT TMS/TD
Test 10	Effect of changing fault current on IDMT operating times
Test 11	Minimum pick-up of starts and trips for IDMT curves
Test 12	Accuracy of reset timers
Test 13	Effect of any blocking signals, opto inputs, VTS, autoreclose
Test 14	Voltage polarisation memory

Table E1.2:
Overcurrent relay element functional type tests

3. Electrical type tests

Various electrical type tests must be performed, as follows:

3.1 Rating tests

Rating type tests are conducted to ensure that components are used within their specified ratings and that there are no fire or electric shock hazards under a normal load or fault condition of the power system. This is in addition to checking that the product complies with its technical specification. The following are amongst the rating type tests conducted on protection relays, the specified parameters are normally to IEC 60255-1.

3.2 Relay burden

The burdens of the auxiliary supply, optically isolated inputs, VTs and CTs are measured to check that the product complies with its specification. The burden of products with a high number of input/output circuits is application specific, i.e. it increases according to the number of optically isolated input and output contact ports which are energised under normal power system load conditions. It is usually envisaged that not more than 50% of such ports will be energised in any application.

3.3 Relay inputs

Relay inputs are tested over the specified ranges. Inputs include those for auxiliary voltage, VT, CT, frequency, optically isolated digital inputs and communication circuits.

3.4 Relay output contacts

Protection relay output contacts are type tested to ensure that they comply with IEC 60255-27 and ANSI C37.90 standards. Particular withstand and endurance type tests have to be carried out using d.c., since the normal supply is via a station battery.

3.5 Auxiliary supplies

Digital and numerical protection relays normally require an auxiliary supply to provide power to the on-board microprocessor circuitry and the interfacing opto-isolated input circuits and output relays. The auxiliary supply can be either a.c. or d.c., supplied from a number of sources or safe supplies - i.e. batteries, UPSs, generators, etc., all of which may be subject to voltage dips, short interruptions and voltage variations. Relays are designed to ensure that operation is maintained and no damage occurs during a disturbance of the auxiliary supply.

Tests are carried out for both a.c. and d.c. auxiliary supplies and include mains variation both above and below the nominal rating, supply interruptions derived by open circuit and short circuit, supply dips as a percentage of the nominal supply, repetitive starts. The duration of the interruptions and supply dips range from 2 ms to 60 s intervals. A short supply interruption of at least 20 ms whilst the relay is 50% loaded should not cause any malfunction of the relay.

Malfunctions include the operation of output relays and watchdog contacts, the reset of microprocessors, alarm or trip indication, disturbance recording, acceptance of corrupted data over the communication link and the corruption of stored data or settings.

For a longer supply interruption, or dip in excess of 20 ms, the relay self recovers without the loss of any function, data, settings or corruption of data. No operator intervention is required to restore operation after an interruption or dip in the supply. Many relays have a specification that exceeds this requirement, tolerating dips of up to 200 ms without operation being affected.

In addition to the above, the relay is subjected to a number of repetitive starts or a sequence of supply interruptions. Again the relay is tested to ensure that no damage or data corruption has occurred during the repetitive tests.

Specific tests carried out on d.c. auxiliary supplies include reverse polarity, a.c. waveform superimposed on the d.c. supply and the effect of a rising and decaying auxiliary voltage. All tests are carried out at various levels of loading of the relay auxiliary supply.

4. Electromagnetic compatibility tests

There are numerous tests that are carried out to determine the ability of relays to withstand the electrical environment in which they are installed. The substation environment is a very severe environment in terms of the electromagnetic interference that can arise. There are many sources of interference within a substation, some originating internally, others being conducted along the overhead lines or cables into the substation from external disturbances.

The type and level of those disturbances are defined in the standard IEC 61000-6-5 according to the location in the station (see Figure E1.6). The most common sources are:

a. switching operations

b. system faults

c. lightning strikes

d. conductor flashover

e. telecommunication operations e.g. mobile phones, walkie talkies etc

A whole suite of tests are performed to simulate these types of interference, and they fall under the broad umbrella of what is known as EMC, or Electromagnetic Compatibility tests.

Broadly speaking, EMC can be defined as:

'The ability of equipment to co-exist in the same electromagnetic environment'

It is not a new subject and has been tested for by the military ever since the advent of electronic equipment. EMC can cause real and serious problems, and does need to be taken into account when designing electronic equipment. EMC tests determine the impact on the relay under test of high-frequency electrical disturbances of various kinds. Relays manufactured or intended for use in the EEC have to comply with EEC Directive 2004/108/EC in this respect. To achieve this, in addition to designing for statutory compliance to this Directive, the following range of tests are carried out:

a. radiated emission

b. conducted emission

c. electrostatic discharge

d. radio-frequency (RF) immunity

e. magnetic field immunity

f. d.c. dip and short interruption immunity

g. a.c. dip and short interruption immunity

h. a.c. ripple on d.c. supply

i. gradual shut down/start-up for d.c. power supply

j. conducted disturbance induced by radio-frequency

k. fast transients immunity

l. surge immunity

m. slow and fast damped oscillatory wave

n. power frequency interference

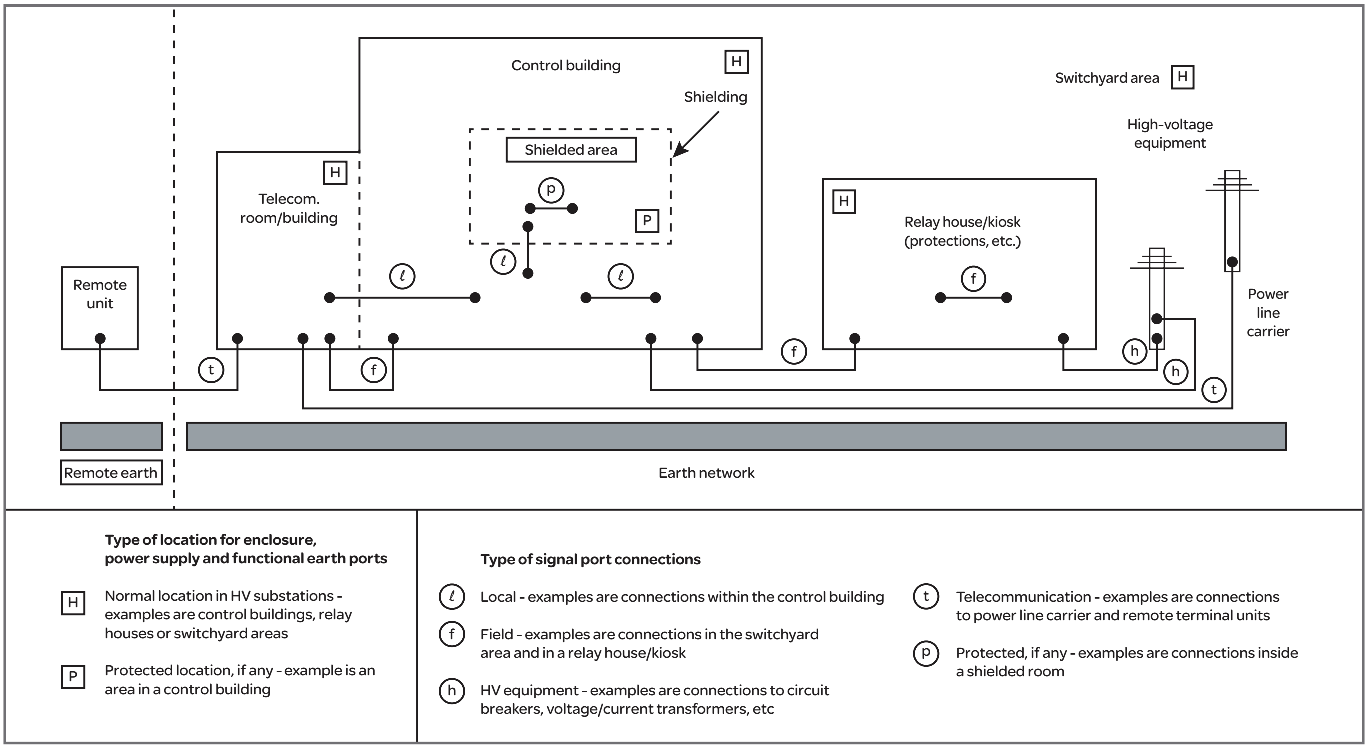

Figure E1.6:
Example of selection of specifications for apparatus and related connections (IEC 61000-6-5) in power substation

E1

4. Electromagnetic compatibility tests

4.1 d.c. and a.c. voltage dip and short interruption

This is a test to determine the maximum length of time that the relay can withstand an interruption in the auxiliary supply without de-energising, e.g. switching off, and that when this time is exceeded and it does transiently switch off, that no maloperation occurs. It simulates the effect of a loose fuse in the battery circuit, or a short circuit in the common d.c. supply, interrupted by a fuse. Another source of d.c. interruption is if there is a power system fault and the battery is supplying both the relay and the circuit breaker trip coils. When the battery energises the coils to initiate the circuit breaker trip, the voltage may fall below the required level for operation of the relay and hence a d.c. interrupt occurs. The test is specified in IEC 61000-4-29 for d.c. power supply and IEC 61000-4-11 for a.c. power supply and comprises interruptions of 2, 5, 10, 20, 30, 50, 100, 200 ms, 500 or 1000 ms. For interruptions lasting up to and including 20 ms. The relay must not de-energise or maloperate, while for longer interruptions it must not maloperate. The relay is powered from a battery supply, and both short circuit and open circuit interruptions are carried out. Each interruption is applied 10 times, and for auxiliary power supplies with a large operating range, the tests are performed at minimum, maximum, and other voltages across this range, to ensure compliance over the complete range.

4.2 a.c. ripple on d.c. supply

This test (IEC 61000-4-17) determines that the relay is able to operate correctly with a superimposed a.c. voltage on the d.c. supply. This is caused by the station battery being charged by the battery charger, and the relevant waveform is shown in Figure E1.7. It consists of a 12% peak-to-peak ripple superimposed on the d.c. supply voltage.

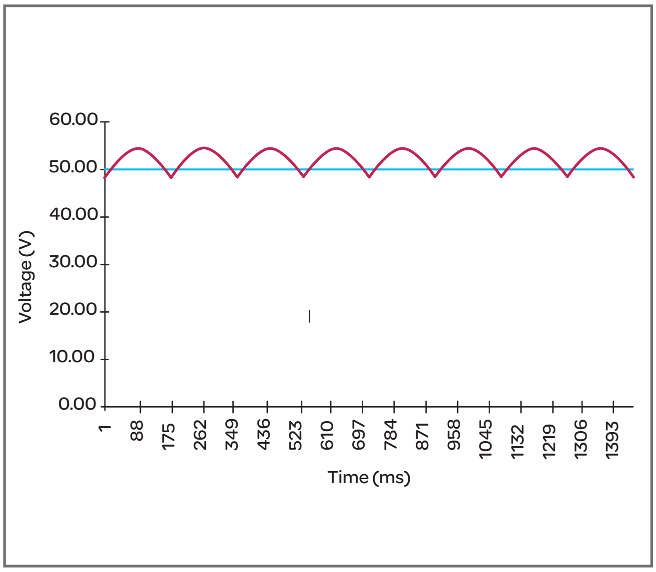

Figure E1.7:
a.c. ripple superimposed on d.c. test

For auxiliary power supplies with a large operating range, the tests are performed at minimum, maximum, and other voltages across this range, to ensure compliance for the complete range. The interference is applied using a full wave rectifier network, connected in parallel with the battery supply. The relay must continue to operate without malfunction during the test.

4.3 Gradual shut-down/start-up for a.c. & d.c. power supply

The a.c. voltage change takes place over a short period, and may occur due to change of load or stored energy in local power networks. The primary cause of d.c. voltage variations is the discharging and recharging of battery systems; however they are also created when there are significant changes to the load condition of the d.c. network. The test is specified in IEC 61000-4-29 for d.c. power supply and IEC 61000-4-11 for a.c.

4.4 Slow & fast damped oscillatory wave

During opening or closing disconnector operations, between both contacts of the operated device, a large number of restrikes take place due to the slow speed of the contacts. Therefore, disconnector switch operations generate very fast transients, which propagate as travelling waves in the busbars of the substation. The electrical length of the shielded conductors and the length of the open circuit busbars determine the oscillation frequencies of the transient overvoltages. It consists of a 100 KHz or 1 MHz decaying sinusoidal waveform for slow damped oscillatory wave and 3 MHz, 10 MHz, or 30 MHz for fast damped oscillatory wave (see Figure E1.8). The interference is applied across each independent circuit (differential mode) and between each independent circuit and earth (common mode) via an external coupling and switching network. The product is energised in both normal (quiescent) and tripped modes for this test, and must not maloperate when the interference is applied. The test is specified in IEC 61000-4-18 standard.

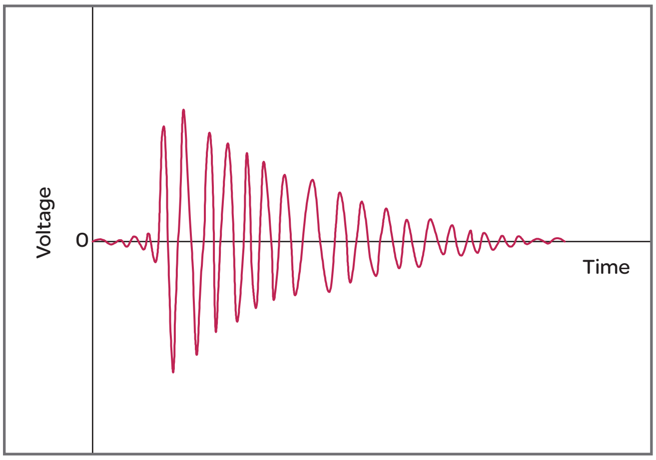

Figure E1.8:
Slow damped oscillatory waveform

4. Electromagnetic compatibility tests

4.5 Fast transient

The fast transient test simulates the HV interference caused by disconnector operations in GIS (gas-insulated switchgear) substations or breakdown of the SF6 (Sulphur Hexafluoride) insulation between conductors and the earthed enclosure. This interference can either be inductively coupled onto relay circuits or can be directly introduced via the CT or VT inputs. It consists of a series of 15 ms duration bursts at 300 ms intervals, each burst consisting of a train of 50 ns wide pulses with very fast (5 ns typical) rise times (Figure E1.9), with a peak voltage magnitude of 4 kV.

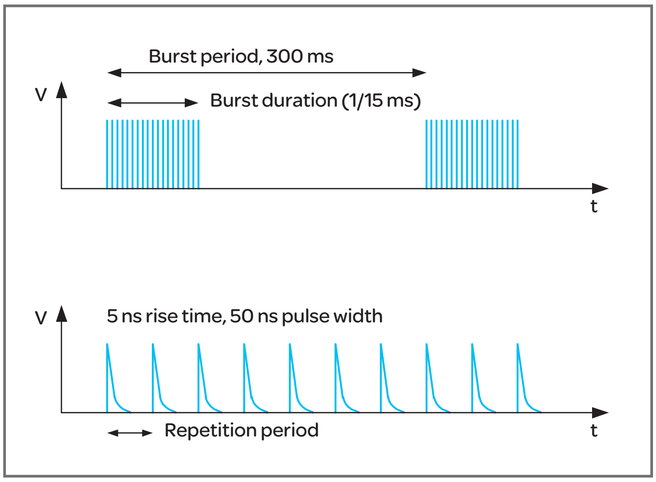

Figure E1.9:
Fast transient waveform

The product is energised in both normal (quiescent) and tripped modes for this test. It must not maloperate when the interference is applied in common mode via the integral coupling network to each circuit in turn, for 60 seconds. Interference is coupled onto communications circuits, if required, using an external capacitive coupling clamp. The test is specified in IEC 61000-4-4 standard.

4.6 Surge immunity

The surge immunity test simulates interference caused by major power system disturbances such as capacitor bank switching and lightning strikes on overhead lines within 5 km of the substation. The test waveform has an open circuit voltage of 4 kV for common mode surges and 2 kV for differential mode surges. The test waveshape consists on open circuit of a 1.2/50 rise/fall time and a short circuit current of 8/20 rise/fall time. The generator is capable of providing a short circuit test current of up to 2 kA, making this test potentially destructive. The surges are applied sequentially under software control via dedicated coupling networks in both differential and common modes with the product energised in its normal (quiescent) state. The product shall not maloperate during the test, shall still operate within specification after the test sequence and shall not incur any permanent damage. The test is specified in IEC 61000-4-5 standard.

4.7 Power frequency interference

This test simulates the type of interference that is caused when there is a power system fault and very high levels of fault current flow in the primary conductors or the earth grid. This is the common mode disturbance in the range d.c. to 150 kHz and can be induced onto control and communications circuits. The international standard used is IEC 61000-4-16. The test voltages shall be applied in common mode to power supply, control, analogue signals and communication ports. The relay shall not maloperate during the test, and shall still perform its main functions within the claimed tolerance.

4.8 Electrostatic discharge (ESD)

This test simulates the type of high voltage interference that occurs when an operator touches the relay's front panel after being charged to a high potential. This is exactly the same phenomenon as getting an electric shock when stepping out of a car or after walking on a synthetic fibre carpet. In this case the discharge is only ever applied to the front panel of the relay, with the cover both on and off as shown in Figure E1.10.

Figure E1.10:
ESD testing

Two types of discharges are applied, air discharge and contact discharge. Air discharges are used on surfaces that are normally insulators, and contact discharges are used on surfaces that are normally conducting.

4. Electromagnetic compatibility tests

IEC 61000-4-2 is the relevant standard this test, for which the test parameters are:

a. cover on: Class 4, 8 kV contact discharge, 15 kV air discharge

b. cover off: Class 3, 6 kV contact discharge, 8 kV air discharge

In both cases above, all the lower test levels are also tested. The discharge current waveform is shown in Figure E1.11.

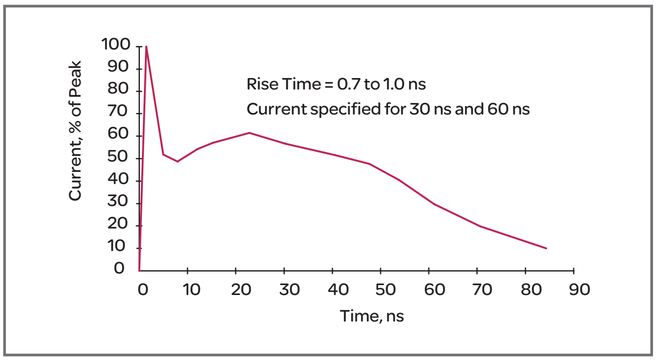

Figure E1.11:
ESD current waveform

The test is performed with single discharges repeated on each test point 10 times with positive polarity and 10 times with negative polarity. The time interval between successive discharges is greater than 1 second. Tests are carried out at each level, with the relay in the following modes of operation:

a. current and voltage applied at 90% of setting (relay not tripped)

b. current and voltage applied at 110% of setting (relay tripped)

c. main protection and communications functions are tested to determine the effect of the discharge. To pass, the relay shall not maloperate, and shall still perform its main functions within the claimed tolerance

4.9 Conducted and radiated emission

These tests arise primarily from the essential protection requirements of the European Community (EU) directive on EMC.

These require manufacturers to ensure that any equipment to be sold in the countries comprising the European Union must not interfere with other equipment. To achieve this it is necessary to measure the emissions from the equipment and ensure that they are below the specified limits.

Conducted emissions are measured only from the equipment's power supply ports and are to ensure that when connected to a mains network, the equipment does not inject interference back into the network which could adversely affect the other equipment connected to the network.

Radiated emissions measurements are to ensure that the interference radiated from the equipment is not at a level that could cause interference to other equipment. This test, using equipment as shown in Figure E1.12, is normally carried out on an Open Area Test Site (OATS) where there are no reflecting structures or sources of radiation, and therefore the measurements obtained are a true indication of the emission spectrum of the relay. An example of a plot obtained during conducted emissions tests is shown in Figure E1.13.

Figure E1.12:
Example of radiated emission test equipment

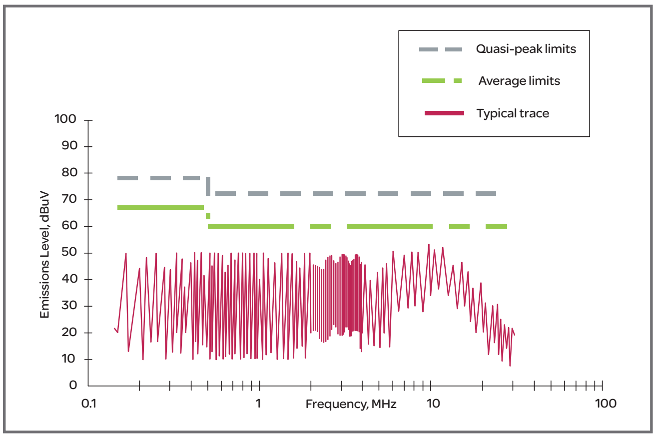

Figure E1.13:
Conducted emissions test plot

When performing these two tests, the relay is in a quiescent condition, i.e. not tripped, with currents and voltages applied at 90% of the setting values. This is because for the majority of its life, the relay will be in the quiescent state and the emission of electromagnetic interference when the relay is tripped is considered to be of no significance. Tests are conducted in accordance with IEC 60255-25 and IEC 61000-6-4, and are detailed in Table E1.3.

4. Electromagnetic compatibility tests

Radiated tests		
Frequency range	**Specified limits**	**Test limits**
30-230 MHz	30dB(μV/m) at 30m	40dB(μV/m) at 30m
230-1000 MHz	37dB(μV/m) at 30m	47dB(μV/m) at 30m
Conducted tests		
Frequency range	**Specified limits**	**Test limits**
0,15 – 0,5 MHz	79dB(μV) quasi-peak 66dB(μV) average	79dB(μV) quasi-peak 66dB(μV) average
0,5 – 30 MHz	73dB(μV) quasi-peak 60dB(μV) average	73dB(μV) quasi-peak 60dB(μV) average

Table E1.3:
Test criteria for conducted/radiated emission tests

4.10 Radiated, radio-frequency, electromagnetic field immunity

This tests the immunity of electrical and electronic equipment to radiated electromagnetic energy, and is typically undertaken in a semi-anechoic chamber as shown in Figure E1.14.

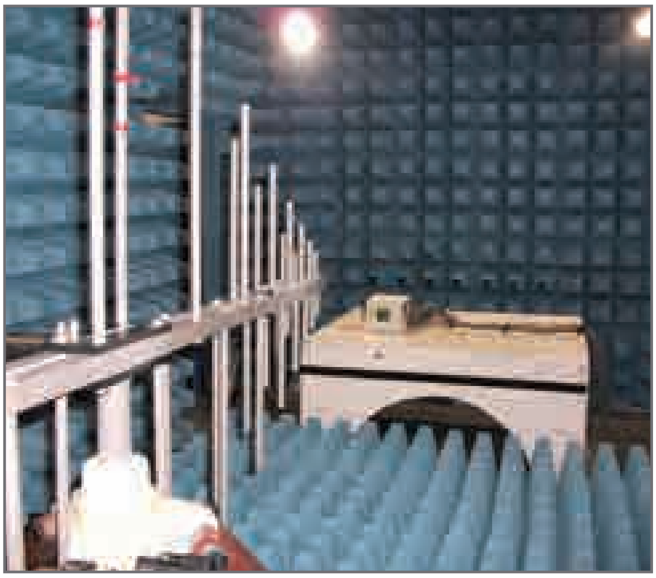

Figure E1.14:
Example of radiated test immunity in semi-anechoic chamber

Although the test standards state that all 6 faces of the equipment should be subjected to the interference, in practice this is not carried out. Applying interference to the sides and top and bottom of the relay would have little effect as the circuitry inside is effectively screened by the earthed metal case. However, the front and rear of the relay are not completely enclosed by metal and are therefore not at all well screened, and can be regarded as an EMC hole. Electromagnetic interference when directed at the front and back of the relay can enter freely onto the PCBs inside. When performing this test, the relay is in a quiescent condition, i.e. not tripped, with currents and voltages applied at minimum of the setting values. However, spot checks are performed at selected frequencies when the main protection and control functions of the relay are exercised, to ensure that it will operate as expected. The test is specified in IEC 61000-4-3 standard.

Level for IEC: Class III, 10V/m, 80MHz -2700MHz with 80% of amplitude modulation (AM) at 1kHz

Level for ANSI/IEEE: 20V/m 80MHz - 1000MHz with 80% of amplitude modulation (AM) at 1kHz

(ANSI/IEEE C37.90.2 : equipment built to US standards).

4.11 Conducted disturbance induced by RF - immunity tests

This test is applicable to the immunity against source of disturbance electromagnetic field, coming from intended RF transmitters, that may act on the whole length of cables connected to installed equipment. with all the cabling taken into account. The interference has to be physically introduced by conduction, hence the conducted immunity test. When performing this test, the relay is in a quiescent condition, i.e. not tripped, with currents and voltages applied at minimum of the setting values. However, spot checks are performed at selected frequencies when the main protection and control functions of the relay are exercised, to ensure that it will operate as expected. The test is specified in IEC 61000-4-6 standard. Level: Class III, 10 V r.m.s., 150 kHz - 80 MHz

4.12 Magnetic field tests

These tests are designed to ensure that the equipment is immune to magnetic interference. The three tests, power frequency, pulsed and damped oscillatory magnetic field, arise from the fact that for different site conditions the level and waveshape is altered. An example of the test configuration is shown in Figure E1.15.

4.12.1 Power frequency magnetic field

These tests simulate the magnetic field that would be experienced by a device located within close proximity of the power system. Testing is carried out by subjecting the relay to a magnetic field generated by two induction coils. The relay is rotated such that in each axis it is subjected to the full magnetic field strength. IEC 61000-4-8 is the relevant standard, using a signal level of:

- Long magnetic field: 30 A/m continuously
- Short magnetic field: 300 A/m (1 to 3 s)

To pass the power frequency test, the relay shall not maloperate, and shall still perform its main functions within the claimed tolerance. During the application of the short duration test, the main protection function shall be exercised and verified that the operating characteristics of the relay are unaffected.

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4. Electromagnetic compatibility tests

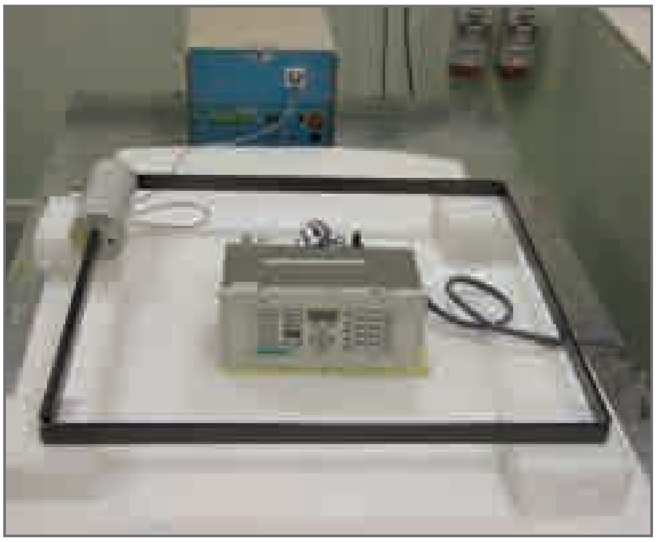

Figure E1.15:
Example of power frequency/pulse/damped oscillatory magnetic field test equipment

4.12.2 Pulsed magnetic field

These tests simulate the magnetic field that would be experienced by a device located within close proximity of the power system during a transient fault condition. According to IEC 61000-4-9 standard, the equipment is configured as for the power frequency magnetic field test, and the waveshape is applied with a level of 300 A/m. The relay shall not maloperate, and shall still perform its main functions within the claimed tolerance during the test.

4.12.3 Damped oscillatory magnetic field

These tests simulate the magnetic field that would be experienced by a device located within close proximity of the power system during a transient fault condition. IEC 61000-4-10 standard specifies that the generator for the coil shall produce an oscillatory waveshape with a frequency of 0.1 MHz and 1 MHz, to give a signal level in accordance with the level of 30 A/m.

5. Product safety type tests

A number of tests are carried out to demonstrate that the product is safe when used for its intended application. The essential requirements are that the relay is safe and will not cause an electric shock or fire hazard under normal conditions and in the presence of a single fault. A number of specific tests to prove this may be carried out, as follows.

5.1 Thermal withstand

The thermal withstand of VTs, CTs and output contact circuits is determined to ensure compliance with the specified continuous and short-term overload conditions. In addition to functional verification, the pass criterion is that there is no detrimental effect on the relay assembly, or circuit components, when the product is subjected to overload conditions that may be expected in service. Thermal withstand is assessed over a time period of 1 s for CTs and 10 s for VTs.

5.2 Insulation resistance

The insulation resistance test is carried out according to IEC 60255-5, i.e. 500 V d.c. 110%, for a minimum of 5 seconds.

This is carried out between all circuits and case earth, between all independent circuits and across normally open contacts. The acceptance criterion for a product in new condition is a minimum of 100 MΩ.

After a damp heat test the pass criterion is a minimum of 10 MΩ.

5.3 Dielectric voltage withstand

Dielectric Voltage Withstand testing is carried out as a routine test on every unit prior to dispatch (example see Figure E1.16). The purpose of this test is to ensure that the product build is as intended by design. This is done by verifying the clearance in air, thus ensuring that the product is safe to operate under normal use conditions. The following tests are conducted unless otherwise specified in the product documentation:

a. 2.0 kV r.m.s., 50/60Hz for 1 minute between all terminals and case earth and also between independent circuits, in accordance with IEC 60255-27. Some communication circuits are excluded from this test, or have modified test requirements e.g. those using D-type connectors

b. 1.5 kV r.m.s., 50/60 Hz for 1 minute across normally open contacts intended for connection to tripping circuits, in accordance with ANSI/IEEE C37.90

c. 1.0 kV r.m.s., 50/60 Hz for 1 minute across the normally open contacts of watchdog or changeover output relays, in accordance with IEC 60255-27

5. Product safety type tests

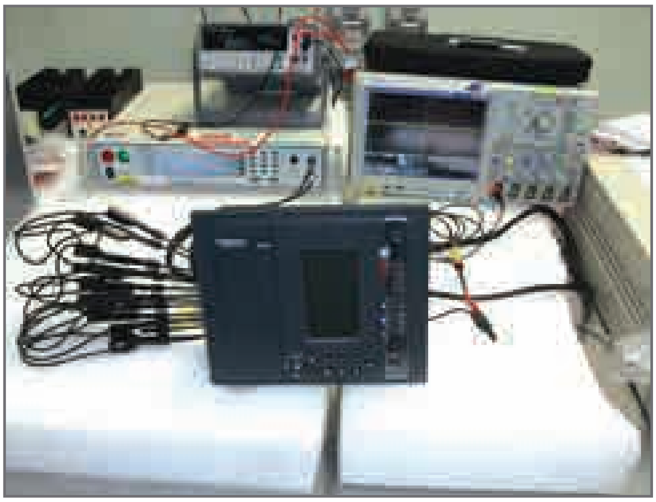

Figure E1.16:
Example of set-up of dielectric test with generator

The routine dielectric voltage withstand test time may be shorter than for the 1 minute type test time, to allow a reasonable production throughput, e.g. for a minimum of 1 second at 110% of the voltage specified for 1 minute.

5.4 Insulation withstand for over-voltages

The purpose of the High Voltage Impulse Withstand type test is to ensure that circuits and their components will withstand overvoltages on the power system caused by lightning. Three positive and three negative high voltage impulses, 5 kV peak, are applied between all circuits and the case earth and also between the terminals of independent circuits (but not across normally open contacts). As before, different requirements apply in the case of circuits using D-type connectors. The test generator characteristics are as specified in IEC 60255-27 and are shown in Figure E1.17. No disruptive discharge (i.e. flashover or puncture) is allowed. If it is necessary to repeat either the Dielectric Voltage or High Voltage Impulse Withstand tests these should be carried out at 75% of the specified level, in accordance with IEC 60255-27, to avoid overstressing insulation and components.

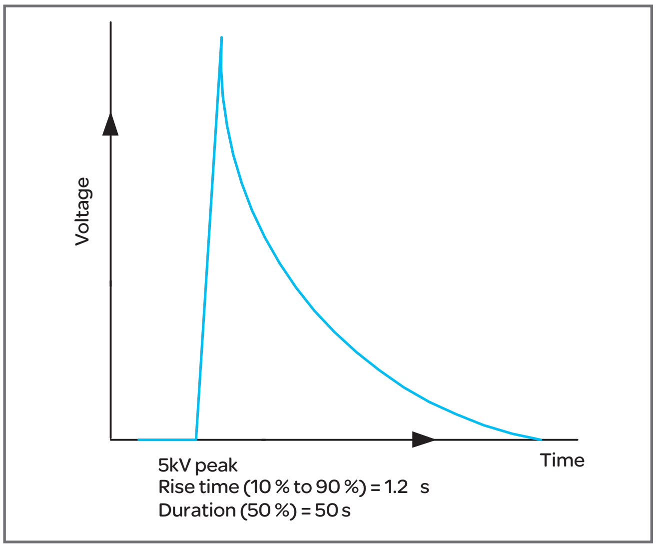

Figure E1.17:
Generator characteristics for insulation withstand test

5.5 Single fault condition assessment

An assessment is made of whether a single fault condition such as an overload, or an open or short circuit, applied to the product may cause an electric shock or fire hazard. In the case of doubt, type testing is carried out to ensure that the product is safe.

5.6 Earth bonding impedance

Class 1 products that rely on a protective earth connection for safety are subjected to an earth bonding impedance (EBI) type test. An example of the test installation is shown in figure E1.18. This ensures that the earth path between the protective earth connection and any accessible earthed part is sufficiently low to avoid damage in the event of a single fault occurring. The test is conducted using a test voltage of 12 V maximum and a test current of twice the recommended maximum protective fuse rating. After 1 minute with the current flowing in the circuit under test, the EBI shall not exceed 0.1 Ω.

Figure E 1.18:
Example of earth bonding impedance test done between the front panel of the protection relay and the metal parts

5.7 CE marking

A CE mark on the product, or its packaging, shows that compliance is claimed against relevant European Community directives e.g. Low Voltage Directive (LVD) 2006/95/EC and Electromagnetic.

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6. Environmental type tests

Various tests have to be conducted to prove that the relay can withstand the effects of the environment in which it is expected to work. They consist on the following tests:

a. temperature

c. humidity

d. enclosure protection

e. mechanical

These tests are described in the following sections.

6.1 Temperature test

Temperature tests are performed to ensure that a product can withstand extremes in temperatures, both hot and cold, during transit, storage and operating conditions.

a. Storage and transit conditions are defined as a temperature range of -25°C to +55°C (special cases -40°C to +70°C)

b. Operating conditions are defined as a temperature range of –25°C to +55°C (special cases -40°C to +70°C)

c. Dry heat withstand tests are performed at 70°C for 96 hours with the relay de-energised

d. Cold withstand tests are performed at –40°C for 96 hours with the relay de-energised

e. Operating range tests are carried out with the product energised, checking all main functions operate within tolerance over the specified working temperature range –25°C to +55°C (special cases -40°C to +70°C)

The test is specified in IEC 60068-2-1 standard.

Figure E1.19:
Climatic chambers

6.2 Humidity test

The humidity test is performed to ensure that the product will withstand and operate correctly when subjected to 93% relative humidity at a constant temperature of 40°C for 56 days. Tests are performed to ensure that the product functions correctly within specification after 21 and 56 days. After the test, visual inspections are made for any signs of unacceptable corrosion and mould growth. The test is specified in IEC 60068-2-78 standard.

6.3 Cyclic temperature/humidity test

This is a short-term test (6 days) that stresses the relay by subjecting it to temperature cycling in conjunction with high humidity. The test does not replace the 56 day humidity test, but is used for testing minor modifications to prove that the design is unaffected. The applicable standard is IEC 60068-2-30 and test conditions of:

+25°C ± 3°C and at least 95% relative humidity +55°C ± 2°C and 93% ± 3% relative humidity are used, over the 24 hour cycle shown in Figure E1.20.

For these tests the relay is placed in a humidity cabinet, and energised with normal in-service quantities for the complete duration of the tests. In practical terms this usually means energising the relay with currents and voltages such that it is 10% from the threshold for operation. Throughout the duration of the test the relay is monitored to ensure that no unwanted operations occur.

Once the relay is removed from the humidity cabinet, its insulation resistance is measured to ensure that it has not deteriorated to below the claimed level. The relay is then functionally tested again, and finally dismantled to check for signs of component corrosion and growth. The acceptance criterion is that no unwanted operations shall occur including transient operation of indicating devices.

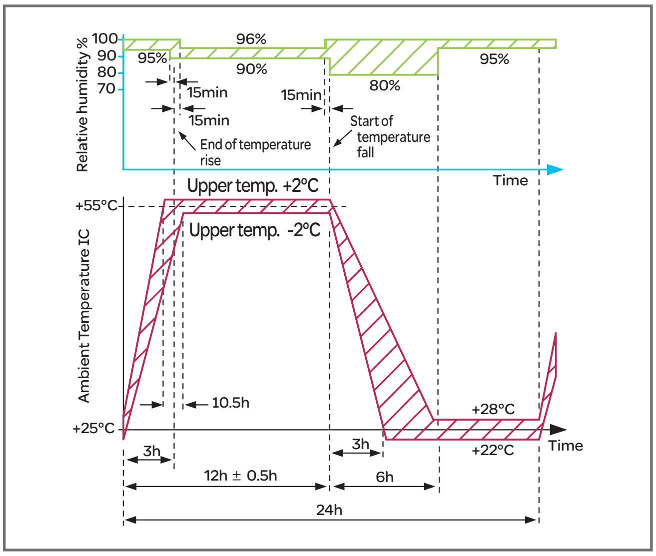

Figure E1.20:
Cyclic temperature/humidity test profile

6. Environmental type tests

After the test the relay's insulation resistance should not have significantly reduced, and it should perform all of its main protection and communications functions within the claimed tolerance. The relay should also suffer no significant corrosion or growth, and photographs are usually taken of each PCB and the case as a record of this.

6.4 Fast cyclic temperature

This test is intended to determine the effect on the product of a change of temperature or a succession of changes of temperature. The effect of such tests is determined by:

a. values of high and low conditioning temperature

b. the rate of change

c. the number of cycles

d. the amount of heat transfer onto or from the product under test

The test is specified in IEC 60068-2-14 standard.

6.5 Enclosure protection test

Enclosure protection tests prove that the casing system and connectors on the product protect against the ingress of dust, moisture, water droplets (striking the case at pre-defined angles) and other pollutants. An 'acceptable' level of dust or water may penetrate the case during testing, but must not impact the normal product operation, safety or cause tracking across insulated parts of connectors. This test is specified in IEC 60529 standard.

6.6 Mechanical tests

Mechanical tests simulate a number of different mechanical conditions that the product may have to endure during its lifetime. These fall into two categories:

a. response to disturbances while energised

b. response to disturbances during transportation (de-energised state)

Tests in the first category are concerned with the response to vibration, shock and seismic disturbance. The tests are designed to simulate normal in-service conditions for the product, for example earthquakes. These tests are performed in all three axes, with the product energised in its normal (quiescent) state.

During the test, all output contacts are continuously monitored for change using contact follower circuits. Vibration levels of 1gn, over a 10 Hz-150 Hz frequency sweep are used. Seismic tests use excitation in a single axis, using a test frequency of 35 Hz and peak displacements of 7.5 mm and 3.5 mm in the x and y axes respectively below the crossover frequency and peak accelerations of 2.0 gn and 1.0 gn in these axes above the crossover frequency.

The second category consists of vibration endurance, shock withstand and bump tests. They are designed to simulate the longer-term affects of shock and vibration that could occur during transportation. These tests are performed with the product de-energised.

After these tests, the product must still operate within its specification and show no signs of permanent mechanical damage.

Equipment undergoing a seismic type test is shown in Figure E1.21, while the waveform for the shock/bump test is shown in Figure E1.22. The test levels for shock and bump tests are:

a. shock response (energised):
3 pulses, each 10g, 11 ms duration

b. shock withstand (de-energised):
3 pulses, 15g, 11 ms duration

c. bump (de-energised):
1000 pulses, 10g, 16 ms duration

The test is specified in the standards IEC 60255-21-1, IEC 60255-21-2, IEC 60255-21-3.

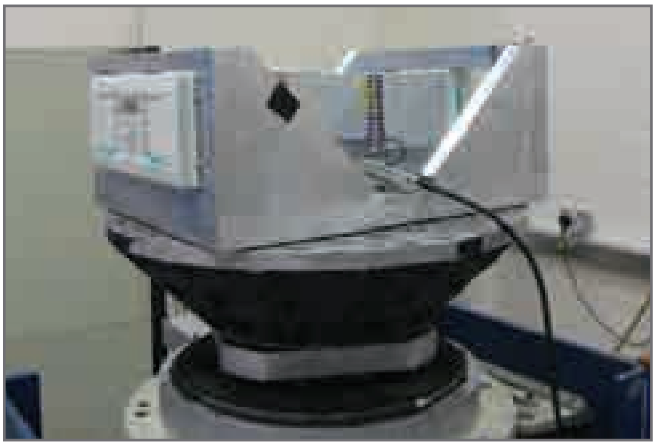

Figure E1.21:
Example of seismic-vibration test equipment

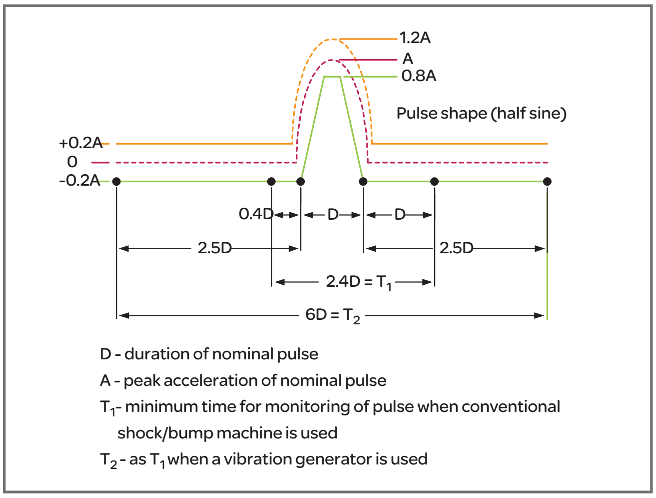

Figure E1.22:
Shock/bump impulse waveform

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7. Software type tests

Digital and numerical relays contain software to implement the protection, measurement and control-command functions of a relay. This software must be thoroughly tested, to ensure that the relay complies with all specifications and those disturbances of various kinds do not result in unexpected results.

Software is tested in various stages:

a. unit testing

b. integration testing

c. functional qualification testing

The purpose of unit testing is to determine if an individual function or procedure implemented using software, or small group of closely related functions, is free of data, logic, or standards errors. It is much easier to detect these types of errors in individual units or small groups of units than it is in an integrated software architecture and/or system. Unit testing is typically performed against the software detailed design and by the developer of the unit(s).

Integration testing typically focuses on these interfaces and also issues such as performance, timings and synchronisation that are not applicable in unit testing. Integration testing also focuses on 'Stressing' the software and related interfaces.

Integration testing is 'black box' in nature, i.e. it does not take into account the structure of individual units. It is typically performed against the software architectural and detailed design. The specified software requirements would typically also be used as a source for some of the test cases.

Functional qualification testing includes a verification test and a validation test.

The verification test is to demonstrate the product fulfils its design specification; the test will be performed on prototype or simulation devices.

The validation test is to demonstrate the product fulfils its requirement for its intended use, when placed into intended environment (real or simulated).

7.1 Static unit testing

Static Unit Testing (or static analysis as it is often called) analyses the unit(s) source code for complexity, precision tracking, initialisation checking, value tracking, strong type checking, macro analysis etc. While Static Unit Testing can be performed manually, it is a laborious and error prone process and is best performed using a proprietary automated static unit analysis tool. It is important to ensure that any such tool is configured correctly and used consistently during development.

7.2 Dynamic unit testing

Dynamic Testing is concerned with the runtime behaviour of the unit(s) being tested.

Dynamic unit testing can be sub-divided into 'black box' testing and 'white box' testing. 'Black box' testing verifies the implementation of the requirement(s) allocated to the unit(s). It takes no account of the internal structure of the unit(s) being tested. It is only concerned with providing known inputs and determining if the outputs from the unit(s) are correct for those inputs. 'White box' testing is concerned with testing the internal structure of the unit(s) and measuring the test coverage, i.e. how much of the code within the unit(s) has been executed during the tests. The objective of the unit testing may, for example, be to achieve 100% statement coverage, in which every line of the code is executed at least once, or to execute every possible path through the unit(s) at least once.

7.3 Unit testing environment

Both Dynamic and Static Unit Testing are performed in the host environment rather than the target environment. Dynamic Unit Testing uses a test harness to provide the environment in which the unit tests can be executed. The test harness is designed such that it simulates the interfaces of the unit(s) being tested - both software-software interfaces and software-hardware interfaces - using what are known as stubs. The test harness provides the test data to those units being tested and outputs the test results in a form understandable to a developer. There are many commercially available testing tools to automate test harness production and the execution of tests.

7.4 Software/software integration testing

Software/Software Integration Testing is performed in the host environment. It uses a test harness to simulate inputs and outputs, hardware calls and system calls (e.g. the target environment operating system).

7.5 Software/hardware integration testing

Software/Hardware Integration Testing is performed in the target environment, i.e. it uses the actual target hardware, operating system, drivers etc. It is usually performed after Software/Software Integration Testing. Testing the interfaces to the hardware is an important feature of Software/Hardware Integration Testing. Test cases for Integration Testing are typically based on those defined for Validation Testing. However the emphasis should be on finding errors and problems. Performing a dry run of the validation testing often completes Integration Testing.

7.6 Verification testing

The purpose of verification testing is to verify that the product fulfils its product specification. It could be done by the software design engineer or be done by someone independent; it could be opened-box (white-box) or black-box testing. All features of the protection relay should be tested, one by one, to check if they comply with their product specification.

7.7 Validation testing

The purpose of validation testing is to validate that the product meets the user requirements of the product. It should be done by someone independent of the software development and approached as a 'black box' testing as a whole. For the protection relay, no attention should be paid to the software architecture; attention should be paid to protection output, user interface (keypad, display, configuration tools), records and communication signal at the same time if one fault is injected). Validation tests

7. Software type tests

not only cover functional tests such as protection, control, measurements, recording, data logging and communication, but also cover non-functional tests such as performance, robustness and endurance tests. The validation tests can be complemented by field tests to evaluate the behaviour of the protection relays in a real situation and its intended environment. Each validation test should have predefined evaluation criteria, to be used to decide if the test has passed or failed. The evaluation criteria should be explicit with no room for interpretation or ambiguity.

7.8 Traceability of verification and validation tests

Product offer requirements are provided by marketing to describe the intended use of the product and intended environment. Product specification requirement are provided by R&D to describe how the product will be designed to meet the offer requirements. Generally, each documented product specification requirement should be covered by at least one verification test case, and each documented product offer requirement should be covered by at least one validation test case. But in practice, some verification test is very close to validation test, in this case the verification test case could be used as evidence to show how the offer requirement to be covered. It is important to use requirements versus test cases matrix to prove this.

7.9 Software modifications - Regression testing

Regression Testing is not a type test in its' own right. It is the overall name given to the testing performed when an existing software product is changed. The purpose of Regression Testing is to show that unintended changes to the functionality (i.e. errors and defects) have not been introduced. Each change to an existing software product must be considered in its own right. It is impossible to specify a standard set of regression tests that can be applied as a 'catch-all' for introduced errors and defects. Each change to the software must be analysed to determine what risk there might be of unintentional changes to the functionality being introduced. Those areas of highest risk will need to be regression tested. The ultimate regression test is to perform the complete Validation Testing programme again, updated to take account of the changes made. Regression Testing is extremely important. If it is not performed, there is a high risk of errors being found in the field. Performing it will not reduce to zero the chance of an error or defect remaining in the software, but it will reduce it. Determining the Regression Testing that is required is made much easier if there is traceability from properly documented software requirements through design (again properly documented and up to date), coding and testing.

8. Dynamic validation tests

There are two possible methods of dynamically proving the satisfactory performance of protection relays or schemes; the first method is by actually applying faults on the power system and the second is to carry out comprehensive testing on a power system simulator. The former method is extremely unlikely to be used; lead times are lengthy and the risk of damage occurring makes the tests very expensive. It is therefore only used on a very limited basis and the faults applied are restricted in number and type. For these reasons different power system simulators have been developed. They can be divided into two types:

a. those which use analogue models of a power system

b. those which model the power system mathematically using digital simulation techniques

8.1 Use of power system analogue models

For many years, relays have been tested on analogue models of power systems such as artificial transmission lines, or test plant capable of supplying significant amounts of current. However, these approaches have significant limitations in the current and voltage waveforms that can be generated, and are not suitable for automated, unattended, testing programs. While still used on a limited basis for testing electromechanical and static relays, a radically different approach is required for dynamic testing of numerical relays.

8.2 Use of microprocessor based simulation equipment

The complexity of numerical relays, reliant on software for implementation of the functions included, dictates some kind of automated test equipment. The functions of even a simple numerical overcurrent relay (including all auxiliary functions) can take several months of automated, 24 hours/day testing to test completely. If such test equipment was able to apply realistic current and voltage waveforms that closely match those found on power systems during fault conditions, the equipment can be used either for type testing of individual relay designs or for a complete protection scheme designed for a specific application. In recognition of this, a new generation of power system simulators has been developed, which is capable of providing a far more accurate simulation of power system conditions than has been possible in the past. The simulator enables relays to be tested under a wide range of system conditions, representing the equivalent of many years of site experience. This kind of simulation where the relay interacts directly with the simulator is usually called simulation with Hardware In the Loop (HIL).

E1

8. Dynamic validation tests

8.2.1 Simulation hardware

Equipment is now available to provide high-speed, highly accurate modelling of a section of a power system. The equipment is based on distributed microprocessor-based hardware containing software models of the various elements of a power system, and is shown in Figure E1.23.

Figure E1.23:
Digital power system simulator for relay and protection scheme testing

The modules have outputs linked to current and voltage sources that have a similar transient capability and have suitable output levels for direct connection to the inputs of relays – i.e. 1 A / 5 A for current and 100V / 110V / 115V / 120V for voltage or sample values according to IEC 61850-9-2.

Inputs are also provided to monitor the response of relays under test (contact closures for tripping, GOOSE message according to IEC 61850, etc.) and these inputs can be used as part of the model of the power system. The software is also capable of modelling the dynamic response of CTs and VTs accurately. When it is desired to check the response of a relay or protection scheme to an actual power system transient, the transient can be simulated using sophisticated power systems analysis software and the results transferred digitally to the simulator, or the event recorder recording of the transient can be used, in either digital or analogue form, as inputs to the simulator model. Output signal conversion involves circuits to eliminate the quantisation steps normally found in conventional Digital/Analogue conversion. Analogue models of the system transducer characteristics can be interposed between the signal processors and the output amplifiers when required. This equipment shows many advantages over traditional test equipment:

a. the power system model is capable of reproducing high frequency transients such as travelling waves

b. tests involving very long time constants can be carried out

c. it is not affected by the harmonic content, noise and frequency variations in the a.c. supply

d. it is capable of representing the variation in the current associated with generator faults and power swings

e. saturation effects in CTs and VTs can be modelled

f. a set of test routines can be specified in software and then left to run unattended (or with only occasional monitoring) to completion, with a detailed record of test results being available on completion.

A block schematic of the equipment is shown in Figure E1.24. It is based on a computer which calculates the digital data representing the system voltages and currents. The computer controls conversion of the digital data into analogue signals, and it monitors and controls the relays being tested.

8.2.2 Simulation software

Unlike most traditional software used for power systems analysis, the software used is suitable to model the fast transient phenomenons that occur in the first few milliseconds after fault inception. Two

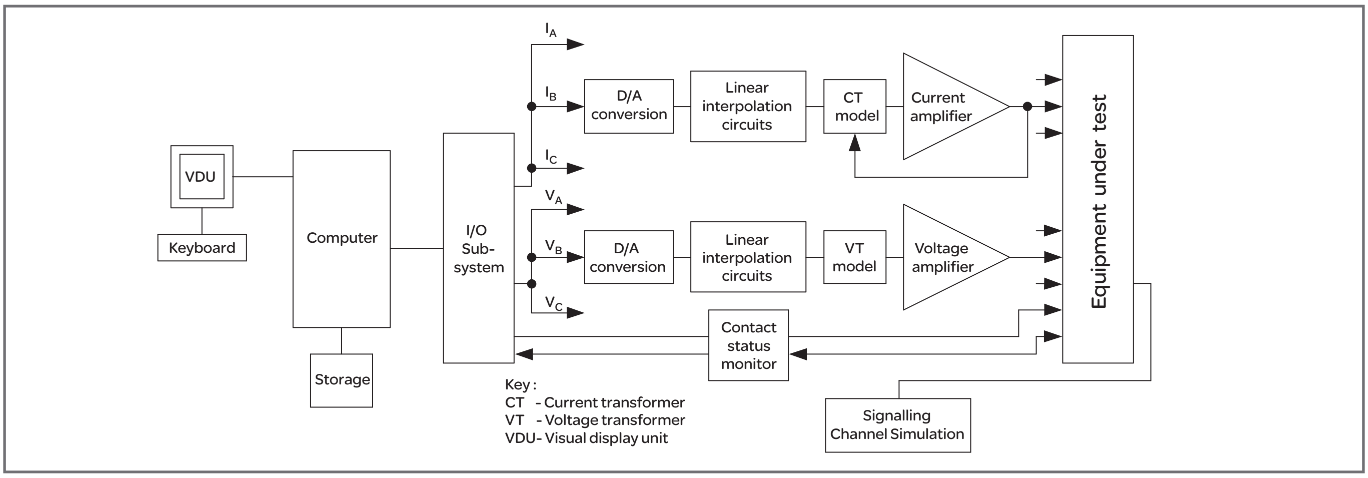

Figure E1.24:
Block diagram of microprocessor based automated test system

very accurate simulation programs are used, one based on time domain and the other on frequency domain techniques.

In both programs, single and double circuit transmission lines are represented by fully distributed parameter models. The line parameters are calculated from R,L,C parameters or from the physical construction of the line (symmetrical, asymmetrical, transposed or non-transposed), taking into account the effect of conductor geometry, conductor internal impedance and the earth return path. It also includes, where appropriate, the frequency dependence of the line parameters in the frequency domain program. The frequency dependent variable effects are calculated using Fast Fourier Transform algorithms and the results are converted to the time domain.

The fault can be applied at any point in the system and can be any combination of phase-to-phase or phase-to-earth, resistive, or non-linear phase to earth arcing faults. For series compensated lines, flashover across a series capacitor following a short circuit fault can be simulated.

The frequency domain model is not suitable for developing faults and switching sequences, therefore a power system simulator, working in the time domain, is employed in such cases.

In addition to these two programs, a simulation program based on lumped resistance and inductance parameters is used. This simulation is used to represent systems with long time constants and slow system changes due, for example, to power swings.

8.2.3 Simulator applications

The simulator is used for checking the accuracy of calibration and performing type tests on a wide range of protection relays during their development. It has the following advantages over traditional test methods:

a. 'state of the art' power system modelling data can be used to test relays

b. freedom from frequency variations and noise or harmonic content of the a.c. supply

c. the relay under test does not burden the power system simulation

d. all tests are accurately repeatable

e. wide bandwidth signals can be produced

f. a wide range of frequencies can be reproduced

g. selected harmonics may be superimposed on the power frequency

h. the use of direct coupled current amplifiers allows time constants of any length

i. capable of simulating slow system changes

j. reproduces fault currents whose peak amplitude varies with time

k. transducer models can be included

l. automatic testing removes the likelihood of measurement and setting errors

m. two equipments can be linked together to simulate a system model with two relaying points

The simulator is also used for the production testing of relays, in which most of the advantages listed above apply. As the tests and measurements are made automatically, the quality of testing is also greatly enhanced. Further, in cases of suspected malfunction of a relay in the field under known fault conditions, the simulator can be used to replicate the power system and fault conditions, and conduct a detailed investigation into the performance of the relay.

Finally, complex protection schemes can be modelled, using both the physical relays intended for use (Hardware in the Loop) and virtual relays embedded in the software, to check the suitability of the proposed scheme under a wide variety of conditions.

To illustrate this, Figure E1.25 shows a section of a particular power system modelled. The waveforms of Figure E1.26 show an example of three phase voltages and currents at the secondary of VT and CT for a given fault conditions.

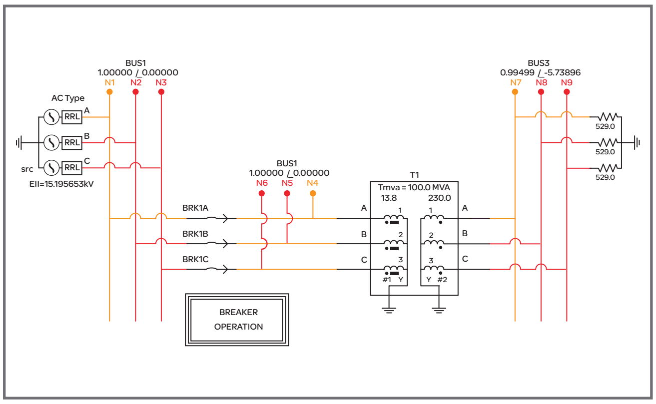

Figure E1.25:
Example of application study of a power system

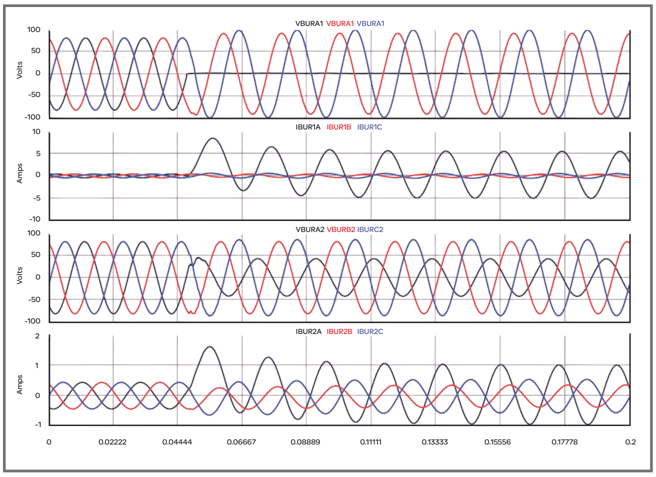

Figure E1.26:
Example of application study of a power system with display of CT/VT signals

9. Production tests

Production testing of protection relays is becoming far more demanding as the accuracy and complexity of the products increase. Electronic power amplifiers are used to supply accurate voltages and currents of high stability to the relay under test. The inclusion of a computer in the test system allows more complex testing to be performed at an economical cost, with the advantage of speed and repeatability of tests from one relay to another.

Figure E1.27 shows a technical inspection of components and incoming electronic boards before product assembly.

Figure E1.27:
Technical inspection of electronic boards

Figure E1.28 shows a computer-controlled test bench. The hardware is mounted in a special rack. Each unit of the test system is connected to the computer via an interface bus. Individual test programs for each type of relay are required, but the interface used is standard for all relay types. Control of input waveforms and analogue measurements, the monitoring of output signals and the analysis of test data are performed by the computer.

Figure E1.28:
Computer controlled testbench

A printout of the test results can also be produced if required.

Because software is extensively tested at the type-testing stage, there is normally no need to check the correct functioning of the software. Checks are limited to determining that the analogue and digital I/O is functioning correctly. This is achieved for inputs by applying known voltage and current inputs to the relay under test and checking that the software has captured the correct values.

Similarly, digital outputs are exercised by using test software to actuate each output and checking that the correct output is energised. Provided that appropriate procedures are in place to ensure that only type-tested software is downloaded, there is no need to check the correct functioning of the software in the relay.

The final step is to download the software appropriate to the relay and store it in the memory of the device.

E2 Relay Commissioning

Network Protection & Automation Guide

Chapter E2

Relay Commissioning

E2

1. Commissioning tests

Installation of a protection scheme at site creates a number of possibilities for errors in the implementation of the scheme to occur. Even if the scheme has been thoroughly tested in the factory, wiring to the CTs and VTs on site may be incorrectly carried out, or the CTs/VTs may have been incorrectly installed. The impact of such errors may range from simply being a nuisance (tripping occurs repeatedly on energisation, requiring investigation to locate and correct the error(s)) through to failure to trip under fault conditions, leading to major equipment damage, disruption to supplies and potential hazards to personnel. The strategies available to remove these risks are many, but all involve some kind of testing at site.

Commissioning tests at site are therefore invariably performed before protection equipment is set to work. The aims of commissioning tests are:

a. to ensure that the equipment has not been damaged during transit or installation

b. to ensure that the installation work has been carried out correctly

c. to prove the correct functioning of the protection scheme as a whole

The tests carried out will normally vary according to the protection scheme involved, the relay technology used, and the policy of the client. In many cases, the tests actually conducted are determined at the time of commissioning by mutual agreement between the client's representative and the commissioning team. Hence, it is not possible to provide a definitive list of tests that are required during commissioning. This section therefore describes the tests commonly carried out during commissioning.

The following tests are invariably carried out, since the protection scheme will not function correctly if faults exist.

a. wiring diagram check, using circuit diagrams showing all the reference numbers of the interconnecting wiring

b. general inspection of the equipment, checking all connections, wires on relays terminals, labels on terminal boards, etc.

c. insulation resistance measurement of all circuits

d. perform relay self-test procedure and external communications checks on digital/numerical relays

e. test main current transformers

f. test main voltage transformers

g. check that protection relay alarm/trip settings have been entered correctly

h. tripping and alarm circuit checks to prove correct functioning

In addition, the following checks may be carried out, depending on the factors noted earlier.

i. secondary injection test on each relay to prove operation at one or more setting values

j. primary injection tests on each relay to prove stability for external faults and to determine the effective current setting for internal faults (essential for some types of electromechanical relays)

k. testing of protection scheme logic

This section details the tests required to cover items (a)–(f) above.

Section 2 covers secondary injection test equipment

Section 3 details the secondary injection testing that may be carried out (i)

Section 4 covers primary injection testing (j)

Section 5 details the checks required on any logic involved in the protection scheme (k)

Section 6 details the tests required on alarm/tripping circuits tripping/alarm circuits (h).

1.1 Insulation tests

All the deliberate earth connections on the wiring to be tested should first be removed, for example earthing links on current transformers, voltage transformers and d.c. supplies. Some insulation testers generate impulses with peak voltages exceeding 5kV. In these instances any electronic equipment should be disconnected while the external wiring insulation is checked.

The insulation resistance should be measured to earth and between electrically separate circuits. The readings are recorded and compared with subsequent routine tests to check for any deterioration of the insulation.

The insulation resistance measured depends on the amount of wiring involved, its grade, and the site humidity. Generally, if the test is restricted to one cubicle, a reading of several hundred megohms should be obtained. If long lengths of site wiring are involved, the reading could be only a few megohms.

1.2 Relay self-test procedure

Digital and numerical relays will have a self-test procedure that is detailed in the appropriate relay manual. These tests should be followed to determine if the relay is operating correctly. This will normally involve checking of the relay watchdog circuit, exercising all digital inputs and outputs and checking that the relay analogue inputs are within calibration by applying a test current or voltage. For these tests, the relay outputs are normally disconnected from the remainder of the protection scheme, as it is a test carried out to prove correct relay, rather than scheme, operation.

Unit protection schemes involve relays that need to communicate with each other. This leads to additional testing requirements. The communications path between the relays is tested using suitable equipment to ensure that the path is complete and that the received signal strength is within specification. Numerical relays may be fitted with loopback test facilities that enable either part of or the entire communications link to be tested from one end.

1. Commissioning tests

After completion of these tests, it is usual to enter the relay settings required. This can be done manually via the relay front panel controls, or using a portable PC and suitable software. Whichever method is used, a check by a second person that the correct settings have been used is desirable, and the settings recorded. Programmable scheme logic that is required is also entered at this stage.

1.3 Current transformer tests

The following tests are normally carried out prior to energisation of the main circuits.

1.3.1 Polarity check

Each current transformer should be individually tested to verify that the primary and secondary polarity markings are correct; see Figure E2.1. The ammeter connected to the secondary of the current transformer should be a robust moving coil, permanent magnet, centre-zero type. A low voltage battery is used, via a single-pole push-button switch, to energise the primary winding. On closing the push-button, the d.c. ammeter, A, should give a positive flick and on opening, a negative flick.

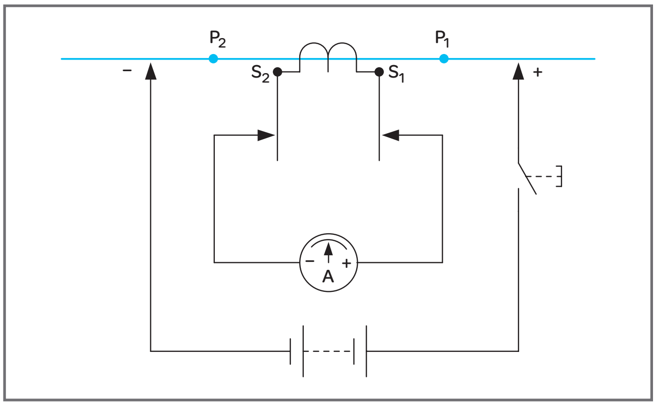

Figure E2.1:
Current transformer polarity check

1.3.2 Magnetisation curve

Several points should be checked on each current transformer magnetisation curve. This can be done by energising the secondary winding from the local mains supply through a variable auto-transformer while the primary circuit remains open; see Figure E2.2.

The characteristic is measured at suitable intervals of applied voltage, until the magnetising current is seen to rise very rapidly for a small increase in voltage. This indicates the approximate knee-point or saturation flux level of the current transformer. The magnetising current should then be recorded at similar voltage intervals as it is reduced to zero.

Care must be taken that the test equipment is suitably rated. The short-time current rating must be in excess of the CT secondary current rating, to allow for the measurement of the

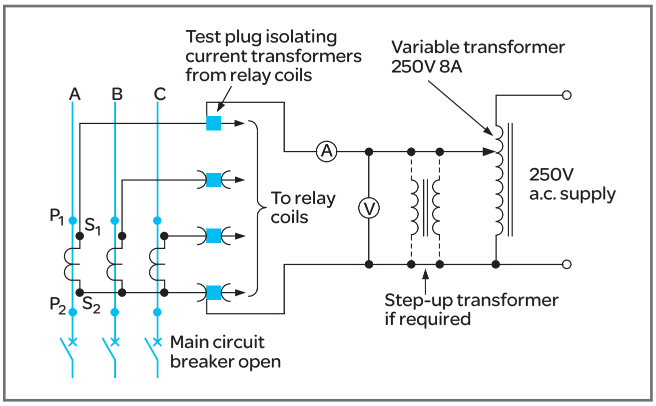

Figure E2.2:
Testing current transformer magnetising curve

saturation current. This will be in excess of the CT secondary current rating. As the magnetising current will not be sinusoidal, a moving iron or dynamometer type ammeter should be used.

It is often found that current transformers with secondary ratings of 1A or less have a knee-point voltage higher than the local mains supply. In these cases, a step-up interposing transformer must be used to obtain the necessary voltage to check the magnetisation curve.

1.4 Voltage transformer tests

Voltage transformers require testing for polarity and phasing.

1.4.1 Polarity check

The voltage transformer polarity can be checked using the method for CT polarity tests. Care must be taken to connect the battery supply to the primary winding, with the polarity ammeter connected to the secondary winding. If the voltage transformer is of the capacitor type, then the polarity of the transformer at the bottom of the capacitor stack should be checked.

1.4.2 Ratio check

This check can be carried out when the main circuit is first made live. The voltage transformer secondary voltage is compared with the secondary voltage shown on the nameplate.

1.4.3 Phasing check

The secondary connections for a three-phase voltage transformer or a bank of three single-phase voltage transformers must be carefully checked for phasing. With the main circuit alive, the phase rotation is checked using a phase rotation meter connected across the three phases, as shown in Figure E2.3. Provided an existing proven VT is available on the same primary system, and that secondary earthing is employed, all that is now necessary to prove correct phasing is a voltage check between, say, both 'A' phase secondary outputs. There should be nominally little or no voltage if the phasing is correct.

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1. Commissioning tests

However, this test does not detect if the phase sequence is correct, but the phases are displaced by 120° from their correct position, i.e. phase A occupies the position of phase C or phase B in Figure E2.3. This can be checked by removing the fuses from phases B and C for example and measuring the phase-earth voltages on the secondary of the VT. If the phasing is correct, only phase A should be healthy, phases B and C should have only a small residual voltage. Correct phasing should be further substantiated when carrying out 'on load' tests on any phase-angle sensitive relays, at the relay terminals. Load current in a known phase CT secondary should be compared with the associated phase to neutral VT secondary voltage. The phase angle between them should be measured, and should relate to the power factor of the system load.

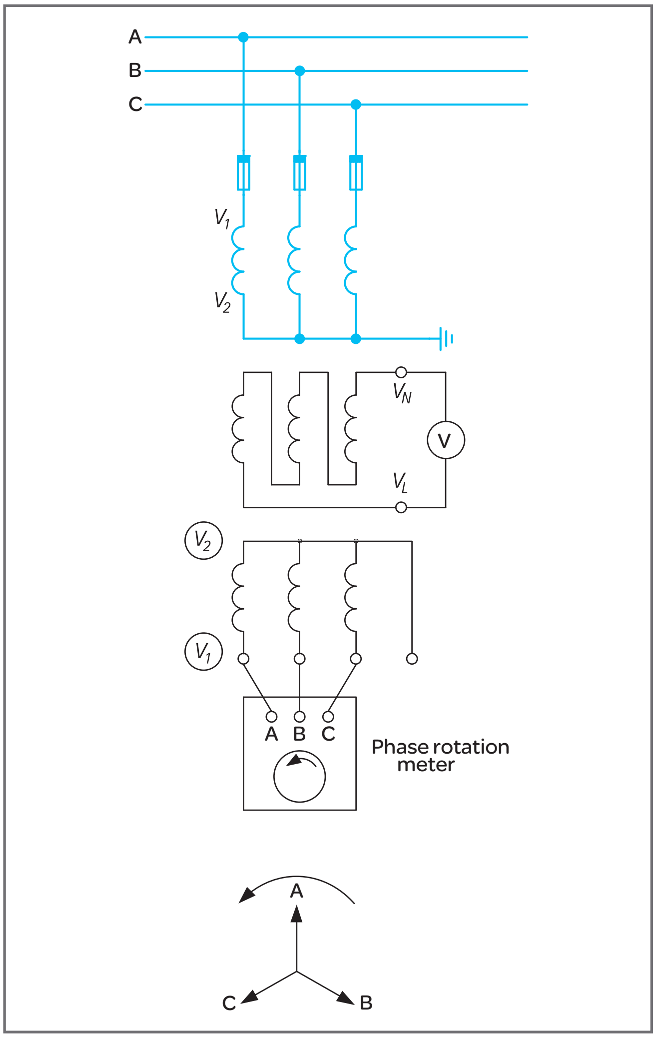

Figure E2.3:
Voltage transformer phasing check

If the three-phase voltage transformer has a broken-delta tertiary winding, then a check should be made of the voltage across the two connections from the broken delta V_N and V_L, as shown in Figure E2.3. With the rated balanced three-phase supply voltage applied to the voltage transformer primary windings, the broken-delta voltage should be below 5V with the rated burden connected.

1.5 Protection relay setting checks

At some point during commissioning, the alarm and trip settings of the relay elements involved will require to be entered and/or checked. Where the complete scheme is engineered and supplied by a single contractor, the settings may already have been entered prior to despatch from the factory, and hence this need not be repeated. The method of entering settings varies according to the relay technology used. For electromechanical and static relays, manual entry of the settings for each relay element is required. This method can also be used for digital/numerical relays. However, the amount of data to be entered is much greater, and therefore it is usual to use appropriate software, normally supplied by the manufacturer, for this purpose. The software also makes the essential task of making a record of the data entered much easier.

Once the data has been entered, it should be checked for compliance with the recommended settings as calculated from the protection setting study. Where appropriate software is used for data entry, the checks can be considered complete if the data is checked prior to download of the settings to the relay. Otherwise, a check may be required subsequent to data entry by inspection and recording of the relay settings, or it may be considered adequate to do this at the time of data entry. The recorded settings form an essential part of the commissioning documentation provided to the client.

2. Secondary injection test equipment

The purpose of secondary injection testing is to prove the correct operation of the protection scheme that is downstream from the inputs to the protection relay(s). Secondary injection tests are always done prior to primary injection tests. This is because the risks during initial testing to the LV side of the equipment under test are minimised. The primary (HV) side of the equipment is disconnected, so that no damage can occur. These tests and the equipment necessary to perform them are generally described in the manufacturer's manuals for the relays, but brief details are given below for the main types of protection relays.

2.1 Test blocks/plugs for secondary injection equipment

It is common practice to provide test blocks or test sockets in the relay circuits so that connections can readily be made to the test equipment without disturbing wiring. Test plugs of either multi- finger or single-finger design (for monitoring the current in one CT secondary circuit) are used to connect test equipment to the relay under test.

The top and bottom contact of each test plug finger is separated by an insulating strip, so that the relay circuits can be completely isolated from the switchgear wiring when the test plug is inserted. To avoid open-circuiting CT secondary terminals, it is therefore essential that CT shorting jumper links are fitted across all appropriate 'live side' terminals of the test plug BEFORE it is inserted. With the test plug inserted in position, all the test circuitry can now be connected to the isolated 'relay side' test plug terminals. Some test blocks incorporate the live-side jumper links within the block and these can be set to the 'closed' or 'open' position as appropriate, either manually prior to removing the cover and inserting the test plug, or automatically upon removal of the cover. Removal of the cover also exposes the colour-coded face-plate of the block, clearly indicating that the protection scheme is not in service, and may also disconnect any d.c. auxiliary supplies used for powering relay tripping outputs.

Withdrawing the test plug immediately restores the connections to the main current transformers and voltage transformers and removes the test connections. Replacement of the test block cover then removes the short circuits that had been applied to the main CT secondary circuits. Where several relays are used in a protection scheme, one or more test blocks may be fitted on the relay panel, enabling the whole scheme to be tested, rather than just one relay at a time.

Test blocks usually offer facilities for the monitoring and secondary injection testing of any power system protection scheme. The test block may be used either with a multi-fingered test plug to allow isolation and monitoring of all the selected conductor paths, or with a single finger test plug that allows the currents on individual conductors to be monitored. A test block and test plugs are illustrated in Figure E2.4.

Figure E2.4:
Test block/plugs

2.2 Secondary injection test sets

The type of the relay to be tested determines the type of equipment used to provide the secondary injection currents and voltages. Many electromechanical relays have a non-linear current coil impedance when the relay operates and this can cause the test current waveform to be distorted if the injection supply voltage is fed directly to the coil. The presence of harmonics in the current waveform may affect the torque of electromechanical relays and give unreliable test results, so some injection test sets use an adjustable series reactance to control the current. This keeps the power dissipation small and the equipment light and compact.

Many test sets are portable and include precision ammeters and voltmeters and timing equipment. Test sets may have both voltage and current outputs. The former are high voltage, low current outputs for use with relay elements that require signal inputs from a VT as well as a CT. The current outputs are high current, low voltage to connect to relay CT inputs.

It is important, however, to ensure that the test set current outputs are true current sources, and hence are not affected by the load impedance of a relay element current coil. Use of a test set with a current output that is essentially a voltage

2. Secondary injection test equipment

source can give rise to serious problems when testing electromechanical relays. Any significant impedance mismatch between the output of the test set and the relay current coil during relay operation will give rise to a variation in current from that desired and possible error in the test results. The relay operation time may be greater than expected (never less than expected) or relay 'chatter' may occur. It is quite common for such errors to only be found much later, after a fault has caused major damage to equipment through failure of the primary protection to operate. Failure investigation then shows that the reason for the primary protection to operate is an incorrectly set relay, due in turn to use of a test set with a current output consisting of a voltage source when the relay was last tested. Figure E2.5 shows typical waveforms resulting from use of test set current output that is a voltage source – the distorted relay coil current waveform gives rise to an extended operation time compared to the expected value.

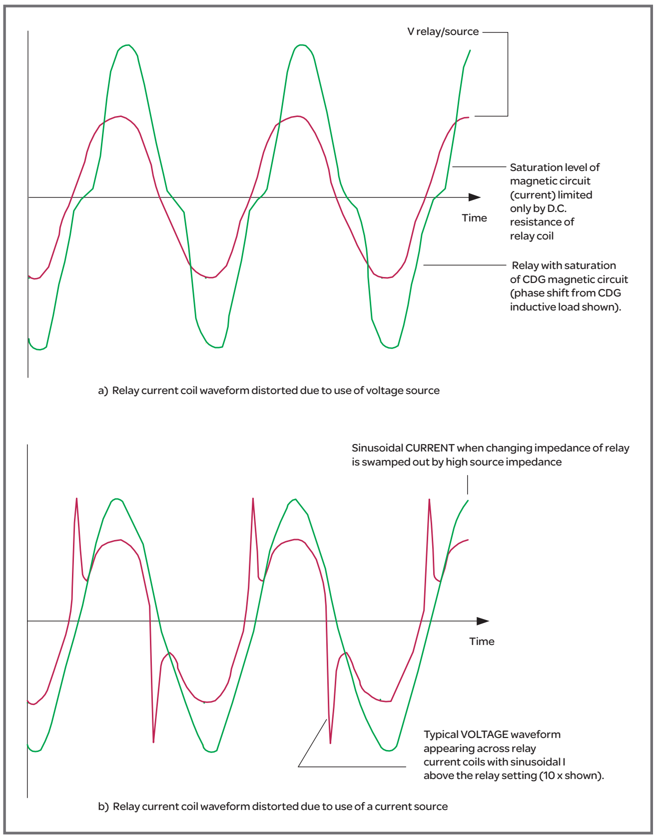

Figure E2.5:
Relay current coil waveforms

Test sets are computer based and comprise a PC (usually a standard laptop PC with suitable software) and a power amplifier that takes the low level outputs from the PC and amplifies them into voltage and current signals suitable for application to the VT and CT inputs of the relay. The phase angle between voltage and current outputs will be adjustable, as also will the phase angles between the individual voltages or currents making up a 3-phase output set. Much greater precision in the setting of the magnitudes and phase angles is possible, compared to traditional test sets. Digital signals to exercise the internal logic elements of the relays may also be provided. The alarm and trip outputs of the relay are connected to digital inputs on the PC so that correct operation of the relay, including accuracy of the relay tripping characteristic, can be monitored and displayed on-screen, saved for inclusion in reports generated later, or printed for an immediate record to present to the client. Optional features may include GPS time synchronising equipment and remote-located amplifiers to facilitate testing of unit protection schemes, and digital I/O for exercising the programmable scheme logic of relays.

The software for test sets is capable of testing the functionality of a wide variety of relays, and conducting a set of tests automatically. Such sets ease the task of the commissioning engineer. The software will normally offer options for testing, ranging from a test carried out at a particular point on the characteristic to complete determination of the tripping characteristic automatically. This feature can be helpful if there is any reason to doubt that the relay is operating correctly with the tripping characteristic specified. Figure E2.6 illustrates a PC-based test set.

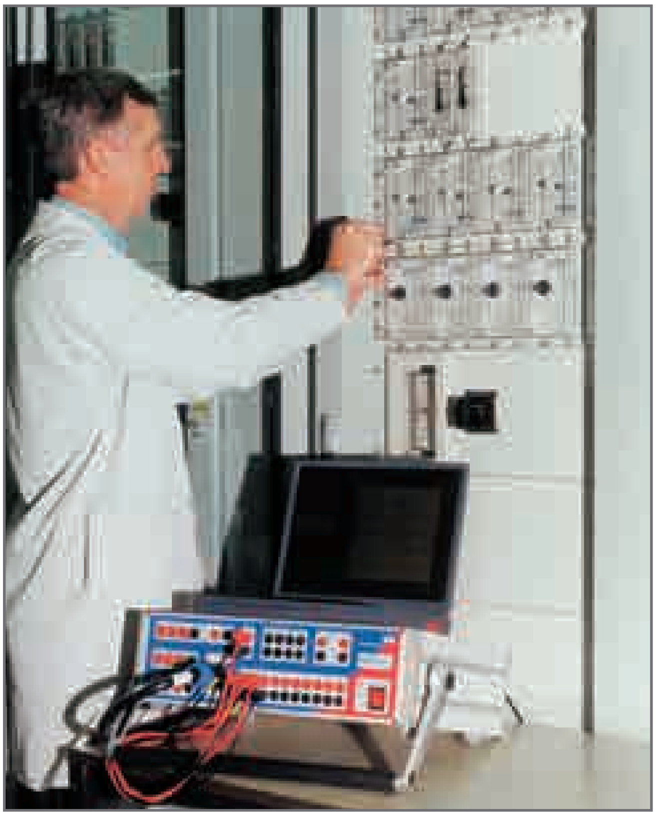

Figure E2.6:
PC-based secondary injection test set

2. Secondary injection test equipment

Traditional test sets use an arrangement of adjustable transformers and reactors to provide control of current and voltage without incurring high power dissipation. Some relays require adjustment of the phase between the injected voltages and currents, and so phase shifting transformers may be used. Figure E2.7 shows the circuit diagram of a traditional test set suitable for overcurrent relay resting, while Figure E2.8 shows the circuit diagram for a test set for directional/ distance relays. Timers are included so that the response time of the relay can be measured.

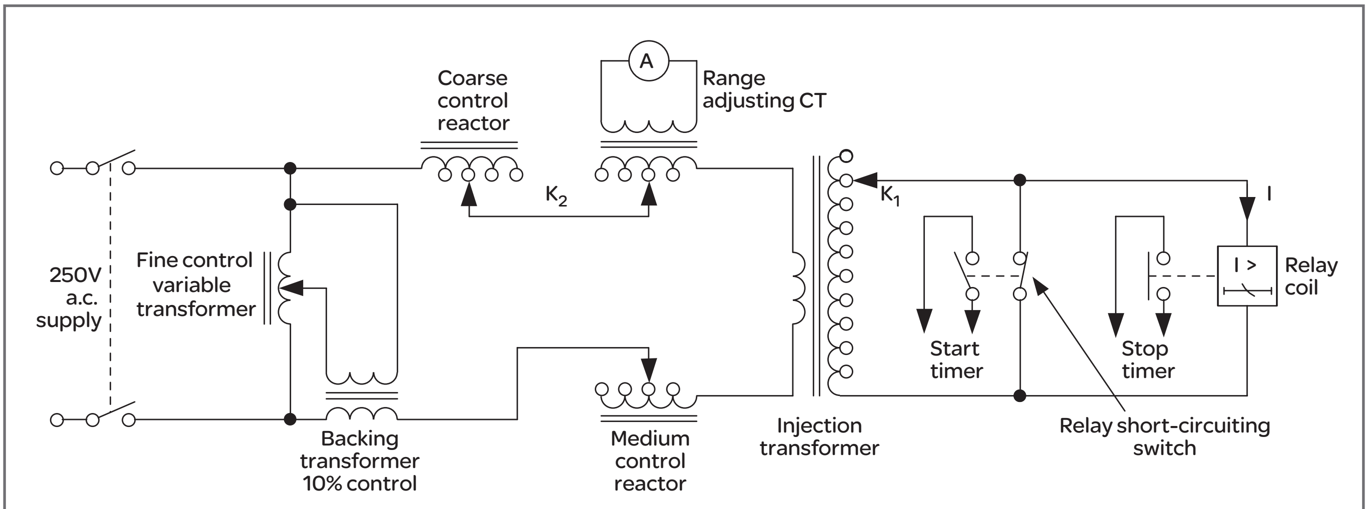

Figure E2.7:
Circuit diagram of traditional test set for overcurrent relays

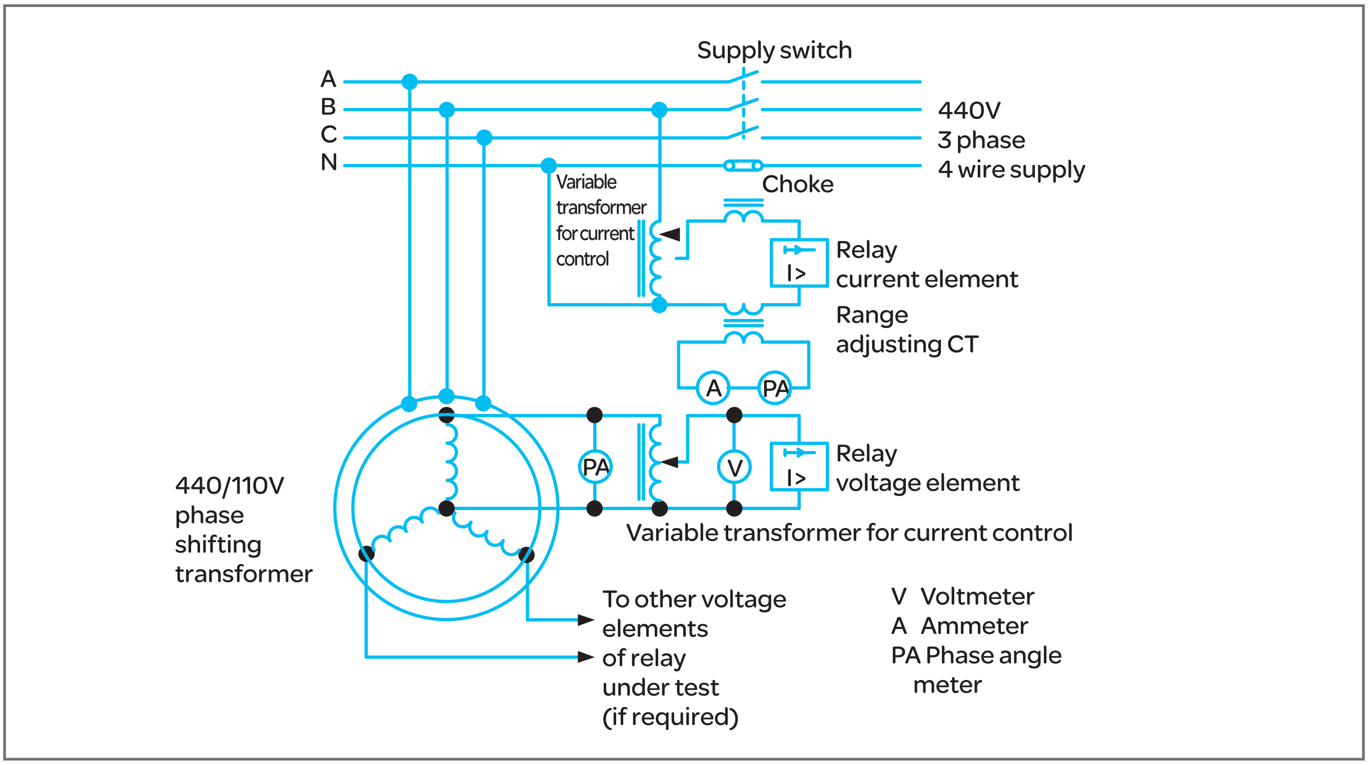

Figure E2.8:
Circuit diagram for traditional test set for directional / distance relays

3. Secondary injection testing

The purpose of secondary injection testing is to check that the protection scheme from the relay input terminals onwards is functioning correctly with the settings specified. This is achieved by applying suitable inputs from a test set to the inputs of the relays and checking if the appropriate alarm/trip signals occur at the relay/control room/CB locations. The extent of testing will be largely determined by the client specification and relay technology used, and may range from a simple check of the relay characteristic at a single point to a complete verification of the tripping characteristics of the scheme, including the response to transient waveforms and harmonics and checking of relay bias characteristics. This may be important when the protection scheme includes transformers or generators.

The testing should include any scheme logic. If the logic is implemented using the programmable scheme logic facilities available with most digital or numerical relays, appropriate digital inputs may need to be applied and outputs monitored (see Section 13). It is clear that a test set can facilitate such tests, leading to a reduced time required for testing.

3.1 Schemes using digital or numerical relay technology

The policy for secondary injection testing varies widely. In some cases, manufacturers recommend, and clients accept, that if a digital or numerical relay passes its' self-test, it can be relied upon to operate at the settings used and that testing can therefore be confined to those parts of the scheme external to the relay. In such cases, secondary injection testing is not required at all. More often, it is required that one element of each relay (usually the simplest) is exercised, using a secondary injection test set, to check that relay operation occurs at the conditions expected, based on the setting of the relay element concerned.

Another alternative is for the complete functionality of each relay to be exercised. This is rarely required with a digital or numerical relay, probably only being carried out in the event of a suspected relay malfunction.

To illustrate the results that can be obtained, Figure E2.9 shows the results obtained by a test set when determining the reach settings of a distance relay using a search technique. Another example is the testing of the power swing blocking element of a distance relay. Figure E2.10 illustrates such a test, based on using discrete impedance points.

This kind of test may not be adequate in all cases, and test equipment may have the ability to generate the waveforms simulating a power swing and apply them to the relay (Figure E2.11).

3.2 Schemes using electromechanical / static relay technology

Schemes using single function electromechanical or static relays will usually require each relay to be exercised. Thus a scheme with distance and back-up overcurrent elements will require a test on each of these functions, thereby taking up

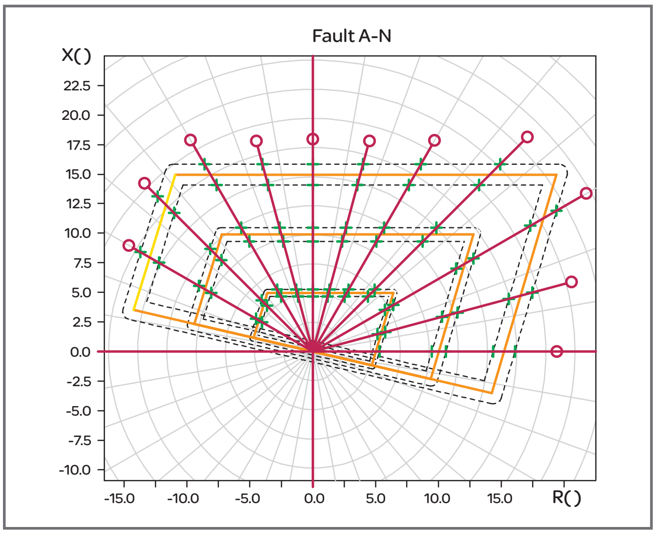

Figure E2.9:
Distance relay zone checking using search technique and tolerance bands

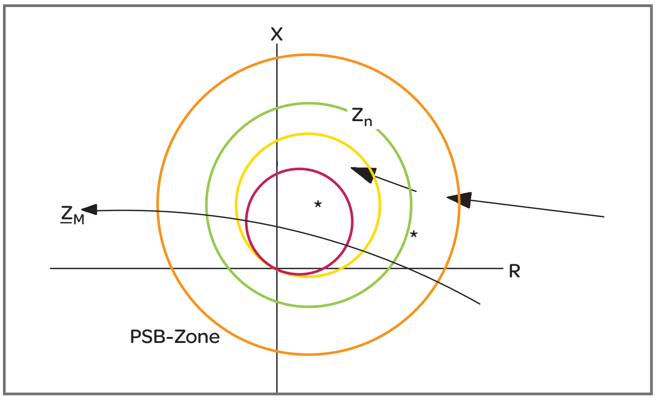

Figure E2.10
Testing of power swing blocking element – discrete points

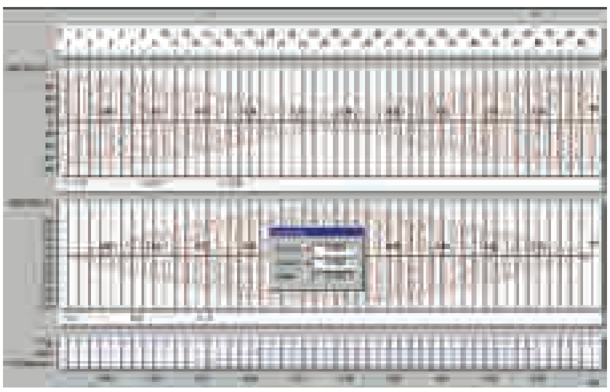

Figure E2.11:
Simulated power swing waveform

3. Secondary injection testing

more time than if a digital or numerical relay is used. Similarly, it may be important to check the relay characteristic over a range of input currents to confirm parameters for an overcurrent relay such as:

a. the minimum current that gives operation at each current setting

b. the maximum current at which resetting takes place

c. the operating time at suitable values of current

d. the time/current curve at two or three points with the time multiplier setting TMS at 1

e. the resetting time at zero current with the TMS at 1

Similar considerations apply to distance and unit protection relays of these technologies.

3.3 Test circuits for secondary injection testing

The test circuits used will depend on the type of relay and test set being used. Unless the test circuits are simple and obvious, the relay commissioning manual will give details of the circuits to be used. Commonly used test circuits can also be found in reference [Ref E2.1: Protection Relay Application Guide, Chapter 23]. When using the circuits in this reference, suitable simplifications can easily be made if digital or numerical relays are being tested, to allow for their built-in measurement capabilities – external ammeters and voltmeters may not be required.

All results should be carefully noted and filed for record purposes. Departures from the expected results must be thoroughly investigated and the cause determined. After rectification of errors, all tests whose results may have been affected (even those that may have given correct results) should be repeated to ensure that the protection scheme has been implemented according to specification.

4. Primary injection testing

This type of test involves the entire circuit; current transformer primary and secondary windings, relay coils, trip and alarm circuits, and all intervening wiring are checked. There is no need to disturb wiring, which obviates the hazard of open-circuiting current transformers, and there is generally no need for any switching in the current transformer or relay circuits. The drawback of such tests is that they are time consuming and expensive to organise. Increasingly, reliance is placed on all wiring and installation diagrams being correct and the installation being carried out as per drawings, and secondary injection testing being completed satisfactorily. Under these circumstances, the primary injection tests may be omitted. However, wiring errors between VTs/CTs and relays, or incorrect polarity of VTs/CTs may not then be discovered until either spurious tripping occurs in service, or more seriously, failure to trip on a fault. This hazard is much reduced where digital/numerical relays are used, since the current and voltage measurement/display facilities that exist in such relays enable checking of relay input values against those from other proven sources. Many connection/wiring errors can be found in this way, and by isolating temporarily the relay trip outputs, unwanted trips can be avoided.

Primary injection testing is, however, the only way to prove correct installation and operation of the whole of a protection scheme. As noted in the previous section, primary injection tests are always carried out after secondary injection tests, to ensure that problems are limited to the VTs and CTs involved, plus associated wiring, all other equipment in the protection scheme having been proven satisfactory from the secondary injection tests.

4.1 Test facilities

An alternator is the most useful source of power for providing the heavy current necessary for primary injection. Unfortunately, it is rarely available, since it requires not only a spare alternator, but also spare busbars capable of being connected to the alternator and circuit under test. Therefore, primary injection is usually carried out by means of a portable injection transformer (Figure E2.12), arranged to operate from the local mains supply and having several low voltage, heavy current windings.

These can be connected in series or parallel according to the current required and the resistance of the primary circuit. Outputs of 10V and 1000A can be obtained. Modern PC-controlled test sets have power amplifiers capable of injecting currents up to about 200A for a single unit, with higher current ratings being possible by using multiple units in parallel.

If the main current transformers are fitted with test windings, these can be used for primary injection instead of the primary winding. The current required for primary injection is then greatly reduced and can usually be obtained using secondary injection test equipment. Unfortunately, test windings are not often provided, because of space limitations in the main current transformer housings or the cost of the windings.

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4. Primary injection testing

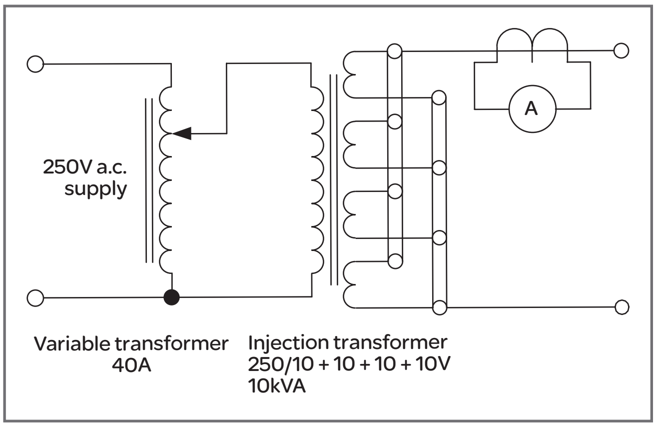

Figure E2.12:
Traditional primary injection test set

4.2 CT ratio check

Current is passed through the primary conductors and measured on the test set ammeter, A_1 in Figure E2.13. The secondary current is measured on the ammeter A_2 or relay display, and the ratio of the value on A_1 to that on A_2 should closely approximate to the ratio marked on the current transformer nameplate.

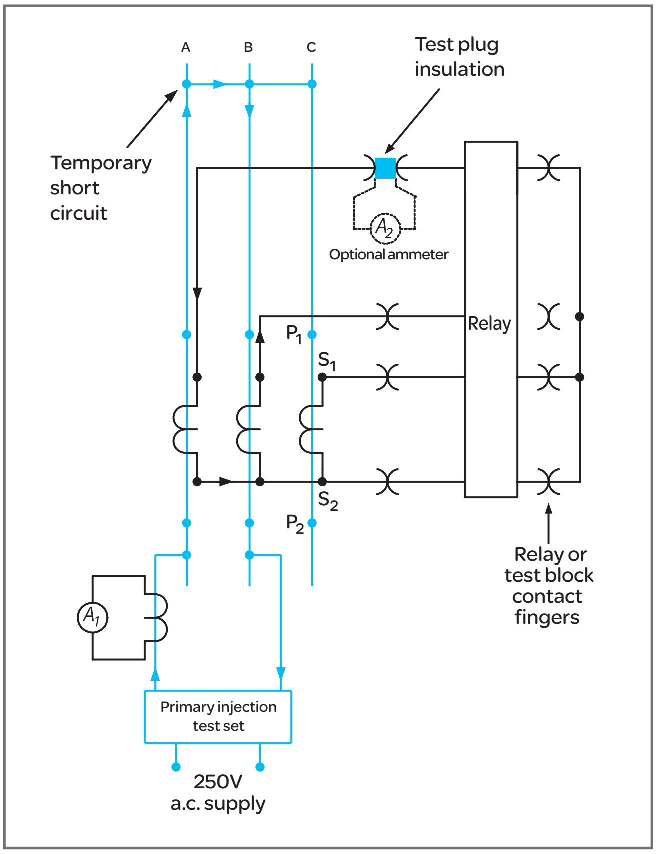

Figure E2.13:
Current transformer ratio check

4.3 CT polarity check

If the equipment includes directional, differential or earth fault relays, the polarity of the main current transformers must be checked. It is not necessary to conduct the test if only overcurrent relays are used.

The circuit for checking the polarity with a single-phase test set is shown in Figure E2.14.

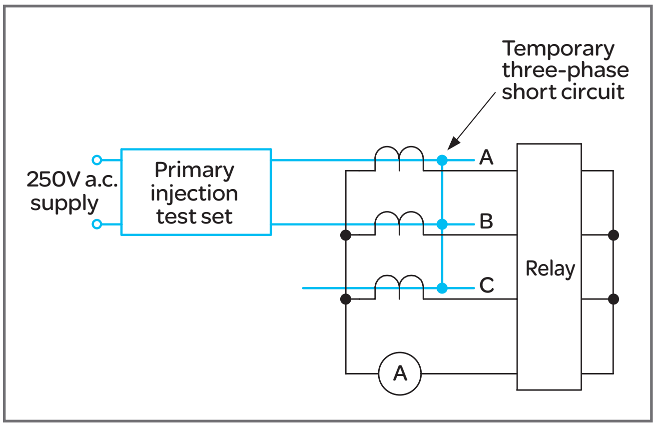

Figure E2.14:
Polarity check on main current transformers

A short circuit is placed across the phases of the primary circuit on one side of the current transformers while single-phase injection is carried out on the other side. The ammeter connected in the residual circuit, or relay display, will give a reading of a few milliamperes with rated current injected if the current transformers are of correct polarity. A reading proportional to twice the primary current will be obtained if they are of wrong polarity. Because of this, a high-range ammeter should be used initially, for example one giving full-scale deflection for twice the rated secondary current. If an electromechanical earth-fault relay with a low setting is also connected in the residual circuit, it is advisable to temporarily short-circuit its operating coil during the test, to prevent possible overheating. The single-phase injection should be carried out for each pair of phases.

4.4 Primary injection testing of relay elements

As with secondary injection testing, the tests to be carried out will be those specified by the client, and/or those detailed in the relay commissioning manual. Digital and numerical relays usually require far fewer tests to prove correct operation, and these may be restricted to observations of current and voltage on the relay display under normal load conditions.

5. Testing of protection scheme logic

Protection schemes often involve the use of logic to determine the conditions under which designated circuit breakers should be tripped. Simple examples of such logic can be found in Chapters [C1: Overcurrent Protection for Phase and Earth Faults] and [D1: Auto-Reclosing]. Traditionally, this logic was implemented by means of discrete relays, separate from the relays used for protection. Such implementations would occur where electromechanical or static relay technology is used. However, digital and numerical relays normally include programmable logic as part of the software within the relay, together with associated digital I/O. This facility (commonly referred to as Programmable Scheme Logic, or PSL) offers important advantages to the user, by saving space and permitting modifications to the protection scheme logic through software if the protection scheme requirements change with time. Changes to the logic are carried out using software hosted on a PC (or similar computer) and downloaded to the relay. Use of languages defined in IEC 61131, such as ladder logic or Boolean algebra is common for such software, and is readily understood by Protection Engineers. Further, there are several commonly encountered protection functions that manufacturers may supply with relays as one or more 'default' logic schemes.

Because software is used, it is essential to carefully test the logic during commissioning to ensure correct operation. The only exception to this may be if the relevant 'default' scheme is used. Such logic schemes will have been proven during relay type testing, and so there is no need for proving tests during commissioning. However, where a customer generates the scheme logic, it is necessary to ensure that the commissioning tests conducted are adequate to prove the functionality of the scheme in all respects. A specific test procedure should be prepared, and this procedure should include:

a. checking of the scheme logic specification and diagrams to ensure that the objectives of the logic are achieved

b. testing of the logic to ensure that the functionality of the scheme is proven

c. testing of the logic, as required, to ensure that no output occurs for the relevant input signal combinations

The degree of testing of the logic will largely depend on the criticality of the application and complexity of the logic. The responsibility for ensuring that a suitable test procedure is produced for logic schemes other than the 'default' one(s) supplied lies with the specifier of the logic. Relay manufacturers cannot be expected to take responsibility for the correct operation of logic schemes that they have not designed and supplied.

6. Tripping and alarm annunciation tests

If primary and/or secondary injection tests are not carried out, the tripping and alarm circuits will not have been checked. Even where such checks have been carried out, CB trip coils and/or Control Room alarm circuits may have been isolated. In such cases, it is essential that all of the tripping and alarm circuits are checked.

This is done by closing the protection relay contacts manually and checking that:

a. the correct circuit breakers are tripped

b. the alarm circuits are energised

c. the correct flag indications are given

d. there is no maloperation of other apparatus that may be connected to the same master trip relay or circuit breaker.

Many designs of withdrawable circuit breaker can be operated while in the maintenance position, so that substation operation can continue unaffected except for the circuit controlled by the circuit breaker involved. In other cases, isolators can be used to avoid the need for busbar de-energisation if the circuit involved is not ready for energisation.

E2

7. Periodic maintenance tests

Periodic testing is necessary to ensure that a protection scheme continues to provide satisfactory performance for many years after installation. All equipment is subject to gradual degradation with time, and regular testing is intended to identify the equipment concerned so that remedial action can be taken before scheme maloperation occurs. However, due care should be taken in this task, otherwise faults may be introduced as a direct result of the remedial work.

The clearance of a fault on the system is correct only if the number of circuit breakers opened is the minimum necessary to remove the fault. A small proportion of faults are incorrectly cleared, the main reasons being:

a. limitations in protection scheme design

b. faulty relays

c. defects in the secondary wiring

d. incorrect connections

e. incorrect settings

f. known application shortcomings accepted as improbable occurrences

g. pilot wire faults due to previous unrevealed damage to a pilot cable

h. various other causes, such as switching errors, testing errors, and relay operation due to mechanical shock

The self-checking facilities of numerical relays assist in minimising failures due to faulty relays. Defects in secondary wiring and incorrect connections are virtually eliminated if proper commissioning after scheme installation/alteration is carried out. The possibility of incorrect settings is minimised by regular reviews of relay settings. Network fault levels change over time, and hence setting calculations may need to be revised. Switching and testing errors are minimised by adequate training of personnel, use of proven software, and well-designed systematic working procedures. All of these can be said to be within the control of the user.

The remaining three causes are not controllable, while two of these three are unavoidable – engineering is not science and there will always be situations that a protection relay cannot reasonably be expected to cover at an affordable cost.

7.1 Frequency of inspection and testing

Although protection equipment should be in sound condition when first put into service, problems can develop unchecked and unrevealed because of its infrequent operation. With digital and numerical relays, the in-built self-testing routines can be expected to reveal and annunciate most faults, but this does not cover any other components that, together, comprise the protection scheme. Regular inspection and testing of a protection scheme is therefore required. In practice, the frequency of testing may be limited by lack of staff or by the operating conditions on the power system.

It is desirable to carry out maintenance on protection equipment at times when the associated power apparatus is out of service. This is facilitated by co-operation between the maintenance staff concerned and the network operations control centre. Maintenance tests may sometimes have to be made when the protected circuit is on load. The particular equipment to be tested should be taken out of commission and adequate back-up protection provided for the duration of the tests. Such back-up protection may not be fully discriminative, but should be sufficient to clear any fault on the apparatus whose main protection is temporarily out of service.

Maintenance is assisted by the displays of measured quantities provided on digital and numerical relays. Incorrect display of a quantity is a clear indication that something is wrong, either in the relay itself or the input circuits.

7.2 Maintenance tests

Primary injection tests are normally only conducted out during initial commissioning. If scheme maloperation has occurred and the protection relays involved are suspect, or alterations have been made involving the wiring to the relays from the VTs/CTs, the primary injection tests may have to be repeated.

Secondary injection tests may be carried out at suitable intervals to check relay performance, and, if possible, the relay should be allowed to trip the circuit breakers involved. The interval between tests will depend upon the criticality of the circuit involved, the availability of the circuit for testing and the technology of the relays used. Secondary injection testing is only necessary on the selected relay setting and the results should be checked against those obtained during the initial commissioning of the equipment.

It is better not to interfere with relay contacts at all unless they are obviously corroded. The performance of the contacts is fully checked when the relay is actuated.

Insulation tests should also be carried out on the relay wiring to earth and between circuits, using a 1000V tester. These tests are necessary to detect any deterioration in the insulation resistance.

8. Protection scheme design for maintenance

If the following principles are adhered to as far as possible, the danger of back-feeds is lessened and fault investigation is made easier:

a. test blocks should be used, to enable a test plug to be used, and a defective unit to be replaced quickly without interrupting service

b. circuits should be kept as electrically separate as possible, and the use of common wires should be avoided, except where these are essential to the correct functioning of the circuits

c. each group of circuits which is electrically separate from other circuits should be earthed through an independent earth link

d. where a common voltage transformer or d.c. supply is used for feeding several circuits, each circuit should be fed through separate links or fuses. Withdrawal of these should completely isolate the circuit concerned

e. power supplies to protection schemes should be segregated from those supplying other equipment and provided with fully discriminative circuit protection

f. a single auxiliary switch should not be used for interrupting or closing more than one circuit

g. terminations in relay panels require good access, as these may have to be altered if extensions are made. Panels are provided with special test facilities, so that no connections need be disturbed during routine testing

h. junction boxes should be of adequate size and, if outdoors, must be made waterproof

i. all wiring should be ferruled for identification and phase-coloured

j. electromechanical relays should have high operating and restraint torques and high contact pressures; jewel bearings should be shrouded to exclude dust and the use of very thin wire for coils and connections should be avoided. Dust-tight cases with an efficient breather are essential on these types of electromechanical element

k. static, digital and numerical relays should have test facilities accessible from the front to assist in fault finding. The relay manual should clearly detail the expected results at each test point when healthy

9. References

[E2.1] Protective Relays Application Guide
3rd edition, 1987.

AX1

Terminology

Network Protection & Automation Guide

Life Is On | Schneider Electric

Appendix

AX1

Terminology

The introduction of computer technology means that the Protection Engineer must now be familiar with a range of technical terms in this field, in addition to the terms long associated with Protection and Control. Below is a list of terms and their meanings that are now commonly encountered in the Protection and Control field.

A

AC	Alternating Current.
ACB	Air Circuit Breaker.
Access point	Represent a network interface of a physical device connected to one Communication Sub Network.
Accuracy	The accuracy of a transducer is defined by the limits of intrinsic error and by the limits of variations.
Accuracy class	A number used to indicate the accuracy range of a measurement transducer, according to a defined standard.
ACSI	Abstract Communication Service interface (acc. Communication standards like IEC 61850).
Active power transducer	A transducer used for the measurement of active electrical power.
ADC	Analogue to Digital Converter.
A/D conversion	The process of converting an analogue signal into an equivalent digital one, involving the use of an analogue to digital converter.
Adjustment	The operation intended to bring a transducer into a state of performance suitable for its use.
AGC	Automatic Gain Control.
AGR	Nuclear Advanced Gas Cooled Reactor.
AI	Analogue Input.
AIS	Air Insulated Switchgear.
Alarm	An alarm is any event (see below) tagged as an alarm during the configuration phase.
All-or-nothing relay	An electrical relay which is intended to be energised by a quantity, whose value is either higher than that at which it picks up or lower than that at which it drops out.
ANSI	American National Standards Institute (standards).
Anti-pumping device	A feature incorporated in a Circuit Breaker or reclosing scheme to prevent repeated operation where the closing impulse lasts longer than the sum of the relay and CB operating times.
AO	Analogue Output.
AR	Auto Reclose: A function associated with CB, implemented to carry out reclosure automatically to try to clear a transient fault.
ARBITER	Proprietary protocol for time synchronisation from ARBITER Systems, Inc. Paso Robles, California USA.
Arcing time	The time between instant of separation of the CB contacts and the instant of arc extinction.
Auto-transformer	A power transformer that does not provide galvanic isolation between primary and secondary windings.
AUX	Auxiliary.
Auxiliary circuit	A circuit which is usually energised by the auxiliary supply but is sometimes energised by the measured quantity.
Auxiliary relay	An all-or-nothing relay energised via another relay, for example a measuring relay, for the purpose of providing higher rated contacts, or introducing a time delay, or providing multiple outputs from a single input.
Auxiliary supply	An a.c. or d.c. electrical supply other than the measured quantity which is necessary for the correct operation of the transducer.
AVR	Automatic Voltage Regulator.

B

Back-up protection A protection system intended to supplement the main protection in case the latter should be ineffective, or to deal with faults in those parts of the power system that are not readily included in the operating zones of the main protection.

Bay Set of LV, MV, or HV plant and devices, usually controlled by a bay computer.

BC Bay Computer: Computer dedicated to the control of one or several bays within a substation.

BCD Binary Coded Decimal.

BCP Bay Control Point: A local keypad at bay level to control the elements of a single bay.

Biased relay A relay in which the characteristics are modified by the introduction of some quantity other than the actuating quantity, and which is usually in opposition to the actuating quantity.

Bias current The current used as a bias quantity in a biased relay.

BIOS Basic Input/Output System (of a computer or microprocessor).

Broadcast communication Communication message from one source to all connected partners in a communication network.

Booster transformer A current transformer whose primary winding is in series with the catenary and secondary winding in the return conductor of a classically-fed a.c. overhead electrified railway. Used at intervals to ensure that stray traction return currents, with their potential to cause interference in nearby communication circuits, are minimised.

BT Booster Transformer.

Burden The loading imposed by the circuits of the relay on the energising power source or sources, expressed as the product of voltage and current (volt-amperes, or watts if d.c.) for a given condition, which may be either at 'setting' or at rated current or voltage. The rated output of measuring transformers, expressed in VA, is always at rated current or voltage and it is important, in assessing the burden imposed by a relay, to ensure that the value of burden at rated current is used.

C

C Capacitance.

CAD Computer Aided Design.

Calibration The set of operations which establish, under specified conditions, the relationship between values indicated by a transducer and the corresponding values of a quantity realised by a reference standard. (This should not be confused with 'adjustment', q.v.).

CB Circuit Breaker.

CBC Compact Bay Controller: Small capacity bay computer for Medium Voltage applications.

CBCT Core Balance Current Transformer.

CCR Central Control Room.

CDC Common Data Class (data model element in IEC 61850).

C

CDM Conceptual Data Modelling is an activity whose aims are:

- to define objects and links and naming conventions for their identifications
- to guarantee interoperability between subsystems
- to define standard exchange formats between system configurator and subsystem configurator.

CET Central European Time.

Characteristic angle The angle between the vectors representing two of the energising quantities applied to a relay and used for the declaration of the performance of the relay.

Characteristic curve The curve showing the operating value of the characteristic quantity corresponding to various values or combinations of the energising quantities.

Characteristic impedance ratio (C.I.R.) The maximum value of the System Impedance Ratio up to which the relay performance remains within the prescribed limits of accuracy.

Characteristic quantity A quantity, the value of which characterises the operation of the relay, for example, current for an overcurrent relay, voltage for a voltage relay, phase angle for a directional relay, time for an independent time delay relay, impedance for an impedance relay.

Check protection system An auxiliary protection system intended to prevent tripping due to inadvertent operation of the main protection system.

CHP Combined Heat and Power.

CID Configured IED Description (IEC 61850 engineering file format based on XML/SCL).

Circuit insulation voltage The highest circuit voltage to earth on which a circuit of a transducer may be used and which determines its voltage test.

Class index The number which designates the accuracy class.

Client Entity that requests a service from a server in a communication network.

Closing impulse time The time during which a closing impulse is given to the CB.

Closing time The time for a CB to close, from the time of energisation of the closing circuit to making of the CB contacts.

Communication service Service to exchange information between two communication partners with well-defined procedures and data models.

Compliance voltage (accuracy limiting output voltage) For current output signals only, the output voltage up to which the transducer meets its accuracy specification.

Conjunctive test A test of a protection system including all relevant components and ancillary equipment appropriately interconnected. The test may be parametric or specific.

Control services A set of communication services used by a client to act on the process or on a IED.

Conversion coefficient The relationship of the value of the measurand to the corresponding value of the output.

Core balance current transformer A ring-type Current Transformer in which all primary conductors are passed through the aperture of the CBCT. Hence the secondary current is proportional only to any imbalance in current. Used for sensitive earth-fault protection.

Counting relay A relay that counts the number of times it is energised and actuates an output after a desired count has been reached.

CSV Character (or Comma) Separated Values format: A widely used format for the exchange of data between different software, in which the individual data items are separated by a known character – usually a comma.

CT Current Transformer.

Current transducer A transducer used for the measurement of a.c. current.

C

CVT Capacitor Voltage Transformer: A voltage transformer that uses capacitors to obtain a voltage divider effect. Used at EHV voltages instead of an electromagnetic VT for size/cost reasons.

D

DA Data Attribute (data model element in IEC 61850).

DAC Digital to Analogue Converter.

DAR Delayed Auto-Reclose.

DAT Digital Audio Tape.

Data model Data structure of an IED used to communicate with other communication partners.

Data set Ordered group of DO (Data Object) and DA (Data Attribute) references.

DBMS Data Base Management System.

DCF 77 LF transmitter located at Mainflingen, Germany, broadcasting a time signal on a 77.5 kHz frequency.

DCP Device Control Point: Local keypad on device level to control the switchgear, often combined with local/remote switch.

DCS Distributed Control System.

Dead time (auto- reclose) The time between the fault arc being extinguished and the CB contacts re- making.

De-ionisation time (auto-reclose) The time required for dispersion of ionised air after a fault is cleared so that the arc will not re-strike on re-energisation.

Delayed auto-reclose An auto-reclosing scheme which has a time delay in excess of the minimum required for successful operation.

Dependent time measuring relay A measuring relay for which times depend, in a specified manner, on the value of the characteristic quantity.

DER Distributed Energy Resource.

DFT Discrete Fourier Transformation.

DG Distributed Generation.

Digital signal processor A microprocessor optimised in both hardware architecture and software instruction set for the processing of analogue signals digitally, through use of the DFT and similar techniques.

Digital signal processing A technique for the processing of digital signals by various filter algorithms to obtain some desired characteristics in the output. The input signal to the processing algorithm is usually the digital representation of an analogue signal, obtained by A/D conversion.

Directional relay A protection relay in which the tripping decision is dependent in part upon the direction in which the measured quantity is flowing.

Discrimination The ability of a protection system to distinguish between power system conditions for which it is intended to operate and those for which it is not intended to operate.

Distortion factor The ratio of the r.m.s. value of the harmonic content to the r.m.s. value of the non- sinusoidal quantity.

D

DNP, DNP3 Distributed Network Protocol: A proprietary communication protocol used on secondary networks between HMI, substation computers or bay computers and protective devices.

DO Data Object (data model element in IEC 61850).

DOL Direct-on-Line.

Direct-on-line A method of motor starting, in which full line voltage is applied to a stationary motor.

Drop-out (or drop-off) A relay drops out when it moves from the energised position to the un-energised position.

Drop-out /pick-up ratio The ratio of the limiting values of the characteristic quantity at which the relay resets and operates. This value is sometimes called the differential of the relay.

DSP Digital Signal Processor, Digital Signal Processing.

DT Definite Time.

E

Earth fault protection system A protection system which is designed to respond only to faults to earth.

Earthing transformer A three-phase transformer intended essentially to provide a neutral point to a power system for the purpose of earthing.

Effective range The range of values of the characteristic quantity or quantities, or of the energising quantities to which the relay will respond and satisfy the requirements concerning it, in particular those concerning precision.

Effective setting The 'setting' of a protection system including the effects of current transformers. The effective setting can be expressed in terms of primary current or secondary current from the current transformers and is so designated as appropriate.

Electrical relay A device designed to produce sudden predetermined changes in one or more electrical circuits after the appearance of certain conditions in the electrical circuit or circuits controlling it.

NOTE: The term 'relay' includes all the ancillary equipment calibrated with the device.

Electromechanical relay An electrical relay in which the designed response is developed by the relative movement of mechanical elements under the action of a current in the input circuit.

EMC Electro-Magnetic Compatibility: Immunity against electromagnetic interferences.

Embedded generation Generation that is connected to a distribution system (possibly at LV instead of HV) and hence poses particular problems in respect of electrical protection.

E.m.f. Electro-Motive Force (or voltage).

Energising quantity The electrical quantity, either current or voltage, which along or in combination with other energising quantities, must be applied to the relay to cause it to function.

EPROM Electrically Programmable Read Only Memory.

Error (of a transducer) The actual value of the output minus the intended value of the output, expressed algebraically.

Ethernet Most used networking technology for LAN.

Event An event is any information acquired or produced by the digital control system.

F

FACTS	Flexible Alternative Current Transmission System.
FAT	Factory Acceptance Test: Validation procedures witnessed by the customer at the factory.
Fault passage indicator	A sensor that detects the passage of current in excess of a set value (i.e. current due to a fault) at the location of the sensor. Hence, it indicates that the fault lies downstream of the sensor.
FBD	Functional Block Diagram: One of the IEC 61131-3 programming languages.
FC	Functional constraint (data model element in IEC 61850).
Fiducial value	A clearly specified value to which reference is made in order to specify the accuracy of a transducer. (For transducers, the fiducial value is the span, except for transducers having a reversible and symmetrical output, when the fiducial value may be either the span or half the span as specified by the manufacturer. It is still common practice, however, for statements of accuracy for frequency transducers to refer to 'percent of centre-scale frequency' and, for phase angle transducers, to an error in electrical degrees).
FLS	Fast Load Shedding.
FN	Functional Naming is the reflection of the functional application view (like in a substation) in the naming of the structural elements of an IED data model in IEC 61850.
FPI	Fault Passage Indicator.
fPN	Flexible Product Naming in IEC 61850 to describe the capability of an IED to allow restructuring of the device data model.
Frequency transducer	A transducer used for the measurement the frequency of an a.c. electrical quantity.
Full duplex communication	A communications system in which data can travel simultaneously in both directions.

G

Gateway	The Gateway is a computer which provides interfaces between the local computer system and one or several SCADA (or RCC) systems.
GBit	Giga-Bit (transfer rate for data communication).
GCB	GOOSE Control Block (GOOSE = Generic Object Oriented Substation Event) used to configure the subscription of a GOOSE in the IEC61850 communication network.
GIS	Gas Insulated Switchgear (usually SF6).
Global positioning system	A system used for locating objects on Earth precisely, using a system of satellites in geostationary orbit in space. Used by some numerical relays to obtain accurate time information.
GMT	Greenwich Mean Time.
GOOSE	Generic Object Oriented Substation Event (used for fast data transfer on low communication layer acc. IEC 61850).
GPS	Global Positioning System.
GTO	Gate Turn-off Thyristor.

H

Half-duplex communication
A communications system in which data can travel in both directions, but only in one direction at a time.

High-speed reclosing
A reclosing scheme where re-closure is carried out without any time delay other than that required for de-ionisation, etc.

HMI
Human Machine Interface: The means by which a human inputs data to and receives data from a computer-based system. Usually takes the form of a Personal Computer (PC) (desktop or portable) with keyboard, screen and pointing device.

HRC
High Rupturing Capacity (applicable to fuses).

HSR
a) High Speed Reclosing

b) High availability Seamless Redundancy protocol (see IEC 62439-3).

HV
High Voltage.

HVDC
High Voltage Direct Current.

I

I
Current.

ICCP
Term used for IEC 60870-6-603 protocol.

ICD
IED Capability Description (IEC 61850 engineering file format based on XML/SCL).

ICT
Interposing Current Transformer (software implemented).

I.D.M.T.
Inverse Definite Minimum Time.

IEC
International Electro Technical Commission (standards).

IEC 60870-5-101/103/104
Set of conventional communication protocols used for automation sytems named as "Telecontrol equipment and systems: Transmission protocols for the informative interface of protection equipment" (T101 for network control level, T103 for substation control level, T104 for mapping of T101 over Ethernet).

IEC 61850
International standard for the communication networks and systems for power utility automation.

IED
Intelligent Electronic Device: Equipment containing a microprocessor and software used to implement one or more functions in relation to an item of electrical equipment (e.g. a bay controller, remote SCADA interface/protocol converter). A microprocessor-based numerical relay is also an IED. IED is a generic term used to describe any microprocessor-based equipment, apart from a computer.

IEEE
Institute of Electrical and Electronics Engineers.

IEEE 1588
Also named PTP for Precision Time Protocol.

IEEE 1815
IEEE name for DNP3.

IET
IED Configuration Tool (acc. IEC 61850).

IID
Instantiated IED Description (IEC 61850 engineering file format based on XML/SCL).

IGBT
Insulated Gate Bipolar Transistor.

Independent time measuring relay A measuring relay, the specified time for which can be considered as being independent, within specified limits, of the value of the characteristic quantity.

Influence quantity A quantity which is not the subject of the measurement but which influences the value of the output signal for a constant value of the measurand.

Input quantity The quantity, or one of the quantities, which constitute the signals received by the transducer from the measured system.

Instantaneous relay A relay that operates and resets with no intentional time delay.

NOTE: All relays require some time to operate; it is possible, within the above definition, to discuss the operating time characteristics of an instantaneous relay.

Insulated gate bipolar transistor A special design of transistor that is suitable for handling high voltages and currents (relative to an ordinary transistor). Frequently used in static power control equipment (inverters, controlled rectifiers, etc) due to the flexibility of control of the output.

Interchangeability Possibility to replace one intelligent electronic device by another one, without additional modifications of the equipment around it. This possibility is normally only given when the same type of IED or system component from the same vendor on the same product platform is used as a replacement.

Interoperability Ability of two or more intelligent electronic devices from the same vendor, or different vendors, to exchange information and to use that information for correct co-operation.

Intrinsic error An error determined when the transducer is under reference conditions.

Inverse time delay relay A dependent time delay relay having an operating time which is an inverse function of the electrical characteristic quantity.

Inverse time relay with definite minimum time (I.D.M.T.) An inverse time relay having an operating time that tends towards a minimum value with increasing values of the electrical characteristic quantity.

IRIG-B An international standard for time synchronisation.

ISO International Standards Organisation.

IP Internet Protocol.

I/O Input/Output.

K

K-bus (K-bus courier)	Term used for the Courier protocol on K-Bus interface.
Knee-point e.m.f.	That sinusoidal e.m.f. applied to the secondary terminals of a current transformer, which, when increased by 10%, causes the exciting current to increase by 50%.

L

L	Inductance.
LAN	Local Area Network.
LCD	Liquid Crystal Display.
LD	a) Ladder Diagram. One of the IEC 61131-3 programming languages b) Logical Device (data model element in IEC 61850).
LDC	Line Drop Compensator.
LED	Light Emitting Diode.
Limiting value of the output current	The upper limit of output current which cannot, by design, be exceeded under any conditions.
LN	Logical Node (data model element in IEC 61850).
Local control mode	When set for a given control point it means that the commands can be issued from this point.
Lock-out (auto-reclose)	Prevention of a CB reclosing after tripping.
Long-term stability	The stability over a period of one year.
Low-speed auto-reclose	See Delayed Auto-Reclose.
LV	Low Voltage.

M

Main protection	The protection system which is normally expected to operate in response to a fault in the protected zone.
Maximum permissible values of the input current and voltage	Values of current and voltage assigned by the manufacturer which the transducer will withstand indefinitely without damage.
MCB	Miniature Circuit Breaker.
MCCB	Moulded Case Circuit Breaker.
Mean-sensing transducer	A transducer which actually measures the mean (average) value of the input waveform but which is adjusted to give an output corresponding to the r.m.s. value of the input when that input is sinusoidal.
Measurand	A quantity subjected to measurement.
Measuring element	A unit or module of a transducer which converts the measurand, or part of the measurand, into a corresponding signal.
Measuring range	That part of the span where the performance complies with the accuracy requirements.
Measuring relay	An electrical relay intended to switch when its characteristic quantity, under specified conditions and with a specified accuracy, attains its operating value.

M

Metering (non-tariff)	Values computed depending on the values of digital or analogue inputs during variable periods.
Metering (tariff)	Energy values computed from digital and/ or analogue inputs during variable periods and dedicated to energy measurement for billing (tariff) purposes.
MICS	Model Implementation Conformance Statement (IEC 61850 engineering file).
Mid point sectioning substation (MPSS)	A substation located at the electrical interface of two sections of electrified railway. It contains provision for the coupling of the sections electrically in the event of loss of supply to one section.
MMS	Manufacturing Messaging Specification (used acc. IEC 61850 as interface between TCP/IP and the application layer).
ModBus	Proprietary communication protocol used on secondary networks between HMI, substation computers or bay computers and protective devices.
MPSS	Mid Point Sectioning Substation (for electrified railways).
MTA	Maximum Torque Angle.
Multicast communication	Communication message from one source to a group of selected partners in a communication network.
Multi-element transducer	A transducer having two or more measuring elements. The signals from the individual elements are combined to produce an output signal corresponding to the measurand.
Multi-section transducer	A transducer having two or more independent measuring circuits for one or more functions.
Multi-shot reclosing	A reclosing scheme that permits more than one reclosing operation of a CB after a fault occurs before lock-out occurs.
MV	Medium Voltage.

N

N/C	Normally Closed.
N/O	Normally Open.
Nominal range of use	A specified range of values which it is intended that an influence quantity can assume without the output signal of the transducer changing by amounts in excess of those specified.
Notching relay	A relay which switches in response to a specific number of applied impulses.
NPS	Negative Phase Sequence.
NS	Neutral Section (electrified railways).
Numerical relay	A protection relay which utilises a Digital Signal Processor to execute the protection algorithms in software.
NVD	Neutral Voltage Displacement (protection).

O

OCB	Oil Circuit Breaker.
Off-load tap changer	A tap changer that is not designed for operation while the transformer is supplying load.
OHL	Overhead Line
OLTC	On Load Tap Changer.
On load tap changer	A tap changer that can be operated while the transformer is supplying load.
Opening time	The time between energisation of a CB trip coil and the instant of contact parting.
Operating current (relay)	The current at which a relay will pick up.
Operating time (CB)	The time between energisation of a CB trip coil and arc extinction.
Operating time (relay)	With a relay de-energised and in its initial condition, the time which elapses between the application of a characteristic quantity and the instant when the relay operates.
Operating time characteristic	The curve depicting the relationship between different values of the characteristic quantity applied to a relay and the corresponding values of operating time.
Operating value	The limiting value of the characteristic quantity at which the relay actually operates.
OPGW	Optical Ground Wire: A ground wire that includes optical fibres to provide a communications link.
OSI 7-layer model	The Open Systems Interconnection 7-layer model is a model developed by ISO for modelling of a communications network.
Output common mode interference voltage	An unwanted alternating voltage which exists between each of the output terminals and a reference point.
Output current (of a transducer)	The current produced by the transducer which is an analogue function of the measurand.
Output load	The total effective resistance of the circuits and apparatus connected externally across the output terminals.
Output power (of a transducer)	The power available at the transducer output terminals.
Output series mode interference voltage	An unwanted alternating voltage appearing in series between the output terminals and the load.
Output signal	An analogue or digital representation of the measurand.
Output span (span)	The algebraic difference between the lower and upper nominal values of the output signal.
Overcurrent relay	A protection relay whose tripping decision is related to the degree by which the measured current exceeds a set value.
Overshoot time	The overshoot time is the difference between the operating time of the relay at a specified value of the input energising quantity and the maximum duration of the value of input energising quantity which, when suddenly reduced to a specific value below the operating level, is insufficient to cause operation.

Parametric conjunctive test	A conjunctive test that ascertains the range of values of each parameter for which the test meets specific performance requirements.
PCB	Printed Circuit Board.
PCC	Point of Common Coupling.
PD	Physical Device (data model element in IEC 61850).
PED	Power Electronic Device.
Phase angle transducer	A transducer used for the measurement of the phase angle between two a.c. electrical quantities having the same frequency.
Pick-up	A relay is said to 'pick-up' when it changes from the de-energised position to the energised position.
PICS	Protocol Implementation Conformance Statement (IEC 61850 engineering file).
Pilot channel	A means of interconnection between relaying points for the purpose of protection.
PIXIT	Protocol Implementation eXtra Information for Testing (IEC 61850 engineering file).
PLC	Programmable Logic Controller: A specialised computer for implementing control sequences using software.
PLCC	Power Line Carrier Communication.
PN	Product Naming is the fixed or default data model of the IED reflecting the complete hierarchy/ structure of the functions inside an IED in IEC 61850.
Point of common coupling	The interface between an in-plant network containing embedded generation and the utility distribution network to which the in-plant network is connected.
POW	Point-on-Wave: Point-on-Wave switching is the process to control the moment of switching to minimise the effects (inrush currents, overvoltages).
Power electronic device	An electronic device (e.g. thyristor or IGBT) or assembly of such devices (e.g. inverter). Typically used in a power transmission system to provide smooth control of output of an item of plant.
Power factor	The factor by which it is necessary to multiply the product of the voltage and current to obtain the active power.
Power line carrier communication	A means of transmitting information over a power transmission line by using a carrier frequency superimposed on the normal power frequency.
PPS	Positive Phase Sequence.
Protected zone	The portion of a power system protected by a given protection system or a part of that protection system.
Protection equipment	The apparatus, including protection relays, transformers and ancillary equipment, for use in a protection system.
Protection relay	A relay designed to initiate disconnection of a part of an electrical installation or to operate a warning signal, in the case of a fault or other abnormal condition in the installation. A protection relay may include more than one electrical element and accessories.
Protection scheme	The co-ordinated arrangements for the protection of one or more elements of a power system. A protection scheme may comprise several protection systems.
Protection system	A combination of protection equipment designed to secure, under predetermined conditions, usually abnormal, the disconnection of an element of a power system, or to give an alarm signal, or both.
Protocol	A set of rules that define the method in which a function is carried out – commonly used in respect of communications links, where it defines the hardware and software features necessary for successful communication between devices.

P

PRP Parallel Redundancy Protocol (see IEC 62439-3).

PSM Plug Setting Multiple: A term used in conjunction with electromechanical relays, denoting the ratio of the fault current to the current setting of the relay.

PSTN Public Switched Telephone Network.

PT100 Platinum resistance temperature probe.

R

R Resistance.

R.m.s. sensing transducer A transducer specifically designed to respond to the true r.m.s. value of the input and which is characterised by the manufacturer for use on a specified range of waveforms.

Ratio correction A feature of digital/numerical relays that enables compensation to be carried out for a CT or VT ratio that is not ideal.

Rating The nominal value of an energising quantity that appears in the designation of a relay. The nominal value usually corresponds to the CT and VT secondary ratings.

RCA Relay Characteristic Angle.

RCB Report Control Block used to configure the publishing of a report by the related communication server.

RCD Residual Current Device. A protection device which is actuated by the residual current.

RCP Remote Control Point: The Remote Control Point is a SCADA interface. Several RCP's may be managed with different communication protocols. Physical connections are done at a Gateway or at substation computers or at a substation HMI.

Reactive power (Var) transducer A transducer used for the measurement of reactive electrical power.

Reclaim time (auto-reclose) The time between a successful closing operation, measured from the time the auto-reclose relay closing contact makes until a further reclosing sequence is permitted in the event of a further fault occurring.

REF Restricted Earth Fault.

Reference conditions Conditions of use for a transducer prescribed for performance testing, or to ensure valid comparison of results of measurement.

Reference range A specified range of values of an influence quantity within which the transducer complies with the requirements concerning intrinsic errors.

Reference value A specified single value of an influence quantity at which the transducer complies with the requirements concerning intrinsic errors.

Relay See Protection Relay.

Report Set of data sent from a server to a client in a communication network.

Resetting value The limiting value of the characteristic quantity at which the relay returns to its initial position.

Residual current The algebraic sum, in a multi-phase system, of all the line currents.

Residual voltage The algebraic sum, in a multi-phase system, of all the line-to-earth voltages.

R

Response time The time from the instant of application of a specified change of the measurand until the output signal reaches and remains at its final steady value or within a specified band centred on this value.

Reversible output current An output current which reverses polarity in response to a change of sign or direction of the measurand.

Ripple content of the output With steady-state input conditions, the peak-to-peak value of the fluctuating component of the output.

R.m.s. Root Mean Square.

RMU Ring Main Unit.

ROCOF (protection relay) Rate Of Change Of Frequency.

ROCOV (protection relay) Rate Of Change Of Voltage.

RSVC Relocatable Static Var Compensator.

RTD Resistance Temperature Detector.

RTOS Real Time Operating System.

RTU Remote Terminal Unit: An IED used specifically for interfacing between a computer and other devices. Sometimes may include control/monitoring/storage functions.

S

SAT Site Acceptance Test: Validation procedures for equipment executed with the customer on site.

SCADA Supervisory Control and Data Acquisition.

SCD Substation Configuration Description (IEC 61850 engineering file format based on XML/SCL).

SCL Substation Configuration Language: Normalised configuration language for substation modelling (as expected by IEC 61850-6).

SCP Substation Control Point: HMI computers at substation level allowing the operators to control the substation.

SCS Substation Control System.

SCT System Configuration Tool (acc. IEC 61850).

SDA Sub Data Attribute (data model element in IEC 61850).

SDO Sub Data Object (data model element in IEC 61850).

SED System Exchange Description (IEC 61850 engineering file format based on XML/SCL).

Server Entity that manages data and responds to requests from clients in a communication network.

Setting The limiting value of a ‘characteristic’ or ‘energising’ quantity at which the relay is designed to operate under specified conditions. Such values are usually marked on the relay and may be expressed as direct values, percentages of rated values, or multiples.

SFC Sequential Function Chart: One of the IEC 61131-3 programming languages.

Short-term stability The stability over a period of 24 hours.

Simplex communications system A communications system in which data can only travel in one direction.

Single-shot reclosing An auto-reclose sequence that provides only one reclosing operation, lock-out of the CB occurring if it subsequently trips.

S.I.R. System Impedance Ratio.

S

Single element transducer	A transducer having one measuring element.
SLD	Single Line Diagram.
SNTP	Simple Network Time Protocol: Used acc. IEC 61850 for time synchronisation.
SOE	Sequence Of Events.
SOTF	Switch On To Fault (protection).
Specific conjunctive test	A conjunctive test using specific values of each of the parameters.
Spring winding time	For spring-closed CB's, the time for the spring to be fully charged after a closing operation.
SSD	System Specification Description (IEC 61850 engineering file format based on XML/SCL).
SST	System Specification Tool (acc. IEC 61850).
ST	Structured Text: One of the IEC 61131-3 programming languages.
Stability (of a transducer)	The ability of a transducer to keep its performance characteristics unchanged during a specified time, all conditions remaining constant.
Stability (of a protection system)	The quantity whereby a protection system remains inoperative under all conditions other than those for which it is specifically designed to operate.
Stability limits (of a protection system)	The r.m.s. value of the symmetrical component of the through fault current up to which the protection system remains stable.
Starting relay	A unit relay which responds to abnormal conditions and initiates the operation of other elements of the protection system.
STATCOM	A particular type of Static Var Compensator, in which Power Electronic Devices such as GTO's are used to generate the reactive power required, rather than capacitors and inductors.
Static relay	An electrical relay in which the designed response is developed by electronic, magnetic, optical or other components without mechanical motion. Excludes relays using digital/numeric technology.
Static var compensator	A device that supplies or consumes reactive power, comprised solely of static equipment. It is shunt-connected on transmission lines to provide reactive power compensation.
STC	Short Time Current (rating of a CT).
Storage conditions	The conditions, defined by means of ranges of the influence quantities, such as temperature, or any special conditions, within which the transducer may be stored (non-operating) without damage.
SVC	Static Var Compensator.
System disturbance time (auto-reclose)	The time between fault inception and CB contacts making on successful re-closure.
System impedance ratio	The ratio of the power system source impedance to the impedance of the protected zone.

T

T101, T103 Term used for IEC 60870-5-101 and -103 protocol.

Tap changer A mechanism, usually fitted to the primary winding of a transformer, to alter the turns ratio of the transformer by small discrete amounts over a defined range.

TCP/IP Transmission Control Protocol/ Internet Protocol: A common protocol for the transmission of messages over the Internet.

TCS Trip Circuit Supervision.

TC57 Technical Committee 57 working for the IEC and responsible for producing standards in the field of Protection (e.g. IEC 61850)

TF
a) Transfer Function of a device (usually an element of a control system)
b) Transient Factor (of a CT).

Through fault current The current flowing through a protected zone to a fault beyond that zone.

TICS Technical Issue Conformance Statement (IEC 61850 engineering file).

Time delay A delay intentionally introduced into the operation of a relay system.

Time delay relay A relay having an intentional delaying device.

Tissue Technical issues on a standard raised after its publication.

TPI Tap Position Indicator (for transformers).

TR Technical Report (of a standard)

Transducer (electrical measuring transducer) A device that provides a d.c. output quantity having a definite relationship to the a.c. measurand.

Transducer with zero (live zero) A transducer which gives an offset predetermined output other than zero when the measurand is zero.

Transducer with suppressed zero A transducer whose output is zero when the measurand is less than a certain value.

TS Technical Specification (of a standard).

U

Unicast communication Message from one source to one selected partner in a communication network.

Unit electrical relay A single relay that can be used alone or in combination with others.

Unit protection A protection system that is designed to operate only for abnormal conditions within a clearly defined zone of the power system.

Unrestricted protection A protection system which has no clearly defined zone of operation and which achieves selective operation only by time grading.

UCA Utility Communications Architecture.

UFLS Underfrequency Load Shedding.

UPS Uninterruptible Power Supply.

UTC Universal Time Coordinates.

V

V Voltage.

VCB Vacuum Circuit Breaker.

VDEW Term used for IEC 60870-5-103 protocol. The VDEW protocol is a subset of the IEC 60870-5-103 protocol (VDEW: German association of the electro-technical and water industry.

Vector group compensation A feature of digital and numerical relays that compensates for the phase angle shift that occurs in transformers (including VT's) due to use of dissimilar winding connections – e.g. transformers connected delta/star.

VLAN Virtual Local Area Network.

Voltage transducer A transducer used for the measurement of a.c. voltage.

VT Voltage Transformer.

W, X, Y, Z

WAN Wide Area Network.

Web service Standardised method of communication between two devices on a communication network.

X Reactance.

XML Extensible Markup Language: Used to structure ASCII characters to define specific data file formats.

X/R Ratio of system reactance to resistance.

Y Admittance (reciprocal of impedance).

Z Impedance.

AX2

ANSI & IEC Function References

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Appendix AX2

ANSI & IEC Function References

There are three methods for indicating protection relay functions in common use. One is using Logical Nodes from the IEC 61850 standard, one is given in ANSI Standard C37-2, and uses a numbering system for various functions plus additional letters when further clarification is required. The last one is given in IEC 60617, and uses graphical symbols with the operating quantity symbol. To assist the Protection Engineer in converting from one system to the other, a cross reference list of IEC LN, ANSI device numbers and their IEC equivalents is given in Figure AX2.1.

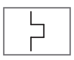
Description	IEC 61850	ANSI	IEC 60617
Overspeed relay	PZSO *)	12	$\omega >$
Underspeed relay	PZSU	14	$\omega <$
Distance relay	PDIS	21	$Z <$
Overtemperature relay	PTTR	26	$\theta >$
Undervoltage relay	PTUV	27	$U <$
Directional overpower relay	PDOP	32	$\overrightarrow{P >}$
Underpower relay	PDUP	37	$P <$
Undercurrent relay	PTUC	37	$I <$
Negative sequence overcurrent relay	PTOC	46	$I_2 >$
Negative sequence overvoltage relay	PTOV	47	$U_2 >$
Thermal relay	PTTR	49	
Instantaneous overcurrent relay	PIOC	50	$I >>$
Inverse time overcurrent relay	PTOC	51	$I >$
Inverse time earth fault overcurrent relay	PTOC	51G	$I_{\perp} >$
Definite time earth fault overcurrent relay	PTOC	51N	$I_{\perp} >$
Voltage restrained/ controlled overcurrent relay	PVOC	51V	$U/I >$
Power factor relay	POPF / PUPF	55	$\cos\varphi >$
Overvoltage relay	PTOV	59	$U >$
Neutral point displacement relay	PTOV	59N	$U_{rsd} >$
Earth-fault relay	PTOC	64	$I_{\perp} >$
Directional overcurrent relay	PTOC	67	$\overrightarrow{I >}$
Directional earth fault relay	PTOC	67N	$\overrightarrow{I_{\perp} >}$
Phase angle relay	PPAM	78	$\varphi >$
Autoreclose relay	RREC	79	$O \rightarrow I$
Underfrequency relay	PTUF	81U	$f <$
Overfrequency relay	PTOF	81O	$f >$
Differential relay	PDIF	87	$I_d >$

Figure AX2.1:
IEC 61850 / ANSI number / IEC symbol comparison

) proposed, but not standardized

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