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Protection Relay Coordination

Working Group
B5.19

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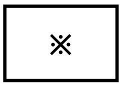
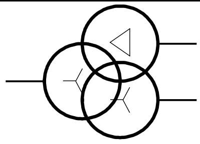
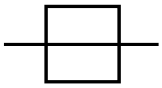
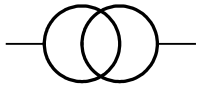
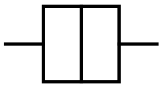
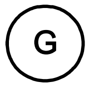
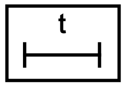
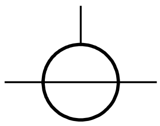
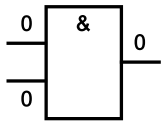
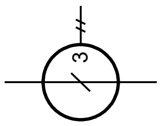
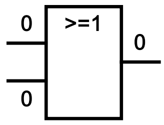
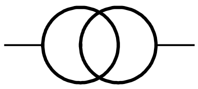
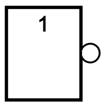
Abbreviations

ABWR	Advanced Boiling Water Reactor
APWR	Advanced Pressurised Water Reactor
BOP	Blocking Overreach Protection
BP	Busbar Protection
CB	Circuit Breaker
CBF	Breaker Failure Protection
BWR	Boiling Water Reactor
CT	Current Transformer
EF	Earth Fault Overcurrent Protection
EHV	Extra High Voltage
ES	Earthing Switch
FCR	Fault Clearance Relay
HV	High Voltage
HVDC	High Voltage Direct Current
IUP	Intertripping Underreach Protection
LP	Line Protection
MDAA	Modified Differential Approximation Algorithm
MTTR	Mean Time To Repair
MV	Medium Voltage
NCP	Neutral Current Protections
OC	Overcurrent Protection
PLC	Power Line Carrier
POP	Permissive Overreach Protection
PUTT	Permissive Underreach Transfer Trip
REF	Restricted Earth Fault Protection
Ry	Relay
SPS	Special Protection Scheme
TP	Transformer Protection
UOP	Unblocking Overreach Protection
VT	Voltage Transformer

The technical terms defined by IEV 448 are basically used in this report.

Symbols

Element	Symbol	Element	Symbol
Relay		EVT	
Breaker		Transformer	
Tripped / Opened Breaker		Generator	
Opened Disconnector		Delayed Timer	
CT		AND Logic	
ZCT		OR Logic	
VT		NOT Logic	

1. Introduction

It has proven to be very difficult to eliminate power system blackouts completely even today when power systems have grown so large in scale and when sophisticated protection relays and control systems for power system stabilisation have become available. One of the reasons for this is the occurrence of unpredicted types of fault, which result in cascade tripping of protection relays. Power systems have been extended as the economy of each country has grown and power consumption has increased and, as a consequence it has become more difficult to protect the power systems effectively. Power system engineers have had to make increasing efforts to maintain the reliability of the power systems, and coordination between relays is one of the objectives of those engineers' efforts.

Since no single protection relay gives complete and selective protection for every kind of fault, coordination between relays is necessary to fully protect the power system. It is clear that the importance and difficulty of coordination increases with the size and complexity of the power system.

However, as far as we know, no document specifically targeting coordination itself based on the practical experiences and accumulated knowledge of engineers from around the world has been issued. It is presumed that many relay engineers have experienced difficulties in solving coordination problems and have applied compromise solutions on a country by country basis.

The first step that this working group took was to send a questionnaire about relay coordination to many countries and then to analyse the result. Working group members were able to learn the practice of many countries, which formed the starting point for discussion. This report is the result of the sincere discussion among protection engineering experts from many countries based on reported facts and practices.

The working group included in this report as many solutions as possible for relay coordination issues based on the principles of electrical phenomena and application practices for most transmission arrangements.

The working group has produced this report to be useful in providing hints and solutions to relay engineers who experience relay coordination problems. Furthermore, readers may be able to find improved solutions to coordination issues. When a change of protection method is planned, the associated coordination issues and potential solutions may also be found within this document.

This report also includes principles of protection, which would be useful for engineers intending to learn about protection, and especially to learn the basic principles of relay setting in order to gain a better understanding of relays.

In addition to relay coordination between fault clearance relays, this report includes coordination between SPS (Special Protection Scheme) and fault clearance relays and also between SPS and SPS. Since SPS can have various functions, it is difficult to cover all cases of coordination. Nevertheless it should be possible to give some hints to engineers about coordination of SPS.

This report will give guidance regarding many coordination issues, which might be viewed as a kind of coordination between power system protection engineers.

2. General Introduction of Fault Clearance Relay and SPS

2.1 Classification of Power System Protection

Protection relays are classified into “Fault clearance protection” and “Special protection scheme (SPS)” as shown in **Figure 2.1-1**. Regarding the fault clearance protection (relays), there are main protection relays and backup protection relays. As a main protection relay is installed at all primary equipment, the main protection relay for the equipment in which the fault occurs should operate the fastest. The main purpose of the fault clearance relays is the reduction of equipment damage and isolation of faulty part from rest of the power system. Therefore, high-speed operation to clear the fault as soon as possible and sensitivity and selectivity to minimise the influence of the fault are required for the fault clearance relays. This report identifies four types of SPSs. These are installed to prevent the fault extension from the abnormal phenomena such as out-of-step or abnormal frequency or abnormal voltage or overload. Most of them are triggered by the system faults.

This report covers fault clearance protection relays in transmission systems except for direct-current power systems, shunt reactors, capacitor-banks and distribution systems.

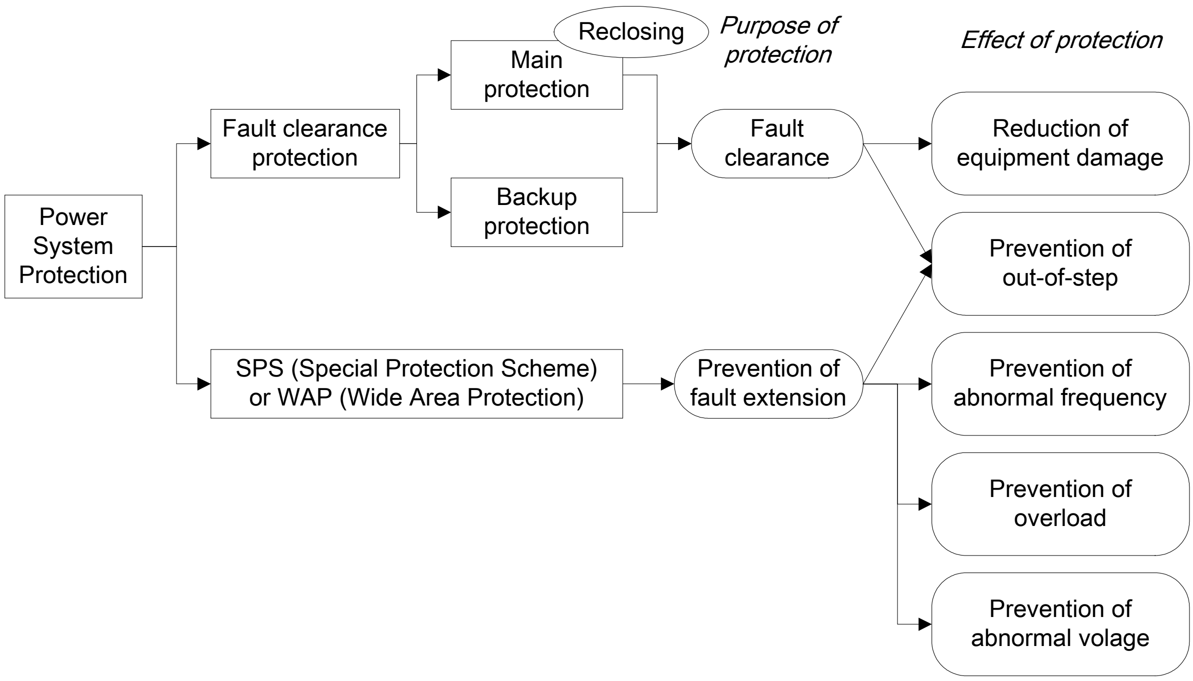


Figure 2.1-1 Classification of Protection Relays

Figure 2.1-2 shows an example of the operating time of each protection relay. The total clearing time (relay operating time + CB opening time) is one of the important factors for determining the protection scheme which is applied in the power system. The protection relay selected must have sufficient margin to the operation conditions or the withstanding capability of the equipment to be protected. Backup protection should be designed to operate when neither the main protection nor its associated equipment is able to operate for a fault, so the time delay of the backup protection should be set to time grade with the main protection. In overhead lines, automatic reclosing will be carried out after the fault clearance for the purpose of maintaining stability of the power system or high-speed restoration of the system or ensuring systems remain interconnected, and so on. In almost all cases, the automatic reclosing will initiated by the operation of the main protection. Automatic reclosing won't be carried out generally, when a fault occurs in an underground cable, a busbar or a transformer.

A behaviour-assumption type of SPS whose prediction calculations are carried out for discriminating the power system stability based upon pre-determined fault conditions using on-line or off-line data will operate very quickly, especially for transient stability. On the other hand, a behaviour-confirmation type of SPS will operate after the operation of fault clearance relays, as it responds to the abnormal phenomena generated by sudden change of the power flow or a large amount of loss of power sources after fault clearance.

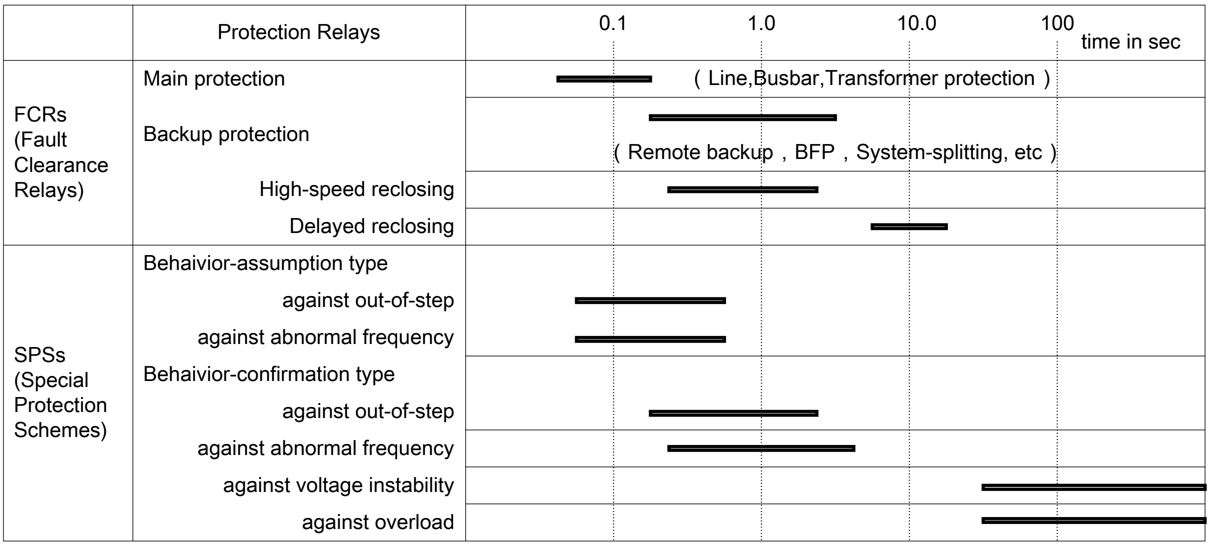


Fig.2.1-2 Example of Fault Clearing Time for Various Kinds of Protection Relays

2.2 Purpose of Protection Relays

The purpose of the protection system is summarized as follows;

1) Enhance public safety following system events
2) Reduction of damage to the equipment
3) Keeping power system stability
4) Isolating the fault element from the healthy system

For this reason, protection relays must provide the following functions.

- Detection of fault current at high-speed to reduce equipment damage, to prevent the fault from expanding into the broader power system
- Separation of the faulty section of the power system from the healthy section and minimizing the isolated area to prevent a wide-area blackout or a long-term blackout
- Control of transmission power, control of reactive power, generator shedding or load shedding to prevent the power system disturbance causing a wide-area blackout
- High-speed and definite tripping is a fundamental function, and that for improvement of reliability is also an indispensable function for a protection relay.
- Various actions that will prevent expansion of the fault or to minimize the consequences of the fault including effects arising from failure of a relay or breaker The abnormal phenomenon originated by failure to operate a relay or a breaker to operate correctly, a sudden change of power flow, or splitting of the system during the process of fault clearance, any of which may cause the expansion of the fault, and the deterioration of the power system stability.

Figure 2.2-1 illustrates the role of the fault clearance relays and SPSs. The crosses "X" in this figure means the prevention of the fault extension by correct operations of the protection relays. When one of the protection relays does not operate or one of the circuit breakers fails to operate, then backup relays will operate to prevent the fault expanding. When the fault is very severe such as many lines are tripped simultaneously, sudden change of power flow may occur or the power system may be split into some small power systems or the power system may continue to be unstable. In any of these cases, SPS will operate and control the generators or loads to stabilise the power system.

The criterion for the installation of SPS depends upon the system configuration and/or the criterion for the system operation.

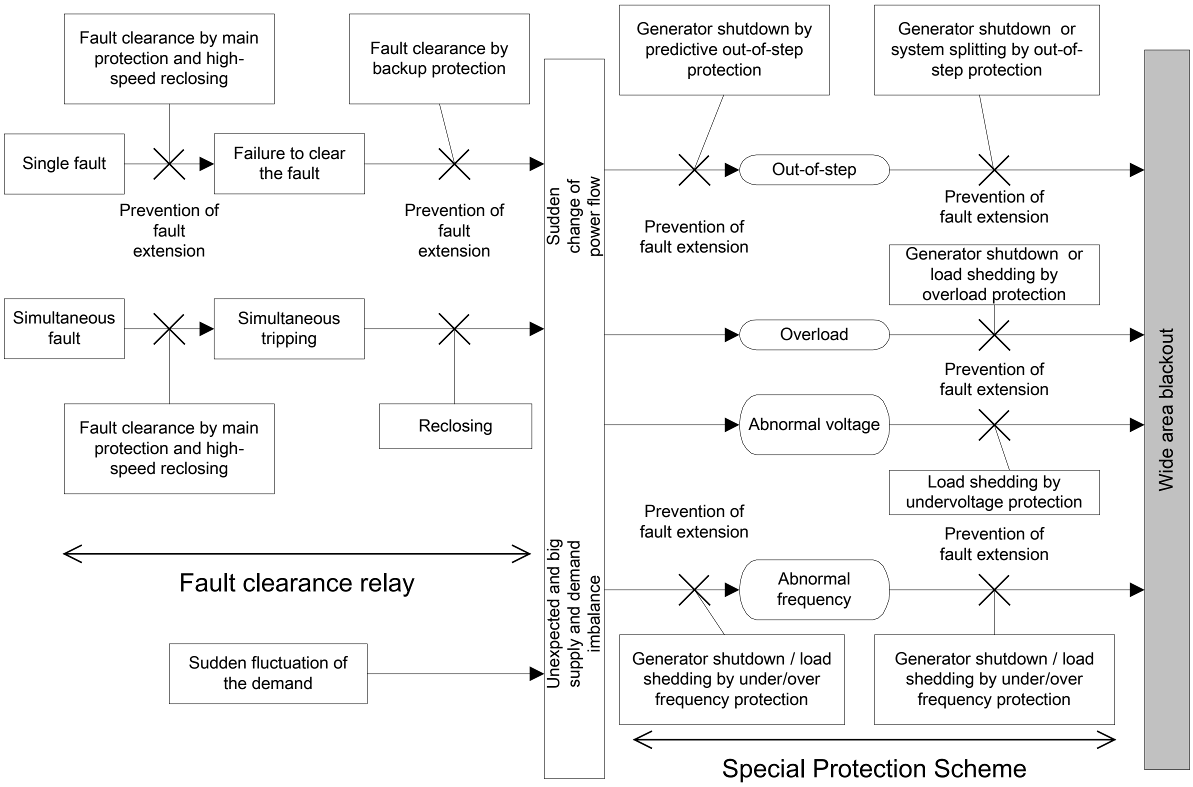


Figure 2.2-1 Functional Diagram of Protection Relays

2.3 Requirements of Fault Clearance Relays

2.3.1 Performance Required of the Protection Relays

Requirements for the protection relays are summarized into the following three closely related items:

1) Fault clearance performance in respect of
   a) Speed;
   b) Selectivity;
   c) Sensitivity;
2) Reliability; and
3) Cost

High-speed operation of the protection relays prevents the power system from heavy damages and also from instability.

Protection relays with excellent selectivity enable minimum faulty-zone separation.

Sensitivity is the ability to detect the lowest level of the fault.

To achieve higher reliability of protection, there are three approaches:

- High security
- Duplication and Redundancy
- Self-diagnostic functions

Reliability is the assurance that the relay will operate correctly when it is supposed to.

Security is the ability of the protection relay to not operate when not required to operate.

Duplication and redundancy of equipment will enhance reliability of fault clearance even if there is a failure in one relay.

Cost must be considered in respect of the extent of redundancy, the use of backup and the overall life cycle cost throughout operation of the substation.

Numerical type relays, in general, have high performance self-diagnostic functions and remote alarms that may remarkably reduce their MTTR (Mean Time to Repair) compared to previous technologies where the device may remain in a non-operational state until its next scheduled test, or worse still, until the next time a fault occurs and it fails to operate correctly.

Requirements for the protection relays include not only fault clearance performance but also performances related to tripping/reclosing, because automatic reclosing is desirable for maintaining power system stability, minimising outages and maintaining continuity of supply.

When introducing new protection system, these several factors are studied and each specification is decided according to the power system requirements.

2.3.2 Factors Affecting Performance of Protection Relays

In addition to choosing protection devices with the appropriate inherent performance, it is also necessary to select the protection scheme in consideration of the requirements of the power system, such as the importance of the system to be protected, and the limitation of system operation. Performances such as sensitivity, operating time and selectivity are required in introducing the protection relay into a power system as shown in **Figure 2.3-1**.

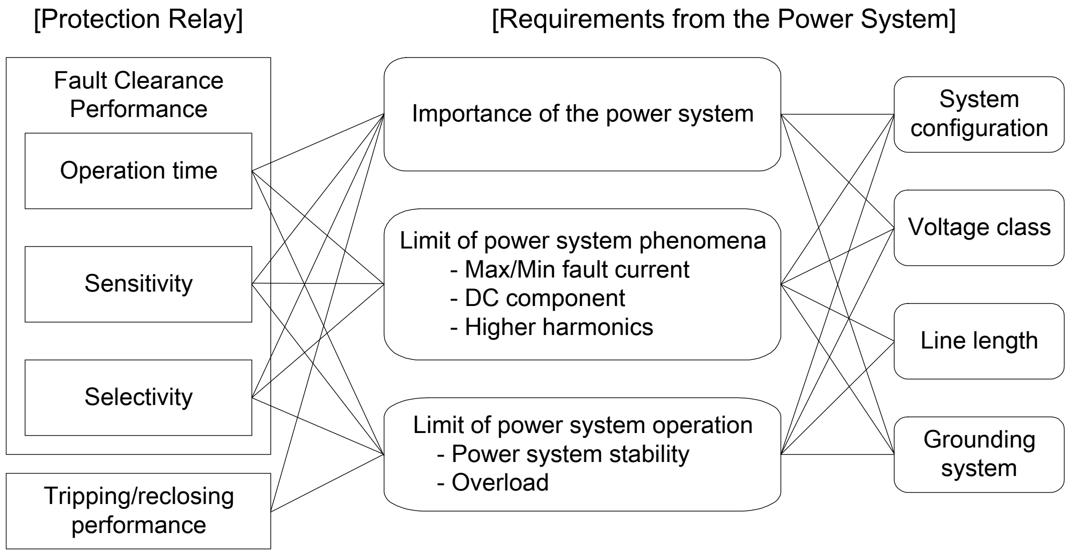


Figure 2.3-1 Consideration Factors in Applying Protection Scheme

2.3.3 Protective Zone

Protective zone is an important factor that determines selectivity among the performances in which a protection relay should be required.

Unit protection provides a protective zone by the location of the CTs to detect faults only between the CT locations as a well defined zone according to the sensitivity of the settings.

Non-unit protection (excluding directional comparison) has a zone which changes in accordance with the setting values and is not constrained by other CT locations.

The coordination between protection relays is the procedure to ensure that all the protection relays operate systematically to minimize the power system outage area against any fault, considering the operation limits or restriction conditions. On the other hand, when a fault occurs in equipment which the protective zone does not cover, it may not be cleared, or it may take longer time for the fault to develop into the protective zone and then be cleared. Therefore a fundamental principle of protection is that at least two different devices are capable of detecting any fault anywhere on the power system.

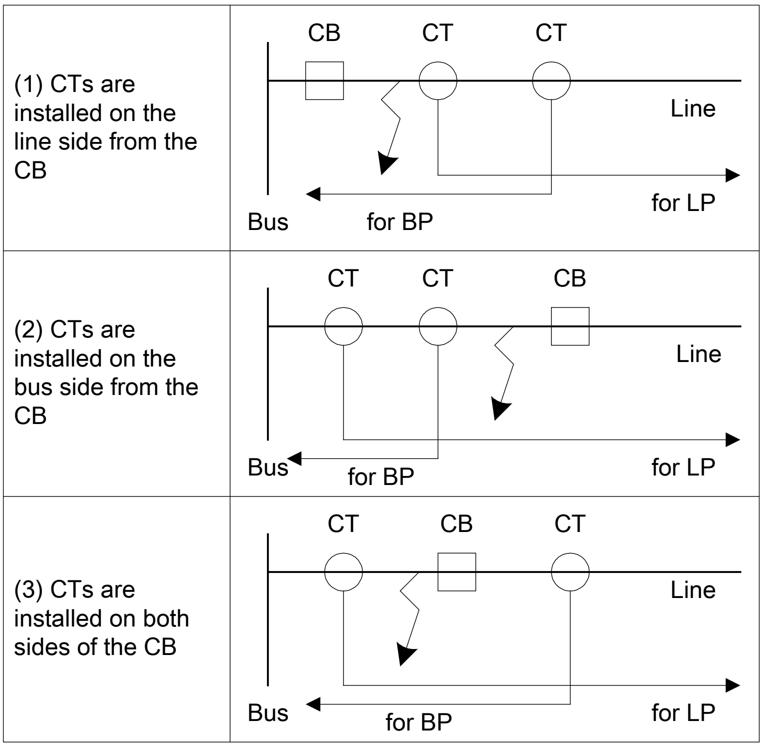
2.3.4 CT Arrangement

There are three kinds of arrangement of CTs shown in **Figure 2.3-2**. This figure shows the arrangement of CTs for line protection and busbar protection as an example. The third arrangement is generally considered the best arrangement, because there is no dead zone for fault detection between the CTs and the breaker as in the first two arrangements. However, each must be considered in regards to the type of CT to be used (e.g. bushing or post), or the substation space.

In arrangement (1), a CT for busbar protection and a CT for line protection are installed at the line side from the breaker. In this case, the busbar protection will operate for a fault between the CT and the breaker, which should essentially be a line fault, so a part of the busbar will be blacked out. However, as the fault is not totally cleared by the busbar protection, the fault will also need to be cleared by the remote backup protection.

In arrangement (2), CTs for busbar protection and CT for power line protection are installed at the busbar side of the CB. In this arrangement, when a fault occurs between the CT and the CB, which is originally a busbar fault, the line protection will operate and therefore, the line will be out of operation. However, as the fault is not totally cleared by the line protection, it will also need to be cleared by the remote backup protection or locally by CBF if used.

In arrangement (3), the CTs are installed at both sides of the CB; that is the CT for line protection is installed at busbar side of the CB and the CT for busbar protection is installed at line side of the CB. As both the line protection and the busbar protection will operate against the fault between the CT and the CB, a fault as shown in **Figure 2.3-2** will be cleared at high speed.



<Note> LP: Line Protection, BP: Busbar Protection

Fig.2.3-2 CT Arrangement

2.3.5 Main Protection

Main protection is installed for every equipment unit, such as a transmission line, a busbar, a transformer etc. **Figure 2.3-3** shows the protective zones provided by different main protection relays installed to protect each section of the power system. The protective zone of the main relay in this figure corresponds to the case of the installation of CTs on the both sides of the breaker. (Refer **Chapter 3.2** regarding the relation between the protective zone and the coordination of the protection between the zones). When a fault occurs on any part of the power system, the main protection closest to the fault must operate faster than the other protection to minimize the extent of the power system that must be isolated to clear the fault. The protection must operate the circuit breakers at the edge of the protection zone to clear the fault with minimum disruption to the rest of the power system. As the protection zones must overlap, consideration must be given to how the selectivity is achieved to not cause both zones to be tripped as shown in **Fig 2.3-3**.

Main protection is generally provided as independent duplicate protection at higher voltages where the risk of one system failing to operate correctly in the intended high speed would cause widespread consequential damage or power system instability. This is generally referred to as Main 1 and Main 2, or X and Y protection. Both protections are intended to operate independently with approximately the same speed typically less than two cycles such that either relay will clear the fault. The duplicate system caters for failure of the relay internal fault detection system to detect the fault due to differences in characteristic or algorithms, physical failure of the relay or physical open circuit of the trip circuit to the breaker. This arrangement will provide secure protection operation in a variety of contingencies except for failure of the breaker mechanism itself in which case Circuit Breaker Fail protection is used as described in the following section on Backup Protection.

Duplicate protection is therefore provided using:

- two independent CT cores at the same location
- two VT signals on independent circuits from the VT although may be derived from the same VT core due to the difficulty of duplicating VT posts
- two relays of different operating principles or vendors – e.g. distance and differential, two distance from different vendors or two differential relays from different vendors
- two independent trip coils in a common circuit breaker

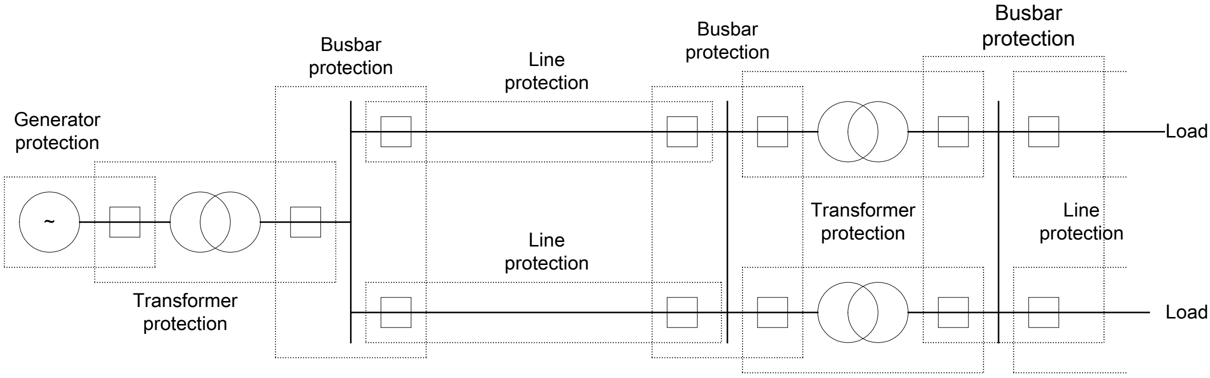


Figure 2.3-3 Protective Zone for Main Protection in Case of Installation of CTs on Both Sides of the Breaker (Dotted square means “Protective Zone” for Main Protection)

2.3.6 Backup Protection

(1) Necessity of Backup Protection

The backup protection is essential to clear a fault and not to expand the impact of the fault, either when the main protection, circuit breaker, or the VT, CT has failed to operate correctly. Therefore, t the backup protection must operate as follows:

- In case of the occurrence of a fault within the protective zone if the main protection operation is blocked

- In case of failure in operation of the main protection due to some reason (failure/settings/characteristic etc)
- In case of the occurrence of a particular type of fault that the main protection cannot detect, for example, the transverse differential protection (see **3.1.1(6)**) can't detect a simultaneous phase-to-earth fault on both lines because there is no zero differential current
- In case of erroneous inputs to the relay because of the VT transients, or the CT saturation or failure, or failure of the breaker
- In case of a fault on busbar without busbar protection

(2) Classification of Backup Relays

There are 4 kinds of backup relays as shown in **Figure 2.3-4**;

Local backup relay: It is installed locally in the same substation and operates when the main relay fails to operate for a fault. These relays generally have a slower operating time than the main protection perhaps due to different operating characteristics or due to grading between the relays. An example is an instantaneous overcurrent relay with local back up provided by using an inverse time overcurrent relay which may be in a different relay connected to the same CT or on a different circuit such as the incomer to the substation using different CTs allowing both types to see the fault with one intended to operate faster. This is different to the provision of duplicate ‘main’ protection relays (referred to as Main 1 and Main 2, or X and Y protection) connected to the same measurement point intended to have both relays operate independently but in approximately the same time.
This is also different to the use of Circuit Breaker Fail protection described below.

Remote backup relay: It is installed at the remote substation primarily to protect its own substation and the power line, but is also to able to detect faults that would normally be expected to be cleared by the local protection. The remote back up relay will therefore have a slower operating time for faults in the local substation but will operate if the local protection system (relay and breaker) fail to clear the fault.

This remote back up protection is generally considered to be fully independent in operation from the local protection i.e. the backup protection does not require any signals from the local substation to provide or prevent operation. This is different to distance protection schemes which may use permissive or blocking signals to control the operation of the remote protection in different circumstances such that the local and remote relays must operate to effectively clear the fault.

For example, when distance protection is applied for the lines, the zone 2 will provide remote backup protection to the local busbar protection for faults on the far end busbar if the main busbar protection at the far end doesn’t operate. A distance scheme or an overcurrent scheme is widely used as backup protection, which can detect an internal fault by inputting the electrical quantities from its own remote end in order to determine the slow or non operation of the main protection at the local end.

Circuit Breaker Failure protection (CBF): It is installed to provide local backup in case of non-operation of circuit breaker upon receipt of trip command. CBF assumes the local protection has operated correctly and attempted to operate the circuit breaker but the circuit breaker itself has failed either due to an open circuit from the relay to the trip coil or failure of the CB mechanism itself. CBF protection is described in detail in the next section.

Bus coupler sequential splitting: A bus-coupler splitting relay should separate the bus-tie in order to separate a faulty busbar and a healthy busbar, when a main protection relay or a breaker doesn't operate or a severe fault occurs. This minimizes the blackout range, to mitigate the influence of a system fault, and to improve the stability of a power system. A system splitting relay should operate more quickly than other backup relays, and should separate a system, so that the influence of the fault does not extend to a higher voltage class system or another part of the substation which could otherwise remain operational. It is sometimes installed in a transformer or an interconnecting point.

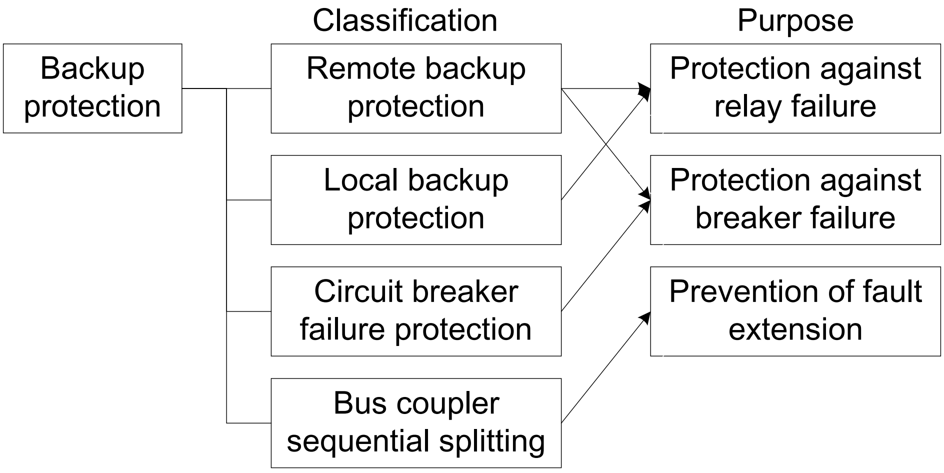


Fig.2.3-4 Classification of Backup Relays

(3) Circuit Breaker Failure protection (CBF)

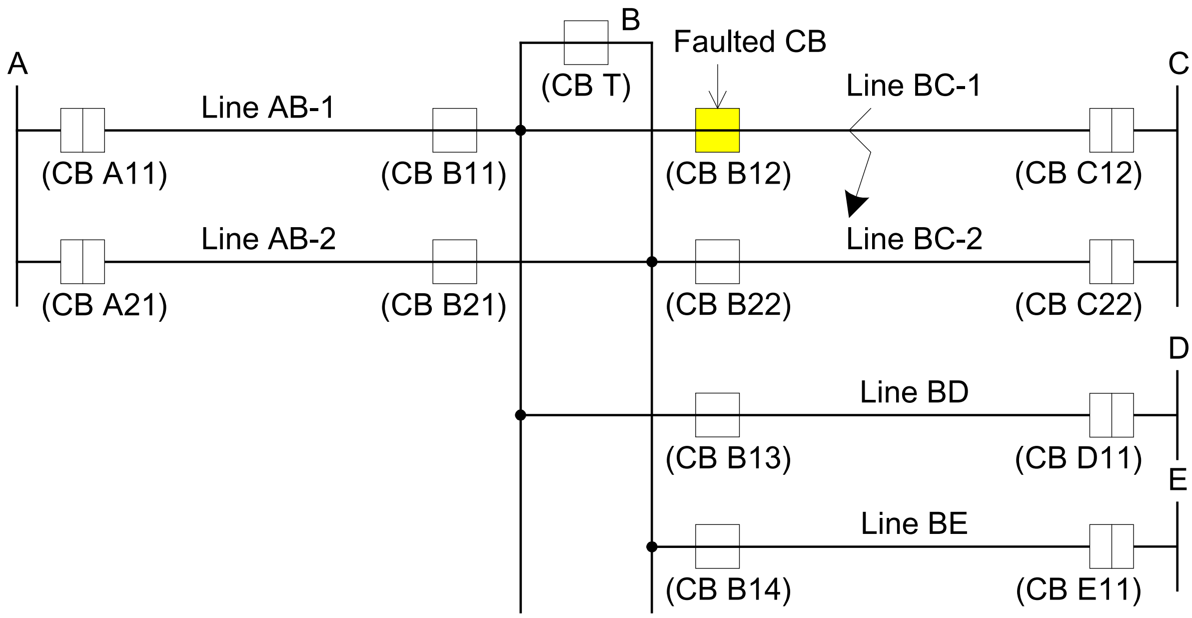
When the protection relay operates correctly for a fault, and the breaker does not open, the power system may be unstable due to the fault persisting until other slower or delayed back up protection detects the fault and operates. The circuit breaker failure protection (CBF) operates following the relay closest to the fault initiating a trip to its circuit breaker. The trip signal is used to initiate the CBF such that if the fault current is not cleared within a short time, the circuit breaker is assumed to have failed to operate either due to an open circuit in the trip circuit from the relay to the trip coil, or failure of the circuit breaker mechanism itself. The CBF will then initiate tripping of circuit breakers on adjacent lines in the substation or busbar, and possibly the remote end, which whilst increasing the extent of power system outage, will minimise the consequential damage of sustained or slow clearing faults. CBF is generally arranged to operate via the same tripping circuits as used by the busbar protection as it inherently is configured to trip adjacent faults and the CBF means the fault effectively needs to be treated as a bus protection trip. Whilst this may mean an entire bus section is tripped, this will prevent further widespread operation of remote back up protection causing even further blackout.

In selecting CBF it is therefore essential that not only will it detect the non operation of the breaker, but in the case of slow but eventual operation of the breaker, it is critical the relays have a fast reset characteristic to avoid unnecessary operation of the CBF causing unnecessary widespread outage.

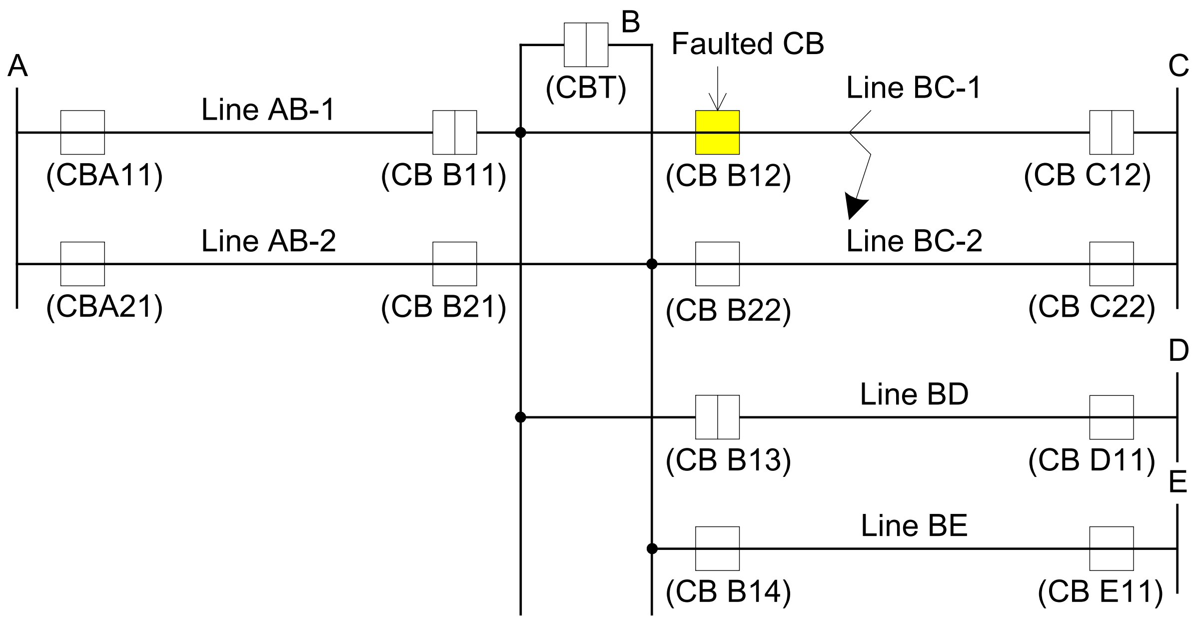
Figure 2.3-5 shows the fault clearance method with and without CBF protection when the breaker CBB12 does not open against the fault in the Line BC1.

Figure 2.3-5 (1) shows the power system following a circuit breaker failure without the breaker failure protection at B substation. In this case, as the C end of the Line BC1 is tripped by the main protection but the breaker at B end does not open, all the remote backup protection relays at the remote ends of the lines connected to B substation will operate. Substation B will go into blackout due to both the breakers at the A substation opening as remote backup.

Figure 2.3-5 (2) shows the power system after the same fault but with the breaker failure protection at the B substation. The main protection at substation B and C operates as in **Figure 2.3-5 (1)** with correct operation at the C end of Line BC1. In this case, the breaker failure protection recognizes as non-operation of the breaker at B-end due to the continuation of the fault current. The breaker failure protection gives the information about the continuation of the fault to the busbar protection at substation B, and the breakers at the lines connected to the breaker at the B busbar and the bus-tie will open as minimize the blackout area.



(1) Fault Clearance by Remote Backup Relays



(2) Fault Clearance by Breaker Failure Protection

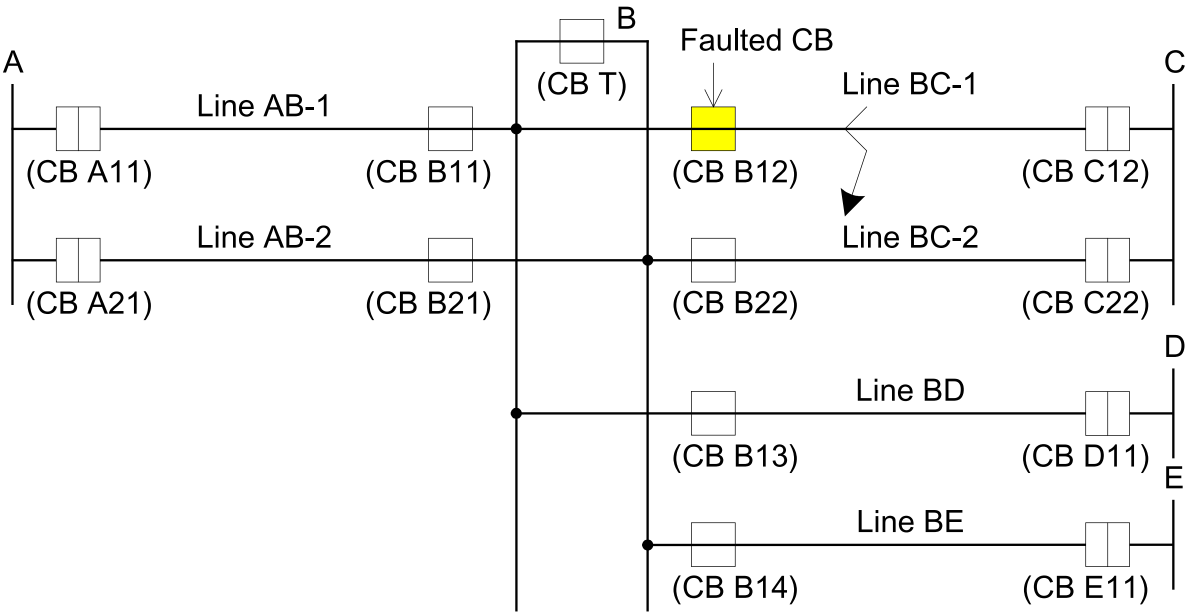
Figure 2.3-5 Effect of Installation of Breaker Failure Protection

(4) Bus coupler sequential Splitting

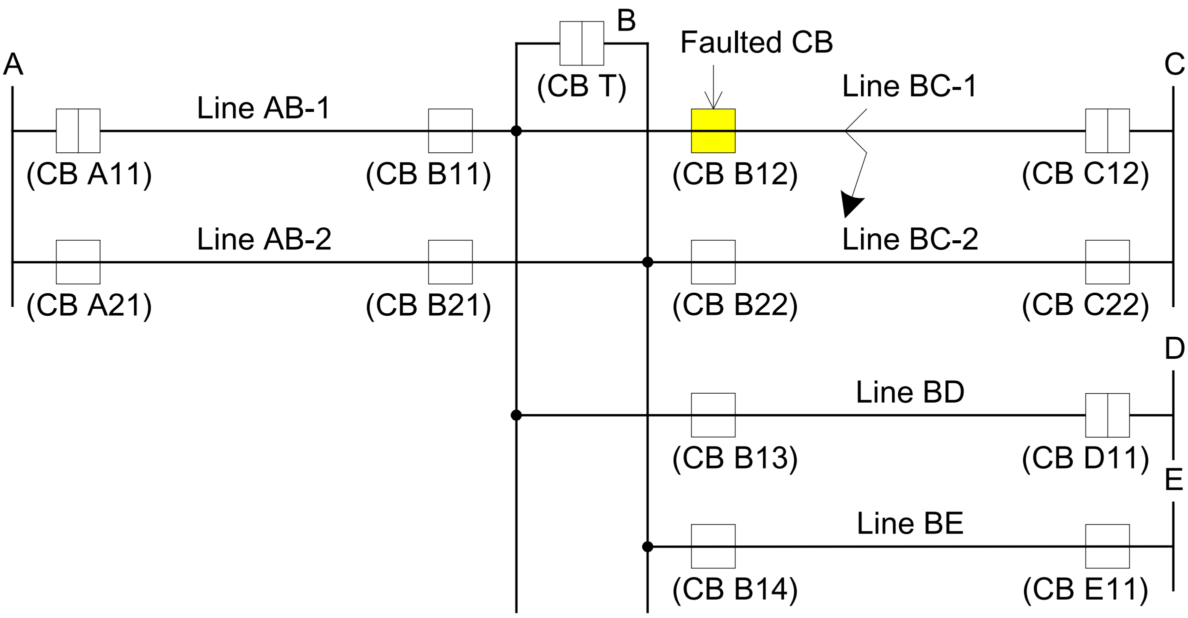
This application is typically used in double-bus arrangement substations. It is installed for the purpose of allowing continued operation of the healthy busbar by tripping the bus tie CB. This isolates the faulty busbar in order to avoid a blackout of the whole substation when

- a line CB fails to operate for a line fault, or
- the busbar differential protection fails for a fault on one of the two bus bars, or
- when there is a fault on a busbar or section of it (blind spot) that is not equipped with busbar differential protection.

The relay should be set to detect a minimum phase-phase or phase-earth fault at the far-end of the line with the maximum impedance, or any fault associated with any capacitor bank connected to the busbar, considering the prevention of the fault extension. It is necessary to set the time delay of the system splitting relay slower than the local back-up relay and faster than the remote backup relay. For short lines, the reach of the distance relay should be considered to ensure sufficient coordination (See **Fig.2.3-6**.). Depending on the substation, system topology and the generation scenario, it may be a difficult task to satisfy all these potentially conflicting requirements.



(1) Fault clearance by Remote Backup Relays



(2) Fault clearance by System Splitting Relay

Figure 2.3-6 Effect of Installation of Bus coupler sequential Splitting

2.4 Requirements of SPS

2.4.1 Typical Process to Wide-Area Blackout

A fault which occurs in a power system will be usually cleared at high speed and with the minimum blackout area by the selective tripping of fault clearance relays to maintain stable operation in the power system and localising the section of the network to be isolated.

However, if the initial fault is followed by further or consequential events such as breaker failure or unsuccessful reclosing the network outage may extend to the whole power system, which may cause a wide area and/or long duration blackout. It is rare that such consequential events occur independently but rather two or more of these events occur sequentially or in parallel. An example of the process to wide-area blackout is shown in **Fig.2.4-1**.

Introduction of SPSs is one of the solutions to mitigate the influence of consequential events in the network.

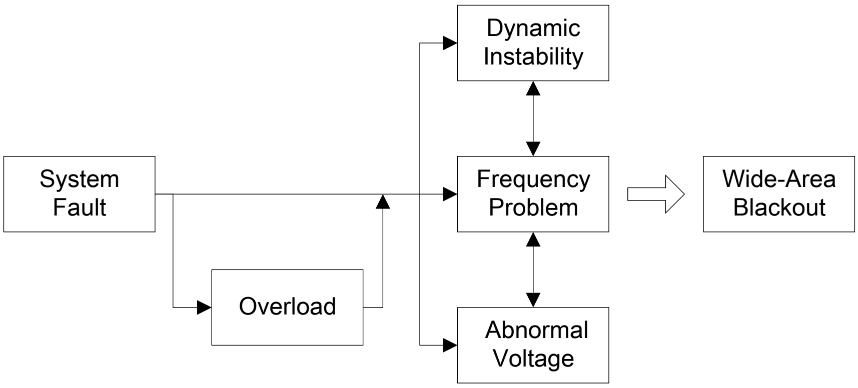


Figure 2.4-1 Typical Process to Wide-Area Blackout

2.4.2 Abnormal Phenomenon to be considered by the SPS

(1) Out-of-Step

In some cases power system faults may evolve into “cross country faults” affecting more than one transmission line simultaneously or sequentially causing significant changes in power flows on the network. Power flows may also be affected by sudden load changes or loss of generators on the grid. When these events occur, possibly in combination, the mechanical power input and electric power output of generators may become unbalanced leading to under/over frequency or under/over voltage on the network. In such conditions the generators will lose synchronization with the power system. If this out-of-synchronism or out-of-step condition is sustained for too long, cascading trip of the generators will be caused, and it has a possibility of causing islanding of the power system network or widespread blackout of the whole power system, such as occurred in Japan in 1965. When such an event occurs, the suitable controls which stabilize the power system by various kinds of protection relays or SPSs are necessary to be executed in the power system including the generators which fall into out-of-step.

There are three kinds of SPSs against out-of-step:

- behaviour-confirmation type,
- behaviour-assumption type,
- behaviour-prediction type

which are explained in Section 4.1.1. The behaviour-confirmation type detects out-of-step near the electrical centre, performs system splitting and prevents the extension of the event. When a severe fault occurs in the system, the latter predicts out of synchronous, and conducts the proper control such as a part of power shedding or system splitting to stabilize the power system at an early stage.

(2) Abnormal Frequency

Severe fault on the power system sometimes causes cascaded tripping of the lines or generators. The unbalanced condition of generation of active power and consumption of power will cause fluctuation of the frequency. If the supply is less than the demand, frequency will fall, whilst if the supply is in excess of the demand, frequency will rise.

If the cascaded tripping of heavily loaded lines along with a power station outage causes the frequency to drop, a SPS scheme will initiate controlled tripping such as load shedding or tripping of a pumped storage generator during pumping in order to maintain the frequency. SPS schemes may also try to maintain the correct frequency in an islanded part of the system until it can be reconnected to the rest of the system. The wide area blackout resulting from abnormal frequency occurred in Malaysia in 1996.

(3) Voltage Instability

When voltage stability begins to collapse, capacitors or shunt reactors are controlled by a SPS and maintenance and recovery of voltage are performed so that it may not expand to the whole system. The wide area blackout resulting from voltage instability occurred in Sweden in 1983, in Tokyo in 1987 and in Western USA in 1996.

(4) Overload

When transmission lines, bus bars, transformers or even the switchgear are overloaded above their rated limits, it may be necessary to use an SPS to initiate load shedding or generator shedding to prevent damage to the overloaded item that may otherwise lead to a more significant power system fault. As one example, such overloads may be caused by a fault on one of two parallel lines is cleared by tripping of the faulted line which subsequently causes overload on the unfaulted line. This may be avoided for example by the use of autoreclose on the faulted line to prevent sustained overload of the healthy line. The New York 1977 wide area blackout was due to line overload.

Overloads may also occur due to specific operator action. For example two parallel lines with a river crossing may be switched off to allow large ships to pass on the river as happened in 2006. With these two lines out of service, the power flow was transferred to other lines which were consequently overloaded. This overload caused consequent cascading line tripping throughout the UCTE area. The UCTE synchronously interconnected network was split into 3 islands. As a result, imbalance between supply and demand arose in each island, and more than 15 million households fell into blackout [1].

2.4.3 “n-1” Criterion and SPS

There are three kinds of measures against the prevention of wide area blackouts as a result of fault expansion throughout the network;

1) The use of parallel lines and mesh grid arrangements of the power system
2) Operator controlled switching of the power system to manage power flows
3) The use of protection relays to minimise consequential power system damage to permit fast restoration of supply

Service reliability of the power system is maintained by giving the suitable priority for these measures.

Whereas normal general protection schemes are designed to deal with one fault event as an “n-1” criteria, the introduction of SPS also deals with an "n-2" fault or an "n-3" fault. The use of SPSs is generally more economical than significant power system network development to create parallel lines or mesh grids. **Table 2.4-1** shows an example of the maintenance of the service reliability.

Table 2.4-1 Example of Criteria of Service Reliability against Abnormal Phenomenon

	Criteria of Service Reliability
Power system formation	Stability of the power system, operation limit against abnormal frequency, or overload limit should be maintained against every n-1 fault.
System operation	Stability of the power system or overload limit should be maintained against every n-1 fault. Operation limit against abnormal frequency should be maintained against every n-1 fault and a cascading trip of parallel lines.
Protection relays	Failure extension should be prevented by a SPS against a n-1 fault, or a bus-bar fault or a cascading trip of parallel lines.

2.5 Improvements in Reliability

Reliability: is an index that expresses the attribute of a protective relay or system to operate correctly for situations in which it is designed to operate. This also includes the attribute of not operating (incorrectly) for all other situations. Reliability is expressed in terms of two fundamental attributes: dependability and security

Dependability: is the aspect of reliability that expresses the degree of certainty that a relay will operate correctly

Security (relay or relay system): That facet of reliability that expresses the degree of certainty that a relay or relay system will not operate incorrectly irrespective of the nature of the operating state of the power system.

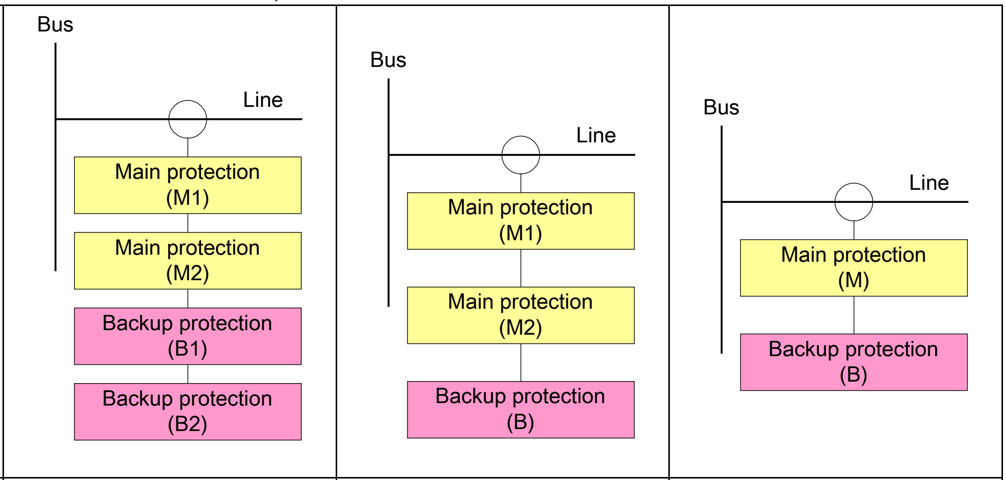
Selectivity (protective systems): A general term describing the interrelated performance of relays and breakers, and other protective devices; complete selectivity being obtained when only the minimum, necessary, amount of equipment is removed from service for isolation of a fault or other abnormality.

2.5.1 Redundancy of Protection Relays

Redundant Primary/Main Protection System: To increase reliability, this principle uses components that are redundant to or that compliment the primary protection system components, such as a second set of protective relays which have similar functionality to the relays of the primary protection system. This is also called Main 2 protection or Dual Protection.

The rate of failure to operate is reduced by installing two or more main protection or backup protection to detect the same fault. There are three different ways to achieve this objective. **Figure 2.5-1** illustrates survey data resulting from the questionnaire. Usually, redundancy is considered according to certain rules which reflect the strategic importance of the operation criterion, etc. of the power system in which the protection relay is installed. In many applications, M1 differs from M2, or M1 and M2 have different sensitivity or speed of operation, whilst in other applications, the relays with the same principle are applied for M1 and M2.

For further improvement of redundancy, separation of CT as well as DC power supply between M1 and M2 or between M and B can be applied.



Redundancy	M	double	double	single
	B	double	single	single

Figure 2.5-1 Redundancy of Protection Relays

Some users insist that each of the primary sensing relays in a duplicated protection scheme shall be sourced from a different manufacturer or if from the same manufacturer, the relays shall be based on different operating principles. This is to minimise the possibility of a common component or design defect causing both relays to fail or mal-operate concurrently. The typical exception to this is the high impedance busbar protection relays that are identical and accepted by proven field experience.

In contrast, some utilities have accepted that low impedance differential schemes may be applied using the same manufacturer for both main systems, provided the relay has extensive supervision and alarming. This is in consideration of the complexity of training for operators and technicians for a system that can rarely be taken out of service for testing.

2.5.2 Automatic Supervision

Modern numerical or digital protection relays generally have built-in self-supervision and automatic diagnostics to detect failure of the device in any respect. In electromechanical or analogue-static relays, this could only be achieved by additional hardware with limited coverage and arguably adding further hardware that itself could fail potentially leading to mis-placed confidence in the health of the relay.

The continuous monitoring function as part of automatic supervision can detect a faulty relay without interrupting the relay function as shown in **Figure 2.5-2**. If any failure is detected by the continuous monitoring, the relay is immediately blocked. This monitoring may also include a restart sequence in case of transient failure.

The Mean Time To Restore (MTTR) the relay to full service, which affects the availability statistics of the protection, includes both the time to detect and repair the fault. Since the continuous monitoring can block the relay from catastrophic mal-function and alarm the failure to the operators, the MTTR can be significantly reduced, especially compared to older practice solely relying on annual testing to prove correct functioning of the relay. Continuous monitoring can detect both modes of potential ‘mal-operation’ (unwanted trip) and ‘failure to operate’ conditions.

In some self diagnostic systems, automatic testing may block the relay operation whilst the test is being conducted involving simulated current and voltage inputs to the relay. If the self test sequence extends beyond the next data sample to initiate the protection function for a real fault, as shown in **Fig.2.5-3**, the relay may be at risk of maloperation due to the running of the test sequence. Therefore, some relays have the function which returns immediately to the relay function when a fault occurs during this period. Automatic testing will generally detect potential ‘failure to operate’ modes of failure.

The reliability and availability of the protection relay has been shown to be very high by proper maintenance procedure involving periodic testing and monitoring combined with automatic supervision functions. According to a study in Japan of digital relays applied above 66kV, systems without automatic monitoring had an estimated duration of 210 hours per year where the relay was effectively out of service, whilst systems employing automatic supervision reduced this figure to only 16 hours a year.[2]. Application of the automatic supervision function enables us to operate the protection relays in the healthy state with very high reliability in this way.

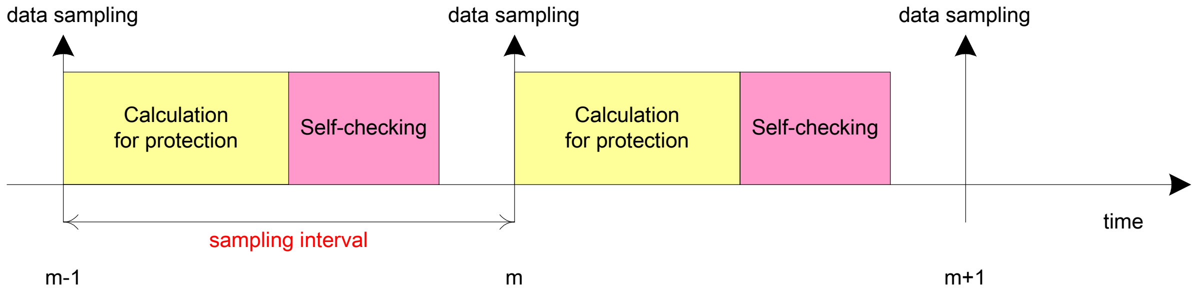


Figure 2.5-2 Continuous Monitoring

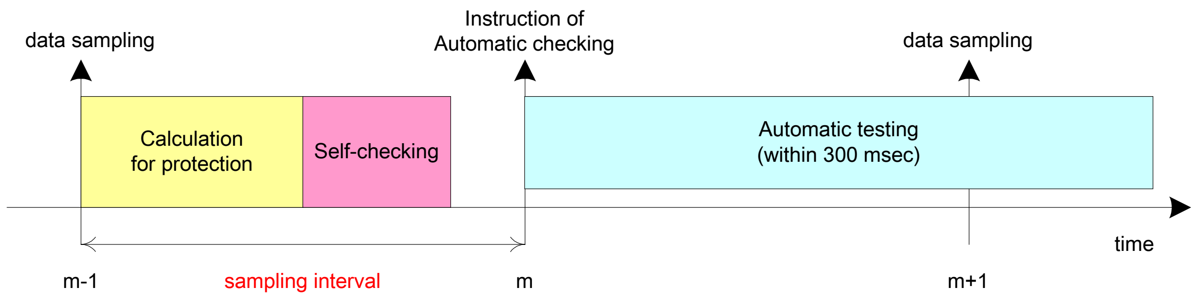


Figure 2.5-3 Automatic Testing

Whilst relay self monitoring capabilities will improve the overall protection system availability, verification of the correct operation of the entire system must also take into consideration the entire chain of current and voltage sensing on the primary plant through to correct trip coil operation in the circuit breaker. Self monitoring is therefore not a complete replacement to routine testing of the entire protection system. More intelligent schemes however can be used based on analysis of correct operations of the system during general power system operation and events in order to reset the schedule for the next manual test.

2.5.3 Digitalization

Introduction of digital relays have brought many advantages such as reducing the number of components and having less mechanical parts than analogue or electromechanical relays with the result that the physical reliability of the protection relays has been vastly improved. This has also brought other advantages such as reduced CT burdens leading to lower CT size requirements and the possibility to combine CT cores for line and busbar protection, as well as reduced DC supply power requirements. Moreover, it recently enables us to realize the new functions such as the substation automation and, remote maintenance by applying LAN technology.

The deployment of digital relays has therefore rapidly increased over the last decade. As an example, the deployment of digital protection relays in the Japanese transmission systems 66kV and above is shown in **Figure 2.5-4**. According to this figure, about 60% of a total population of over 35000 protection relays are digital as of March, 2004 and it reaches about 75% regarding that in transmission systems.

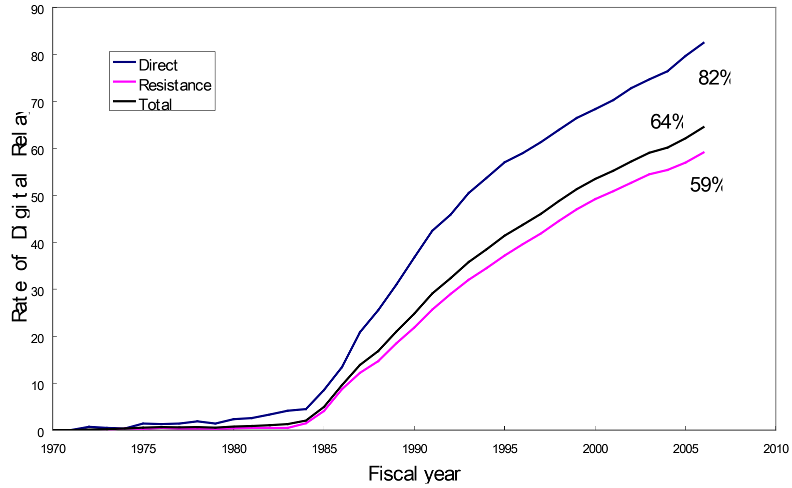


Figure 2.5-4 Population of Digital Relays in Transmission Systems above 66kV in Japan [2]

2.5.4 Addition of Failsafe Check Element

To prevent an unwanted trip in the case of a relay mal-function, a fail-safe or check function is sometimes added to the trip condition. For example, as shown in **Figure 2.5-5**, under voltage elements may be used as fail-safe relays for the current differential scheme of a bus bar or line differential protection system on the principle that an internal fault will also generate an under voltage condition depending on the network configuration and impedances. If the differential relay suffers an internal fault or for some reason does not receive all the current signals from all the zone CTs on the bus bar or the remote end of the line (e.g. a communications system failure) it may incorrectly try to operate as an internal zone fault, but the trip signal is blocked by the addition of the fail-safe relay such as an under voltage relay.

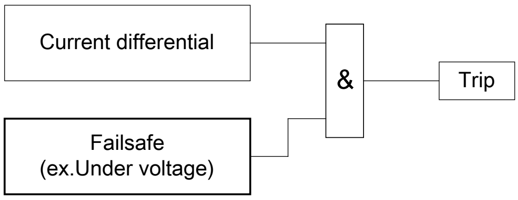


Figure 2.5-5 Addition of Failsafe Relay to Prevent Unwanted Trip

2.5.5 Monitoring of Related Equipment

If open-phase state of the power system (sometimes referred to as single phasing) continues for a long time, it may result in damage of equipment such as overheating of a motor or generator.

On the other hand, the unbalance current due to the open-phase may cause unwanted operation of the protection system itself although no particular power system fault yet exists. There are some kinds of the open-phase or pole discordance/discrepancy monitoring / protection as shown in **Figure 2.5-6**.

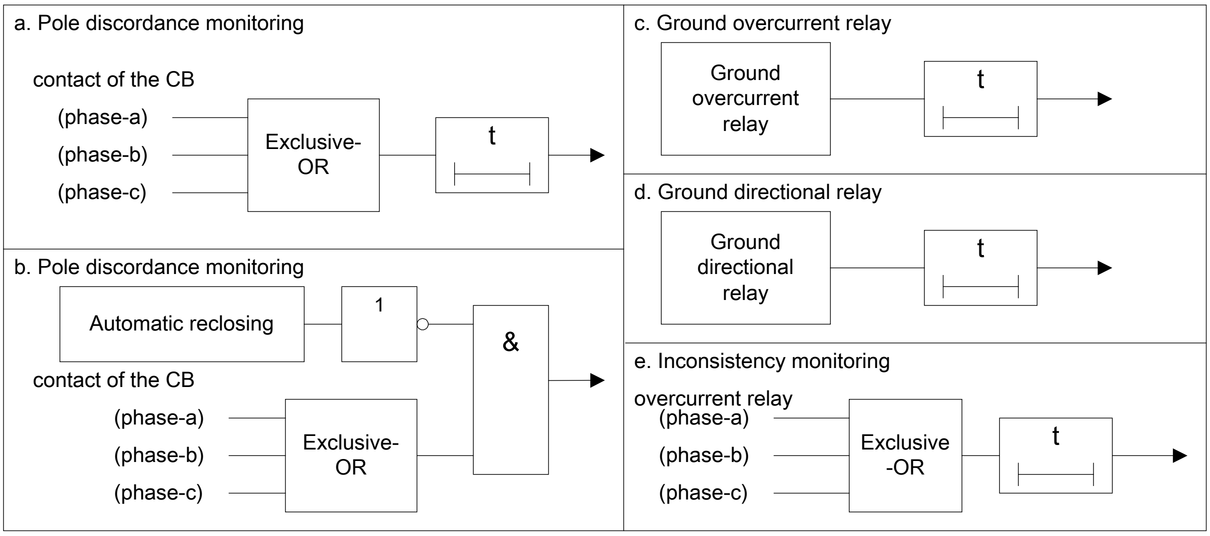


Figure 2.5-6 Open Phase Monitoring / Protection

Figure 2.5.6 (a) is used to detect any situation where one phase of the CB is open, i.e. the normal healthy state is all phases are open or closed.

Figure 2.5.6 (b) shows a refinement associated with single phase autoreclose systems where the pole discrepancy is blocked during single pole trip and reclose sequence.

Figure 2.5.6 (c) uses a ground over current relay to detect the unbalance current which appears as an earth fault.

Figure 2.5.6 (d) is a refinement of the above to only operate for unbalance from the supply side rather than potential earth faults on the equipment itself to provide better discrimination indication to the maintenance staff

Figure 2.5.6 (e) uses sensing of each phase of the over current relay inputs to detect general unbalance currents which are not high enough to trigger a fault trip in their own right, i.e. normally the individual phases would be all equal for a balanced load

2.6 Questionnaire Results

The WG surveyed the protection relays that are widely used in transmission systems and their coordination. The necessity of backup protection is summarized according to the classification as either EHV (187kV – 765kV) or HV (66kV – 154kV) according to the general IEC categories although EHV and UHV have been combined as the relays and applications applied in UHV are generally the same as for EHV. Relays used in distribution systems are not covered in the report.

2.6.1 Power System Configuration

Transmission systems range from 22kV to 735kV with most countries having several levels of voltage classes. 24 voltage levels are reported in total.

The result of the questionnaire about the power system configuration, the voltage class and the earthed neutral systems adopted in each country is shown in **Table 2.6-1**.

According to this, the configuration of transmission systems is mesh in most countries using solidly earthed neutral system. The mesh configuration is generally adopted due to the reasons of reduction of transmission loss and improvement of stability in long-distance transmission systems. Asian countries in particular, such as South Korea and Japan, generally use loop configurations of the power system because there are no significant interconnections.

Power systems below 154kV, such as in Japan, may use radial systems with resistance earthed neutral system to limit the zero sequence current, and reduce the induced current in parallel telecommunication lines. Since the sensitivity of the earth fault relay is decreased, protection relays using zero sequence voltage and current to detect an earth fault are widely used. In addition, the protection relay is equipped with the countermeasure against circulating current.

In highly dense power networks, the sharing of towers for EHV and HV transmission lines induces circulating current on HV transmission line. This is another reason of this requirement in Japan.

Table 2.6-1 Overview of Transmission Systems Survey Responses

	Voltage (in kV)	AU	CA	CN	ES	FR	IN	JP	KR	MY	PT	SE	UK
EHV	765	-	-	R	-	-		-	L	-	-	-	-
	735	-	M	-	-	-	-	-	-	-	-	-	-
	500	M,L,R	-	M	-	-	-	L	-	R	-	-	-
	400	-	-	-	M	M		-	-	-	M	M	M
	345	-	-	-	-	-	-	-	L	-	-	-	-
	330	M,L	-	M	-	-	-	-	-	-	-	-	-
	315	-	M	-	-	-	-	-	-	-	-	-	-
	275	R	-	-	-	-	-	R	-	M,L,R	-	-	M
	230	-	M	-	-	-	-	-	-		-	-	-
	225	-	-	-	-	L,R	-	-	-	-	-	-	-
	220	M,L	-	M,L,R	M	-		R	-	-	M	M	-
	187	-	-	-	-	-	-	R	-	-	-	-	-
HV	154	-	-	-		-	-	R	L	-	-		
	150	-	-	-		L,R	-	-	-	-	M		
	132	M	-	-		-		-	-	M,L,R	-		
	120	-	L,R,M	-		-	-	-	-	-	-		
	110	-	-	R		-	-	R	-	-	-		
	90	-	-	-			-	-	-	-	-		
	77	-	-	-		-	-	R	-	-	-		
	66	L		R		-	-	R	-	R	-		
	63	-	-	-			-	-	-	-	-		
	33	-	-	R		-	-	R	-	-	-		
	22	-	-	-		-	-	R	-	-	-		
	20	-	-	R			-	-	-	-	-		

<Note> L: Loop, M: Mesh, R: Radial

: Resistance earthed neutral, : Petersen coil earthed neutral

2.6.2 CT Arrangement

Table 2.6-2 shows the result of the questionnaire for the arrangement of CTs. According to this table, the arrangement shown in **Fig 2.3-2 (c)** without any dead zone from protection relays is desirable, but in practical application, CT arrangement is chosen appropriately by taking into consideration the importance of the power system, the system configuration, the installation space, etc.

Table 2.6-2 CT Arrangement

CT arrangement	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
(a) CTs are installed on the line side from the CB	×	×	×	×	×	×	×	×	×	×	×	-	×	×	-	×	×	×	×	×	×
(b) CTs are installed on the bus side from the CB	-	-	×	×	-	-	×	-	-	-	-	-	-	-	-	-	-	×	×	×	-
(c) CTs are installed on both sides of the CB	×	×	-	-	×	×	-	-	-	-	-	×	×	×	×	×	×	-	-	-	×

2.6.3 Necessity of Backup Protection

Table 2.6-3 shows the necessity of backup protection for lines, bus bars, and transformers based upon the result of the questionnaire. The results indicate slight differences between HV and EHV applications in consideration of redundancy, sensitivity, power system conditions, or the composition of the main protection. Although this table shows the overall necessity of backup protection there are some small differences in requirements for the protected equipment of lines, bus bars, and transformers. The necessity of backup protection for bus bars is generally related to the busbar configuration. In Japan, the resistance earthed neutral system is adopted in the power systems below HV, and since relatively few power sources are connected to these systems, and the importance is relatively low, it has been determined that specific backup protection is generally not required although Zone 2 line protection at the remote ends provides the backup protection for the busbar.

Table 2.6-3 Necessity of Backup Protection

	Necessity	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
		EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Line protection	a	-	-	×	×	×	×	×	-	-	×	×	×	×	×	×	×	×	-		-	-
	b	×	×	×	×	×	×	×	-	×	×	×	×	×	×	×	×	×	×		×	×
	c	×	×	×	×	×	×	-	×	×	×	×	×	×	×	-	-	-	-		×	×
	d	×	×	×	×	×	×	-	-	-	×	×	×	-	×	×	×	×	-		-	×
	e	-	-	-	-	×	×	-	-	-	-	-	-	-	-	-	-	-	×		-	-
Busbar protection	a	-	-	×	-	×	-	×	Not Available	Not Available			×	Not Available	Not Available	Not Available	×	×	-	-	-	Not Available
	b	-	-	×	-	-	-	×	Not Available	Not Available			×	Not Available	Not Available	Not Available	×	×	×	×	×	Not Available
	c	×	×	-	-	-	-	-	Not Available	Not Available			×	Not Available	Not Available	Not Available	-	-	-	-	×	Not Available
	d	×	×	×	×	-	×	-	Not Available	Not Available			×	Not Available	Not Available	Not Available	-	-	-	-	-	Not Available
	e	-	-	-	-	-	-	-	Not Available	Not Available			-	Not Available	Not Available	Not Available	×	×	-	-	-	Not Available
Transformer protection	a	-	-	-	-	×	×	×	-	-	×	×	×	×	×	×	×	×	-		-	-
	b	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×		×	×
	c	×	×	×	×	×	×	-	-	-	×	×	×	×	×	×	-	-	-		×	×
	d	×	×	×	×	×	×	-	-	-	×	×	×	-	×	-	×	×	-		-	-
	e	-	-	-	-	×	×	-	-	-	×	×	-	-	×	-	-	-	×		-	×

<Note> a. Against a fault during blocking of the main relay(s)

b. Failure of the main relay(s)

c. Against particular type of a fault which cannot be detected by the main protection

d. CT, or VT, or CB failure

e. Against a fault at an apparatus which no main relay protect

2.6.4 Reliability

(1) Duplication and Redundancy

Protection systems are often referred to as redundant systems where there two systems, i.e. duplicated protection, with nominally the same performance capability to clear the fault in the required time. The redundant systems may be provided as two different types such as distance and current differential rather than duplications of the same type. This is different to back up systems which only operate in case of failure of the main protection system and hence with a delayed fault clearance compared to the main protection requirement.

Table 2.6-4 shows the questionnaire result about the redundancy of the main protection and backup protection for transmission lines, bus bars, and transformers, respectively.

According to this table, main line protection for EHV transmission lines are mostly provided in redundant configuration whilst generally the backup protection is not provided in redundant configurations even for EHV applications.

The busbar protection results show a greater acceptance of non redundant protection compared to that for line protection. Very few utilities apply redundancy of backup busbar protection.

The transformer protection, results show protection relay for the transformer more than 154kV level are generally applied in redundant configurations, and most of utilities answered to use non redundant backup protection schemes for the protection for transformer.

As described above, redundancy is different from a country or voltage level perspective in consideration of the importance of the power system.

Table 2.6-4 Redundancy

	Voltage Class		AU	CA	CN	ES	FR	IN	JP	KR	MY	PT	SE	UK
Line protection	EHV (765- 187)	M	2	2	2	2	2	2	2	2	2	1 or 2	2	2
		B	1 or 2	1	2	1	1	1	1 or 2	1 or 2	1	1	1 or 2	1
	HV (below 154)	M	2	2	1		1	1	1	1	1	1 or 2		
		B	1 or 2	1	1		1	1	1or NA	1	1	1		
Busbar protection	EHV (765- 187)	M	2	1	2	2	1	1 or 2	2	1 or 2	2	1 or 2	1 or 2	1
		B	1 or 2	1	2	1	NA		1	NA	1	1	1	NA
	HV (below 154)	M	2	2	1		1	1	1	1	1			
		B	1 or 2	1	1		NA		NA	NA	1			
Transformer protection	EHV (765- 187)	M	2	2	2	2	1	1	2	1 or 2	2	1 or 2	2	1
		B	1 or 2	1	2	1 or 2	1	1	1 or 2	1	1	1	2	1
	HV (below 154)	M	2	2	1		1	1	1	1	1			
		B	1 or 2	1	1		1	1	1or NA	1	1			
BFP	EHV(765- 187)		1 or 2	1	1	1	1		1 or 2	1	1	1	1	1
	HV (below 154)		1or NA	1	1				NA	1	NA	-		

<Note> M: Main protection, B: Backup protection

(2) Types of Relays

Table 2.6-5 shows the questionnaire result about types of protection relays applied to the system.

Even though digital relays are the majority of the devices being installed, analogue or mechanical relays are still used in some applications, notably for high impedance busbar protection for example due to its simplicity of application, speed of operation and proven high reliability.

However it is clear that the global situation is transitioning from analogue / mechanical to digital relays. Also, it shows the strategies of digital-transition of some countries, which is to start with EHV, especially for Line protection. Digital relays are enhanced in several points. Automatic supervision function is one of basic features of digital relays which has contributed to this change as indicated in the next section.

Table 2.6-5 Type of Protection Relays

Type			AU	CA	CN	ES	FR	IN	JP	KR	MY	PT	SE	UK
Line Protection	Main	EHV	D,A,M	D,A,M	D	D	D,A,M	D,A	D	D	D,A	D,A,M	D,A,M	D,A
		HV	D,A,M		D	/	D,A,M	D,A	D,A,M	D	D,A,M	D,A,M	/	/
	Backup	EHV	D,A,M	D,A,M	D	D		D,A	D	D	D,A	D,A,M	D,A,M	D,A,M
		HV	D,A,M		D	/		D,A	D,A,M	D	D,A,M	D,A,M	/	/
Busbar Protection	Main	EHV	D,A,M	D,A,M	D,A	D,A		D,A	D	D,A	D,A	D,A,M	D,A,M	D,A,M
		HV	D,A,M		D,A	/		D,A	D,A,M	D,A	D,A	D,A,M	/	/
	Backup	EHV	D,A,M	D,A,M	D	D,A	NA	D,A	D,M	NA	D,A	D,A,M	D,A,M	NA
		HV	D,A,M		D	/	NA	D,A	NA	NA	D,A	D,A,M	/	/
Transformer Protection	Main	EHV	D,A,M	D,A,M	D,A	D,A		D,A	D,A,M	D	D	D,A	D,A,M	D,A,M
		HV	D,A,M	D,A,M	D,A	/		D,A	D,A,M	D	D,A	D,A,M	/	/
	Backup	EHV	D,A,M	D,A,M	D,A	D,A,M		D,A	D,A,M	D	D,A	D,A,M	D,A,M	D,A,M
		HV	D,A,M	D,A,M	D,A	/		D,A	D,A,M	D	D,A	D,A,M	/	/
BFP		EHV	D,A,M	D,A,M	D	D			D	D	D,A	D,A	D,A,M	D,A,M
		HV	D,A,M		D	/			NA	D	NA	D,A	/	/

<Note> D: Digital, A: Analogue Static, M: Mechanical

(3) Automatic Supervising

The questionnaire result about the application of automatic supervision is shown in **Table 2.6-6**. According to this table, the tendency for automatic monitoring is summarized as follows: most of countries apply continuous monitoring only. Some countries apply automatic testing as well as continuous monitoring. The tendency is the same for line protection, busbar protection and transformer protection. This feature is considered one of the main drivers for the increasing deployment of digital relays year by year.

In **Table 2.6-6**, CM stands for Continuous Monitoring and AT stands for Automatic Testing. Moreover, the slash corresponds to the case that some protection is not applied in **Table 2.6-4**. Therefore, if the protection has no automatic monitoring function, "NA" is chosen in this table.

Table 2.6-6 Application of Automatic Supervising Function

			AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
			EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Line protection	M	CM+AT	-	-	×	×	×	×	-	-	-	-	-	×	×	-	-	-	-	-	-	-	-
		CM	×	×	-	-	-	-	×	×	×	×	×	-	-	×	×	×	×	×	×	×	×
		AT	×	×	×	×	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		NA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	B	CM+AT	-	-	×	×	×	×	-	-	-	-		×	×	-	-	-	-	-	-	-	-
		CM	×	×	-	-	-	-	×	×	×	×		-	×	×	×	×	×	×	×	×	×
		AT	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-
		NA	×	×	-	-	-	-	-	-	-	-		-	×	-	-	-	-	-	-	-	-
Busbar protection	M	CM+AT	-	-	×	×	×	×	-	-	-	-		×	×	-	-	-	-	-	-	-	-
		CM	×	×	-	-	-	-	×	×	-	×		-	×	×	×	×	×	×	×	×	×
		AT	-	-	-	-	-	-	-	-	-	-		×	×	-	-	-	-	-	-	-	-
		NA	×	×	-	-	-	-	×	-	-	-		-	×	-	-	-	-	-	-	-	-
	B	CM+AT	-	-	×	×	×	×	-			-		×				-	-	-	-	-	
		CM	×	×	-	-	-	-	×			×		-				×	×	×	×	×	
		AT	-	-	-	-	-	-	-			-		-				-	-	-	-	-	
		NA	×	×	-	-	-	-	-			-		×				-	-	-	-	-	
Transformer protection	M	CM+AT	-	-	×	×	×	×	-	-	-	×	×	×	×	×	×	-	-	-	-	-	-
		CM	×	×	-	-	-	-	×	×	×	×	×	-	×	×	-	×	×	×	×	×	×
		AT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		NA	×	×	-	-	-	-	-	-	-	-	-	×	×	-	-	-	-	-	-	-	-
	B	CM+AT	-	-	×	×	×	×	-	-	-	-	-	×	×	×	×	-	-	-	-	-	-
		CM	×	×	-	-	-	-	×	×	×	×	×	-	-	×	-	×	×	×	×	×	
		AT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		NA	×	×	-	-	-	-	×	-	-	-	-	×	×	-	-	-	-	-	-	-	×
BFP		CM+AT	-	-	×	×	×	×	-	-	-			×	×	-		-		-	-	-	-
		CM	×	×	-	-	-	-	×	×	×			-	-	×		×		×	×	×	×
		AT	-	-	-	-	-	-	-	-	-			×	-	-		-		-	-	-	-
		NA	×	×	-	-	-	-	-	-	-			×	×	-		-		-	-	-	-

(4) Open Phase Monitoring

The questionnaire result for the open-phase monitoring / protection is shown in **Table 2.6-7**. According to this table, the open-phase monitoring / protection is adopted in trunk transmission systems in each country or each electric power companies.

Pole discrepancy monitoring is most widely used. Other schemes are earth fault relay or overcurrent relay, as shown in **Table 2.6-7**. The setting of the timer is required to coordinate with the dead time of the automatic reclosing.

Table 2.6-7 Application of Open Phase Monitoring / Protection

Open phase Monitoring	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
a.Pole discordance monitoring	×	×	-	-	×	×	×	×	×			×	-	×	-	×	-	×	×	-	×
b.Pole discordance monitoring	-	-	-	-	-	-	-	-	-			-	-	×	-	-	-	-	-	-	-
c.Ground overcurrent relay	-	-	-	-	×	×	-	-	-			-	-	×	-	-	-	-	-	×	×
d.Ground directional relay	-	-	-	-	-	-	×	-	-			-	-	-	-	-	-	-	-	×	-
e.Inconsistency monitoring	-	-	-	-	-	-	-	-	-			-	-	-	-	-	-	-	-	-	-
Not Available	×	×	×	×	-	-	-	-	-			-	×	-	×	-	×	-	-	-	-

<References>

[1] UCTE Annual Report 2006

[2] H. Kameda and K. Yamashita,"Fundamental Study on Rationalization of Maintenance Procedure based upon Reliability Analysis", Wiley, Volume 156 Number 2, July 30, 2006, pp25-31

3. Fault Clearance Relays

3.1 Line Protection

3.1.1 Protection Scheme

Table 3.1-1 shows outline of line protection schemes, which are widely used in each country. In the same table, if a protection scheme is carrier protection, the medium of the telecommunication is shown. Where the protection scheme is applied for an overhead line, the use of reclosing is also shown.

Table 3.1-1 Line Protection

Scheme	Prnciple	communication	Reclosing	Note
Current differential	Current data at the self-end is transmitted to the remote-end. Differential current is calculated from currents of all-ends. Whether the fault occurs within the protective zone or not is discriminated from the differential current.	Micro-wave Optical-fiber	Single-pole Multi-pole Three-pole	The high performance enables us to apply it as main protection for trunk transmission lines.
		Pilot-wire	Three-pole	It applies for relatively short lines.
Overcurrent	An internal fault is discriminated from the value of the measured current. It is not directional.	Not available	Three-pole	As it is not directional, time coordination is required.
Distance	An internal fault is discriminated from the impedance from the relay to the fault point measured by input voltage and current.	Not available	Three-pole	It is applied as main protection for relatively simple transmission systems and also applied as backup protection as well.
Directional comparison	An internal fault is discriminated from combination of the response of the directional relay against an internal fault and that against an external fault at the self-end and the response of the relays at the remote-end through the communication system.	Micro-wave Optical-fiber PLC	Single-pole Three-pole	It is widely applied as main protection. One of advantages is that a power-line carrier is available as the communication system.
Phase comparison	An internal fault is discriminated by comparison of current phases at all-ends. If the direction of the current from the bus to the line is positive, the phase of currents at both ends are in phase against an internal fault, and they are in opposition against an external fault.	Micro-wave Optical-fiber	Single-pole Three-pole	It has been replaced by a current differential relay.
Transverse differential	The current difference between both lines are nearly zero against an external fault, and that is large against an internal fault. The faulted line is discriminated by the absolute value of the current difference between both lines and its direction.	Not available	Three-pole	It widely applies for a parallel line in Japanese HV systems.

(1) Protection with Current Differential Relays

(a) Principle and Characteristics

Current differential scheme is a highly reliable method for the line protection, however, data transmission between the substations is one of the technical issues for its introduction. The operating principle is quite simple, where the vector sum of both-terminal current is zero when the line is healthy or an external fault exists. In the case of an internal fault on the line, the vector sum of both terminal currents is equal to a fault current, causing the relays at each end to trip.

A usual characteristic of current differential relay is shown in **Figure 3.1-1** where characteristic is percentage biased, with the relay operating when the ratio of differential current to restraint current is above the lines. The differential current is the magnitude of the vector summation of currents at each end whilst the restraint current is the magnitude summation of the currents only. In the ‘large-current’ zone, the percentage ratio to cause operation is required to be larger in order to prevent mal-operation caused by CT saturation. In small-current zone, percentage ratio is smaller so that faults can be detected with more sensitivity.

It is desirable that the same type CTs are used at both terminals having the same characteristics in order to have the same excitation characteristic and hence no difference in performance for external faults, however different type CTs with different ratio can be also applicable by setting the values of CT ratios at each terminal.

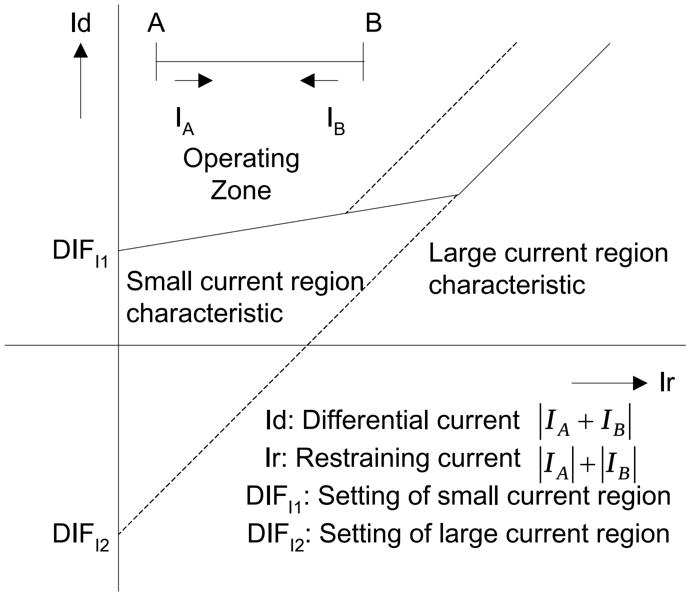


Figure 3.1-1 Characteristics of Current Differential Relay

(b) Data transmission and Synchronism for Data Sampling

Analogue pilot-wire relays with current or voltages connected directly to each end have been a traditional solution for these schemes although with some limitations on distance between the substations. Digital type current differential relay is rapidly becoming the mainstream application including further distances between substations. In the digital type current differential scheme, synchronism for data sampling is essential. When an exclusive data channel with a constant time delay for data transmission between the substations is used, such as micro-wave or optical fiber, relay devices can generate synchronized sampling timing by themselves. If the data transmission delay time between the substations is inconsistent, GPS clock is effective for generating synchronized timing.

(c) Multi-Terminal Line Protection

Current differential scheme is also suitable for protection of multi-terminal transmission line, where data transmission is a key technique. **Figure 3.1-2** shows an example of current differential relay application to three-terminal line using peer-to-peer data transmission. For the lines with more than four-terminals, ring type data transmission is applicable, as shown in **Figure 3.1-3**, where the protection system is composed of one central device and other remote terminals in this example. Terminal data are transmitted to the central device via ring transmission route. In case of an internal fault, the central 'parent' device detects the fault and trip commands are sent to each terminal 'child' device.

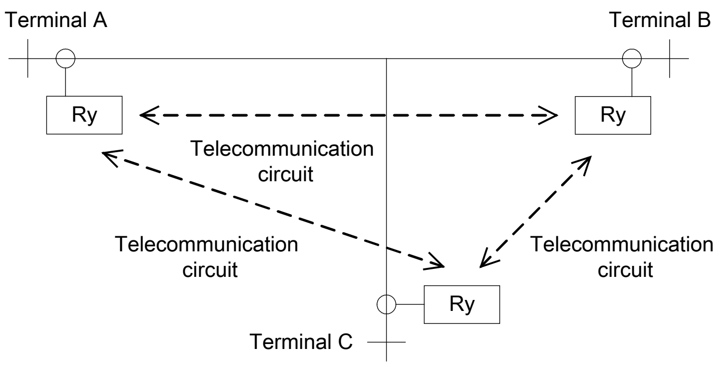


Figure 3.1-2 Data Transmission for Three-Terminal Protection

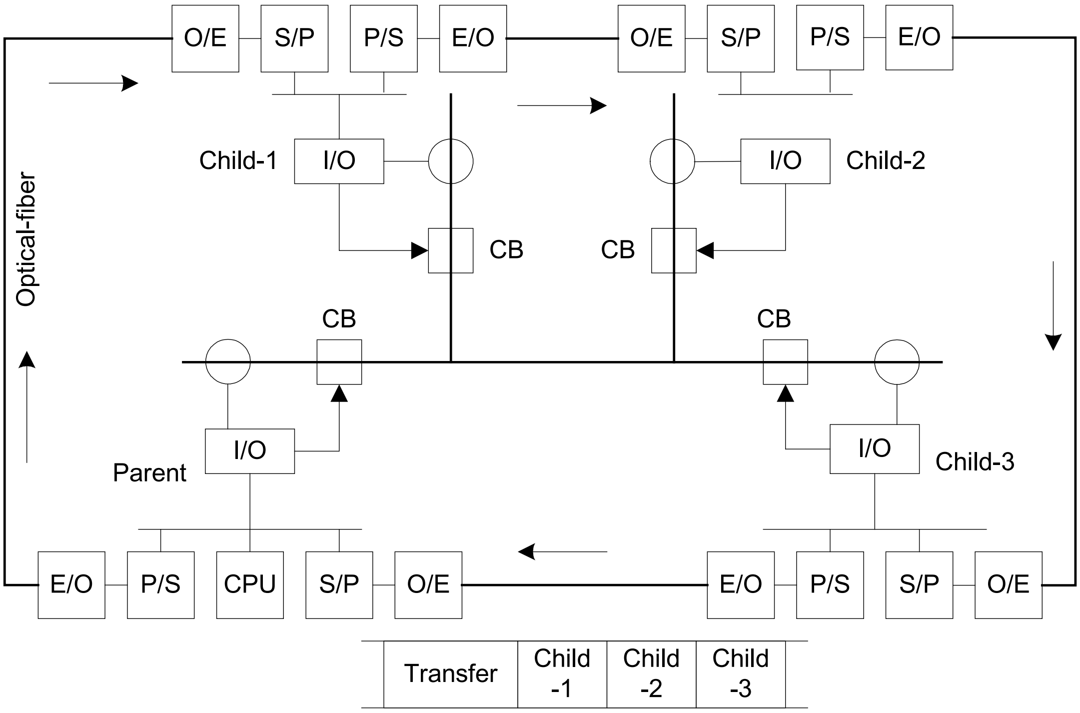


Figure 3.1-3 Data Transmission for Four-Terminal Protection
O/E, E/O Optical/Electrical interface of communication channel
S/P, P/S: Signal Processing
CPU: Central Processing Unit
I/O Input / Output

(d) Setting Issue

Settings of the line current differential relay are determined so that the relay operates correctly for the smallest-current internal fault, and not to operate for an external fault with pseudo differential current caused by line-charging current, CT saturation or other error components. Especially when the relay is applied to a three-terminal line, settings should be determined taking account of an internal fault with the largest outflow current as shown in **Figure 3.1-4**. In the figure, an internal fault occurs on the line between terminals A and B in a three-terminal double-circuit line. Half of the fault current outflows via terminal-C (1/2 outflow), and re-flows-in from the terminal-B. Hence the current differential protection applied to the lower A-B-C line must cater for a through fault entering at terminal C and outflow at terminal B

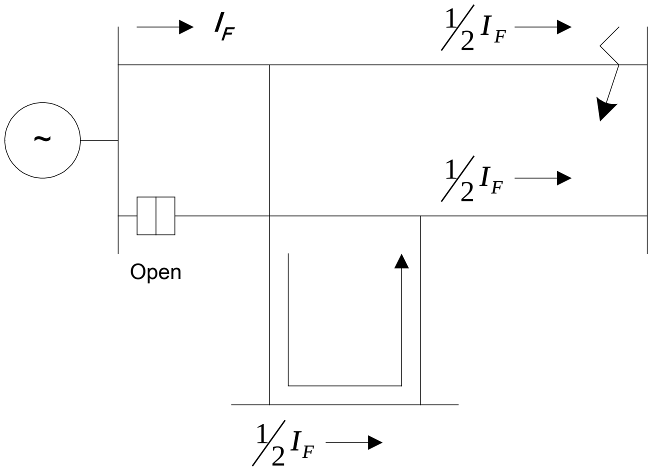


Figure 3.1-4 Maximum Outflow for Three-Terminal Line

Figure 3.1-5 shows an example of the current differential relay characteristics that are applied to a three-terminal line, where operating characteristics are composed of three current zones.

Setting of the relay for a two-terminal line should be determined to operate correctly for an internal fault with the smallest fault current and not to operate for charging current or error current caused by an external fault.

Setting of the relay for a three-terminal line should be determined to operate correctly for an internal fault with the largest outflow current (see **Figure 3.1-4**) and not to unwantedly operate against CT saturation caused by through-current of an external fault.

The minimum operating value of the relay I_{dk} is usually set for two or three times larger than the smallest internal fault current. **Figure 3.1-4** shows the case of internal fault with maximum outflow, where half of the fault current outflows from the terminal-C (1/2 outflow).

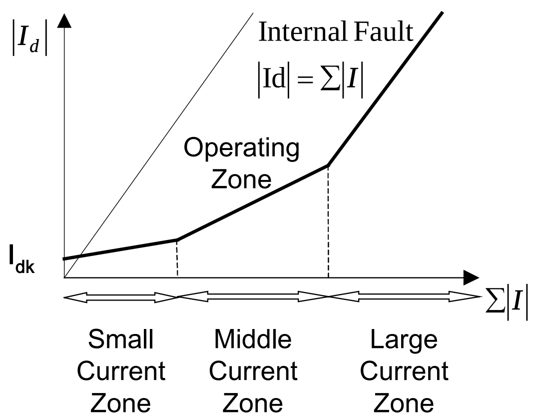


Figure 3.1-5 Example of Line Current Differential Relay Applied to Three-Terminal Line

The characteristics of each zone are as follows:

- **<u>Small current zone</u>** - The highest operating sensitivity is achieved for a small fault current.
- **<u>Middle current zone</u>** - Internal fault with maximum outflow current for a three-terminal line is taken into account.
- **<u>Large current zone</u>** - Percentage bias is maximum considering CT saturation caused by an external fault

The following shows a detailed example procedure for determining setting values.

1) Minimum operating value

The minimum operating value of the relay I_{dk} is usually set so that the smallest internal fault current is more than twice or three times of the I_{dk}, where the I_{dk} should also satisfy the equation (3.1) so as not to unwantedly operate for a fixed error, such as line charging current or error originates in relay hardware.

$$I_{dk} \geq \beta \times (n \times I_{\varepsilon} + I_c) \qquad (3.1)$$

where β: margin

n: number of terminals

I_{ε}: error component current per one-terminal, includes analogue error in a relay hardware $I_{\varepsilon f}$, and quantization error $I_{\varepsilon q}$.

I_c: line charging current in the protected zone. When a line charging current is compensated, it means charging current not yet compensated and compensating error.

2) Percentage bias

Percentage bias of each zone is determined as follows;

Small current zone: operating sensitivity is set so as not to unwantedly operate against errors generated by largest passing-through external fault current.

Here,

ε_{CT}: CT error

ε_{SP}: synchronizing error of data sampling, that is caused by change of data transmission time delay

ε_{RY}: proportional error of relay hardware, such as error of input-transformer

Now, the percentage biased characteristics are determined as follows taking account of total error;

$$\varepsilon = \varepsilon_{CT} + \varepsilon_{SP} + \varepsilon_{RY}$$

For an external fault, the following is assumed considering error ε as the worst case;

$$\frac{I_{out}}{I_{in}} = \frac{1-\varepsilon}{1} = 1-\varepsilon$$

Then, equation for the relay operation is as follows;

$$I_{out} \leq (1-\varepsilon)(I_{in} - I_{dk})$$

Where operating quantity and restraint quantity is expressed as the followings.

$$|I_d| = I_{in} - I_{out}$$

$$\Sigma|I| = I_{in} + I_{out}$$

then

$$|I_d| \geq \frac{\varepsilon}{2-\varepsilon}\Sigma|I| + \frac{2(1-\varepsilon)}{2-\varepsilon} I_{dk}$$

here, assuming error $\varepsilon_{CT}=0.02$ (1 % /terminal), $\varepsilon_{SP}=0.04$, $\varepsilon_{RY}=0.04$, considering twice-margins $\varepsilon=0.2$,

$$|I_d| \geq \frac{1}{9}\Sigma|I| + \frac{8}{9} I_{dk}$$

Middle current zone: considering the internal fault with 1/2 out-flow from one terminal

$$\frac{I_{out}}{I_{in}} = \frac{1}{2}$$

Considering margins,

$$\frac{I_{out}}{I_{in}} = \frac{5}{9}$$

Intersection point between small- and middle-current zone should cover minimum fault current with out-flow phenomenon. Expressing current at the intersection point I_{in} as $I_{in} = m \times I_{dk}$,

$$I_{out} \leq \frac{5}{9} I_{in} + \left\{ m\left(\frac{4}{9} - \varepsilon\right) - (1-\varepsilon) \right\} I_{dk}$$

Accordingly,

$$\left|I_d\right| \geq \frac{2}{7}\Sigma\left|I\right| + \frac{9}{7}\left\{m\left(\frac{4}{9}-\varepsilon\right)-\left(1-\varepsilon\right)\right\}I_{dk}$$

Then, assuming $\varepsilon = 0.2$, $m=6$,

$$\left|I_d\right| \geq \frac{2}{7}\Sigma\left|I\right| - \frac{6}{7}I_{dk}$$

Where, $m=6$ is based on the following conditions;

$I_{dk}=600A$ and minimum internal fault current is 4kA, (1/2 of it out-flows).

Namely, minimum internal fault with 1/2 out-flow is assumed that,

$I_{in}=6.6 \times I_{dk}$, $I_{out}=3.3 \times I_{dk}$.

Large current zone: in order to prevent unwanted operation against CT saturation caused by extremely large passing-through current of an external fault, percentage bias is set to 100%, and the characteristic of the relay is determined considering each CT performance.

Average solution for determining relay characteristics is as follows;

In the case CTs have anti-saturation measures for a long-term DC damping, the following characteristic is used that includes maximum internal fault current with 1/2 out-flow.

$$\left|I_d\right| \geq \Sigma\left|I\right| - 48I_{dk}$$

where the point of maximum internal fault current with 1/2 out-flow is specified that

$I_{dk}=600A$,

I_{in}=*about 26kA* ($=43I_{dk}$), I_{out}=*about 13kA*($=21I_{dk}$)

In the case conventional type CTs are used with small burden or passing-through current of an external fault is small, where modified accuracy-limit factor of the *CT n'>10*.

Characteristic is medium between (a) and (c).

$$\left|I_d\right| \geq \Sigma\left|I\right| - 24I_{dk}$$

In the case conventional CTs are used, where modified accuracy-limit factor of the *CT n'>5*

The following characteristic is used in order to avoid unwanted operation against CT saturation.

$$\left|I_d\right| \geq \Sigma\left|I\right| - 12I_{dk}$$

Where,

$$n' = \text{(rated burden/rated secondary current of the CT)} \times \text{(accuracy limit factor of the CT)}$$
$$= \text{(Maximum passing external - fault current/CT ratio)}$$
$$\times \text{(CT internal resistance + resistance of CT burden)}$$

(2) Protection with Overcurrent Relays

(a) Principle and Practice

Overcurrent relay can be applied successfully on transmission networks under certain conditions especially in the radial lines. It determines if a fault is in a relay's zone of protection by using current from one point only. If the current is larger than the setting value, it sends a trip signal to the associated breaker.

The criteria for deciding whether directional relays should be required are typically determined by the ratio of currents flowing in relays at the two ends of a line. Consider a system depicted in **Figure 3.1-6**, where three fault locations are numbered and fault currents at the breaker A corresponding to each fault are shown.

The criteria that have been developed through practice require that a directional relay be applied at A if any of the following load or fault current conditions exist (numbers in parentheses refer to fault locations).

(1) $I_{(1)\min} \geq 0.25_{I(2)\min}$

(2) $I_{(1)\min} \geq 0.25_{I(3)\min}$ *(3.1)*

(3) $I_{LdOut} \geq I_{LdIn}$

Where I_{LdIn} and I_{LdOut} refer to the maximum load currents flowing inside and outside of the protected line at A, respectively.

The need for directional capability depends on the ratio of currents in each direction seen at each relaying point, where the current might be caused to flow in different directions. Fault current for fault at bus (1) is seen "behind" the relay A, while the faults at busbar (2) and (3) are "in front" of the relay. If it is possible to have fault or load currents flowing to the left in the figure and those currents exceed the magnitudes noted, then directional relays are required. If the load current from H to G (I_{LdOu}) is greater than the one from G to H (I_{LdIn}), the use of directional relays will permit more sensitive settings. It is assumed that relay A is also used for remote backup of relay C.

In another scenario, as the fault level immediately to the left of relay B is effectively the same as immediately to the right of relay C. If the B and C relays were non directional, they could potentially not be able to discriminate correctly between them, i.e. B may operate for a fault between C and D, or C may operate for a fault between A and B, hence the need for directional elements.

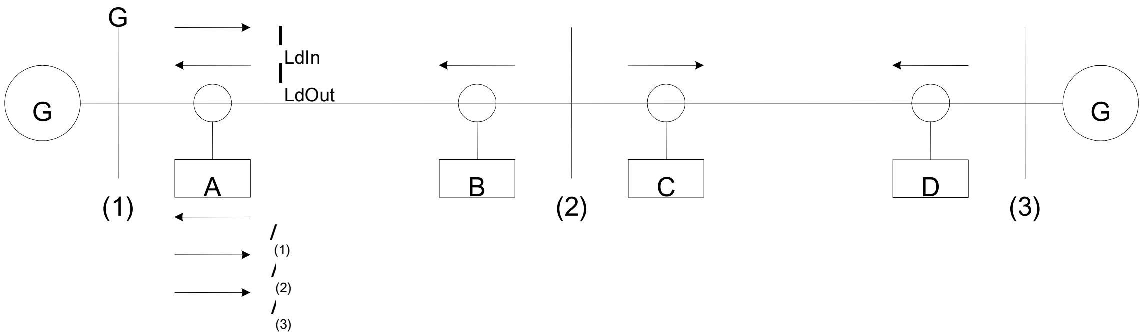


Figure 3.1-6 Criteria for Requiring a Directional Overcurrent Relay

(b) Setting Overcurrent Relays

There are two settings - pick up (tap setting) and time delay (time dial).

The pickup setting is set above the maximum load current and less than the minimum fault current. Note that in the case of electromechanical disc relays, the relay will not close its trip contact until the current has exceeded the nominal setting, in some cases by as much as 120% due to the electromechanical forces in the relay and even so may take several minutes to operate. As a result electromechanical relays cannot be used for low level overload conditions. Modern electronic and digital relays however have much lower requirements typically operating after the time delay for currents as low as 105% of setting. Grading of upstream electronic relays with downstream electromechanical relays must therefore also take this into consideration.

The time dial is selected based on operating times of the relay in order to provide correct grading with the operating times of other relays on the network at the maximum fault current level at that point.

As an example of overcurrent relay setting, let's consider the case of a looped transmission system there is only one source of fault current, such as the system shown in **Figure 3.1-7**. The source of fault current is to the left of bus R. Therefore, it is permissible to use nondirectional overcurrent relays at locations 1 and 10, since the fault currents will only flow to the right.

For those relays to the right of buses G and T (locations 2 to 9), the normal load current could flow in either direction, depending on the relative size of the loads, and this must be taken into account in setting the minimum operating current of all relays in the loop.

Now, consider a fault on line RG. We have already observed that a fault on bus R causes zero fault current in line RG. As the fault location is moved to the right, the fault current seen by relay 2 increases to the value for a fault at bus G. Since the normal directional load current seen by relay 2 Is zero, it can be set with a very low pickup value just above any tapped load current, if any such load exists along the line. Relay 2 can also be an instantaneous device with no intentional time delay as it does not need to grade with any relays downstream of its direction (i.e. towards R). Obviously, the same conclusion can be reached for relay 9.

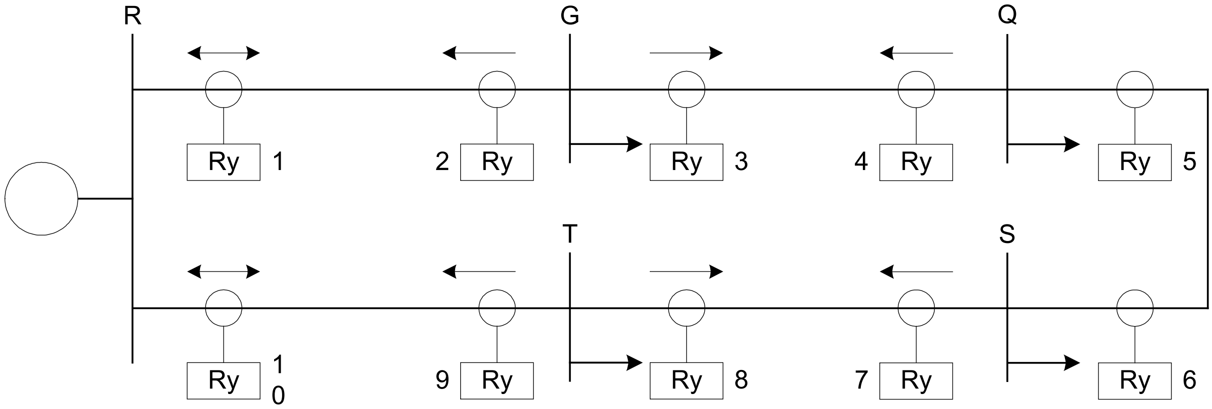


Figure 3.1-7 A Transmission Loop Circuit with Only One Source of Fault Current

Now, as the fault is moved from R toward G, relay 1 will see its maximum fault current for a fault immediately to the right of its location. As the fault position is moved towards G further, the fault current seen by relay 1 will start to decrease and the fault current seen by relay 2 begins to increase from zero.. Since the fault current at 1 is large and consequentially may cause more damage, this relay will be set to trip first in consideration of its operating time at large currents compared to the lower current seen elsewhere around the loop, thereby opening the loop and creating a counter-clockwise radial line now with all the fault current now being seen by relays from 10 through to 2. We then coordinate these relays in exactly the same way as a radial line.

For inverse-time overcurrent relays, the critical coordination is always at maximum current. Therefore, the criterion for coordination of overcurrent relays on the single-source transmission loop is as follows:

1) Consider maximum conditions.
2) Set the last relay in the loop to trip instantaneously (2 or 9).
3) Open the loop at the extreme end (2 or 9).
4) Compute maximum current at the remote bus (G or T).
5) Coordinate upstream relays as if the line were radial.
6) Repeat, traversing the loop in the opposite direction.

For establishing the minimum operating current (minimum pickup):

7) Computes maximum load and add a safety factor for cold load pickup and load growth.
8) Establish minimum pickup with the loop open.

Since maximum fault current flows at any relay location with the loop open, The relays must be coordinated for this condition. i.e., with the loop open at one end. The same must be done for the minimum operating current. Coordinating at maximum current conditions will ensure the greatest coordination time interval (CTI) between adjacent settings. As in the radial system, the relays are coordinated in pairs. Thus, with breaker 1 open, we coordinate 4 with 2, 6 with 4, 8 with 6, and 10 with 8. A similar pattern would be setup in coordinating the loop in the opposite direction.

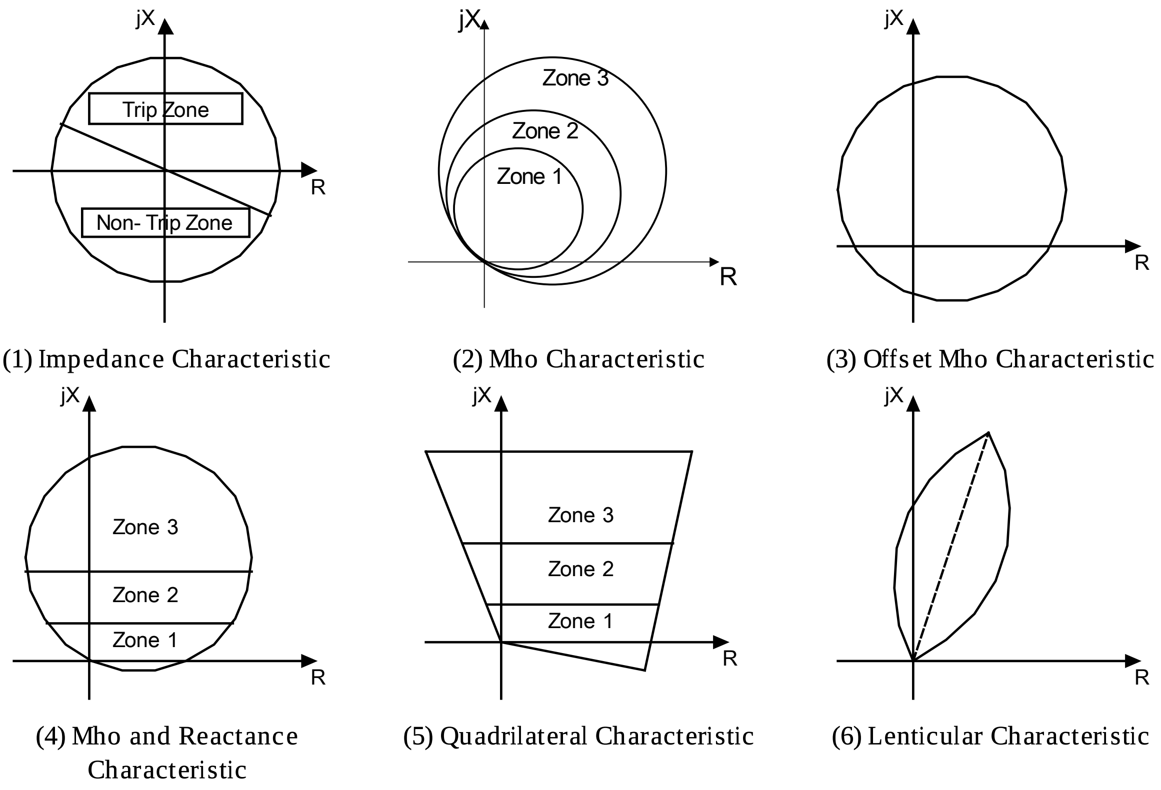
(3) Protection with Distance Relays

(a) Distance Protection

Distance protection is the most commonly used protection scheme for subtransmission and transmission line systems. It has the ability to discriminate between faults occurring in different parts of the systems depending on the impedance measured. Distance relay operates by using both voltage and current to determine if a fault is in a relay's zone of protection. Whilst this requires both current and voltage inputs for the protected line, the distance relay does not in basic scheme arrangements require any communication channels to the remote end as with current differential. Unlike differential relays, it is difficult to set distance relays applied on multi-ended transmission lines due to relative impedances of each segment and the effective reach of the relay. This type of the relay is available for both phase and earth fault protection.

(b) Types of Distance Relay

Distance relays are classified according to their characteristics in the R-X diagram and there are numerous differences in relay characteristics. The relays are set according to the positive and zero-sequence impedance of the transmission line. **Figure 3.1-8** shows the R-X diagrams of common types of distance relays.



(1) Impedance Characteristic
(2) Mho Characteristic
(3) Offset Mho Characteristic
(4) Mho and Reactance Characteristic
(5) Quadrilateral Characteristic
(6) Lenticular Characteristic

Figure 3.1-8 Basic Distance Relay Types

(c) Reach Setting of Distance Relay

Distance relays are set on the basis of the positive-sequence impedance from the relay location up to the point on the line to be protected. Normally, three protection zones in the direction of the fault are used in order to cover a section of line and to provide backup protection to remote sections (see **Figure 3.1-9**).

- **zone 1**: this is set to cover between 80% and 85% of the length of the protected line
- **zone 2**: this is set to cover fully the protected line plus 50% of the shortest next line beyond the remote substation subject to condition that it covers at least 120% of principal line beyond the remote substation

- **zone 3**: this is set to cover all the protected line plus 100% of the second longest line beyond the remote substation, plus 25% of the shortest line beyond the remote substation.

In addition to the unit for setting the reach, each zone unit has a timer unit set to provide sufficient grading taking consideration of circuit breaker operating times, remote line and bus bar protection operating times and circuit breaker fail scheme operation. The operating time for zone 1 is set to trip instantaneously (typically 15-30 milliseconds) . The operating time for zone 2 is usually of the order of 0.25 to 0.4 second, and that of zone 3 is in the range of 0.6 to 1.5 second.

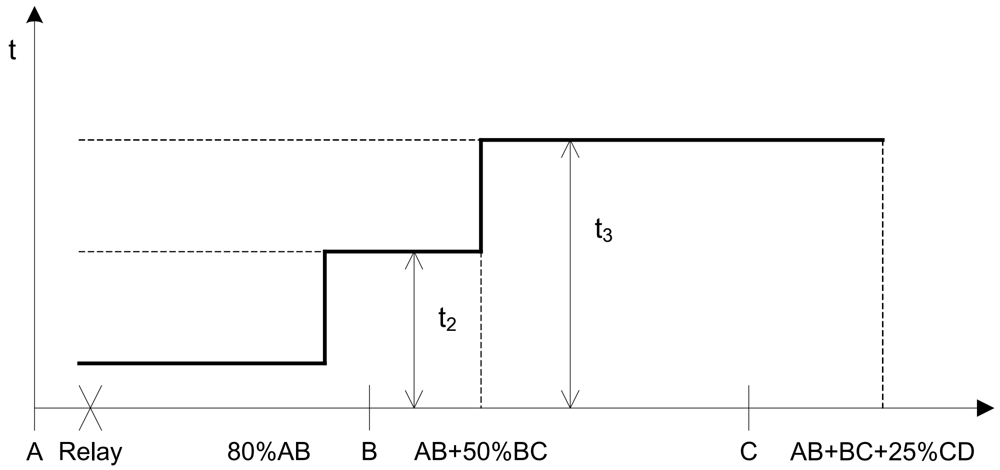


Figure 3.1-9 Distance Relay Protection Zones for a Radial System

(4) Protection with Directional Comparison (Distance Protection Schemes)

In the directional comparison scheme, fault directions detected at both ends are compared to determine whether a fault is internal of the protected section or not, where directional distance relay is used to detect fault direction. Signal of the detected fault directions are transmitted to the opposite end via a telecommunications communications link. Older relays use simple signalling techniques and only require low bandwidth power line carrier channels, but more modern relays which use the benefits of more sophisticated signalling may require additional capacity provided by micro-wave radio or optical fiber.

There are several methods for the directional comparison scheme;

IUP/DUTT (Intertripping underreach protection): A signal is transmitted when a fault is detected by the local Zone 1 protection within the first 80-85% of the line length, and therefore referred to as underreaching the line length. At the far end tripping will be initiated by the far end protection independent of the far end protection detecting the fault , i.e. forcing the remote end relay to trip even if the far end relay does not see the fault. This is also referred to as Direct Underreaching Transfer Tripping (DUTT)

PUP/PUR (Permissive underreach protection): As with IUP/DUTT, a signal is transmitted when a fault is detected by the local Zone 1 protection. At the far end, tripping will only be initiated if its own protection has detected the fault within the zone 2 reach of the far end relay looking back to the local end, and the PUP signal has been received for the duration of the PUP signal time duration setting in order to prevent spurious mal-operation due to signal errors in the communication link.

A variation of this scheme as a “PUP/PUR with Acceleration” scheme uses either the Zone 1 or Zone 2 element to send a signal, as would be the case when these zones share the same fault detectors as in older style relays. At the remote end, the reach is modified to allow the remote relay to see the fault and operate accordingly.

POP/POR (Permissive overreach protection): A signal is transmitted when a fault is detected by the local Zone 2 protection instantaneous fault detectors, i.e. prior to the Z2 time delay. This has the advantage of Zone 2 having a setting overreaching the length of the transmission line. Receipt of the signal at the far end permits the initiation of tripping by the far end Zone 2 fault detectors and bypassing its Zone 2 time delay. For weak-infeed conditions, Echo function is available where echo from the week-infeed end allows tripping at the sending end.

BOP (Blocking overreach protection): A signal is transmitted to the far end when a fault is detected by the Zone 3 element looking in the reverse direction. Receipt of the signal at the far end blocks its Zone 2 and 3 elements that would otherwise see beyond the local relay to the fault in the reverse direction.

In the blocking scheme, there are several coordination issues between reverse-looking element and forward-looking element at the remote end. The reverse-looking element should send the signal before operation of the forward-looking element at the remote end, and also the setting of the reverse-looking element should greater than that of the forward-looking element. This arrangement also assumes that the telecommunication link will operate to transmit the block to prevent tripping of the far end protection for a local reverse fault.

UOP (Unblocking overreach protection): A blocking signal is transmitted continuously to the far end end until a fault is detected by the local Zone 2 protection which removes the blocking signal and sends an unblocking signal to the far end. Removal of the blocking signal together with the receipt of the unblocking signal permits the initiation of tripping by the far end protection. If no unblocking signal is received following removal of the blocking signal, it is usually arranged to permit the Zone 2 or Zone 3 protection to initiate tripping within a variable time-slot usually in the range 100-200 ms in case of communication channel failure.

(5) Protection with Phase Comparison

Phases of fault current at both ends are compared to detect internal fault, where the both phases are reverse for an external fault and almost same for an internal fault. When the scheme is applied to each segregated phase, ability of fault-phase discrimination is complete that enables single-pole or multi-phase reclosing. The phase comparison scheme can be applied to a main protection with high-speed operation. However, there is an application limit for double-circuit multi-terminal lines, because fault current can be out-fed from a certain terminal under some special operating condition of such lines.

(6) Protection with Transverse Differential for Parallel Lines

Transverse differential scheme is a protection scheme for double-circuit parallel transmission lines. In the parallel line, both line currents are balanced for an external fault. On the contrary, unbalanced current flows on both lines for an internal fault on one line. In the scheme, transverse differential current of the both lines is introduced to the relay, where the relay discriminates the faulty line by detecting direction of the transverse differential current as shown in **Figure 3.1-10**. If the fault was on the top line, the direction of current flow in the relay would be reversed. This scheme will detect internal faults on either line without relying on telecommunication links to the remote end. For a fault close to the end of line, fault clearance at the remote-end delays after fault clearance of the faulty end, because transverse differential current does not flow at the remote-end on the initial fault condition.

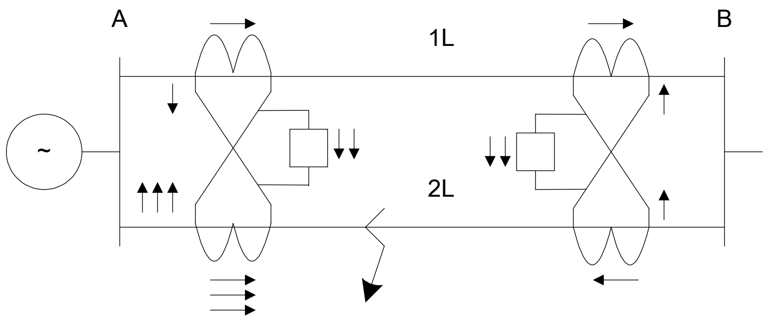


Figure 3.1-10 Principle of Transverse Differential relay

(7) Intertripping

A protection scheme in which the far end circuit-breaker is directly tripped by signals initiated from the local protection independent of the state of the far end protection. This is similar to IUP/DUTT however does not rely on the far end relay initiating the CB trip. For the remote terminal protection, any of protection schemes are available such as distance, phase comparison or current differential.

3.1.2 Main and Backup Protection

Aim of the main protection is to clear a fault with the minimum outage zone at the highest speed, while that of the backup protection is to clear a fault without fail even if the main protection or circuit breaker fails to clear the fault. Often, the protected zone used by the backup relay covers wider area with less discrimination than that by the main protection scheme. Considering these, unit protections such as current differential scheme, phase comparison scheme or directional comparison scheme that protected zones are distinctly decided by CT location, are suitable for the main protection. On the contrary, schemes which protected zones are variable by setting, such as distance protection, over-current or earth-fault directional protection are suitable for backup protection, although they are also applicable for main protection.

3.1.3 Consideration Issues of Line Protection

(1) Zero-Sequence Current with Mutual Coupling

In the systems shown in **Figure 3.1-11**, the zero-sequence networks for A substation to B substation and for C substation to D substation are isolated electrically. But the electromagnetic coupling (Z_{OM}) induces the circulating current in coupled line. An earth fault near one end will cause currents to flow as shown.

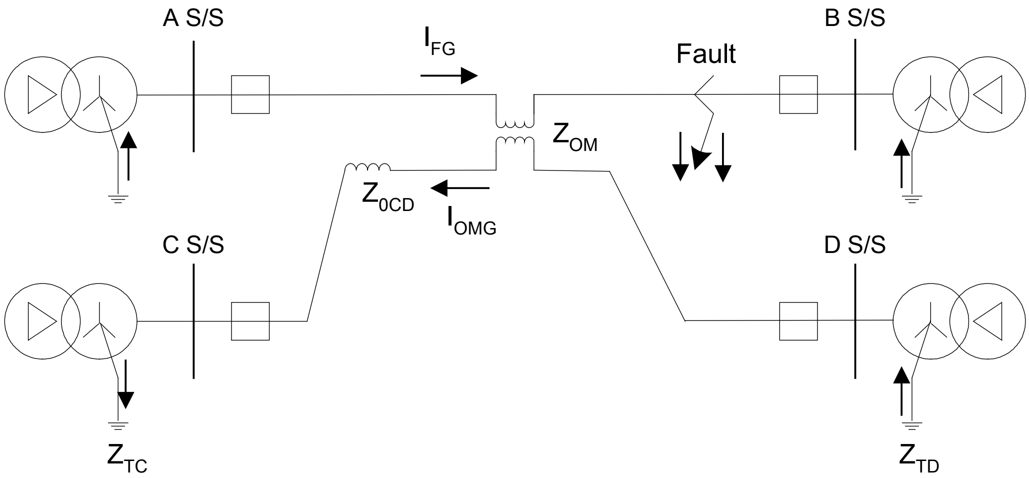


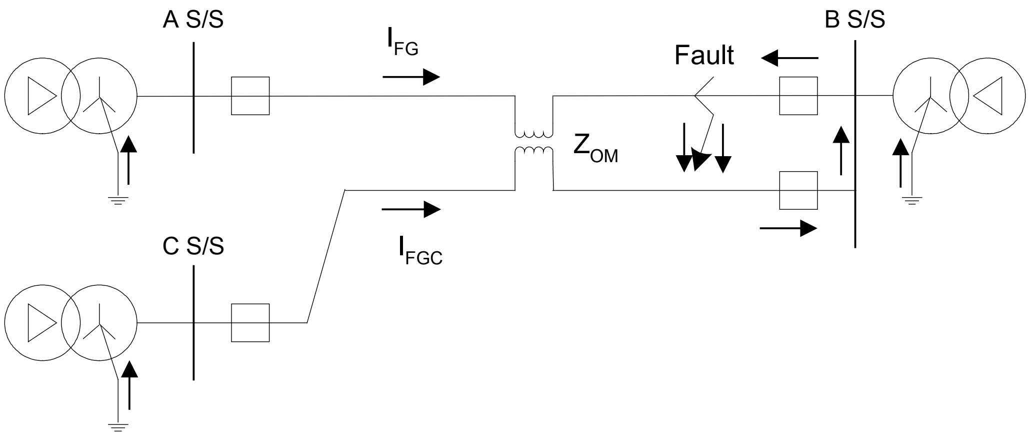
Figure 3.1-11 Fault Current Flow in Lines with Mutual Coupling

In the faulted line, current up the two neutrals and out into the line is in the operating direction for the directional earth fault relays at A substation and B substation. They should operate to open up the CBs. Before that happens, current I_{OMG} is induced in line between substations C and D. The earth fault directional overcurrent relay at D substation will operate as the current is up the neutral and out into the line. The earth fault directional overcurrent relay at C substation also operates, as current in and down the neutral is equivalent to up and out the line. The magnitude of the current can be large enough to operate, with the result that either CB or both may be tripped incorrectly. The magnitude of the current in line between substations C and D is:

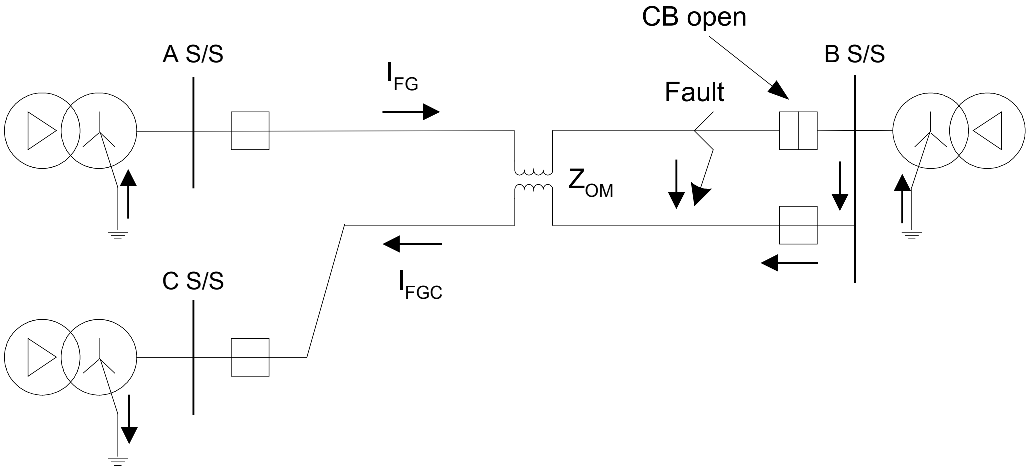
$$I_{OMG} = \frac{Z_{OM} \, I_{FG}}{Z_{TC} + Z_{0CD} + Z_{TD}}$$

In the other systems shown in **Figure 3.1-12**, at initial fault, correct polarizing can be obtained, because the faulted line current up the neutral will be greater than the induced current down the neutral.

Circuit opening in a zero-sequence electrically interconnected system can result in zero-sequence isolation and induced circulating currents. For the earth fault close to B substation, the zero-sequence flows are shown in **Figure 3.1-12(a)**. If the fault is in the zone of the instantaneous relay, they will operate fast to open CB. This now isolates the two circuits electrically, as shown in **Figure 3.1-12(b)**, and until the fault clears, an induced current circulating in the line between substations C and B reverses the line current and cause current to flow down instead of up in the neutral at C substation. Zero-sequence directional overcurrent relay would operate at both ends to indicate an internal fault on line between substations C and B.



(a) Initial Fault near B substation



(b) CB at B substation Trips by Instantaneous Relays

Figure 3.1-12 Zero-Sequence Circuit Isolation by Opening of CB

(2) Branch Effect

Branch effect or infeed effect is illustrated in **Figure 3.1-13**. A solid three-phase fault is assumed at line location F. Distance relay at substation S has to detect this fault. The voltage phase-neutral is formulated as follows:

$$V_S = Z_L \cdot I_L + Z_A \cdot \left(I_L + \sum I_i\right)$$

Z_L: Impedance of the protected line
Z_A: Impedance of the faulted line
I_1, I_2,… I_n: Short-circuit currents from the branches
V_s: Single-phase voltage at location S

$$Z_{meas} = V_S / I_L = Z_L + Z_A \cdot \left(1 + \sum I_i / I_L\right)$$

The measured impedance by relay Z_{meas} is different from the theoretical impedance to measure that is (Z_L+Z_A). An error appears. It is formulated as the following Z_{error} impedance:

$$Z_{error} = Z_A \cdot \sum\left(I_i / I_L\right)$$

Z_{error} is proportional to Z_A and also it is proportional to the current ratio ($\Sigma I_i/I_L$). Normally this current ratio is a large value greater than 1 in module and it is a phasor magnitude. On the other hand Z_A is depending on the fault location. The final result is that the relay is seeing an impedance value larger than the expected theoretical impedance Z_L+Z_A at fault location; i.e. the relay clearly underreaches and this infeed effect needs to be considered when setting the relays for line faults typically in zone 2 and 3 for the relay in S.

As indicated, the branch effect is other error source for the distance relay and it is very important if the short circuit current from the branch is large.
For phase-phase, phase-phase earth faults the effect is similar (typical relay underreaching as for three-phase faults), although the formulation is complicated because negative and/or zero-sequence networks are implied in the formulation of the effect.

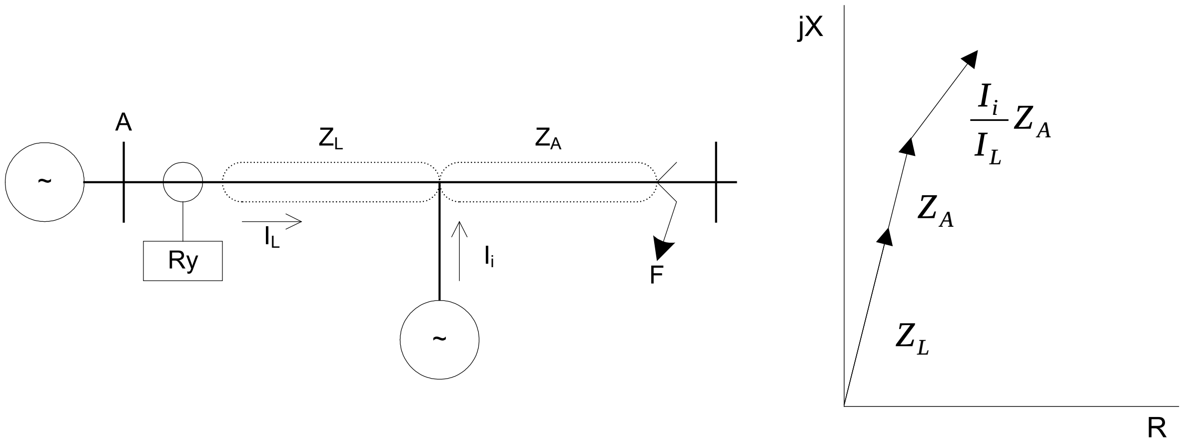


Figure 3.1-13 Branch Effect

(3) Multi-terminal Line

(a) Difficulty of Protection by Distance Relay in Tapped Line

The difficulties of distance protection with a three terminal system and matters that must be considered with regard to coordination are discussed in **Chapter 5.3.2(4)(b)**.

On the other hand, if the tap is a load transformer where Z_{TR} high relative to line impedance, zone 1 of A substation and B substations can be set for 80-90 % of the length of the line between A and B substations to provide good high speed protection. If C substation is a load tap in **Fig.3.1-14**, with negligible current to line faults, distance relays are not applicable at each tap and basically not necessary, as opening CB at the line fault.

When a tapped line comprises three terminals or more, differential protection is the easier solution despite requiring secure and reliable telecommunication links. In some circumstances not all terminals are equipped with CTs which would prevent use of current differential schemes, such as in the following cases:

- The breaker at the load end is omitted and CT is not installed under the premise that protection is achieved at the transmission end.
- There is no CT at the load end since the distance protection is achieved with three terminals.
- A CT for differential protection is not installed since the load is of low capacity.
- There is no cost justification for installing multi-terminal differential protection due to the great number of terminals.

In such cases, to the application of differential protection must be designed such as not to malfunction with transformer inrush current that occurs when energizing the power line.

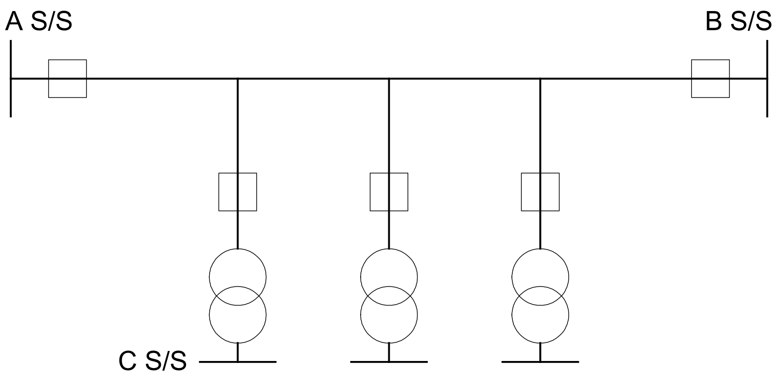


Figure 3.1-14 Multi-Terminal Line with Load Transformer Taps

(b) Solutions to Protection in Tapped Line

The following describes an example of this solution:

Figure 3.1-15 shows an example of the special characteristics of differential protection applied to such a tapped line. The special characteristic of this relay is that its sensitivity deteriorates when there is a low decreasing rate of line voltage due to a fault on the transformer low voltage side coincident with transformer energisation and inrush currents on the high voltage side.

Additionally, even with backup protection of such a tapped line, a similar corrective action is required for inrush. The following describes an example of this solution.

Normal operation is to close the high voltage side CB with no transformer load. The inrush current is normally of no significance to the line protection due to its relatively short duration and only energising one transformer at a time.. However, in case of multi-terminal transmission lines that have no high voltage CB at the load taps, or each tap has its own auto-reclosing following to a line fault clearance, or the distance relays have large back up protection zones, the inrush current caused by simultaneous energisation of more than one transformer must be considered in choosing and setting the main line protection, especially if this is distance protection.

In these circumstances, the impedance seen by the distance relay is affected by the phase angle of transformer inrush current which lags the voltage by 90 degrees. For the conventional distance relay based on steady state sinusoid, it is difficult to distinguish inrush current from the fault current. When the harmonic components of the inrush current are eliminated by a digital filter, the impedance seen by a distance relay reduces with the potential that the zone 3 with its larger impedance coverage might operate unwantedly.

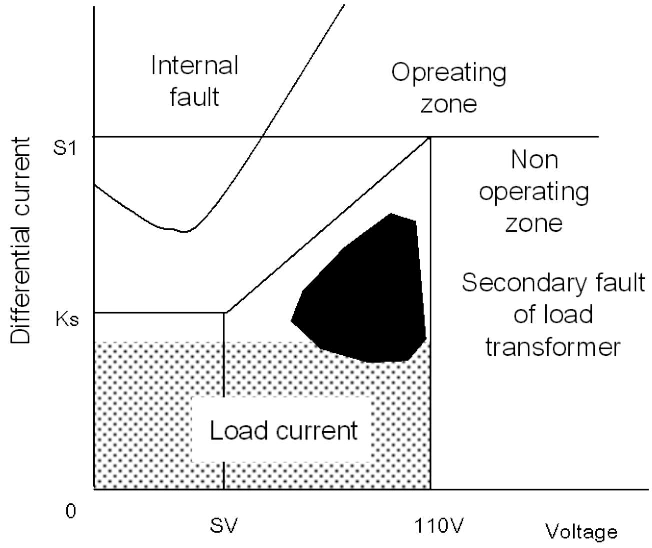
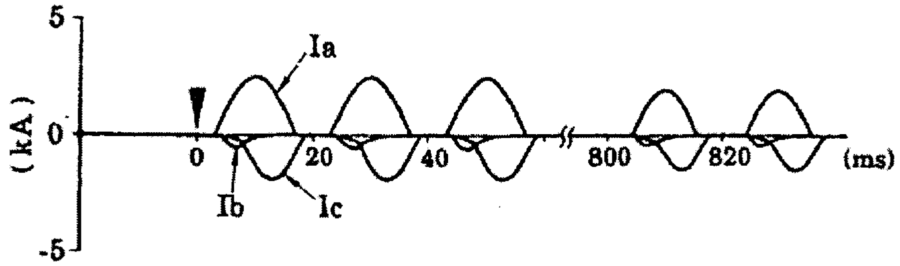


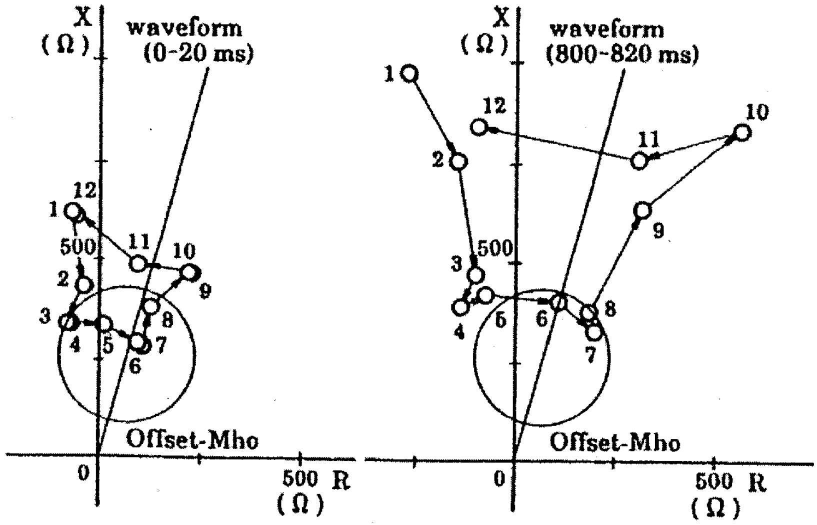
Figure 3.1-15 Example of Differential Relay with Voltage Restraint

Figure 3.1-16(a) shows an example of inrush current flowing in transformers. **Figure 3.1-16(b)** is a plot of the impedance calculated for each sampling interval of a distance relay employing MDAA. The loci are shown for the calculation result of just one cycle (12 points).

As indicated in **Figure 3.1-16**, the impedance loci nearly follow the non-linear change of the excitation inductance, since this relay has good frequency characteristics. Thus, the loci will not stay in the relay operation zone continuously for one cycle. This means that the relay has an excellent ability to distinguish between system faults and inrush phenomena.



(a) Inrush Current Waveform



(b) Loci of Impedance as Measured by the Distance Relay

Figure 3.1-16 Inrush Current and Loci of Impedance for Distance Relay

(4) Zero Sequence Circulating Current

Because power transmission lines, including earth return, cannot be symmetrically arranged, there occur variations in self-impedance or mutual impedance depending on the phase arrangement. This causes line current to carry negative-phase-sequence component and zero-sequence component even with balanced load, the combined level of which typically accounts for several percent of flow current. Negative-phase-sequence current may damage generators connected to the transmission network. Zero-sequence current when occurring in parallel line transmission systems appears as a zero-sequence circulating current, requiring careful consideration in regard to its impact on the resistance earthed neutral system. Therefore, zero sequence current is discussed bellow.

(a) Occurrence of Zero-Sequence Circulating Current

1) Parallel Transmission Line

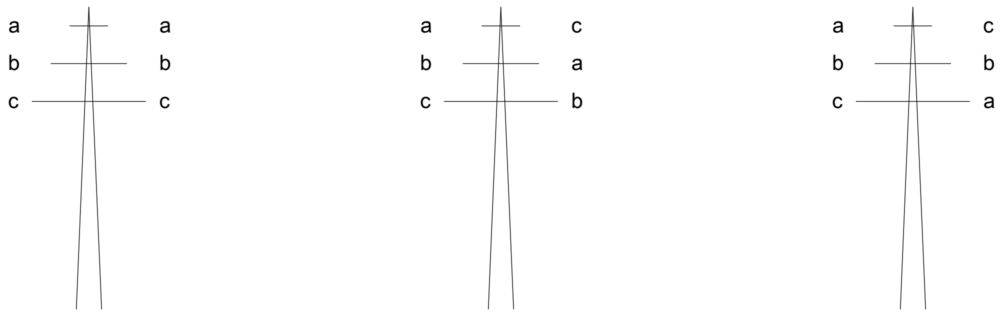
There are situations that lead to unbalance currents in the transmission system due to physical arrangements of parallel lines.

Imbalance in phase arrangement: In asymmetrical conductor phase arrangements as shown in **Figure 3.1-17 (b)**, imbalance in the mutual impedance that exists between different phases creates imbalance currents on respective line phases, permitting zero-sequence circulating current to develop.

In negative phase arrangement as shown in **Figure 3.1-17 (c)**, zero-sequence circulating current can develop depending on the structure of the towers that are used but its level is low as compared with asymmetrical phase arrangement. Zero-sequence circulating current can also develop on a long-distance transmission line as transposition provided in intermediate sections permits asymmetrical phase arrangement to occur.

Imbalance in phase impedance: Zero-sequence circulating current develops if installation of line traps (blocking coils) used for telecommunication power line carrier leads to imbalance in phase impedance and thus imbalance in current conducted in the associated lines.

Imbalance in power cable placing: Imbalance in power cable placing, e.g. three parallel cables in a trench, permits zero-sequence circulating current to develop since it creates imbalance in phase arrangement. Also, the level of zero-sequence current differs with the method used to connect cable sheaths.



(a) Symmetrical Phase Arrangement

(b) Asymmetrical Phase Arrangement

(c) Negative Phase Arrangement

Figure 3.1-17 Phase Arrangement in a Tower

2) Transmission Lines Sharing Towers

This situation is similar to parallel lines in some respects but considers the particular situation when the lines do not necessarily start and finish at the same terminals as a double circuit parallel line, or the situation off a tower having multiple voltage transmission lines.

Imbalance in line-to-line impedance due to joint use of towers: On a 3-line tower as shown in **Figure 3.1-18**, mutual impedance between the line A and line B differs with that between the line A and line C. As a result, a variance occurs between zero-sequence electromotive voltages which are induced in the line B and line C respectively by a current carried on the line A. This voltage differential causes zero-sequence circulating current to flow between the lines B and line C.

Shutdown of one line of parallel lines x 2 routes transmission system sharing towers: When four lines of parallel lines x 2 routes transmission system are symmetrically arranged on a shared tower as illustrated in **Figure 3.1-19(a)**, no zero-sequence circulating current develops if all the four lines are normal operation. But if any one of them, is shut down for maintenance service or due to a fault as shown for line D in **Figure 3.1-19 (b)**, leaving the remaining three lines in operation, imbalance will take place in phase arrangement with the consequence of zero-sequence circulating current flowing between the line A and the line B.

Influence from fault current in a line that shares towers with parallel line transmission system: If a line sharing towers with a parallel line transmission system experiences a fault, induction deriving from resultant fault current causes zero-sequence circulating current to occur.

Influence from tower structure: As can be seen from **Figure 3.1-20**, line arrangements on a tower shared by four lines fall into two broad categories, vertical and horizontal varieties. On the vertical variety, when the respective parallel lines are arranged symmetrically and all the four lines operate normally, no zero-sequence circulating current develops as has been stated. Zero-sequence circulating current develops just in the case that any one of the four lines is interrupted. By contrast, horizontal line arrangement on jointly used towers permits zero-sequence circulating current to be present under the influence of mutual inductance any time the four lines are in service. Zero-sequence circulating current, in the case that one of the four lines is shut down, is less significant than it is with the vertical line arrangement, though.

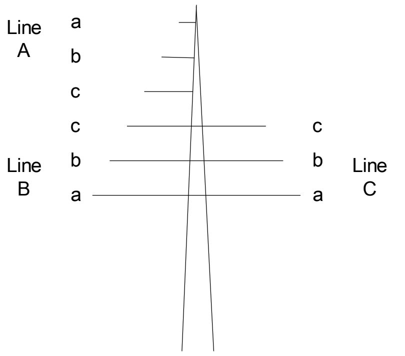
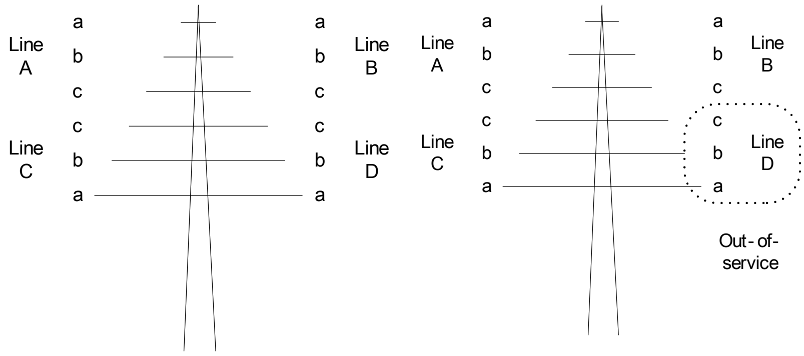
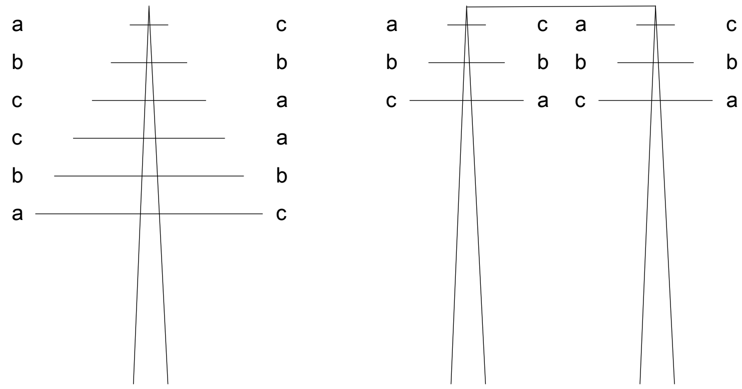


Figure 3.1-18 Three Circuits in a Tower



(a) Steady State Operation (b) One Route out of Operation

Figure 3.1-19 Occurrence of Zero-Sequence Current due to Stop of One Route



(1) Vertical Arrangement (2) Horizontal Arrangement

Figure 3.1-20 Structure of a Tower for Multi-Circuits

(b) Influence of Zero-Sequence Circulating Current

Zero-sequence circulating current is current that travels from one line to another at all times. It reverses the direction of flow at the local end and the opposite end. In the event of an earth fault , this current could be superimposed on or cancelled out by the real fault current, potentially causing an unwanted operation or failure of operation of earth fault protection relays installed in the system.

Typically, transverse differential relays effect 2-line interruption (cross interruption) when an internal or external fault occurs whereas direction comparison relays go into incorrect no-operation state when an internal fault takes place.

(c) Allowable Limits of Zero-Sequence Circulating Current

Earth fault protection relays become unable to operate normally if zero-sequence circulating current rises beyond a certain level. This makes it necessary, as discussed later, to use a relay equipped with countermeasure for zero-sequence circulating current.

If the relay does not have any countermeasure for the zero sequence circulating current, the allowable limits of zero-sequence circulating current (allowable range) are given by the following expression:

$$I_{0th\,relay\,input} \leq current\ setting\ of\ ground\ fault\ relay \times m\arg in$$

For a transverse differential relay, I0th relay input has 2-times more influence. Therefore, the above expression is usually rewritten as follows:

$$I_{0th} \leq current\ setting\ of\ ground\ fault\ relay \times m\arg in \div n$$

Where:

n=1 for direction comparison relay and earth fault direction relay

n=2 for transverse differential relay

(d) Solutions to Zero-Sequence Circulating Current

System-side solution: System-side solution is to increase the capacity of neutral earthing resistors to reduce the proportion of zero-sequence circulating current relative to earth fault current.

Relay-side solution: Where current differential relays are applied, any relay-side solution is not required because current differential relays in principle stand unaffected. Direction comparison relays make use of the following two solutions:

Proportional time-delay integration (the magnitude and direction of current at each terminal are delivered after having been converted into carrier oscillation and stop time, and associated time difference is used for the activation of relay, and reversible sensitivity scanning (sensitivity of 67G is made to change with time in either forward or reverse direction: this scanning direction which is determined according to the operating state of 67G at opposite terminal and own terminal allows all terminals (67G) to operate even if there is a current outflow caused by zero-sequence circulating current at the time of occurrence of internal fault).

Transverse differential relays come in the following two solutions:

- **Rate-of-change detection type**: Zero-sequence circulating current is cancelled out by relay-inputting change in zero-sequence circulating current before and after the occurrence of a fault, so that line containing the fault can be identified.
- **Compensation type**: The amount of zero-sequence circulating current is calculated from tower line arrangement, transmission line conditions, etc., and the amount thus obtained is eliminated from fault current so that line containing the fault can be identified.

Compensation type relays have limited application due to the following:

- If towers are rebuilt or transmission route is altered, the need arises to recalculate amount of compensation and review current settings.
- If imbalanced loads and/or generators are located on any branch line, there is the possibility of malfunction being caused by negative-phase-sequence current deriving from them, which does not justify the adoption of relays of this type.
- Transmission line that shares the same towers with EHV or higher-level power system can, as stated previously, experience zero-sequence circulating current resulting from fault current that occurs in other lines jointly using these towers. In this method, since compensatory error can become so high depending on the fault mode concerned that malfunction is likely to result, constant time delay relays are locked.

Earth fault relay is generally used with inverse time delay characteristic so that its operating time delay may be changed in accordance with the magnitude of zero-sequence circulating current. This provides fast operation at terminals with a higher zero-sequence circulating current, so that the phenomena does not affect the other lines.

(5) Arc Resistance and Load Current

(a) Influence of Arc Resistance

Faults in transmission and distribution overhead lines are characterised by electrical arcs in air. It is so for all type of faults such as single-phase to earth or phase-to-phase faults. Flashover along the surface of an isolator chain, particularly in high pollution or dust environments, in a transmission or distribution tower is the most usual fault case as a phase-to-earth fault. Direct arcs between phase conductors are also possible as double phase faults. Simultaneous arcs between two phases and the tower through isolator flashover are also common as double phase-to-earth faults.

The electrical discharge in air at overhead lines is driven through an electrical arc. The arc in air is a continuous electronic and ionic flow at very high temperature that has a non-lineal volt-ampere characteristic and it can be simulated as a non constant resistance. Classical formulae such as the following Warrington formula are used to evaluate the arc resistance in a fault. Some constraints such as arc length and fault current determine the arc resistance:

$$R_{arc} = 28710 \cdot L / I_{fault}^{1.4}$$

R_{arc}: Arc resistance in ohms
L: Arc length in meters. Normally it is assumed as the distance between phase conductors or the separation between the phase conductor and the metallic tower
I_{fault}: Fault current in Amperes (Arc current)

In **Table 3.1-2,** some values for R_{arc} depending on the nominal system voltage and the considered fault current I_{fault} value are indicated.

The arc resistance can be very significant in the case of short length lines because its impedance can be similar to or greater than the impedance of the overhead line.

Table 3.1-2 Example of Arc Resistance

Separation (m)	System Voltage (KV)	R_{arc} (Ω) (I_{fault} = 1 kA)	R_{arc} (Ω) (I_{fault} = 5 kA)	R_{arc} (Ω) (I_{fault} = 10 kA)
5	110	9.1	1.0	0.4
8	220	14.5	1.5	0.6
11	400	19.9	2.1	0.8

Figure 3.1-21 shows three-phase fault developed through arcs to the tower (simultaneous isolator flashover at three phases). **Figure 3.1-22** shows the equivalent single-line diagram to study the fault and to quantify the distance error that is introduced to the distance relay measure as consequence of the arc resistance R_a.

Case 1) Circuit breaker in substation R is open. The impedance that is measured Z_{meas} by relay in substation S is:

$$Z_{meas} = m \cdot Z_L + R_a$$

The error is R_a that do not affect to the measured reactance. The absolute error only impacts to the resistance measured.

Case 2) Circuit breakers in substations S and R are closed. Operation of line is at no-load before the fault. In this case $E_s = E_r$ in **Figure 3.1-22** and no current flows by the line before the fault. The distance protection at end S detects the following impedance during the fault:

$$Z_{meas} = V_s / I_s = m \cdot Z_L + (1 + I_r / I_S) \cdot R_a$$

As it can see the measured error is $(1+I_r/I_S)R_a$. The above equation is general and it can also be applied if the line is previously loaded. The most unfavourable case is obtained when $I_r >> I_S$: if $Z_r << Z_S$. It is equivalent to say that R is a strong extreme as compared to S.

Normally I_r and I_s are practically in phase when the line operation before fault was at no-load. In this way the error is only in the measured resistance and the reactance measured by he relay in S practically has not error.

Case 3) Circuit breakers in substations S and R are closed. Operation of line is on load before the fault.

In this case $E_S \neq E_r$ and load current flows through the line.

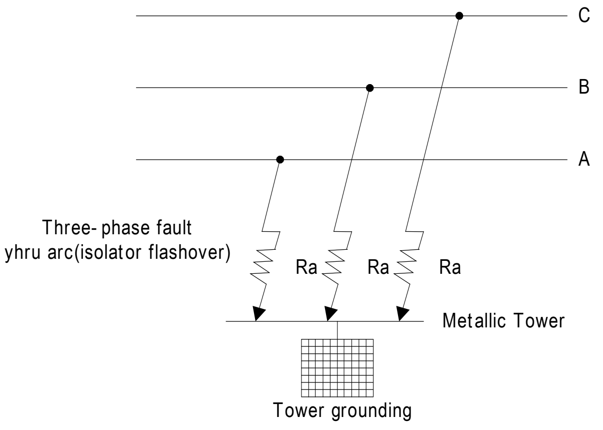


Figure 3.1-21 Three-Phase Earth Fault with Arc Resistance

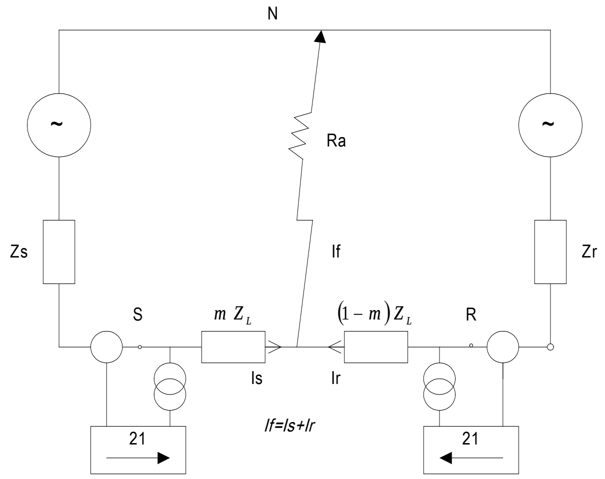


Figure 3.1-22 Equivalent Circuit against Three-Phase Fault in the Line

(b) Overreaching Error in the Distance Delay Located at Bus S

If E_s leads to E_r then prior to the fault, the active power flows from the substation S to the substation R. When the fault occurs, the current (I_s) leads I_r by the same angle β that exists between E_s and E_r source voltages. In **Figure 3.1-23(a)** it is shown the voltage and current phasor diagram at fault condition.

Impedance diagram illustrated in **Figure 3.1-23(b)** shows Z_{meas} that is the impedance detected by the distance relay located in the bus S during the three-phase fault. This vector is different to the line impedance vector mZ_L up to the fault location. As it can see in the referenced Figure, error exists in the measured resistance and also in the measured reactance. The measured reactance of the impedance Z_{meas} has a lower value than the line reactance of the impedance mZ_L up to the fault location. As this means the impedance appears to now fall inside the reach of the relay,the distance relay overreaches. The effect occurs when active power, previous to the fault, flows from the bus S to the bus R. An overreaching error appears in the distance relay and it detects the fault nearer than the actual fault location.

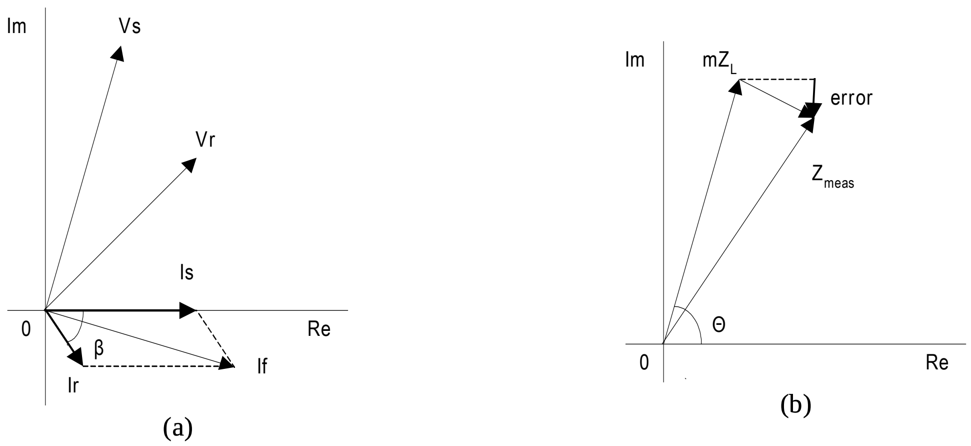


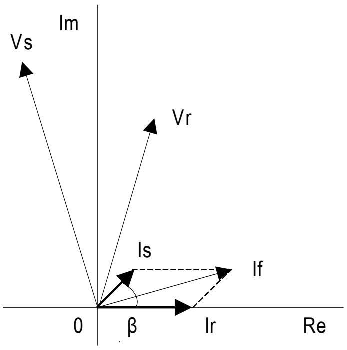
Figure 3.1-23 Vector Diagram

(c) Underreaching Error in the Distance Relay Located at Bus R

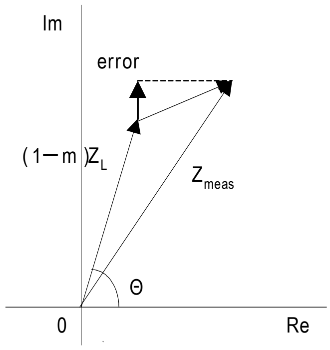
If E_r lags to E_s then, prior to the fault, the active power flows from the Substation S to the Substation R. The short circuit current I_r lags I_r by the same angle β that exists between E_r and E_s source voltages. In **Figure 3.1-24(a)** is shown the voltage and current phasor diagram at fault conditions.

Impedance diagram illustrated in **Figure 3.1-24 (b)** shows Z_{meas} that is the impedance detected by the distance relay located in the bus R during the three-phase fault. This vector is different to the line impedance vector $(1\text{-}m)Z_L$ up to the fault location. As it can see in the referenced Figure, error exists in the measured resistance and also in the measured reactance. The measured reactance has a greater value than the line reactance up to the fault location. It is say that the distance relay underreaches. The effect occurs when active power, previous to the fault, flows from the bus S to the bus R. An underreaching error appears in the distance relay located in R and it detects the fault farther than the actual fault location.

Earth faults can also be of resistive type; such faults can be produced by trees or branches touching the overhead line, or smoke from fires under the overhead line. The resultant resistance between phase and earth will normally have a big and unexpected value. It is not possible know the impedance of these things between the line and earth. Distance relays can detect this type of fault if relay resistive reach is high, and the fault resistance R_f is not high, but it can not to be sure at any case.



(a)



(b)

Figure 3.1-24 Vector Diagram

Fault resistance R_f also can to include arc resistance R_a and always other components such as tree impedance, contact resistance to earth etc. It is very difficult or impossible to know or evaluate the fault resistance.

The effect of R_f in phase-to-earth faults is similar and amplified to described effect for R_a in above paragraphs. The reason for this is that R_f is much greater than R_a and so the distance relay overreaching or underreaching can be too large for these resistive faults.

(d) Solutions for a Fault Resistance Effect

As described above, fault resistance causes overreaching or underreaching in accordance with the pre-fault power flow direction, if active power flows before the fault. Relay setting should be determined so as not to overreach for a fault on the next substation busbar. So, setting of zone 1 should be shorter if a large power transmission is scheduled and large fault resistance is anticipated.

Figure 3.1-25 shows an example of solution for the phenomena, where the reactance elements of a distance relay is sloped from the line impedance point. By this characteristic, fault without fault resistance can be measured correctly and overreaching by a fault resistance can be compensated in accordance with the magnitude of the resistance. In the characteristic, slope angle is varied according to the scheduled power flow.

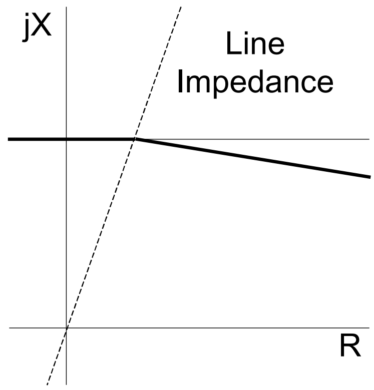


Figure 3.1-25 A Solution for Overreaching

3.1.4 Practice of Line Protection

Transmission lines are sometimes constructed over severe terrains and exposed to severe environmental conditions. Moreover, a power line has various types of configurations according to the amount of the electric power which is transmitted and the site condition of the route. For example, multi-circuits in a tower are constructed where multi-circuits are drawn from the same substation in the same direction or there are few sites for towers. Tapped/Teed lines are sometimes constructed where a substation can't be constructed near to the desired branch location. Furthermore, the power system becomes a mesh in many countries. The whole power system is being complicated from such situations described before. The suitable protection schemes for line are chosen by taking into consideration the importance of the power system and the cost factors for various solutions, with the latter being more significant for new grid connections by an increasing variety of renewable generation providers in otherwise non-planned connection point locations.

Regarding line protection, the questionnaire surveyed main protection for line, communication system for carrier-relays, the existence of the measures against the factor to be considered to affect the protection performance, a backup protection, the number of terminals of a tapped line and so on in order to understand the practice in each country. The questionnaire results about line protection are described below.

(1) Main Protection

Table 3.1-3 shows the result of the questionnaire about main protection for transmission lines. Protection relays with high-selectivity, such as permissive tripping or current differential relay are applied to EHV transmission line protection.

Japan and Korea reports all of EHV transmission line main protections are current differential relay whilst other countries are mixed with both distance and differential applications.

Table 3.1-3 Main Line Protection

Line protection	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
(a1) IUP	-	-	-	×	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	×	-
(a2) PUP	×	×	×	×	-	-	×	×	-	×	×	-	-	-	-	×	×	×	×	×	×
(a3) POP	×	×	×	×	×	×	×	-	-	×	×	-	-	×	×	×	×	×	×	×	-
(a4) BOP	×	×	×	×	×	×	-	×	×	-	-	-	-	-	-	-	-	-	-	-	×
(a5) UOP	-	×	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(b) Distance	×	×	×	×	×	×	×	×	×	×	×	-	×	-	-	×	×	×	×	×	×
(c) Current differential	×	×	×	×	×	×	×	×	-	×	×	×	×	×	-	×	×	×	×	×	×
(d) Phase comparison	×	×	×	-	-	-	×	-	-	×	×	-	-	-	-	×	-	×	×	-	-
(e) Intertripping	×	×	×	-	×	-	-	-	-	×	×	-	-	-	-	-	-	-	-	-	×
Others	-	-	-	-	×	-	-	×	×	×	×	-	×	-	-	-	-	×	×	-	-

Table 3.1-4 shows the result of the questionnaire about communication system for main line protection. Microwave radio, optical fibre and power line carrier (PLC) is reported. Japan and Korea reports that PLC is not applied to EHV network as all EHV transmission line protection is current differential, so optical-fibre or utility-owned microwave radio is applied instead.

Table 3.1-4 Communication System for Main Line Protection

Communication system	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Micro-wave	×	×	×	×	-	-	-	×		-	-	×	×	-	-	×	-	-		×	-
Optical fiber	×	×	×	×	×	×	×	×		-	-	×	×	×	×	×	×	×		×	-
PLC	×	×	×	×	×	×	×	×		×	×	-	×	-	-	×	×	×		×	×
Others	×	×	-	-	-	-	-	-		-	-	-	×	-	-	-	-	-		-	×

(2) Backup Protection

Table 3.1-5 shows the result of the questionnaire about backup protection for transmission lines. EHV transmission line is equipped with backup protection. Generally distance relays are used as the backup system. Backup protection for transmission lines less than 154kV is distance, overcurrent, earth-fault overcurrent, earth-fault directional, earth-fault overvoltage, etc. Mostly, backup protection is not provided in redundant configuration, including EHV transmission line.

Table 3.1-5 Backup Protection

Backup protection	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Distance	×	×	×	×	×	×	×	×	×	×	-	×	×	×	×	×	-	×	×	×	-
Overcurrent	-	-	×	×	×	×	-	×	-	-	×	-	×	-	-	×	×	×	×	-	-
Ground Overcurrent	-	×	-	-	×	×	-	×	-	-	-	×	×	-	-	-	-	-	-	×	×
Ground Directional	×	×	-	×	×	×	×	-	×	×	-	-	×	-	-	-	-	×	×	×	-
Ground Overvoltage	-	-	-	-	-	-	-	-	-	-	-	-	×	-	-	-	-	-	-	-	-
Others	-	-	-	-	-	-	-	-	-	-	-	×	×	-	-	-	-	-	-	-	-

(3) Countermeasures

Countermeasures against high resistive faults are accounted for by the use of proper protection to take into account the effect of charging current and transient harmonics. From the survey shown in **Table 3.1-6**, most countries practice special philosophies to account for high resistance earth faults and transient harmonics. In some countries, these measures are also applied on the transmission system.

Table 3.1-6 Application of Various Kinds of Countermeasures

Counter -measures	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
High resistance fault	× / NA	NA	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
Charging current	NA	NA	×	×	×	NA	×	NA	NA	NA	NA	×	×	× / NA	×	×	×	×	×	×	NA
Transient harmonics	NA	NA	×	×	NA	NA	×	NA	NA	NA	NA	×	×	×	×	×	×	×	×	×	NA

(4) Number of Terminals in Tapped Line

Table 3.1-7 shows the result of the questionnaire about number of terminals in tapped lines. 2 to 8 terminal lines are reported. In Canada, multiple hydro power stations can be connected to a single line and in Japanese HV systems, many loads are branched.

Table 3.1-7 Number of Terminals in Tapped Line

Voltage Class	AU	CA	CN	ES	FR	IN	JP	KR	MY	PT	SE	UK
EHV (765-187)	2	2-5	2-3	2-6	2		2-3	2	2-3		2-4	2-3
HV (below 154)	2	2-5	2-3	/	2		2-8	2	2-3		/	/

3.2 Automatic Reclosing

3.2.1 Classification of Automatic Reclosing

Since power transfer across the network to maintain synchronism will decline when a fault occurs in an overhead transmission line and it is cleared by the line protection relay, it is required to restore the power system by automatic reclosing as soon as possible. The automatic reclosing is applied for the purpose of reduction of outage time, improvement of transient stability, and automatic restoration. Although there are various kinds of the classification of automatic reclosing, it is classified by the purpose and the number of phases here. Note that this classification is not a classification by the timing of control simply

The first classification is high-speed reclosing whose purpose is the improvement of transient stability in the power system. For high-speed reclosing, since maintaining synchronism across the network is the prime concern, single phase trip and reclosing techniques are generally used, and of course assumes single phase circuit breakers with independent trip and close mechanisms per phase.

The second is delayed reclosing whose purpose is to mitigate potential damage to turbine generators and provide automatic restoration of the power system... For delayed reclosing, since it is primarily to allow plant to be disconnected and any transient fault condition (e.g. vegetation or animals) to dissipate, generally three-pole trip and reclosing is carried out.

Next, in the classification by the number of phases, as mentioned before, there are two kinds of reclosing; single-pole reclosing in which only tripped phases would be reclosed following a phase-to-earth fault, and three-pole reclosing in which all of three phases would be reclosed independent of fault types. In addition, for parallel overhead lines, multi-pole reclosing in which only faulted phases will be reclosed according to the fault type is applied in some countries.

(1) Single Pole Trip & Reclosing

When a phase-to-earth fault occurs, distance or current differential relays can distinguish which phase is faulted and trip only that phase if single phase breakers with independent mechanisms are provided. The auto reclose must therefore only initiate reclose on the faulted phase using single-pole-reclosing, as shown in **Figure 3.2-1**. Generally, in the power systems in which a single pole reclosing is applied, the improvement of transient stability is required. The use of single pole trip and reclosing can maintain electric power through the two healthy phases during the fault. Since the high speed reclosing can contribute to the improvement in transient stability, it can be set to reclose in a time just longer than the arc de-ionizing time of any likely fault.

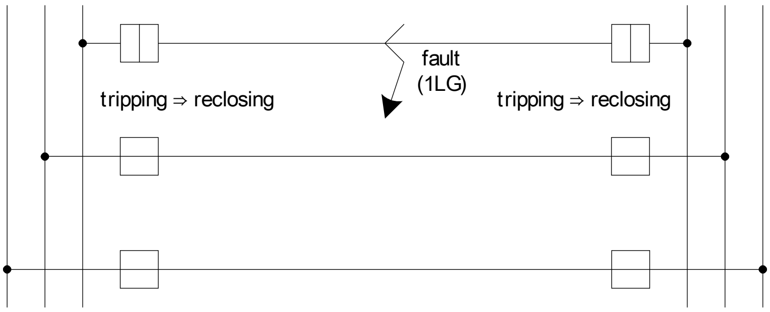


Figure 3.2-1 Single Pole Trip & Reclosing

(2) Three Pole Trip & Reclosing

As shown in **Figure 3.2-2**, three-phase reclosing is the way which recloses all phases after the protection relay tripped three phases, regardless of the kind of fault. Although this method is widely applied for both high-speed and low speed reclosing, it is necessary to consider if the two ends could each have generation sources that would require a permissive signal from a synchronism check relay before initiating the reclose to the final breaker reclosing. This also has to consider different timing of the reclose at each end and the combinations of live/dead bus and live/dead line reclosing conditions..

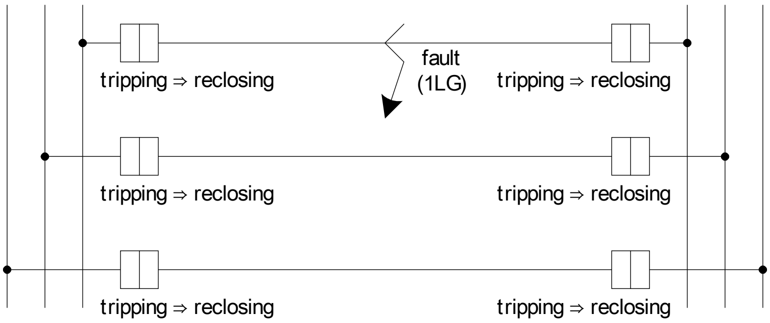


Figure 3.2-2 Three Pole Trip & Reclosing

(3) Multi-Pole Reclosing

When multi-pole fault occurs in two parallel lines, the faulty phases are reclosed after extinguishing the arc whilst maintaining synchronism via the un-faulted phases as shown in **Figure 3.2-3**. The dead time is decided taking into consideration the power system stability and the amplitude of the mechanical torque caused by unsuccessful reclosing.

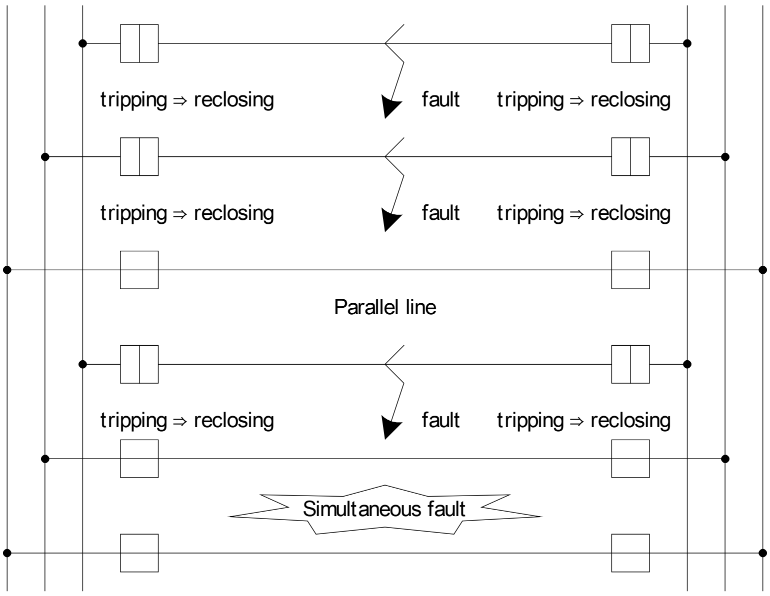


Figure 3.2-3 Multi-Pole Reclosing

3.2.2 Consideration Issues

(1) De-ionizing Time

In general, shorter dead time is more effective to stabilize the power system, but the reclosing cannot be conducted shorter than the arc de-ionizing time. The de-ionizing time is one of the important factors when deciding the dead time for high-speed reclosing.

The de-ionizing time depends upon the insulation recovery time to extinguish the residual ions caused by fault current and to extinguish the secondary arc caused by electromagnetic coupling and electrostatic coupling between the sound phase and the faulty phase during the fault.

(a) Insulation Recovery Time

As air around the fault point ionizes by the fault current, the residual ions exist around the fault point after the fault clearance. The time from the occurrence of the fault to extinction of the residual ions is called the insulation recovery time. The insulation recovery time becomes longer as the system voltage is higher and as the fault current is larger, as shown in **Figure 3.2-4**.

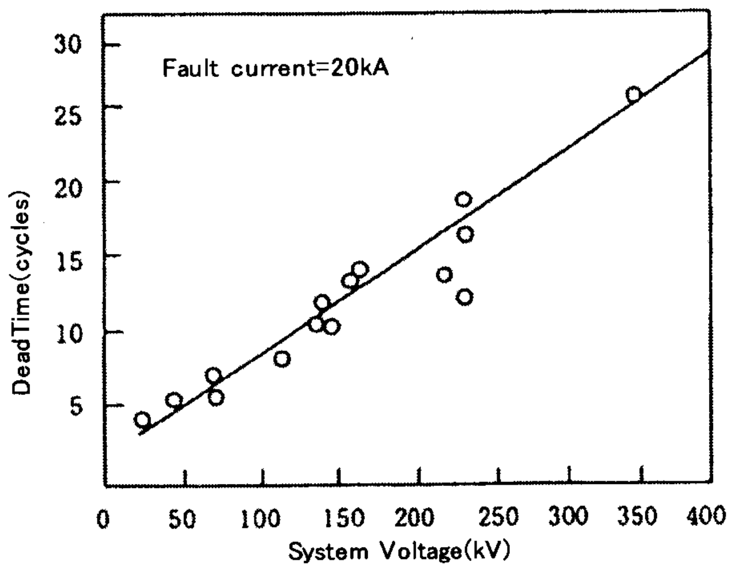


Figure 3.2-4 Relation between System Voltage and Insulating Recovery Time [1]

(b) Secondary Arc Extinction Time

The electrostatic voltage caused by electrostatic capacity between the faulty phase and sound phases and the electromagnetic voltage caused by the fault current and mutual inductance are induced at the faulty phase in single-pole or multi-pole reclosing.

Electrostatic coupling voltage V_c induced at the faulty phase during 1 line opening is given by the following equation (See **Figure 3.2-5**). The electrostatic coupling voltage becomes higher as the system voltage is higher and as the phase-to-phase electrostatic capacity is larger than the phase-to-earth electrostatic capacity.

$$\dot{V}_c = \frac{C_m}{C_s + 2C_m}(\dot{E}_a + \dot{E}_b)$$

Electro-magnetic coupling voltage is given by the following equation.

$$\dot{V}_m = j\omega M(\dot{I}_a + \dot{I}_b)$$

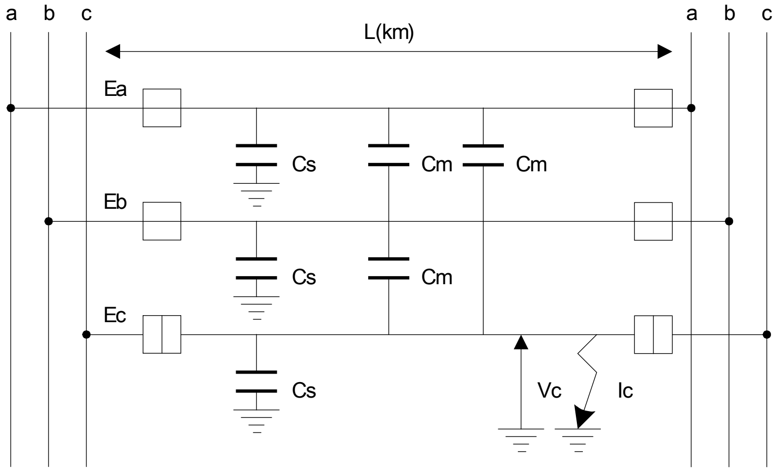


Figure 3.2-5 Electrostatic Coupling and Electromagnetic Coupling during Single Pole Reclosing

Electromagnetic coupling voltage is zero for a fault in the middle of the line, and becomes the maximum against the fault at the end of the line. The voltage whose value comes to the sum of electrostatic coupling voltages and electromagnetic coupling voltage is induced to the faulty phase. This is called the secondary recovery voltage, and about ten amperes current flows into the fault point around which the residual ions remain. This is called the secondary arc current. The secondary arc current caused by electrostatic coupling voltage is given by the following equation. This becomes large in proportion to the line length and the system voltage.

$$\dot{I}_c = j\omega C_m \cdot l \cdot \left(\dot{E}_a + \dot{E}_b\right)$$

The dead time for 500kV power systems in Japan is decided in consideration of arc extinction time and length of the transmission line as shown in **Table 3.2-1**.

Table 3.2-1 Example of Dead Time for 500kV Power Systems

Reclosing scheme	Line length	
	75km	150km
Three pole reclosing	30-35cycles	30-35cycles
Single pole reclosing	30-35cycles	40-45cycles
Multi pole reclosing	35-40cycles	50-55cycles

(2) Mechanical Torque

As larger generators have been installed with higher fault contribution capability and the transmission networks have become more meshed so as to reduce effective line impedances, any particular fault on the network has a more significant effect on the turbines due to the mechanical torque reflected on the turbine, particularly following an unsuccessful reclose if the fault has persisted.

The generators may suffer four torque shocks in an unsuccessful initial reclose sequence as follows:,

- The torque shock of the fault itself
- The shock following initial trip of the fault
- The shock of the fault remaining during the reclose attempt
- The shock of the second trip of the fault

In the worst case, the torque may reach five times larger than the initial fault, which will have big influence on the turbine generator performance and maintenance requirements.

In order to mitigate this, the autoreclose scheme should incorporate such mechanisms as:.
- Shift to delayed reclosing in the case of unsuccessful high-speed reclosing
- Live bus / dead line closing at the far end of the line from the generator, and live bus / live line closing at the generator end of the line after checking synchronising voltage as shown in **Figure 3.2-6**.
-

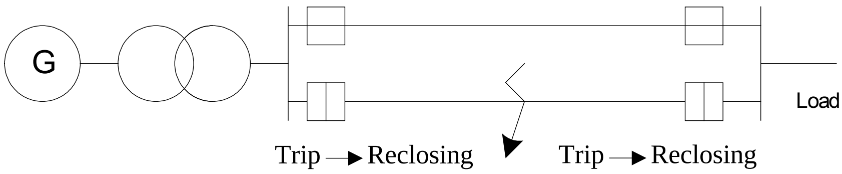


Figure 3.2-6 Reclosing Order of the Breakers for Reducing the Influence on a Generator Shaft

(3) Operating Duty

When a breaker is tripped against a line fault, and it is reclosed after the dead time, the DC system must have sufficient capacity and duty cycle to immediately trip the circuit breaker again if the fault current continues to flow. It is desirable that this second operation is high speed from viewpoint of the requirements from the power system suffering a second fault. The circuit breaker capability must also be considered for its ability to not only to clear fault current twice in quick succession but also its ability to close with fault current flowing. Therefore, reclosing operation must consider the needs from the power system and the breaker performance.

(4) Residual Voltage according to an Induction Motor

When an induction motor is tripped, direct-current current will flow in the secondary circuit because the induction motor will maintain the magnetic flux to some degree whilst it is stopping. Therefore, the secondary circuit becomes the excited circuit by direct-current, which will induce residual voltage at the primary circuit. The following factors will lengthen the damping time of this residual voltage.

1) In case that the induction motor has large-capacity
2) In case that a capacitor is connected to the separated induction motor

As shown in **Figure 3.2-7**, even if the induction motor under operation is opened, transient current will flow in the rotor if load is connected. Residual voltage is generated when the magnetic flux induced by this links with a field winding. **Figure 3.2-8** shows the relation between the amplitude and the phase of the residual voltage after a circuit breaker is tripped. When the automatic reclosing is carried out while residual voltage remains, there are the following problems:

Because arc at a fault point will not be extinguished when voltage in the line does not fall, reclosing will be unsuccessful.

If an induction motor with residual voltage is reclosed at high-speed, it may be damaged by mechanical torque and starting current. It is a security measure for automatic reclosing to reclose after transfer-tripping the load with no voltage and to reclose after checking voltage drop at the load side.

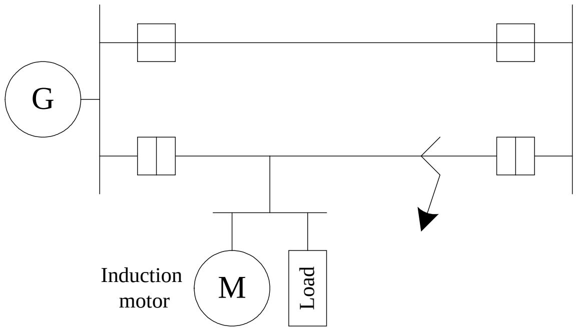


Figure 3.2-7 Splitting of Induction Motor

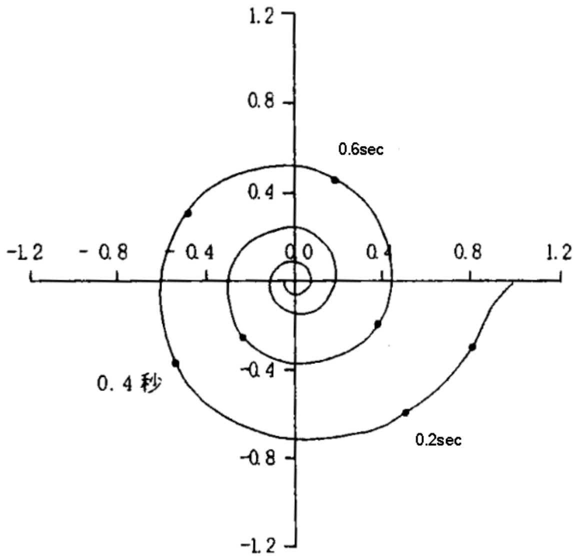


Figure 3.2-8 Relation between Amplitude and Phase of Residual Voltage

3.2.3 Automatic Reclosing in Underground Cable System

(1) Method of Reclosing in Underground Cable System

A fault that occurs in an overhead line is expected to be a transient fault in many cases, so the possibility of success in automatic reclosing is high. But a fault that occurs on an underground cable is usually phase-to-earth fault involving the cable sheath and is a permanent fault in many cases, so the possibility of failure to reclose is high and it has high possibility that automatic reclosing causes fire as a result of the carbon deposits as a result of the initial failure and fault current.

Therefore, in a power system which consists of mixed connection of an underground cable and an overhead line, it is necessary to block the automatic reclosing for a fault which occurs on an underground cable section, but not for a fault on the overhead line section.

The cable fault detection is a current differential relay to discriminate an internal fault only within the bounds of the cable by zero sequence current. Moreover, a blocking signal is transmitted by a telecommunication cable and a signal transmission system as shown in **Fig.3.2-9**. These systems therefore require the ability to install current sensing at the cable-overhead line transition point as well as to physically install and provide operating power to the relay at that point in consideration of potentially outdoor environments far from the substation.

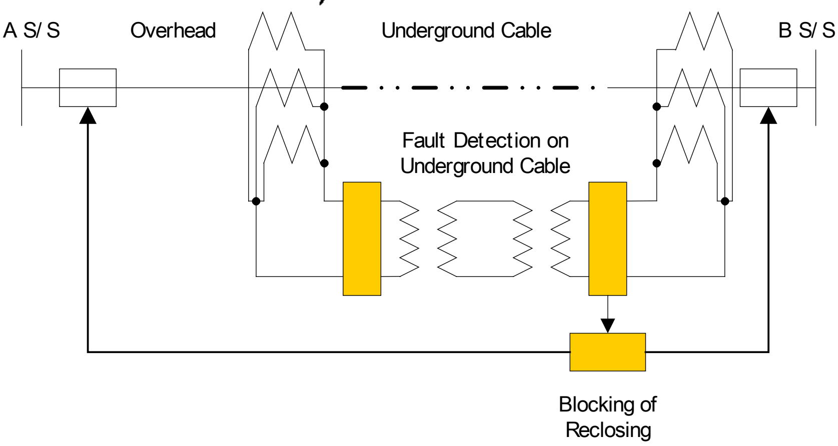


Figure 3.2-9 Outline of Fault Detector on Underground Cable

(2) Setting of Cable Fault Detector

The relay for detecting a cable fault should be set no more than half of the minimum phase-to-earth fault current. The relay for detecting a cable fault should be set as the sum of currents at both ends is twice as large as the minimum operating current against a 30% phase-to-earth fault in the power system where the fault current is the minimum. If the relay does not directly include charging current compensation features, it must be set above the normal minimum charging current of the cable which is seen as zero sequence current.

$$I_{tap} = 1.2 \times (\textit{the value of charging current compensation})$$

Where I_{tap} is the setting of the relay.

For two-terminal line,

$$I_{tap} = I_{R100} \times 0.3 \times \frac{1}{2} = 0.15 \times I_{R100}$$

Where I_{R100} is the minimum phase-to-earth fault current.

For three-terminal line,

$$I_{tap} = I_{R100} \times 0.3 \times \frac{2}{3} \times \frac{1}{2} = 0.1 \times I_{R100}$$

3.2.4 Practice of Automatic Reclosing

(1) Method of Reclosing

In order to improve service reliability, it is necessary to implement the measures related to preventive fault extension and the measures related to swiftness of restoration harmonically. The automatic reclosing which compares the line charging conditions beforehand decided instead of the operator as automatic restoration against an overhead line fault and re-closes the breaker is widely introduced.

Three kinds of the method of reclosing are shown in **Table 3.2-2**, which are illustrated in the questionnaire. In these examples, if the delayed automatic reclosing has not been successful, independent line charging would be done to manually energise the cable. And line charging would be done by load dispatching instruction after inspection of the equipment damage, as the possibility of a permanent fault is very high, if the condition of delayed automatic reclosing is unsuccessful.

The questionnaire result about the method of reclosing illustrated to **Table 3.2-3** is shown in **Table 3.2-3**. In **Table 3.2-2**, case a in the reclosing method is classified into multi-shot, and case b and c are classified into single-shot. According to this table, the multi-shot reclosing is adopted in Canada, Japan, and Sweden and the single-shot reclosing is adopted in other countries.

Table 3.2-2 Method of Reclosing

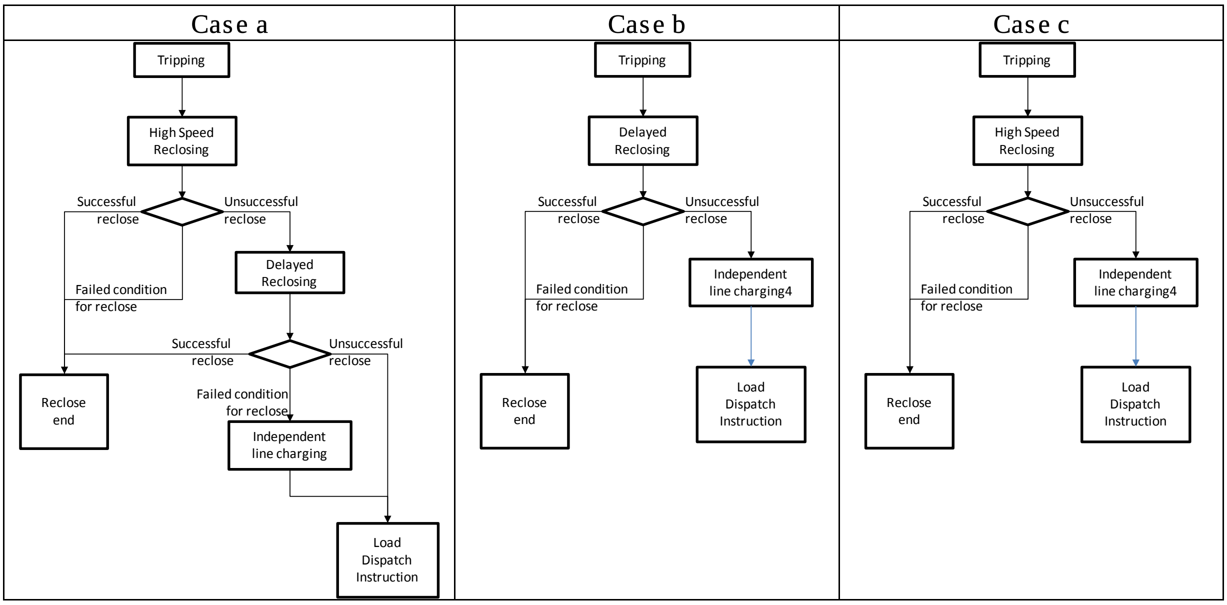


Table 3.2-3 Method of Reclosing

Reclosing method	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
a	-	-	×	×	-	-	-	-	-	-		×	×	-	-	-	-	-	-	×	-
b	×	-	-	-	×	×	-	-	-	-		-	×	-	-	-	-	-	-	-	×
c	×	×	-	-	×	-	×	×	×	-		×	×	×	×	×	×	×	×	-	-
others	-	-	-	-	-	-	-	-	-	×		-	×	×	-	-	-	-	-	-	-

(2) Purpose, Classification, and Dead time of Automatic Reclosing

Automatic reclosing is classified into two as shown in **Table 3.2-4**. This table shows its purpose as well. For EHV transmission line, single pole automatic reclosing is adopted. The “Single Pole + 3Pole”is adopted as well. In Japan and Korea, multi-pole automatic reclosing is adopted at EHV as shown in **Table 3.2-5**.

Most of answers show the dead time between protection trip and reclose command for high speed reclosing is less than 1 second. Transmission lines more than 500kV, most of answers are from 0.8 second to 1 second. For 150kV level, around 0.5 second is applied. Regarding the dead time for high speed reclosing, all utilities consider de-ionizing time to determine the dead time. As a second factor, CB operation duty and power system stability follow.

Table 3.2-4 Classification of Automatic Reclosing

	Dead time	Purpose of automatic reclosing
High-speed reclosing	0.35-1.0 sec	The purpose of the high-speed reclosing is to improve the power system stability and maintain interconnecting the power system. The dead time is decided in consideration of the demonizing time and so on.
Delayed reclosing	5-60sec	The purpose of the delayed reclosing is to maintain interconnecting the power system and to automatically restore the power system when the high-speed reclosing conditions aren't satisfied. The dead time is decided in consideration of the decline of the vibration of a turbine generator, the decline of the residual voltage of induction motors, and the decline of galloping.

Some utilities adopt Three-pole delayed automatic reclosing. Some utilities do not adopt delayed automatic reclosing as shown in **Table 3.2-5**.

Setting of the dead time for delayed reclosing according to the responses was in the range of 15 second to 70 second. The majority of the purpose of delayed reclosing is automatic restoration and reduction of outage as shown in **Table 3.2-7**. Some also apply delayed reclosing in order to prevent overload of adjacent lines. The main decision factor of the dead time is the operation duty cycle of the CB for spring charging etc. Some answers identify generator torque impact as shown in **Table 3.2-8**.

Table 3.2-5 Application of Automatic Reclosing

	Automatic Reclosing	AU		CA		CN		ES		FR		IN		JP		KR		MY		PT		SE		UK	
		H	D	H	D	H	D	H	D	H	D	H	D	H	D	H	D	H	D	H	D	H	D	H	D
EHV	Single-pole	-	-	×	-	×	-	×	-	×	-	×		×	×	-	-	×	-	×	-	-	-	-	-
	Three-pole	-	×	×	×	-	×	×	-	×	-	-		-	×	-	-	-	-	×	-	×	×	-	×
	Multi-pole	-	-	-	-	-	-	-	-	-	-	-		×	×	×	-	-	-	-	-	-	-	-	-
	1+3-pole	-	×	-	-	-	-	×	-	×	-	-		×	-	×	-	-	-	×	-	-	-	-	-
	NA	×	-	-	-	-	-	-	×	-	×	-		-	×	-	×	-	×	-	×	-	×	×	-
HV	Single-pole	-	-	×	-	-	-			-	-			-	-	-	-	-	-	×	-				
	Three-pole	-	×	-	×	-	×			×	-			×	×	×	-	-	×	×	-				
	Multi-pole	-	-	×	-	-	-			-	-			-	-	-	-	-	-	-	-				
	1+3-pole	-	×	×	-	-	-			-	-			-	-	-	-	-	-	×	-				
	NA	×	-	-	-	-	-			×	×			×	×	-	×	×	-	-	×				

<Note> H: High-speed reclosing, D: Delayed reclosing

Tab.3.2-6 Purposes of Automatic Reclosing

	Purposes	AU		CA		CN		ES		FR		IN		JP		KR		MY		PT		SE		UK	
		H	D	H	D	H	D	H	D	H	D	H	D	H	D	H	D	H	D	H	D	H	D	H	D
EHV	(a)	-	×	-	-	×	×	×	-	×	-	×		×	×	×	-	-	-	×	-	×	-	-	×
	(b)	-	×	×	×	×	×	×	-	×	-	×		×	×	×	-	-	-	×	-	×	×	-	×
	(c)	×	-	-	-	×	×	×	-	×	-	×		×	-	×	-	×	-	-	-	-	-	-	-
	(d)	-	-	-	-	×	×	-	-	×	-	-		×	×	×	-	-	-	-	-	-	-	-	×
	Others	-	-	-	-	-	-	-	-	-	-	-		×	×	-	-	-	-	-	-	-	-	-	-
	NA	×	-	-	-	-	-	-	×	-	×	-		-	-	-	×	-	×	-	×	-	-	×	-
HV	(a)	-	×	-	-	-	×			×	-			-	×	×	-	-	-	×	-				
	(b)	-	×	×	×	-	×			×	-			×	×	×	-	-	×	×	-				
	(c)	×	-	-	-	-	×			×	-			×	-	×	-	-	-	-	-				
	(d)	-	-	-	-	-	×			×	-			×	×	×	-	-	-	-	-				
	Others	-	-	-	-	-	-			-	-			×	×	-	-	-	-	-	-				
	NA	×	-	-	-	×	-			-	×			-	-	-	×	×	-	-	×				

<Note1> (a) Reduction of outage time, (b) Automatic restoration, (c) Improvement of transient stability, (d) Prevention of overload in healthy power systems

<Note2> H: High-speed reclosing, D: Delayed reclosing

Tab.3.2-7 Dead-time

Voltage (in kV)		AU	CA	CN	ES	FR	IN	JP	KR	MY	PT	SE	UK
765 - 735	High		0.25	1			1		1				
	Delayed		30	10					NA				
500 - 400	High	1		1	0.9- 1	0.3- 1.5	1	0.83- 1		0.75	0.3- 1.5	0.4	NA
	Delayed	15		10	NA	NA		5- 70		3	NA	60	30
345 - 315	High	1	0.25	1					0.24- 0.8		-	-	NA
	Delayed	2- 15	30	10					NA				30
275 - 187	High	NA	0.25	1	0.9- 1	0.3- 1.5	1	0.33- 0.8		0.75	0.3- 1.5	0.4	NA
	Delayed	2- 3	30	10	NA	NA		7- 70		3	NA	60	30
154 - 110	High	NA	0.25	NA		0.3- 1.5		0.35	0.18- 0.3	NA	0.3- 1.5		
	Delayed	2- 15	30	5		NA		5- 60	NA	3	NA		
below 110	High	NA	0.25	NA				NA	-	NA			
	Delayed	2- 15	30	5				10- 60		3			

<Note> High: High-speed reclosing, Delayed: Delayed reclosing

Tab.3.2-8 Decision Factors of Dead-Time

	Decision Factors	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
		EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
High- speed	a	×	×	×	×	×	-	×	×	×	×		×	×	×	×	×	-	×	×	×	-
	b	×	×	-	-	×	-	×	-	-	-		×	-	×	×	-	-	-	-	×	-
	c	-	-	-	-	×	-	×	×	×	-		×	×	×	×	×	-	×	×	-	-
	d	×	×	-	-	-	-	-	-	-	-		×	-	-	×	-	-	-	-	-	-
	e	-	×	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-
	Others	-	-	-	-	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-
	NA	×	×	-	-	-	×	-	-	-			-	-	-	-	-	×	-	-	-	×
Delayed Reclosing	a	×	×	-	-	×	×	-	-	-			-	-	-	-	-	-	-	-	-	×
	b	×	×	-	-	×	×	-	-	-			-	-	-	-	-	-	-	-	-	×
	c	×	×	-	-	×	×	-	-	-			×	×	-	-	-	×	-	-	×	-
	d	×	-	-	-	-	-	-	-	-			-	-	-	-	-	-	-	-	-	-
	e	-	-	-	-	-	×	-	-	-			-	-	-	-	-	-	-	-	-	-
	Others	-	-	×	×	-	-	-	-	-			-	-	-	-	-	-	-	-	-	-
	NA	-	-	-	-	-	-	×	×	×			-	-	×	×	×	-	×	×	-	-

+<Note> a: De-ionizing time, b: Power system stability, c: Operation duty of CB, d: Torque impact on turbine generators, e: Residual voltage of induction motors

(3) Reclosing for Underground Cable

Cables used as underground cable systems are classified into two types: one is insulated by oil (OF cable), and the other is insulated by a solid (CV cable). Reclosing for cable faults is not carried out as the fault is likely to be a permanent damage cable fault and in the case of OF may lead to an oil fire if a reclose is attempted . However, in mixed connection of underground cable and overhead line, when the fault can be certainly distinguished from that in the overhead section by the method as described in **Chapter 3.2.3**, automatic reclosing may be carried out for faults on the overhead section only. The questionnaire result is shown in **Table 3.2-9**. According to this, automatic reclosing is carried out in some of Japanese electric power companies.

Tab.3.2-9 Automatic Reclosing in Underground Cables

	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
CV	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	×	×	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	-
OF	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	Not att.	-

3.3 Busbar Protection

3.3.1 Bus Configuration

Busbars are the node points of a power system at which large amounts of electrical energy are concentrated. The unplanned or unselective outage of the bus bars can lead to the loss of power supply to a widespread area. The effect of a fault in a bus-zone can be potentially far more damaging than faults on other items of primary plant. The failure to clear a bus fault can lead to considerable equipment damage and system instability.

In the case where no local busbar protection is employed, bus-zone faults would be cleared by the backup or system protection. In some cases this may indeed suffice, e.g. at lower voltage levels, but for higher transmission voltages where security of supply is of paramount importance and fault current levels are high, the non-discriminative fault clearance and relatively slow clearance times would be unacceptable.

Where local busbar protection is employed, the extent of the protected zone will include switching devices (bus selector and bus section disconnectors, circuit breakers, earthing switches), parts of the CT on the bus side of the core used for busbar protection, other connecting parts of the substation construction, in addition to the bus bars themselves. Busbar protection is expected to detect and clear all shunt faults, that is phase-to-earth and phase-to-phase faults where these can occur. Faults can be caused by the failure of an item of primary system plant or indeed human error e.g. , a vehicle or forgotten earthing clamps following maintenance work.

The protection is not normally required to clear open phase faults, i.e., an unbalance in the phase impedances usually caused by the interruption of one or two phases. It is the task of the protection of connected power system objects to detect and clear series faults. There are various types of substation construction, partly depending on the busbar arrangements as well as other specific considerations such as the available space. Many different busbar arrangements are evolved, but the most common busbar arrangements are as follows (See **Table 3.3-1**).

-Double busbar –single breaker with transfer bus
-Double bus –double breaker
-Double bus with four sections
-Single bus-single breaker (also with bus-section circuit breakers)
-Breaker and a half arrangement -1 ½ CB
-Ring busbar /four- breaker mesh
-Main and transfer bus

3.3.2 Main Protection

Busbar protection schemes can generally be categorised as high-impedance, low-impedance and moderate-impedance (effectively a combination of plain circulating current and biased differential scheme).

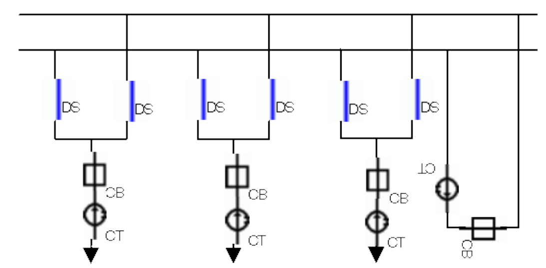
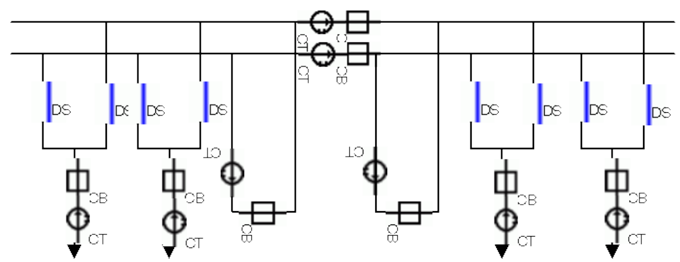
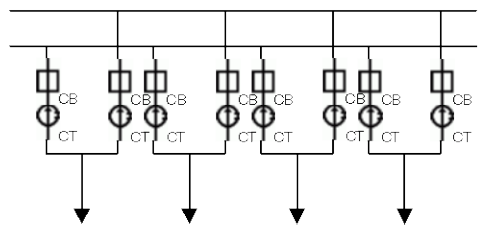
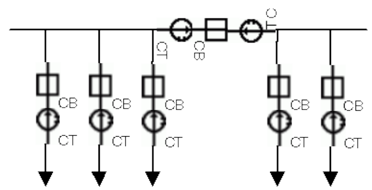
(1) High Impedance Circulating Current Protection

High impedance busbar protection is widely used due to its simplicity and inherent through-fault stability during CT saturation. In the case of CT saturation caused by high through-fault current, the CT secondary impedance is reduced to the resistance of its secondary winding. The measuring circuit comprises a series connected high impedance stabilising resistor connected across the circulating current arrangement of all the CTs in parallel. The value of the stabilising resistor is chosen such that the voltage drop across the relay circuit is insufficient to operate the relay for faults outside the protection zone, i.e., is high compared with the secondary winding resistance of saturated CT and resistance of the leads in the parallel circuit.

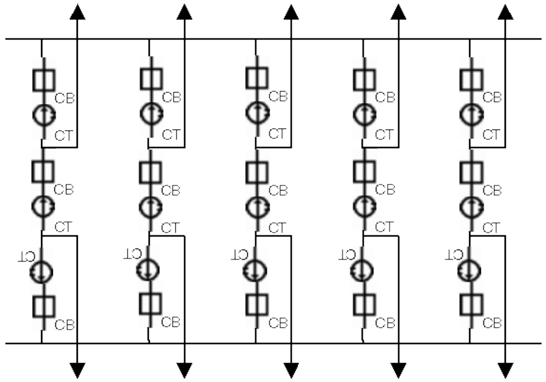
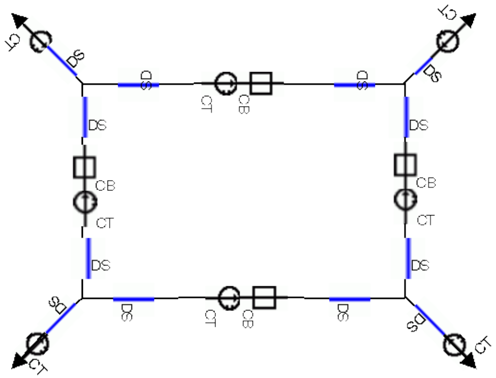
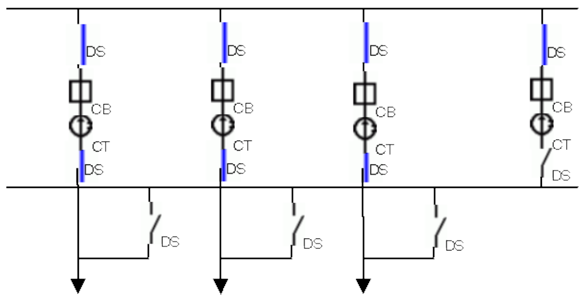
If CT secondary switching is applied, a check zone measurement is usually added to the discriminating measurement, requiring separate CT cores. The check zone measurement is an overall measurement taken over the whole substation and is by definition independent of the isolators' positions and auxiliary contacts. A trip command is only given when both a discriminating measurement and check systems operate.

An advantage of this scheme over low impedance differential schemes is that the primary operating current can be set much below the circuit load resulting in a high sensitivity. Disadvantages of this scheme, are that the relay setting must take the CT secondary winding and wiring resistances into account, which must be kept low, and the CT knee point voltage must be known. All CTs should have the same ratio (no turn correction) and should be of the same type and performance. Furthermore, the stability of the protection is dependent on the fault level. This simple form of high impedance busbar protection is widely used for simple busbar configurations but not really suitable for complex busbar arrangements.

Tab.3.3-1(1) Bus configuration

Double busbar - singel breaker		Both buses are main operating buses and either or both can be energized at any given time. Each feeder can be switched to either of the two buses. Bus sectionalizing further increases flexibility. When a fault occurs in a busbar, the faulted busbar and the lines connected with it will be disconnected. One of the buses and and about half of the lines will disconnected occurrence of a bus fault.
Double bus with four sections		The faulted bus bar and the lines connected with it will be disconnected when a fault occurs in a bus bar. About 1/4 of the bus and the lines will stop at occurrence of a bus fault.
Double busbar-double breaker		The circuit breaker, disconnector and CT are duplicated in each feeder. A fault on one of the two busbars can be cleared selectively with the other bus and the load remaining in service. Busbar interchange and isolation of one bus are possible. Furthermore, where disconnectors are installed between the circuit breaker and the busbar, one breaker can be taken out of service without interrupting operation.
Single bus		As single bus is the simplest configuration, the substation falls into a blackout when a fault occurs in the bus. Therefore, it is applicable to substations in which a few lines are drawn from the bus. The circuit breaker is usually situated between the current transformer and the busbar so as to include it in the protected zone. A sectionaliser allows the station to be split into separate parts and the parts disconnected for maintenance purposes- The busbar can also be divided into sections using a bus-tie breaker, allowing important loads to be fed from two or more sections. A fault on a individual section can be cleared without interrupting the load.

Tab.3.3- 1(2) Bus configuration

Breaker-and-a-half arrangement		This is similar to the double busbar- double breaker arrangement and has the same flexibility. It has however the economic advantage that the two feeder circuits only require three breakers instead of four. A fault on eithet busbar can be cleared without interrupting supply to the two feeders. The boundary of the busbar protection measurement zones is defined by the CT:s. In practice, each of the two busbars is protected by its own busbar protection system. The remaining middle section of the diameter not covered by the busbar protection is protected by the feeder respectively breaker failure protection.
Mesh / Ring bus		As for the breaker- and- a half configuration, the ring bus is used to achieve breaker economy, each branch of the ring only requiring one circuit breaker. Each breaker can however be isolated without interrupting supply to the four feeder circuits. The corner of a mesh substation are protected by differential protection schemes, which are not considered as busbar protection, or by the line protection.
Main and transfer bus		One bus is the main operating bus. The addition of a transfer or bypass busbar, transfer breaker and disconnectors to a single or multiple busbar arrangement, allows a circuit breaker to be isolated for maintenance purposes without disrupting normal operation. All lines will disconnected occurrence of bus fault.

(Notes) ○ : CT

(2) Low Impedance Differential Protection

Low impedance differential protection is the general name given those schemes that do not employ a stabilising resistor, rather utilise currents directly from the CTs. A number of different measurement principles are employed in low impedance differential schemes.

(3) Current Differential Protection

A biased or percentage differential relay is alternatively known as current comparison with current restraint. The operating current is the phasor sum of all feeder currents and the restraint current is the arithmetic sum. A trip command is given when the operating current is greater than its pick-up level (calculated from the minimum busbar short-circuit current) and the stabilising factor, the ratio of operating current to restraint current, exceeds its setting.

Measurement is preferably phase segregated. For reasons of economy and simplicity the three phase currents can be combined into a single phase current using mixing CTs. This is however not very common since the pickup value is dependent on the fault type and there is restricted tolerance to difference in phase angles of the different feeders, in the case where CT ratios differ, the currents have to be balanced by using interposing CTs. In newer numerical protection equipment this is accomplished internally.

Whereas for high impedance differential protection the scheme is inherently stable during CT saturation, special measures must be taken to ensure the protection remains stable during CT saturation. As with high impedance differential protection a check zone independent of the isolator position can be used, or the protection can complemented by a phase comparison protection.

(4) Phase Comparison Protection

The measuring principle for phase comparison protection is based on the assumption that the feeder currents are phase coincident during a busbar fault. The duration of phase coincidence of all feeder currents is checked for positive and negative half-cycles. In addition the non-coincidence is used as a blocking signal. The differential current can also be included in the phase comparison, thereby further improving stability. The pick-up level shall be above load current.

(5) Moderate Impedance Differential Protection

Many of the limitations of high impedance differential protection can be overcome using impedance differential protection (or stabilised high-impedance differential scheme), which is a combination of the normal high-impedance and current stabilised differential scheme. Although heavy through-fault currents may produce a differential current that exceeds the differential pick-up setting, the stabilising current prevents tripping. The requirements made on the primary CTs are subsequently less stringent than for a simple high-impedance differential scheme.

(6) Current Differential Protection Applying Rogowski CT

An increase in the DC time constant increases the potential for CT saturation. Here, an example exists where Rogowski CT based bus protection is employed at a critical substation, such as a UHV system. As shown in **Figure 3.3-1**, the structure uses an insulator instead of a general CT iron core. In consequence, the Rogowski CT is CT saturation free. Another special characteristic of Rogowski CT is that abnormal voltage does not occur when the secondary circuit is open. The Rogowski CT is also light in weight and small in size. It has low output voltage and is quite compatible with digital relays. The Rogowski CT primary/secondary conversion formula is expressed by the below equation and, due to increased high frequency, requires consideration with respect to high frequency countermeasures.

$$v = M\frac{di}{dt}$$

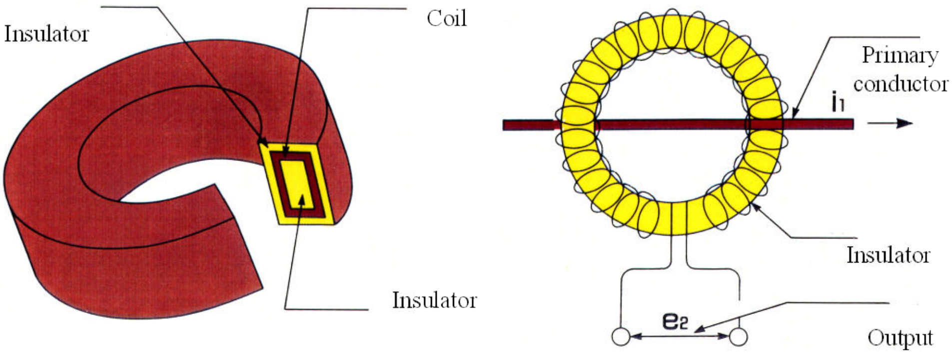


Figure 3.3-1 Rogowski CT

(7) System Protection

Where clearance time and selectivity requirement are not critical, the busbar can be protected by the overreaching element of distance relays in the remote stations. Tripping is therefore at the remote stations, thereby removing more transmission lines and loads than is actually necessary and tripping times are typically from 300 to 600 ms.

3.3.3 Backup Protection

Backup protection of busbar is either provided locally by duplicating parts or all of the protection, or remotely using the overreaching elements of distance relays.

(1) Duplication of Local Busbar Protection

For substations of high strategic importance or where the bus arrangements are complex, the complete busbar protection can be fully duplicated. Duplicated protections invariably employ separate DC circuits and CT cores. Separate trip coils and isolator position auxiliary contacts, although used by some utilities, are however less common.

(2) System Protection

For the majority of substations, especially those at lower transmission voltage levels, backup protection is provided by the system protection, i.e., remote-end distance relay overreaching elements (second zone). An enhancement that is sometimes employed in order to reduce the fault clearance time is to use switchgear optical sensors to start an acceleration signal. A substation-local reverse looking zone 3 element can also provide time-delayed backup protection for busbar faults.

Where the main busbar protection is provided by the system protection (i.e., there is no local protection), backup protection can be considered as being provided by the distance relay third zone elements in the more remote stations.

(3) Splitting Protection

A method of protection known as splitting protection using distance relays is used in some countries as a backup to busbar differential protection. In a station with two bus-zones, two distance relays (or a relay with two directional measuring elements) are installed back-to-back in a coupler bay; each relay has its zone 1 set to be short. For faults on either busbar section the bus-coupler is opened. An alternative arrangement uses a summation of all the feeder currents in a distance relay; a fault within the substation again results in the bus-coupler being opened.

3.3.4 Consideration Issues

A busbar protection must be capable of clearing all phase-to-earth faults, and in the case where they can occur, phase-to-phase faults. Policy regarding fault clearance times required from busbar protection varies from utility to utility. Due to the fact that the short-circuit levels of bus bars are often very high, busbar fault clearance times are required to be as short as possible. This may vary from, i.e., 100 ms for some 400 kV metal-clad substations up to 600 ms for lower voltage levels.

The protection must remain stable during through-faults (outside the bus-zone), especially in the case of CT saturation and switching operations. Due to the high ratio of through-faults to bus-zone faults, busbar protection is called upon to stabilise many more times than it has to operate.

Busbars are divided into zones, the boundaries of which are defined by the circuit breakers or disconnectors and their associated current transformers. Each zone therefore requires an independent zone of protection, such that fault clearance is selective, that is, only those circuit breakers defining the boundary are tripped, With the exception of simple busbar configuration (single busbar and one breaker a half), these boundaries are not fixed, rather depend on the position of the selection isolators. For this reason, the busbar protection must possess an accurate replica of the station's primary configuration.

(1) High Reliability

Busbar protection, the main protection is a unit protection. Hence there is no particular need for coordination of the main protection. As a general rule the backup protection (impedance relay for connected power transformer or distance protection) second zone should at least reach 20 % over the next station to ensure backup for busbar fault.

Many countries are pleased to use instantaneous trip for fault current above rated current But some countries wants the busbar relay to always trip for the lowest infeed power i.e.- normally down to 20% of rated current. To prevent unwanted operation a check zone is used as shown in **Figure 3.3-2**.

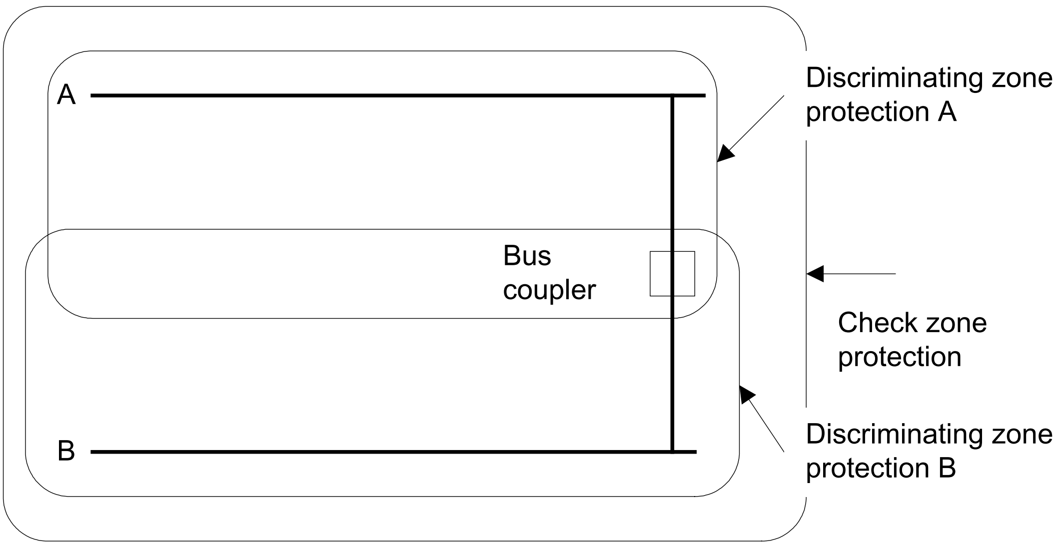


Figure 3.3-2 Protection Scheme for Double Busbar

(2) CT Saturation

There is a terminal which current flows toward the fault point against an external fault as shown in **Figure 3.3-3**. As CT at the terminal may be saturated due to large out-coming current, the busbar protection has possibility not to operate correctly.

One of the countermeasures of this phenomenon is known as high impedance differential protection described in **Chapter 3.3.2**. And, for analogue relays, traditionally adaptive phase comparison differential principle is strong countermeasure against CT saturation.

For digital relays, several principles, for example, no-change detection of differential current is used to measure against CT saturation. The digital busbar protection applying Rogowski CT or non-conventional CT, which is saturation free, is ultimate measure.

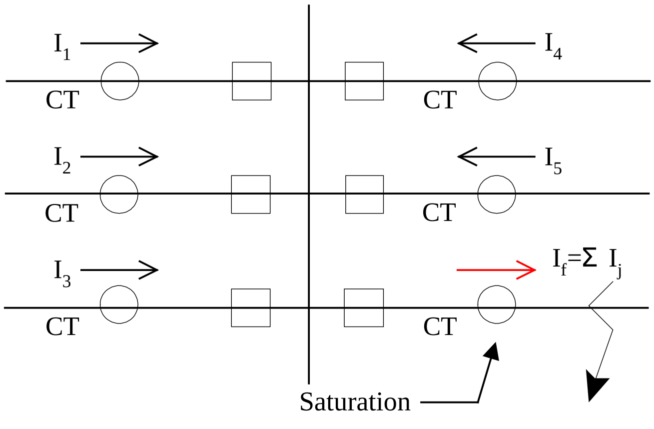


Figure 3.3-3 CT Saturation

(3) Outflow at Occurrence of Internal Fault

(a) Double Busbar Configuration

In a double busbar with four sections, there may be an outflow terminal when an internal fault occurs as shown in the **Figure 3.3-4**.

Figure 3.3-5 shows the outflow for busbar internal fault. Considering the worst case, half of fault current may flow out from the faulty busbar zone.

For current differential relay, outflow must be considered to determine the characteristic as shown in **Figure 3.3-6**.

The slope or the percentage ratio of the operational current, i.e. differential current, to the restraining current, i.e. the summation of current must be lower than the worst outflow case.

Following is calculation based on the worst case of outflow.

$$I_{diff} = I_1 + I_2 + I_3 = I + (-I) + I = I$$

$$I_{res} = |I_1| + |I_2| + |I_3| = 3 \cdot I$$

$$\frac{I_{diff}}{I_{RES}} = \frac{1}{3} \geq K$$

Hence,

$$K = \frac{1}{3}$$

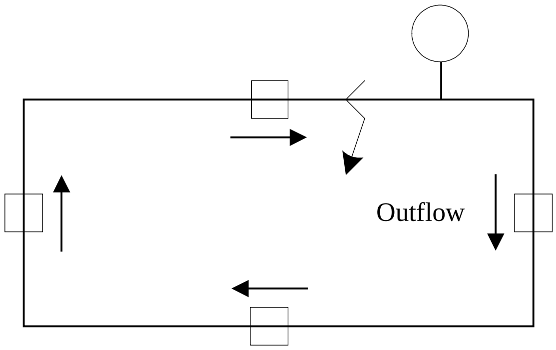


Figure 3.3-4 Outflows at Occurrence of a Busbar Fault in Double Busbar Configuration

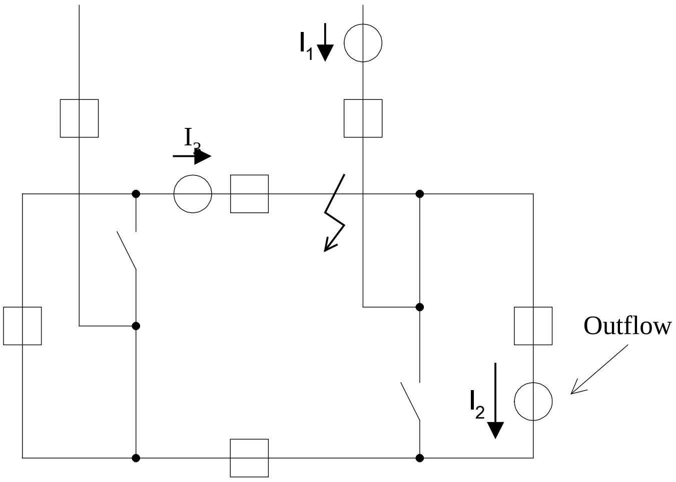


Figure 3.3-5 Occurrences on Outflow at Busbar Fault for Double Busbar Configuration

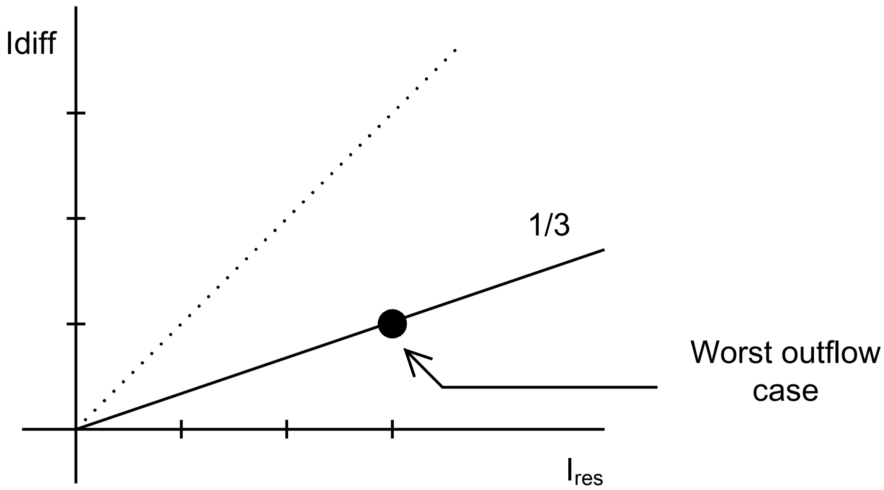
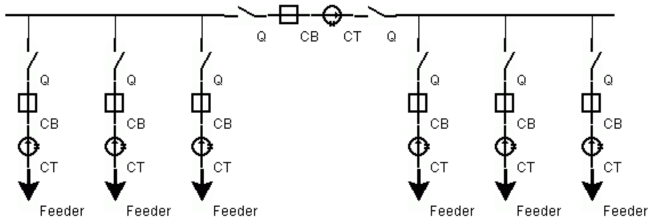


Figure 3.3-6 Percentage Characteristic

(b) Multi Busbar Configuration

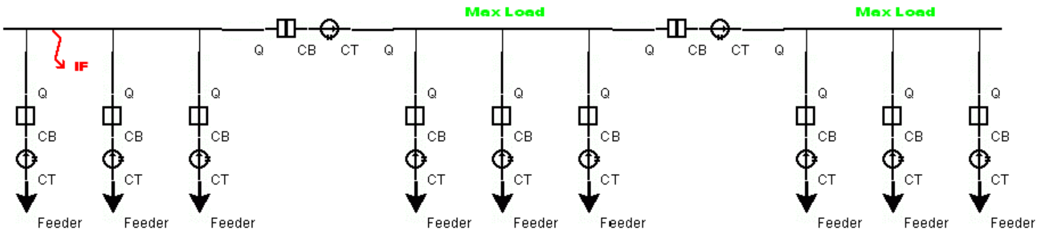
In a substation there are:

- n bars (Independent bars)
- A minimum internal short-circuit value ($I_{cc\ min\ (1\ bar)}$)
- A maximum load for a bar ($I_{loadMax\ (1\ bar)}$).



The worst case is:

- when all these buses are independent (bus sectionalizers open)
- the maximum load is on all the buses (biggest bias current)
- The internal short-circuit value is minimum.

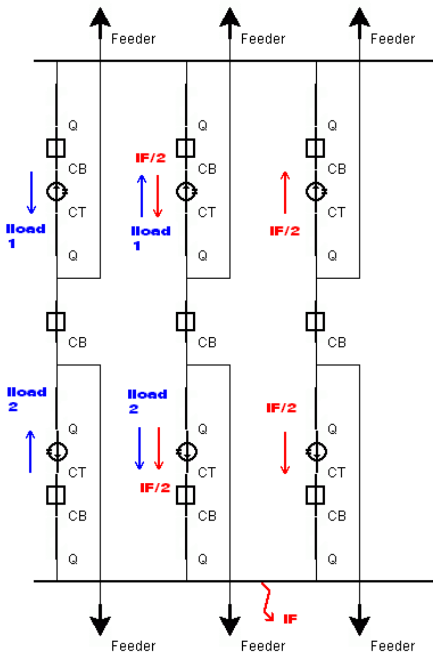


During the internal fault:

- the bias current is:

$$I_{cc\,min\,(1\,bar)} + (n-1) \times I_{loadMax\,(1\,bar)}$$

- the differential current is: Icc min (1 bar)



Thus the biggest slope for the Check Zone to detect the fault is:

$$\frac{I_{cc\,min\,(1\,bar)}}{((Independent\ bars - 1) \times I_{loadMax\,(1\,bar)}) + I_{cc\,min\,(1\,bar)}}$$

For example if there are 3 buses and $I_{cc\,min} = I_{loadMax}$,, then the slope must be below 33%

(c) One and a Half Breaker Busbar Configuration.

For a one and half breaker scheme there are:

- 2 bars (Independent bars)
- A minimum internal short-circuit value ($I_{cc\ min\ (1\ bar)}$)
- A maximum load for a bar ($I_{loadMax\ (1\ bar)}$).

The worst case is:
- when the is split in 2 and goes as well through the opposite bar
- the maximum load is on the 2 buses (biggest bias current)
- The internal short-circuit value is minimum.

During the internal fault:
- the CZ bias current is:

$$I_{cc\ min\ (1\ bar)} + 4 \times I_{loadMax\ (1\ bar)}$$

- the CZ differential current is: Icc min (1 bar)

Thus the biggest slope for the Check Zone to detect the fault is:

$$\frac{I_{cc\ min\ (1\ bar)}}{(4 \times I_{loadMax\ (1\ bar)}) + I_{cc\ min\ (1\ bar)}}$$

If for example: $I_{cc\ min} = I_{loadMax}$, the slope must be below 20%

(4) Gas Insulated Substation (GIS) Specification.

It is compulsory to clear a busbar fault in a GIS within a certain limited time to avoid the arc damaging the gas chamber integrity as a hole in the chamber or seals. Even minor loss of gas chamber integrity can lead to further explosions. Minor damage can take several months to repair involving major substation outage of the damaged and adjacent bays.

The longest total fault clearance time (not just the relay tripping time) should cover the breaker failure mode, which is mostly dependant on the longest Circuit Breaker Operating Time (CBOT).

As an example, if the longest clearance time that can be permitted is 230 ms, the evaluation of the time coordination is as follows:

	Fast Breaker	**Slow Breaker**
Tripping time (sub-cycle):	20ms max	20ms max
CBOT	30ms	60ms
Total Clearance time	50ms	80ms

If a circuit breaker failure happens, the following sequence of events occurs:

	Fast Breaker	**Slow Breaker**	**Slow Breaker And Reduced timer**
Tripping time (sub-cycle):	20ms max	20ms max	20ms max
CBOT (not counted in total clearance time)	(30ms)	(60ms)	(60ms)
Back trip timer *	100ms	150ms	100ms
Relay to operate	5ms	5ms	5ms
CBOT:	30ms	60ms	60ms
Total Clearance time	155ms (fine)	235ms (too long*)	185ms

*: The Back trip timer has to be reduced in the case of slow CBOT to 100ms to keep 45ms margin (100ms is fine because the reset time of the 50BF shall be around 20ms).

It is therefore clear that GIS busbar protection must generally be subcycle performance and must include a fast reset circuit breaker failure protection.

(5) Switching of Internal Terminals

Connections of lines are sometimes changed in the double busbar. And, the busbar protection is needed to change input terminals to trip selectively every time a connection bus is changed.
Especially in High Impedance Differential Relay, the means of changing input terminal change directly CT secondary circuit.

When disconnector auxiliary switches or repeat relays are used for switching CT secondary circuits, they shall also be used to short to earth and disconnect the CT secondary wiring from any common bus wiring when the primary circuit is isolated.

The operating sequence of disconnector auxiliary switches or disconnector repeat relay contacts used in CT secondary circuits shall be such that the auxiliary switches or repeat relay contacts operate as shown in **Figure 3.3-7**:

1) Before reaching the pre-arcing distance on closing the disconnector.
2) After the pre-arcing distance has been exceeded on opening the disconnector.

Combinations of normally open and normally closed auxiliary switches or repeat relay contacts from the same disconnector shall `break' before `make' both for opening and closing the disconnector.

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 disconnectors during the transfer operation.

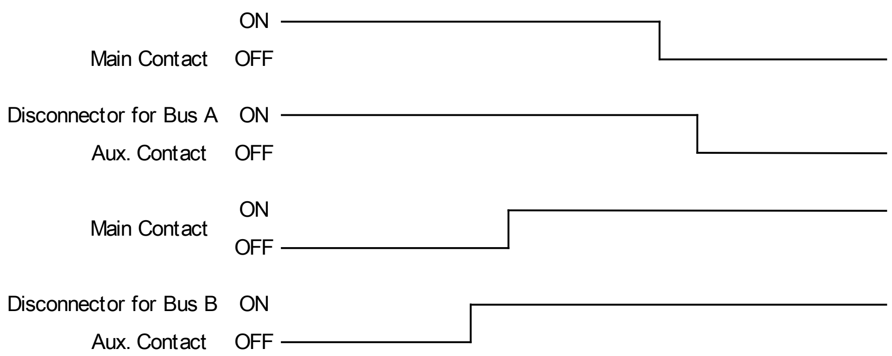


Figure 3.3-7 Timing Requirement for Disconnector Auxiliary Switches or Disconnector Repeat Relay Contacts in Transfer Operation

(6) CT Disconnection for Bus Section and Bus Coupler Current Transformer Cores

In practice there are two different solutions for bus section or bus coupler bay layout. First solution is with two sets of main CTs, which are located on both sides of the circuit breaker, as shown in **Figure 3.3-8**:

Two differential zones overlap across the bus-section or bus-coupler circuit breaker. No special considerations within busbar protection scheme are then necessary for this type of stations.

Due to the high cost of the HV current transformer often only one current transformer is available in bus-section or bus-coupler bay. This is a solution shown in **Figure 3.3-9**.

For this type of solution just one main CT is located on only one side of the circuit breaker. Thus, there is no zone overlapping across the section/coupler circuit breaker as shown in **Fig.3.3-9**. For an internal fault in the dead zone, the differential zone ZA will unnecessarily operate and open the bus section breaker and all other feeder breakers associated with it. Nevertheless the fault will still exists on other busbar section, but is outside the current transformer in the bus section bay and hence outside the zone ZB (i.e. it is external fault for zone ZB). Similar problem will also exist if section/coupler circuit breaker was open before the internal fault in the dead zone. Therefore, the busbar protection scheme does not protect the complete busbar.

In order to improve the busbar protection scheme with this type of station layout, it is often required to disconnect the bus-section or bus-coupler CT from the differential zones as soon as the bus-section or bus-coupler circuit breaker is opened. This arrangement can be achieved in following example.

The open contact of the section/coupler circuit breaker is normally used. However, the timing of this auxiliary contact is very important. Please note that this auxiliary contact initiating CT disconnection shall be a type which closes as soon as the main breaker contacts leave the open position. It shall not be a type which closes when the main breaker contacts reach the closed position. This solution requires good CB maintenance and might experience problems during the life time of the circuit breaker.

Using external relays and this solution does not depend on contact timing between the main contacts and auxiliary contact of the breaker. This will disconnect the section/coupler CTs after about 150ms from the moment of opening of the section/coupler CB. Nevertheless this time delay is absolutely necessary in order to prevent racing between the opening of the main breaker contact and disconnection of the CT from the differential zones .This scheme will as well disconnect the CT in case of the operation of any of the two differential zones involved. This will secure the delayed (about 150ms) clearing and tripping of the internal fault within the dead zone even in case of section/coupler circuit breaker failure during this fault. This facility will improve the performance of the busbar protection scheme when one CT is located on only one side of the bus-section/bus-coupler circuit breaker.

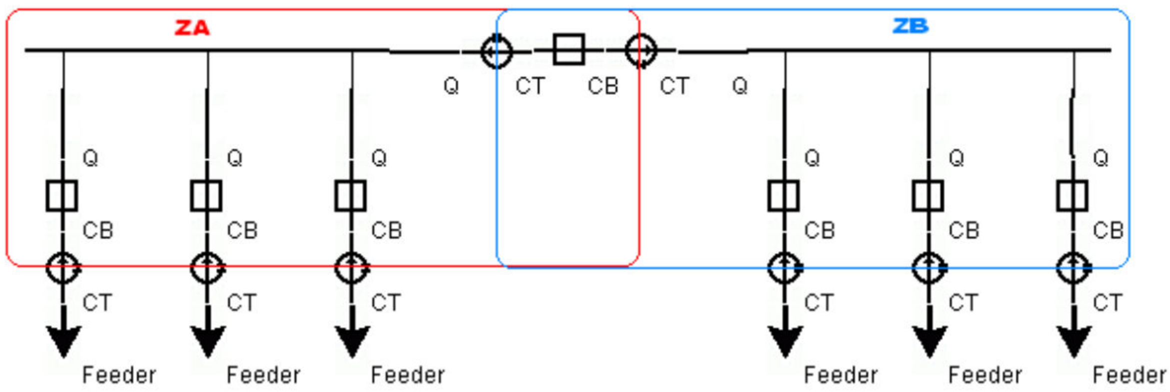


Figure 3.3-8 Two Busbars with 2 CTs Tie

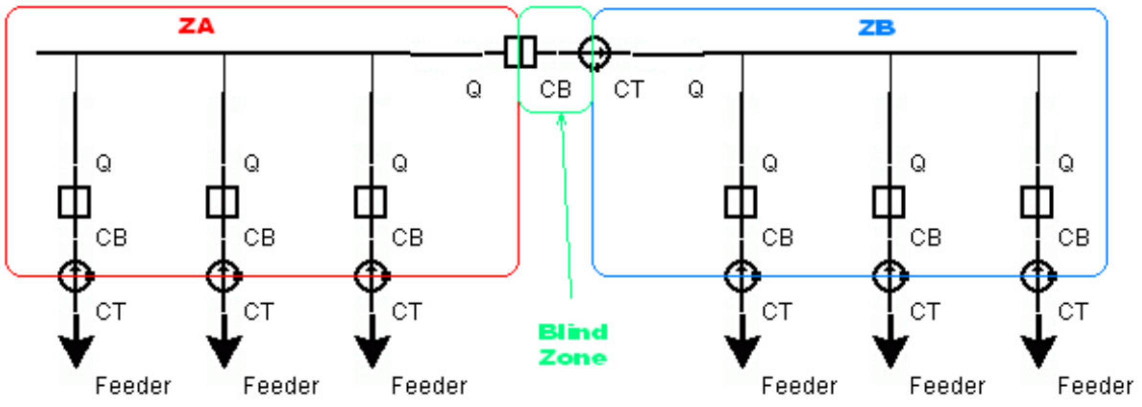
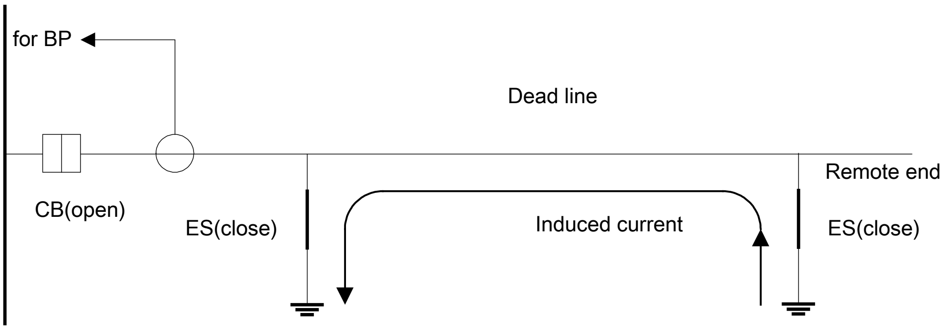


Figure 3.3-9 Two Busbars with 1 CT Tie

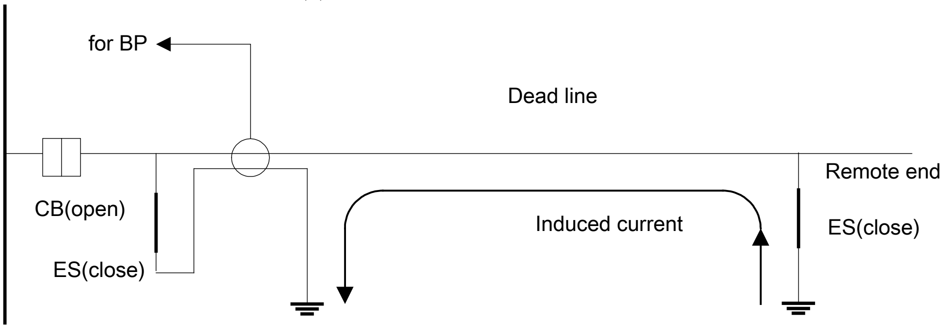
(7) CT Location for Cable Outlet or Earthing Switch for Line

Normally earthing switch (ES), which connects the conductor to earth for safety of dead line, is located line side of CT location. But often, ES is located bus side of CT location because of primary equipment configuration. And then in busbar protection, consideration issue against induced current flowing into ES earthing circuit is as following;

- ES earthing conductor is passed through the CT as shown in **Figure 3.3-10(2)** for cancellation of induced current.
- In case of digital relay, reading ES condition and the relay controls CT secondary output to zero.
- In cable sheath earthing, same phenomena should be considered.



(1) ES Located Line Side of CT



(2) ES Located Bus Side of CT

Figure 3.3-10 Solution for Busbar Protection against the Case of ES Located Bus Side of CT

3.3.5 Practice of Busbar Protection

(1) Bus Configuration

Table 3.3-2 shows the questionnaire result about bus configuration. According to this table, majority is double busbar. Single busbar follows. Some answer ring bus and one and half configuration.

Table 3.3-3 shows the questionnaire result about insulation. Substations are either air-insulated (AIS) or gas-insulated (GIS).

Table 3.3-2 Bus Configuration

Bus configuration	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Double busbar- single breaker with transfer bus	×	×	×		×	×	×	×	-	-		×	×	-	-	×	-	×		×	-
Double busbar with four sections	×	×	-		×	-	-	×	×	-		×	×	-	×	×	×	-		-	×
Double busbar double breaker	×	×	-		-	-	×	-	-	×		-	-	-	-	-	-	-		×	-
1 1/ 2 CB	×	×	×		×	-	×	-	-	×		×	-	×	-	×	-	×		-	-
Ring	×	-	×		-	-	×	-	-	-		-	-	-	-	×	-	×		-	-
Single busbar	×	×	-		-	×	-	×	×	-		×	×	-	-	-	×	-		-	-
Main and transfer busbar	-	-	-		-	-	-	-	-	-		-	-	-	-	-	×	-		×	-
Four switch mesh	×	×	-		-	-	-	-	-	-		-	-	-	-	-	-	-		-	×

Table 3.3-3 Insulation

	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
air	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
gas	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×

(2) Main Protection

(a) Protection Schemes

Table 3.3-4 shows the questionnaire result about main busbar protection. According to this table, most of answers are low impedance differential, high impedance differential and combination of them. In **Table 3.3-4**, moderate impedance differential protection regards as high impedance differential protection.

Table 3.3-4 Main Busbar Protection

Protection relay	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Low Impedance +Low Impedance	×	-	×	-	×	-	-	-	-	-	-	×	×	-	-	-	-	×	×	-	-
High Impedance +Low Impedance	-	-	-	-	-	-	-	-	-	-	-	×	×	-	-	×	-	×	×	-	-
Low Impedance	-	-	-	×	×	×	×	×	×	×	×	-	×	-	-	-	×	-	-	-	×
High Impedance	×	×	-	×	×	×	×	×	×	×	×	-	-	×	×	×	×	-	-	×	×
Distance	-	-	-	-	-	-	-	-	-	-	-	-	×	-	-	-	-	-	-	-	-
Phase Comparison	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Others	×	×	-	-	-	-	-	-	-	-	-	-	×	-	-	-	-	-	-	-	-

(b) Consideration Issues in Applying Busbar Protection

Consideration issues in applying the busbar protection were surveyed. The questionnaire result shows **Table 3.3-5**. Majority of answers is CT saturation, switching of input terminal and outflow terminal follow. In the table, (a) means CT saturation, (b) means switching of input terminal, (c) means outflow terminal at occurrence of a bus fault, and (d) means high reliability.

Table 3.3-5 Consideration Issues in Applying the Busbar Protection

Consideration Issues	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
(a)	×	×	×	×	×	-	×	×	×	×	×	×	×	×	×	×	×	×		×	×
(b)	-	-	×	×	-	-	×	×	×	×	×	×	×	-	-	×	×	×		×	×
(c)	-	-	×	×	×	-	-	×	×	-	-	×	×	-	-	×	×	-		-	×
(d)	×	×	×	×	×	×	×	×	×	×	×	×	×	-	-	×	×	×		×	×
Others	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-

(c) Countermeasure against CT Saturation

The questionnaire result about CT saturation shows **Table 3.3-6**. Most of countries carry out some countermeasures against CT saturation.

Table 3.3-6 Countermeasures against CT Saturation

Countermeasure against CT saturation	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
CT with gap	-	-	×	×	×	-	-	×	×	×	×	×	×	-	-	-	-	-		-	-
Linear coupler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-
High impedance relay	×	×	-	×	-	-	×	-	×	-	-	×	×	×	×	×	×	×		×	×
Others	-	-	-	-	×	×	×	×	×	×	×	×	×	-	-	-	-	-		-	×

(3) Backup Protection

(a) Protection Schemes

The questionnaire result about backup protection for busbar shows **Table 3.3-7**. Majority of answers is distance relay. The distance relay at the remote end is considered as a backup protection of busbar protection. This is the reason why zone 2 of the relay fully covers the bus at the remote end.

Table 3.3-7 Backup Protection

Backup relay	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Distance	-	-	×	×	×	×	×	×	Not Available	×	×	×	Not Available	×	Not Available	×	×	×	Not Available	×	Not Available
Overcurrent	-	-	-	-	×	×	-	×		-	-	×		-		×	×	×		-	
Ground Overcurrent	-	-	-	-	×	×	-	-		-	-	-		-		-	-	-		-	
Ground Directional	-	-	-	-	×	×	-	×		×	×	×		-		-	-	-		×	
Ground Overvoltage	-	-	-	-	-	×	-	-		-	-	-		-		-	-	-		-	
Others	×	×	-	-	-	-	×	-		-	-	-		×		-	-	-		-	

(b) Purpose of Installation

The questionnaire result about purpose of installation of backup protection for busbar shows **Table 3.3-8**. In the table, the meaning of (a) to (c) can be seen in the note 2. If the main protection is duplicated, the issue (a) would not be generally required for the installation of backup protection for busbar. Moreover, the purpose (b) is important when clearing a fault is delayed against a bus fault from the relation of the CT arrangement. CB failure to trip and reduction of operator's recharging manoeuvres of CB are reported as other purposes of installation of backup protection.

Table 3.3-8 Purpose of Installation of Backup Protection

Purpose of installation	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
(a)	-	-	-		×	×	×	×	Not available			×	Not available	×	Not available	×	×	-	Not available	-	Not available
(b)	-	-	×		-	-	×	×	Not available			×	Not available	×	Not available	×	×	-	Not available	×	Not available
(c)	-	-	-		-	-	×	×	Not available			×	Not available	×	Not available	×	×	×	Not available	×	Not available
others	×	×	-		-	-	-	-	Not available			-	Not available	-	Not available	-	-	×	Not available	-	Not available

<Note> (a) To protect the busbar against an internal fault while the main relay is blocked
(b) To protect the busbar when the main relay doesn't operate against an internal fault
(c) To prevent fault extension

(c) Countermeasure against Breaker Failure

The questionnaire result about backup protection for busbar shows **Table 3.3-9**. Most of utilities answer local backup and remote backup. Bus-coupler sequential splitting as local backup and a distance relay of Zone-2 at the remote end as remote backup are considered. It is supposed that the CB failure rate during the busbar fault is very low, therefore, the zone-2 distance relay at the remote end is considered as one of countermeasures.

Table 3.3-9 Countermeasures against Breaker Failure

Countermeasure against CBF	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Remote backup	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×		×	×
Local backup	×	×	×	-	×	-	×	×	-	×	×	-	×	×	×	×	-	×		-	×
Others	-	-	-	-	-	-	-	-	-	-	-	×	×	-	-	-	-	-		-	-

3.4 Transformer Protection

According to the results of the questionnaire, low impedance current differential relays are applied for transformers as main protection in most countries. Some countries apply high impedance differential protection for auto-transformers. These can be summarized as the unit protections applied as transformer main protection.

In regard to backup protection, distance protection or overcurrent (phase current, zero sequence current) protection or both are mainly applied. In addition to the above, mechanical relays such as Buchholz relays and sudden pressure relays are widely applied to transformer protection, and are particular to application to transformer protection. Mechanical relays and tank type transformer protections are intended to detect internal faults in case electrical type relays fail to detect certain fault. In addition to these relays, thermal overload protection is often applied for the purpose of extending transformer life time rather than for detecting faults.

3.4.1 Main Protection

(1) Low Impedance Current Differential

Low impedance biased current differential protection is most commonly applied for transformer protection. **Figure 3.4-1** shows typical application for a star-delta transformer.

The main differences of the transformer current differential protection from current differential protection either for bus bars or transmission lines are as follows.

- Necessity of CT ratio matching
- Necessity of phase angle matching
- Necessity of removal of zero sequence current

Recent digital techniques have enabled relays to do these things by software internally. Recent numerical transformer protection relays have settings for these adjustments and users can configure relays with the settings according to the application. Before that, these problems were dealt with by external connection, for example, by inserting auxiliary CTs etc. for CT ratio matching, and connecting the secondary wiring of the star side in delta for phase angle matching and for removing zero sequence current. There are other issues which are particular to transformer protection.

- Existence of on-load tap changer
- Inrush current

On-load tap changers are often fitted to transformers. When the tap position is changed from the neutral position a differential current appears. A biased differential characteristic has an advantage for managing this problem when compared to a plain differential characteristic. **Figure 3.4-2** shows a typical biased differential characteristic. It is able to give high sensitivity for internal faults while at the same time being robust against the differential current generated by the tap position by applying an appropriate slope setting with consideration of the tap position (Slope 1 in **Figure 3.4-2**). In order to prevent relays from giving unwanted operation because of larger differential current resulting from CT saturation, to have the second steep slope is useful (Slope 2 in **Figure 3.4-2**).

Another big issue for transformer protection is inrush current. When a circuit breaker is switched on, the transformer core could be saturated, and inrush current flows to the transformer. As a consequence, differential current is detected and relays may operate depending on the magnitude of the inrush current. It is well known that quite high 2^{nd} harmonic component is involved in inrush current. Blocking or restraining relay operation by detecting 2^{nd} harmonic component is commonly used in transformer differential protection, which can delay the relay operation.

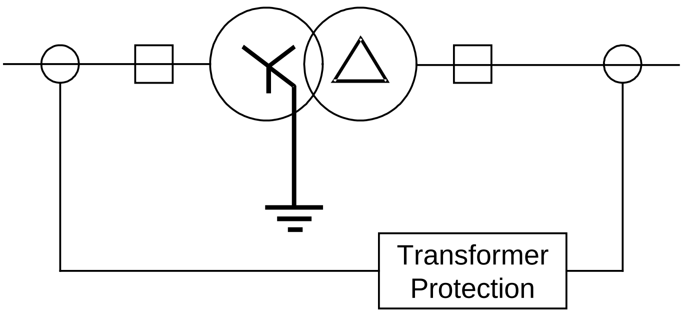


Figure 3.4-1 Typical Application

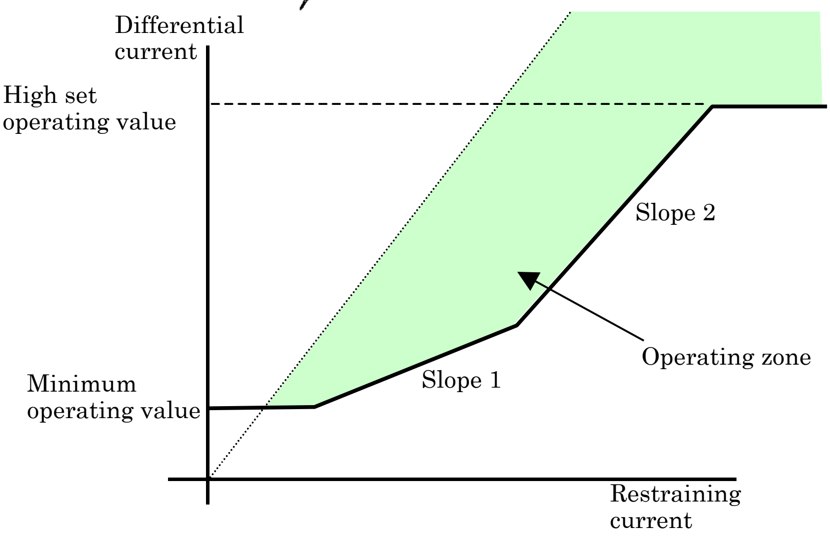


Figure 3.4-2 Biased Current Differential Characteristic

On the other hand, a very large fault current can flow when a fault occurs at the transformer bushing. In that case, the fault must be cleared as quickly as possible, and for that purpose, high set plain differential protection is commonly used. This element is designed to operate very quickly and is not blocked by any other functions. Therefore the setting must be higher than maximum inrush current.

It can be difficult for phase current differential protection to detect faults to earth near transformer neutral points. In this case zero sequence current differential protection comparing the neutral current with the residual current of three phases, which is often called restricted earth fault protection (REF) is suitable to be applied. This function can be combined with phase current differential protection in a single unit as shown in **Figure 3.4-3**.

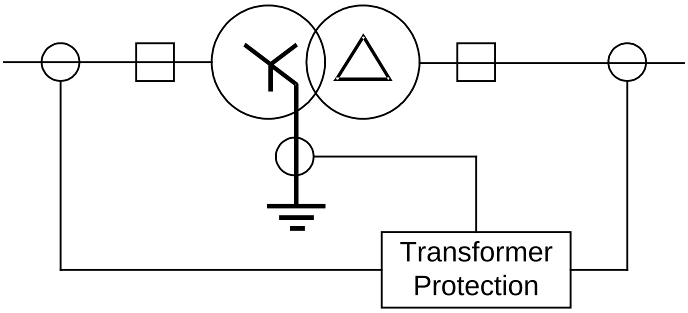


Figure 3.4-3 Typical Application with REF

(2) Restricted earth fault protection (High Impedance Differential Protection principle)

In auto-transformer protection, a high impedance relay can be simply applied as shown in **Figure 3.4-4**. This application is simple, however, the CT ratio of all CTs must be identical.

High impedance protection can be applied for REF for the star side of star-delta transformers as shown in **Figure 3.4-5**.

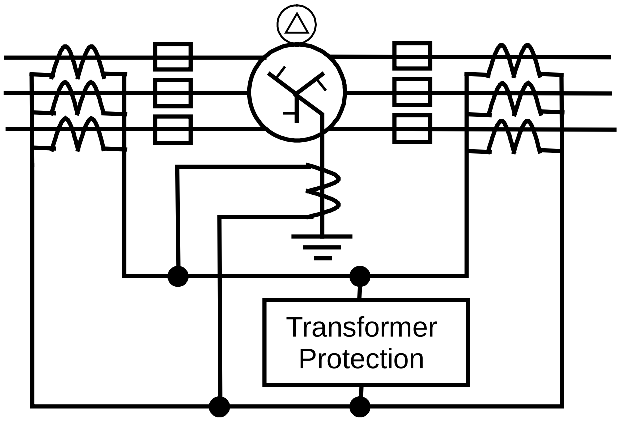


Figure 3.4-4 High Impedance Protection for Auto-Transformers

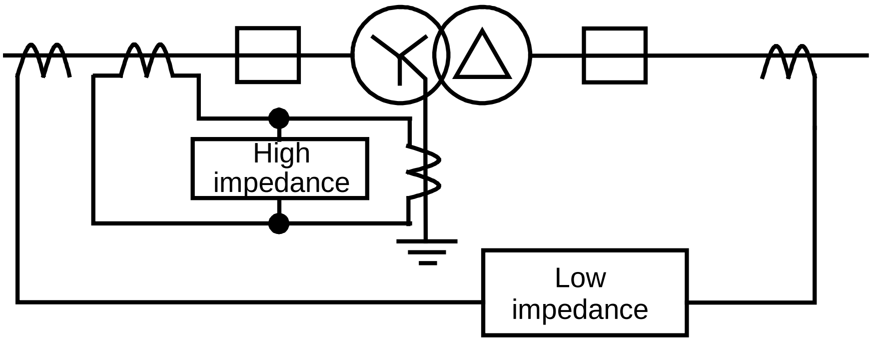


Figure 3.4-5 Typical Application with High Impedance REF

3.4.2 Mechanical Protection

Insulation deterioration of the electrical circuit or the iron core may cause vaporization of insulation fluid. Since differential protection for transformer can not detect such an event, the following mechanical protection should be used.

(1) Conservator protection

The Pitot-tube, which is a measuring instrument that measures the speed of the flow of the fluid, is installed at the pipe between the main unit and the conservator, and it detects the pressure of the oil flow when a fault occurs within the transformer.

(2) Buchholz Relay

The Buchholz relay is installed at the pipe between the main unit and the conservator, and it detects resolved gas by the float switch when a fault occurs within the transformer.

(3) Sudden-Pressure Relay

The sudden-pressure relay is installed in the upper part of a bursting tube, and it detects the sudden increase of internal pressure by the bellows when a fault occurs within the transformer.

3.4.3 Backup Protection

(1) Phase and Earth Fault Overcurrent Protection

It is quite common that overcurrent relays are applied to the high voltage side for transformer backup protection to cover the zone between the transformer and the CT connected on the bus side. It is especially suitable when there is no power source on the lower voltage side, because the overcurrent protection will operate only for faults in the transformer or on the low voltage side. Conversely, it is difficult to decide the setting value when there are any power sources on the lower voltage, because the overcurrent relay may detect the fault current from the low voltage side to faults on high voltage side. It also should be noted that the setting should be higher than maximum inrush current or alternatively a timer should be inserted. Inverse overcurrent relays are sometimes applied to the lower voltage side for back up protection for the lower voltage lines rather than for the transformer.

(2) Distance Protection

If VTs are available, distance relays can be applied for backup protection. An advantage of distance protection is that it can distinguish forward faults from reverse faults. Therefore, distance protection can be applied for backup protection even when there are power sources on the lower voltage side. Also, calculation of the setting value is easier than calculating the setting of overcurrent relays because the operating zone is independent from the system short circuit capacity, which is an another advantage of the distance protection.

It is also possible that distance protection is applied as second main protection of a transformer if the zone 1 reach is set to less than the total impedance of the transformer. (e.g. 80%)

(3) Time Delayed Neutral Overcurrent Protection

Time delayed neutral overcurrent relays are often applied as backup to the primary protection. The time delays associated to these protections should be a major concern for protection setting engineers since coordination is requested with the main protective functions.

3.4.4 Consideration Issues

In the transformer protections, just same as line protections or busbar protections, the purpose of fault clearance relay is that maintain the power system by excluding the fault point from the system. Moreover, for the transformer protection relay, the reduction of environmental pollution, the reduction of the disaster, and the reduction of the equipment damage is an important issue, because the transformer fault has the possibility as that cause the environmental pollution and the disasters like as the explosion, the oil leaking, and a fire, etc.

Therefore, the mechanical protection has the key role in the transformer protection besides electric protection (Refer to **Chapter 3.4.2**). Differential protection provides the best protection for internal faults detection. In applying differential protection, several factors must be considered:

1) Magnetizing inrush current. This is a normal phenomenon which has the appearance of an internal fault (current into but not out of the transformers).
2) Different voltage levels and hence the CTs are of different types, ratios, and performance characteristics.
3) Phase shifts in star-delta-connected banks.
4) Transformer taps for voltage control.
5) Phase shift and/or voltage taps in regulating transformers.

Major consideration issues are described following.

(1) Inrush Current

When system voltage is applied to a transformer, a current transient occurs, known as magnetizing inrush current. As described in **Chapter 3.1.3(3)(b)**, an effective countermeasure against magnetizing inrush current is the second harmonic component restraint. Recent years, however, have seen increases in the number of cable transmission lines and in the capacity of phase modification capacitor which cause transient oscillation frequencies to become still lower than before and get closer to the second harmonic. Meanwhile, the second harmonic component of magnetizing inrush current is on the decline under the influence from improvements in core steel and design. The bounds of what can be done to satisfy the two conditions at the same time are becoming narrower.

Solution to this problem is shown in **Table 3.4-1**.

Table 3.4-1 Solution for Inrush Current [2]

Measures against inrush current			Application		
			500kV	275kV	154kV or less
Former method	Operating time delay scheme				X
	Trip locking scheme for a certain period of time				X
	Two- phase AND scheme				X
	Scheme with undervoltage relay				X
	Sensitivity reduction scheme				X
Harmonic restraint scheme	Harmonic restraint scheme		X	X	X
	2nd harmonic restraint schemes	Phase- segregated detection/ phase- segregated lock	XXX	XXX	XXX
		Phase- segregated detection/ three- phase lock	XXX	XXX	XXX
		Three- phase- sum detection/ phase- segregated lock	XXX	XXX	XXX
		Two- phase- sum detection/ phase- segregated lock			
		Phase- segregated detection/ two- phase AND trip		XXX	XXX
		Three- phase- average detection/ three- phase lock			XXX
New developed method	Asymmetrical locking scheme		X		
	No- change detection scheme		X		
	Impedance locus scheme		X	X	
	Tertiary voltage restraint scheme		X	X	
	Parallel winding current- balance relay scheme		X		
	Differential scheme among primary, secondary and neutral current		X		
	Parallel admittance scheme				
	Dynamic estimation scheme for magnetization curve				
	Power differential scheme				
	Phase comparison of second harmonic with fundamental harmonic scheme				

Note) X: partly used, XXX: widely used

(2) Matching of the Voltage Ratio and the CT Ratio

To match the transformer voltage ratio and CT ratio difference, the matched setting value can be found as follows:

1) In a case where the transformer unit is a star connection and the CT secondary is a delta connection:

$$Matched\ setting\ value = \frac{Transformer\ rated\ capacity}{\sqrt{3} \times Rated\ voltage} \times \frac{CT\ secondary\ rated\ current}{CT\ \ primary\ rated\ current} \times \sqrt{3}$$

2) In a case where the transformer unit is a delta connection and the CT secondary is a star connection:

$$Matched\ setting\ value = \frac{Transformer\ rated\ capacity}{\sqrt{3} \times Rated\ voltage} \times \frac{CT\ secondary\ rated\ current}{CT\ primary\ rated\ current}$$

Where:

Transformer rated capacity = Transformer primary side rated capacity, normally
Rated voltage = Center tap voltage in the case of a tap changing transformer

<Note> With a tap changing transformer, differential current occurs due to a change in the voltage ratio caused by tap switching. Thus, the setting process needs to be performed based on the centre tap voltage, and the biased differential characteristics needs to be set in such a manner that the relay does not operate by the differential current produced when the tap changes.

Thus, because the matched setting value is the CT secondary side reduced value of the transformer rated current, the sensitivity of the biased differential relay is uniformly handled using the transformer rated current as standard. Selecting the setting value giving priority to the degree of consistency per transformer is not preferred since the sensitivity of the transformer rating base may become varied. Further, when sensitivity is set unnecessarily sensitive, a risk of mal-operation caused by load current results. Conversely, a low sensitivity invites a decrease in fault detection sensitivity.

(3) Phase Shifting in Star-Delta Connected Transformer

Between the primary and secondary current of the transformer of a star-delta connection is a phase angle difference of 30°. For this reason, a method that aligns the current phase by differing from the connection of the CT secondary circuit of both sides is taken. The following describes the concept of such a connection.

The transformer unit is connected to the CT secondary circuit on the star connection side by a delta connection and to the CT secondary circuit on the delta connection side by a star connection, thereby acquiring a correct phase relationship with respect to load current and external fault current. **Figure 3.4-6** shows the correct phase relationship with respect to a three-phase current.

Furthermore, with a transformer of a star-star-delta connection that does not use a tertiary circuit, problems caused by phase difference do not arise even if the transformer primary/secondary CT secondary circuit is connected by a star connection. However, this is not applicable in a case where the transformer primary and/or secondary neutral point is earthed since zero sequence current flows to the differential circuit in an external earth fault.

In such a case as well, since the zero sequence current can be negated by connecting the CT secondary circuit using a delta connection, the transformer primary/secondary CT secondary circuit is connected by a delta connection as shown in the **Figure 3.4-7**.

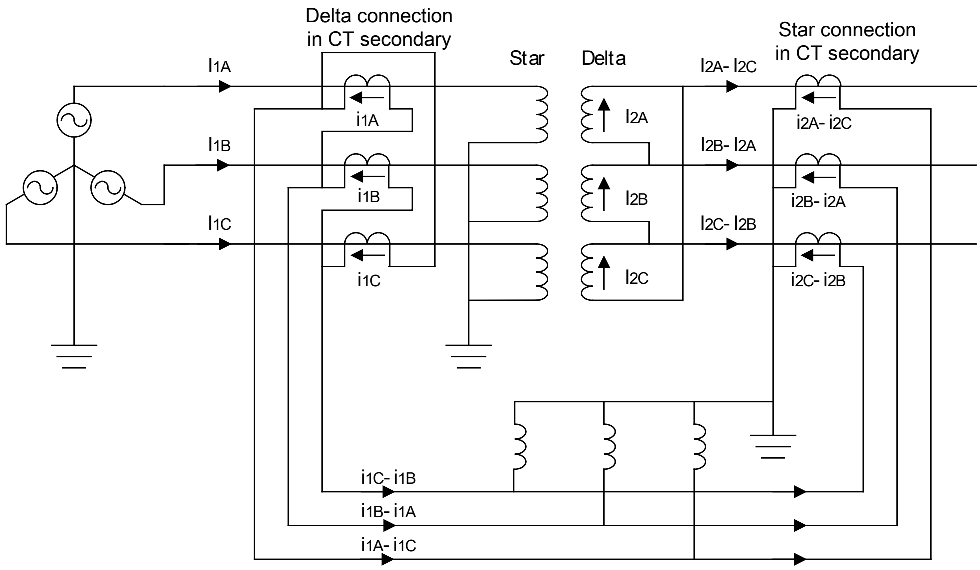


Figure 3.4-6 Appropriate Connection for Differential Protection in Star-Delta-Connection Transformer

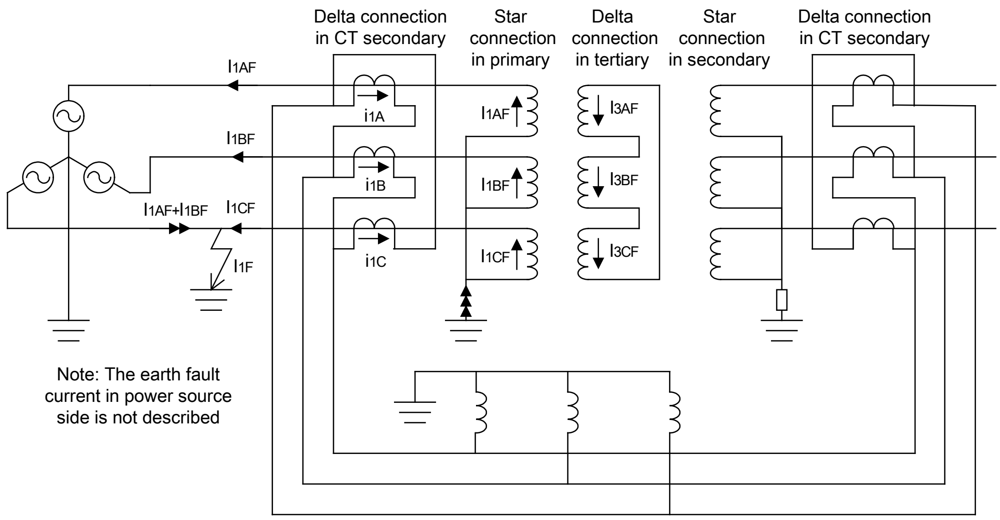


Figure 3.4-7 Current Flow of Differential Protection with Appropriate Connection at External Earth Fault

As described above, when the CT secondary circuit is connected by a delta connection when the transformer unit connection is a star connection, and by a star connection when the transformer unit connection is a delta connection, the differential relay responds correctly with respect to load current and internal and external faults, thereby making this method mainstream.

3.4.5 Practice of Transformer Protection

(1) Transformer Type

The questionnaire result about transformer type shows **Table 3.4-2**. An auto-transformer is applied only in EHV systems in Japan. A transformer type which will be installed is usually determined considering the scale of the substation, the location of it, the cost of the transformer and the ease of conveyance.

Table 3.4-2 Transformer Type

Type	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
3 windings	×	×	×	×	×	×	×	-	-			×	×	×	×	-	×	×	×	×	×
2 windings	×	×	×	×	×	×	-	×	×			×	×	-	-	×	×	-	-	×	×
Auto-transformer	×	×	-	-	×	-	×	×	-			×	-	×	×	×	-	-	-	×	×

(2) Main Protection

(a) Protection Schemes

The questionnaire result about main protection for transformer shows **Table 3.4-3**. Most of answers are percentage differential as main protection for transformer. Also combination of percentage differential and other relay are applied. In France, distance relay is applied as main protection.

Table 3.4-3 Main Transformer Protection

Transformer protection	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Differential	×	×	×	×	×	×	×	-	-	×	×	×	×	×	×	×	×	×	×	×	×
Distance	-	-	-	-	×	-	-	×	×	-	-	-	-	-	-	-	-	-	-	×	-
Overcurrent	-	-	-	-	×	×	-	×	×	-	-	×	×	-	-	-	-	-	-	×	-
Others	×	×	-	-	-	-	-	×	×	×	×	×	×	-	-	-	-	-	-	×	×

(b) Countermeasure against Inrush Current

The magnetizing current of a transformer seems the operating value for a differential relay. The magnetizing current of a transformer is usually very small in a steady state, so it doesn't cause an unwanted operation of the relay. However, when the magnetic flux of a transformer iron core changes suddenly, big magnetizing current inputs to the relay, by which the relay may operate unwantedly. In order to prevent this unwanted operation, a countermeasure against inrush is taken.

The questionnaire result about countermeasure against inrush current shows **Table 3.4-4**. Majority is detection of second harmonics. Other answers are asymmetrical wave blocking.

Table 3.4-4 Countermeasure against Inrush Current

Countermeasure against inrush current	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Detection of 2nd harmonics	×	×	×	×	×	×	×	Not Available	Not Available	×	×	×	×	×	×	×	×	×	×	×	×
Asymmetrical wave blocking	-	-	-	-	×	×	-			-	-	-	-	-	-	-	-	×	×	-	-
Others	-	-	-	-	-	-	-			-	-	-	-	-	-	-	-	-	-	-	×

(3) Mechanical Protection

(a) Practice of Mechanical Relays

Insulation deterioration of an electrical circuit in a transformer may cause decomposition of insulating oil and incidence of gas. Moreover, some mechanical protection is applied as well as electrical protection, as a percentage differential relay can't detect comparatively small rare short circuit fault in the winding.

The questionnaire result about mechanical protection shows **Table 3.4-5**. Most of answers are covered by Buchholz and sudden pressure relief. Pitot-tube follows.

Table 3.4-5 Mechanical Protection

Mechanical protection	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Buchholtz's	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
Sudden pressure	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	-	×
Pitot-tube	-	-	-	-	-	-	-	×	×	-	-	×	-	-	-	-	-	-	-	-	-
Others	×	×	-	-	-	-	-	-	-	-	-	×	×	-	-	-	-	×	×	-	×

(b) Actions Resulting from Operation of Mechanical Relays

A mechanical relay can detect a fault with small current which an electrical relay cannot detect. However, a fault which occurs at a bushing outside of the oil tank cannot be detected. Moreover, a mechanical relay may operate against an earthquake. Since a mechanical relay with such features as described before is applied, either to trip or to alarm is carried out after it operates independently.

The questionnaire result about measure at operation of mechanical relay shows **Table 3.4-6**. Most of answer is only trip. Some utilities use them for alarm only.

Table 3.4-6 Actions at Operation of Mechanical Relay

Measure at operation of mechanical relays	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Trip	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×
Alarm	×	×	-	-	×	×	×	×	×	×	×	×	×	-	-	×	×	-	-	×	×

(4) Backup Protection

The questionnaire result about backup relay for transformer shows **Table 3.4-7**. Majority is overcurrent relay or distance relay.

The questionnaire result about purpose of installation of backup protection for transformer shows **Table 3.4-8**. In the table, the meaning of (a) to (c) can be seen in the note 2. If the main protection is duplicated, the issue (a) would not be generally required for the installation of backup protection for transformer, which is described as **Chapter 3.4.3**. Moreover, the purpose (b) is important when clearing a fault is delayed against a busbar fault from the relation of the CT arrangement. CB's failure to trip and reduction of operator's recharging manoeuvres of CB are reported as other purposes of installation of backup protection.

Table 3.4-7 Backup Protection

Backup protection	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Distance	-	-	-	-	×	-	-	×	×	-	-	×	×	×	×	×	-	×	×	×	-
Overcurrent	×	×	×	×	×	×	×	×	×	×	×	×	×	-	-	×	×	×	×	×	×
Ground Overcurrent	-	×	-	-	×	×	×	×	×	-	-	-	-	-	-	-	-	×	×	×	×
Ground Directional	-	-	-	-	×	×	-	×	×	×	×	×	×	×	×	-	-	×	×	-	-
Ground Overvoltage	-	-	-	-	×	×	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Others	×	×	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	×

Tab.3.4-8 Purpose of Installation

Purpose of Installation	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
(a)	-	-	×	×	×	×	×	×	×			×	×	×	×	×	×	-	-	-	-
(b)	-	-	×	×	×	×	×	×	×			×	×	×	×	×	×	×	×	×	×
(c)	-	-	-	-	-	-	×	×	×			×	×	×	×	×	×	×	×	×	-
Others	×	×	-	-	-	-	×	-	-			×	×	-	-	-	-	×	×	-	-

<Note>

(a) To protect the transformer against an internal fault while the main relay is blocked

(b) To protect the transformer when the main relay doesn't operate against an internal fault

(c) To prevent fault extension

3.5 Circuit Breaker Failure Protection (CBF)

Operation of circuit breaker is one of imperative action to clear fault. Once the incorrect operation of the circuit breaker happens during the fault clearing process, the fault will remain until other backup system trip the neighbouring breakers. In addition, it will directly cause long-time disturbance to the power system and wide area of blackout will be expected. This may be a critical impact on the power system from stability point of view.

To alleviate above enormous disturbance, Circuit Breaker Failure protection (CBF) is introduced especially to the EHV station, where the delay in clearing fault due to the incorrect operation of circuit breaker may cause a stability problem. CBF protection will trip the circuit breakers adjoining the faulty circuit breaker in order to speed up the fault clearance and minimize the area of blackout.

Herein, incorrect operation of breaker due to some faults of itself and which appears after receiving trip command from protection relays is mentioned as "Breaker failure."

Causes of breaker failure are as follows:

Faulty trip-circuit:

- Short circuit or open circuit of tripping circuit
- Faulty of auxiliary contact used in the trip-circuit
- Faulty of power supply for the trip-circuit

Faulty mechanism of circuit breaker

- Low gas or air pressure of breaker operational mechanism
- Faulty of operational mechanism

Faulty breaker main contact

- Flashover between main contact due to multiple-occurrence of lightning
- Faulty operation due to very near end fault
- Fault inside the circuit breaker

3.5.1 General Concept of Circuit Breaker Failure Protection

CBF is to clear the fault by tripping breakers neighbouring the faulty breaker, once the breaker failure happens. **Figure 3.5-1** shows the basic concept of CBF function. CBF will detect the breaker failure by the condition of the operation of main protection and the fault current continuing on the breaker, which is supposed to disappear by the trip of breaker commanded by main protection. CBF has a confirmation timer to wait considerable operating time of problem-free circuit breaker. If the confirmation timer is up, CBF will trip the breakers which connect to the same busbar where the faulty breaker is connected.

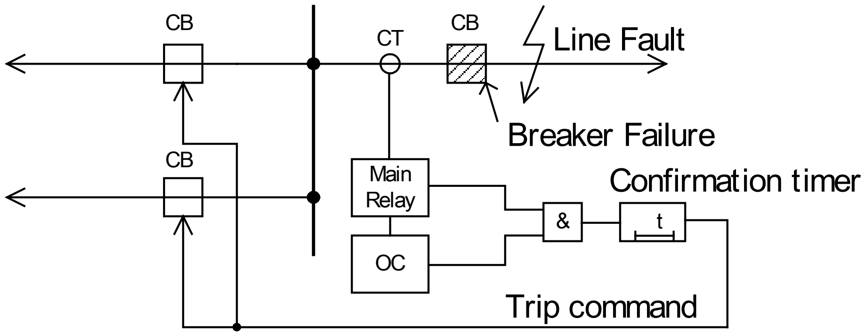


Figure 3.5-1 Concept of CBF Function

3.5.2 CBF Schemes for Each Busbar Configuration

Which breakers should be tripped by CBF depends on the busbar configuration. Appropriate scheme to minimize the area of blackout shall be applied. Following figures show the concept of CBF schemes for each busbar configuration.

(1) Single Busbar

Figure 3.5-2 shows the CBF scheme for single busbar. Against the breaker failure of breaker "1" for the line fault, all breakers , "2"to"6" , connecting to the same busbar, shall be tripped.

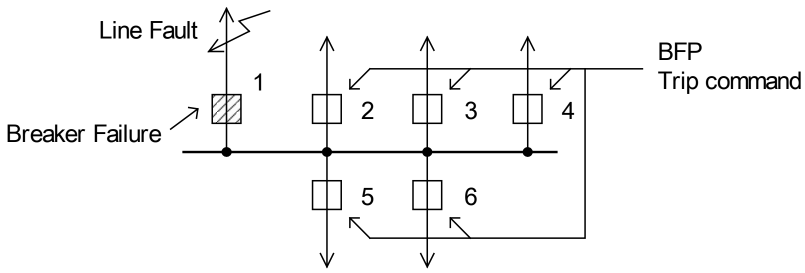


Figure 3.5-2 CBF Scheme for Single Busbar

(2) Double Busbar

Figure 3.5-3 shows the CBF scheme for double busbar. Against the breaker failure of breaker "1" for the line fault, breakers "3" and "6", connecting to the same busbar, and bus-coupler breaker "5" shall be tripped.

If the breaker failure happens during the bus-transfer with any isolators bridged, both sides of busbar shall be tripped.

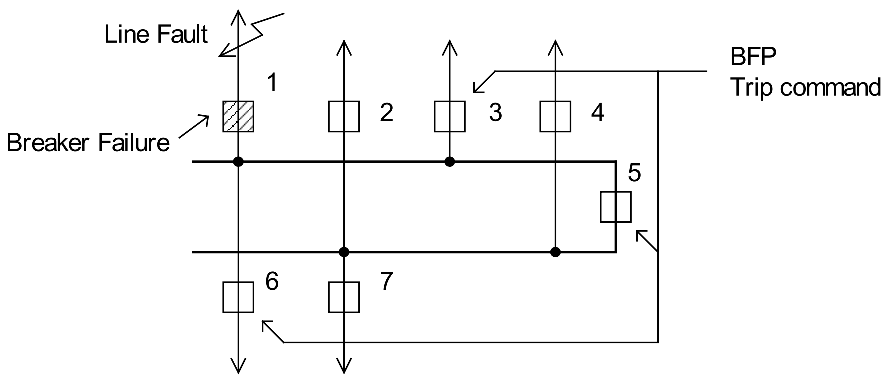


Figure 3.5-3 CBF Scheme for Double Busbar

(3) 1 1/2 CB busbar

As long as breakers are healthy, breakers of “1” and “2” will clear the line fault. Against the breaker failure of the busbar side breaker “1”, breaker “4” shall be tripped. Against the breaker failure of the middle breaker “2”, breaker “3” and remote end breaker “7” shall be tripped. **Figure 3.5-4(1)** and **Figure 3.5-4 (2)** show these concepts. For latter case, tripping of remote end breaker “7” may be expected by the operation of remote backup of the zone 2 of distance protection. If the shorter-time clearance is required, direct transfer trip (DTT) over communication shall be implemented.

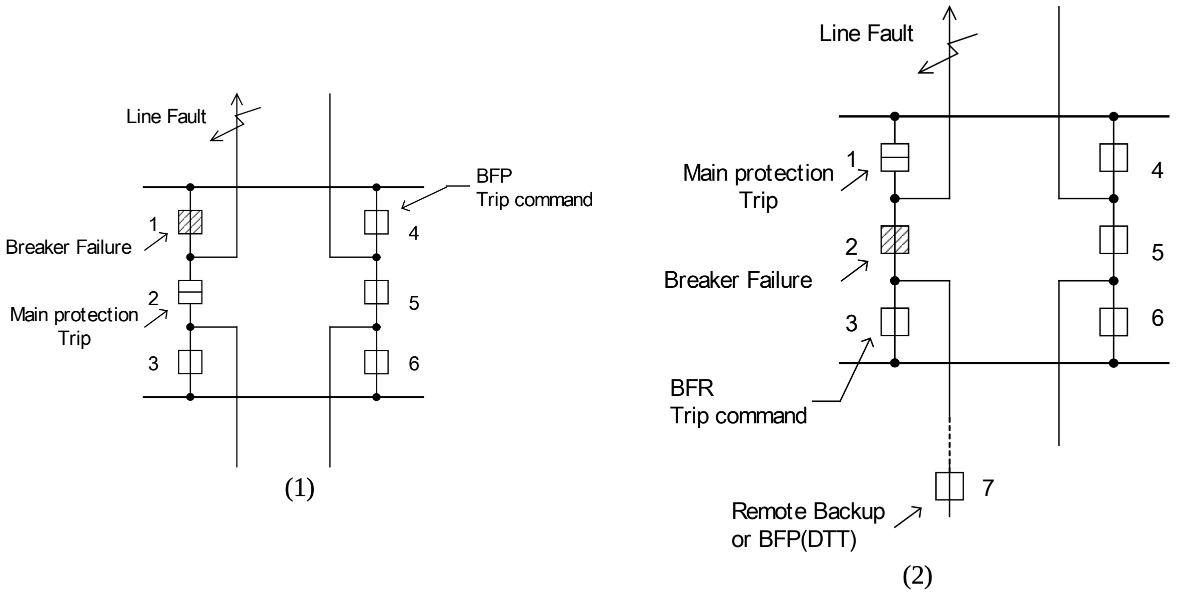


Figure 3.5-4 CBF Scheme for 1 1/2 CB

3.5.3 Additional Implementation for CBF Scheme

The followings illustrate schemes widely applied to improve CBF.

(1) Two Stages of Timer

Usually circuit breaker has two trip coils. If the incorrect operation of breaker is due to one of the trip circuit, breaker can still trip by initiating the other trip circuit. Hence CBF usually has two-stage timer to utilize it as follows.

- At 1st stage, CBF will give RE-trip command to the breaker by initiating both trip circuits.
- At 2nd stage, CBF will give trip signal to all neighbouring breakers to clear fault.

Concept of this scheme is shown in **Figure 3.5-5**.

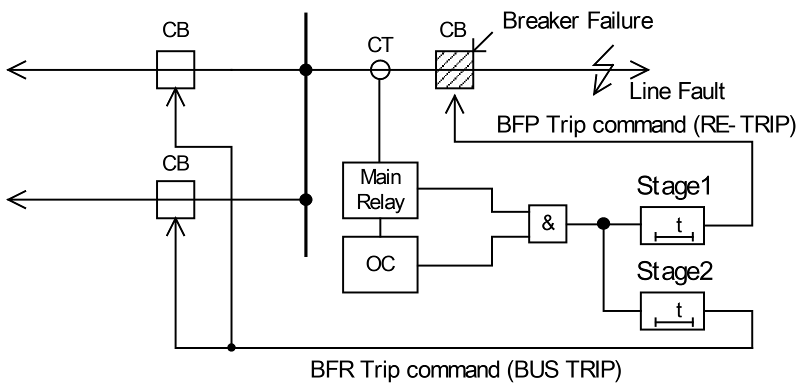


Figure 3.5-5 CBF with Two-Stage Timer

(2) Timer Bypass

When CB gives blocked alarm, such as GAS low alarm of GCB, incorrect operation of breaker is expected if the fault happens. It is no meaning to wait for the time-up of confirmation timer of CBF if the main protection operates. Some utilities apply timer bypass function to speed up the CBF operation. **Figure 3.5-6** shows this concept.

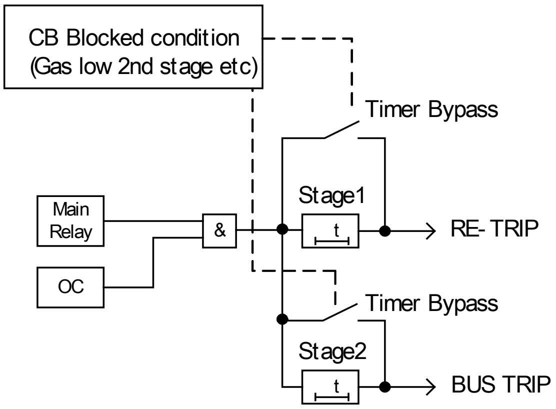


Figure 3.5-6 CBF Scheme with Timer-Bypass Function

(3) Current Bypass

Aforementioned, usually CBF operation will be initiated by the operation of main protection and OC relay condition for the confirmation of the breaker failure. However, concerning the transformer mechanical protection, OC relay cannot pick up some fault in transformer, which shall be detected by transformer mechanical protection such as Buchholz relay or Pitot-tube relay. Some utilities apply current-bypass condition. Shown in **Figure 3.5-7**, it will bypass OC condition in case of transformer mechanical protection.

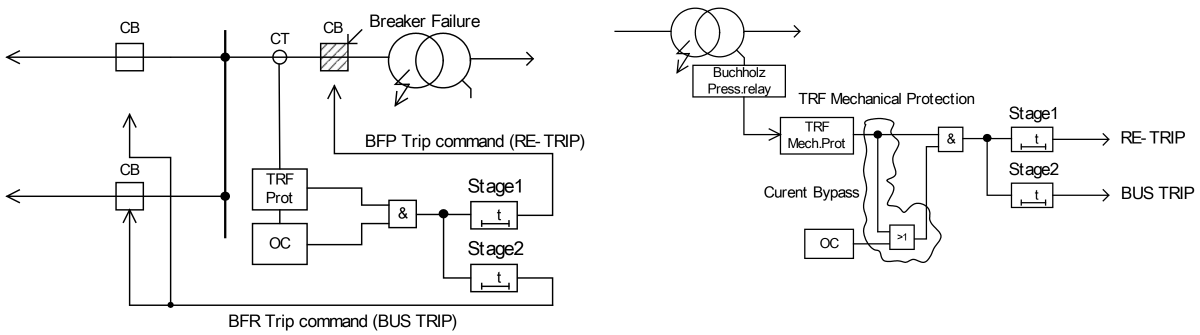


Figure 3.5-7 CBF Scheme with Current-Bypass Function

3.5.4 Setting Issues of Circuit Breaker Failure Protection

Because the judgment of breaker failure only depends on the time once it receives the initiation signal from main protection and OC relay picks up, time coordination is imperative. Setting of CBF confirmation timer includes considerable operating time of breaker and the dropout time of the initiation signal and OC relay after the fault cleared as normal case. CBF must not operate as long as main protection and circuit breaker is healthy. Incorrect coordination of CBF may cause the unwanted busbar tripping for ordinal line fault case.

Typical time-chart of CBF operation is shown in **Figure 3.5-8**. Considering 40ms for CB operational time, 20ms for reset time of 50BF, 20ms for safety margin, 80ms will be typical setting for 1st stage timer. Considering the fault clearance by 1st stage, CBF must not go to 2nd stage.

Another 80ms may be considered to the dropout of 2nd stage initiation. Hence 160ms will be the 2nd stage setting of CBF.

One possibility to overcome this maintenance non secure tripping is to consider two remote tripping signals to be treated, at the receiving end, by a logical "AND" to effectively trip the remote circuit(s) breaker(s). This, of course, will reduce the dependability of the transfer tripping, which may be considered to be an unacceptable disadvantage.

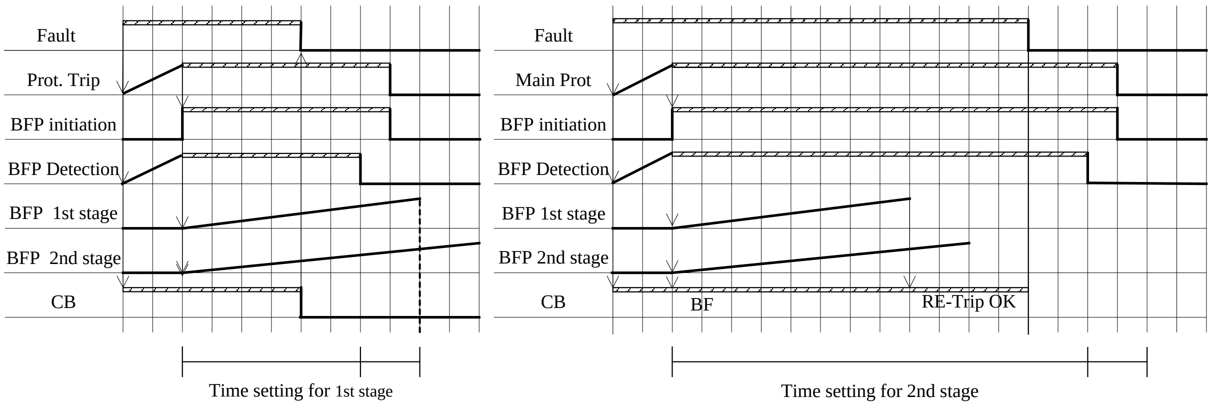


Figure 3.5-8 Typical Time-Chart for CBF

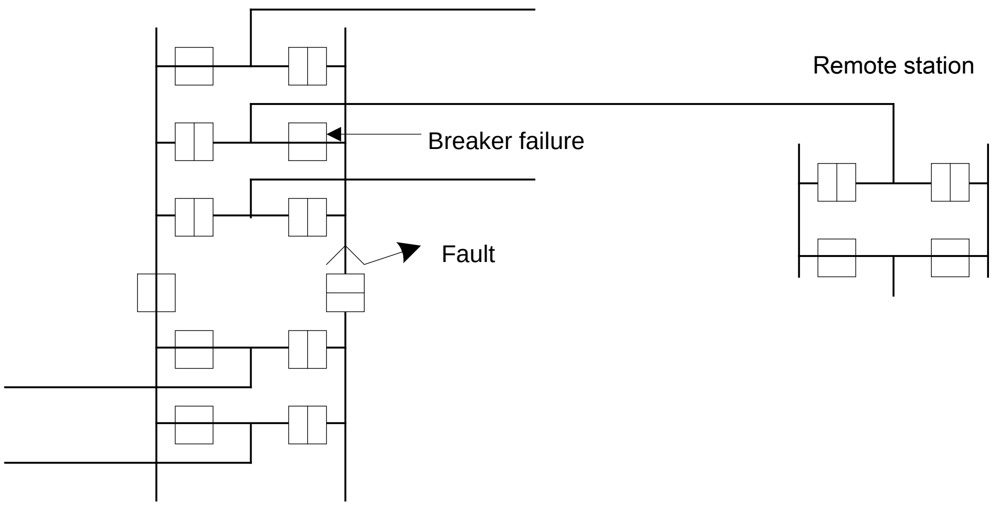


Figure 3.5-9 Busbar Fault with Breaker Failure

Alternative 1: The breaker failure protection send a direct transfer trip signal to the circuit breaker in the remote station (BBP 20 ms + CBF 170 ms + communication 40 ms + CB time ≈ 290 ms). A disadvantage is the risk during maintenance testing can send a signal to trip the remote station.

Alternative 2: The breaker failure protection sends an accelerated Zone2 extension signal to the remote line protection/distance protection. If the distance relay is a full scheme relay, this protection probably already has detected the fault and the time coordination must be introduced to allow the distance protection to trip after about 40-80 ms depending what kind of communication channel and circuit breaker are used. (BBP 20 ms + CBF 170 ms + 40-80 ms + enable Zone2 20 ms + CB time ≈ 310 ms).

Alternative 3: The busbar protection sends a Zone2 extension signal to all of the remote line protections/distance protections. The time delay coordination must be at least the CBF time 170 ms. (BBP 20 ms + communication 40 ms + time delay coordination 170 ms + enable Zone2 20 ms + CB time ≈ 310 ms). A disadvantage is that the communication signal is send to the remote station for all connected lines. That can make the fault analysis more difficult.

3.5.5 Questionnaire Results

Table 3.5-1 shows the application situation of CBF, and **Table 3.5-2** shows a questionnaire result about the transfer method of the signal to CBF. According to these tables, CBFs are widely used from a viewpoint which prevents a wide-area blackout caused by breaker failure. However, there is relatively little application of CBF in HV system in Japan. This is the reason why the configuration of power systems is radial and few power sources are connected to HV systems. Regarding a target of breaker failure, majority is all CBs regardless of its usage, i.e. line, transformer and bus. Regarding trigger condition, majority is output of the relay to protect the faulty equipment.

Local backup is applied as CBF to substations more than 150kV level. Mostly the system is single. Reportedly, it is redundant for EHV substation as shown in **Table 2.6-4**.

Table 3.5-1 Application of Breaker Failure Protection

Faulted CB	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
(a)	×	×	-	Not Available	×	×	×					×	Not Available	×	×	×	Not Available	×		×	×
(b)	×	×	×		×	×	×					×		×	×	×		×		×	×
(c)	×	×	×		×	×	×					-		×	×	×		×		×	×

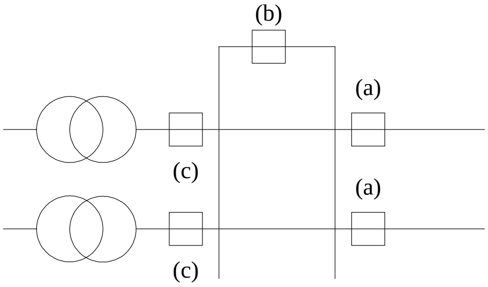


Figure 3.5-2 Target of CBF

Table 3.5-2 Trigger Condition

Trigger condition	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Relay element as the local backup	×	×	-	Not Available	×	×	×	×	×			×	Not Available	-	-	×	Not Available	×	×	-	-
Output of the relay for the faulty CB	×	×	×		×	×	×	×	×			×		×	×	×		×	×	-	×
Auxiliary contact of the CB	-	-	-		-	-	×	-	-			×		×	×	-		-	-	×	-
Others	-	-	-		-	-	-	-	-			×		-	-	-		-	-	-	-

3.6 Generator Protection

3.6.1 Type of Generator Plants

Generators are very important, as they are in the beginning of the supply-demand chain of electric power delivery to customer. Various types and sizes of electric power generators are installed depending on its fuel or resource types, as well as the technology they applied (See **Table 3.6-1**). Such important generators must have appropriate protections for fault clearance and other dangerous power system conditions, against permanent damage or loss-of-life to any of their components.

The working group had distributed a questionnaire form to members of CIGRE Study Committee B5 that included the generator protection practices for generators connected to the transmission systems and required coordination with the power system protective relays. This part of the questionnaires classified the protection practice into the following terms:

- Types of protection relays against the type of faults or abnormalities
- Redundancy practices
- Measures of relay operation (Trip, Alarm or Others)

Questionnaire responses were obtained from Korea, Malaysia, Spain, United Kingdom and Japan. In addition, IEEE Std C37.102-1995 was also referred to represent practices in the United States of America. The questionnaires were divided into four types of generation plants, and its sub-types as listed in the following table. However, the results will only generalize the fault clearance protection, independent of types of generating plant so as to establish types of generator protections that require coordination with the system protection. Furthermore, protection for distributed generation will not be covered in detail.

Table 3.6-1 Types of Generating Plants

Thermal	Nuclear	Hydraulic	Distributed
· Steam turbine (once-through boiler) · Steam turbine (drum boiler) · Gas turbine · Combine-cycle (CC) · Advanced Combine-cycle (ACC)	· Pressurized Water Reactor (PWR) · BWR · ABWR · APWR · Others	· Pumped storage · Adjustable speed pumped storage · Run-off-river · Others	· Diesel · Gas turbine · Gas engine · Photovoltaic · Wind power · Fuel cell · Micro gas turbine · Waste power · Geothermal · Co-generation

3.6.2 Types of Generator Protection Relays

(1) Generator Protection

The protection relays used for protecting the generator were classified into the types of faults and abnormal operating conditions that affecting the generator as tabulated below. Such generator protection relays are important to be coordinated with the power system protection relays to ensure selectivity of the overall protection system.

The result of the questionnaires indicated that all countries considered protection for the types of faults listed in **Table 3.6-2** are important except some are conservative to apply the out-of-step and mostly did not apply motoring protection for hydro-power generating plants. It is foreseen that the use of unit differential protection in the generator zone would not require coordination, however, the use of distance (impedance), current, voltage and frequency relay should be studied carefully to coordinate with the system protection, especially those apparent when abnormal system condition occurred in the system (i.e., the last 5 conditions in **Table 3.6-2**).

(2) Redundancy of Generator Protection Relay

Modern generators are connected to transmission grid system through generator transformer. Therefore, its redundancy of protection system depends on the generator size. The duplication of main protection (M1 and M2) is critical for larger capacity generating plant (>300MW), whereas smaller generator normally opts for single main protection. A single backup protection is also provided for system faults affecting the generator unit.

For duplicated main protection, they are usually grouped into two groups of similar protection functions but different operating principles. It is also possible to have fully redundant functions for even larger generating sets (>700MW). Some utilities use the same multifunction relay types but functionally configured in complementary. Others use separate individual function relays in such similar arrangement. These are listed as in the following table.

The backup protection for generator can be classified into two types. One is zone backup that uses an overall unit differential protection to cover the overall generating unit. In this case, either unit protection can trip the generator instantaneously. The other is the conventional remote backup or system backup, intended to protect the generator from an uncleared fault in the system. This types usually used distance protection at the stator common or a restrained or controlled overcurrent relay at generator terminal.

Table 3.6-2 Protection Types for Generator Faults and Abnormal Conditions

Fault or Abnormal Condition	Descriptions	Types of Protection Relay Applied
Inter-turn short circuit of armature winding	Inter-turn fault that leads to phase-faults and turn-to-turn same-phase-fault causing short-circuit damage to insulation, stator windings and the core, severe mechanical torsional shocks to shaft and coupling	- Differential - Check-zone Differential - Distance - Others
Grounding of armature winding	Earth fault on generator stator causing short-circuit damage and severe mechanical torsional shocks	- Ground Overvoltage - Differential - Others
Grounding of field winding	Double ground (earth) fault on generator field circuit causing rotor vibration damages	- Overcurrent - Others
Motoring	Loss of prime-mover energy supply while generator is still on-line, causing generator to act as synchronous motor risking damage to the prime mover	- Power - Temperature - Others
Over-excitation	Excessive V/Hz conditions during operation of generating unit under regulator control at reduced speed, during load rejection with transmission lines attached and loss of signal voltage or failure in excitation system	- Over-excitation - Others
Overvoltage	Overvoltage without exceeding volts/hertz limit of generator caused by similar operation condition as over-excitation above	- Overvoltage - Others
Loss of excitation	Serious operating condition caused by accidental tripping of field circuit breaker, field open or short circuit, failure of AVR and loss of supply to excitation system	- Reactive Power - Offset Mho - Internal Angle - Others
Out-of-Step	Loss of synchronism caused by prolonged fault clearing time, low system voltage, low machine excitation, high impedance between generator and system and some line-switching action	- Impedance - Out-of-Step - Pole Slipping - Others

(3) Measures at Relays Operation

Several circuit breakers control the switching of the generator units electrical parts. In addition, switching of the excitation system and the prime mover part (e.g., turbine emergency stop valve) also control the output of the generator. A typical tripping and alarm measures of the generator protection relays are shown in **Table 3.6-3**.

The result of the questionnaires also confirmed that tripping and alarm are necessary for all faults and abnormal conditions as stipulated above. The exact circuit breakers to trip the generator unit were not considered in the questionnaires, as they are not critical for this report purpose.

Table 3.6-3 Generator Protection Grouping, Trip and Alarm Configuration

Type of Protection	Protection Groups 1	Protection Groups 2	Trip HVCV	Trip GCB	Trip UCB	Trip TESV	Trip GDE	Alarm Signal
Generator differential	•	-		x		x	x	x
Distance (Generator Stator common)	-	•	x	x	x	x	x	x
100%stator earth fault	•	-	x			x	x	x
90%stator earth fault	-	•		x	x			x
Voltage balance	-	-		x	x		x	x
Over-voltage	S1	S2		x			x	x
Under-voltage	S1	S2		x			x	x
Voltage-restrained / Voltage-controlled overcurrent	-	-	x					x
Negative Phase Sequence	S1	S2	x					x
Over-frequency	S1	S2	x	x	x	x	x	x
Under-frequency	S1	S2	x	x	x	x	x	x
Reverse power relay	S1	S2		x			x	x
Over-excitation/ overfluxing	S1	S2	x	x	x	x	x	x
Stator overload	•	-	x	x	x	x	x	x
Generator inter-turn		•	x	x	x	x	x	x
Rotor earth fault	•						x	x
Rotor overload		•	x	x	x	x	x	x

Type of Protection	Protection Groups 1	Protection Groups 2	Trip HVCV	Trip GCB	Trip UCB	Trip TESV	Trip GDE	Alarm Signal
Pole slip	•	-	x	x	x	x	x	x
Under-excitation (Loss of Excitation)	-	•	x				x	x
Generator Breaker Failure	-	•	x		x	x	x	x
Overall differential	-	•	x	x	x	x	x	x
Step-up transformer differential		•	x	x	x			x
Distance (HV-side Step-up Transformer)	•		x					x
Step-up transformer restricted earth-fault	•	-	x					x
Step-up transformer overcurrent	-	•	x					x
Step-up transformer earth-fault		•	x	x	x			x
Step-up transformer Buccholz	•		x	x	x			x
Over-excitation / overfluxing (LV-side step-up transformer)	S1	S2	x	x	x			x
MV Bus Duct (Busbar) earth-fault		•	x	x	x			x
Unit transformer differential		•			x			x
Unit transformer overcurrent	•				x			x
Unit transformer neutral overcurrent (LV)					x			x
Unit transformer Buchholz	•				x			x
Excitation transformer differential	-		x	x	x	x	x	x
Excitation transformer overcurrent		•	x	x	x	x	x	x

<Note>'●' (Main Function);S1 (Stage 1);S2 (Stage 2) = Recommended practice
GCB = Generator Circuit Breaker
HVCB = Generator Transformer HV Circuit Breaker
UCB = Unit Transformer LV Circuit Breaker
TESV = Turbine Emergency Stop Valve
GDE = Generator De-excitation

(4) Protection of Distributed Generators

The questionnaires for distributed generators were similar for the other generation types except that additional outline of the distributed generation plants was requested such as the direction of firm power, the protection for interconnection and islanding detection. Questionnaire response only from Korea, Malaysia and Japan were obtained.

In these three countries, the type of distributed generators commonly used are gas turbines, photovoltaic and wind power generation. In Malaysia, co-generation is also connected to the network. In Korea and Japan, the distributed generators are allowed to receive power or supply to the network, as their capacity is relatively large (400MVA & 74MVA, respectively). However in Malaysia, they are only allowed to receive power since they are relatively smaller capacity (<35MVA), except for some remote connections.

For detecting islanding of distributed generators, the frequency, reverse power and under-voltage relays are most commonly used but in Japan and Korea, transfer trip and vector surge relay are also used respectively.

For protection for interconnection to the distributed generator, the directional phase-fault, ground over-voltage and under-voltage relays are commonly used. In Korea, the under-frequency relay is also required.

3.6.3 Outline of Generator Protection Relays

(1) Outline of Generator Protection

A generator should be protected from various unusual phenomena such as a short circuit fault or an earth fault. The generator should be paralleled off from the power system at a severe fault such as a short circuit, and stop the operation immediately. However, a light fault or an unusual operation is only alarmed and the generator is taken the measure of preparing for resumption of operation by moving the load to other generators or operating with no excitation.

Figure 3.6-1 shows an example of a generator protection with large capacity. It is a unit-type generator which is operated harmonically with a transformer. In this case, the neutral point is earthed through the transformer of which the resistance is connected at the secondary circuit, as shown in **Figure 3.6-1**.

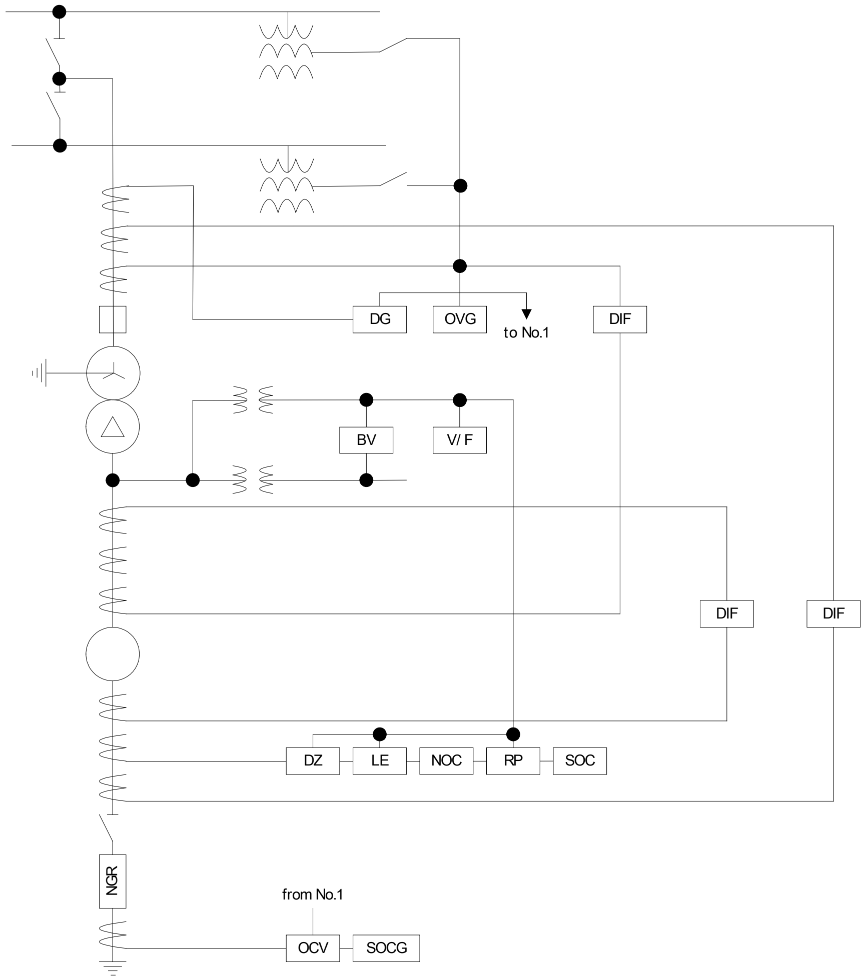


Figure 3.6-1 Example of Generator Protection for Large Capacity Generator

<Note>

DIF: Differential relay, DG: Earth-fault directional relay, OVG: Earth-fault overvoltage relay, OCV: Overcurrent relay with voltage restraint, BV: Voltage balance relay, V/F: Over-excitation relay,. DZ: Distance relay, LE: Loss-of-excitation relay, NOC: Negative sequence overcurrent relay, RP: Reverse power relay, SOC: Overcurrent relay at start-up, SOCG: Earth-fault overcurrent relay at start-up

(2) Protection of the Stator

(a) Protection with Differential Relay

A differential relay is used for protection of a layer earth fault or an earth fault. **Figure 3.6-2** shows an example of the differential protection for a generator with relatively small capacity. In this case, since the generator is earthed through high resistance, the earth fault current is smaller than the rated current. By using a CT with the tertiary winding, the percentage differential relay for phase fault, which responds to the secondary circuit current of the CT which is the difference between phase current and zero-sequence current, and the differential relay for earth fault, which responds to the tertiary circuit current of the CT (zero sequence current), are used.

A differential relay for earth fault has higher sensitivity than that for phase fault in many cases, so it may easily operate unwantedly due to CT error. Since large line current causes the CT error, a percentage differential relay is not expected to have sufficient effect to prevent the maloperation. Therefore, so that a relay can operate only when the neutral current (IN) flows, the relay with time delays to prevent the maloperation is widely used. When earth fault current is slightly larger than the rated current, the relay for phase fault is used also for earth fault. In this case, a residual circuit is constituted by the connection of the dotted line in the secondary circuit of the CT as shown in **Figure 3.6-2**, without connecting the tertiary circuit of the CT.

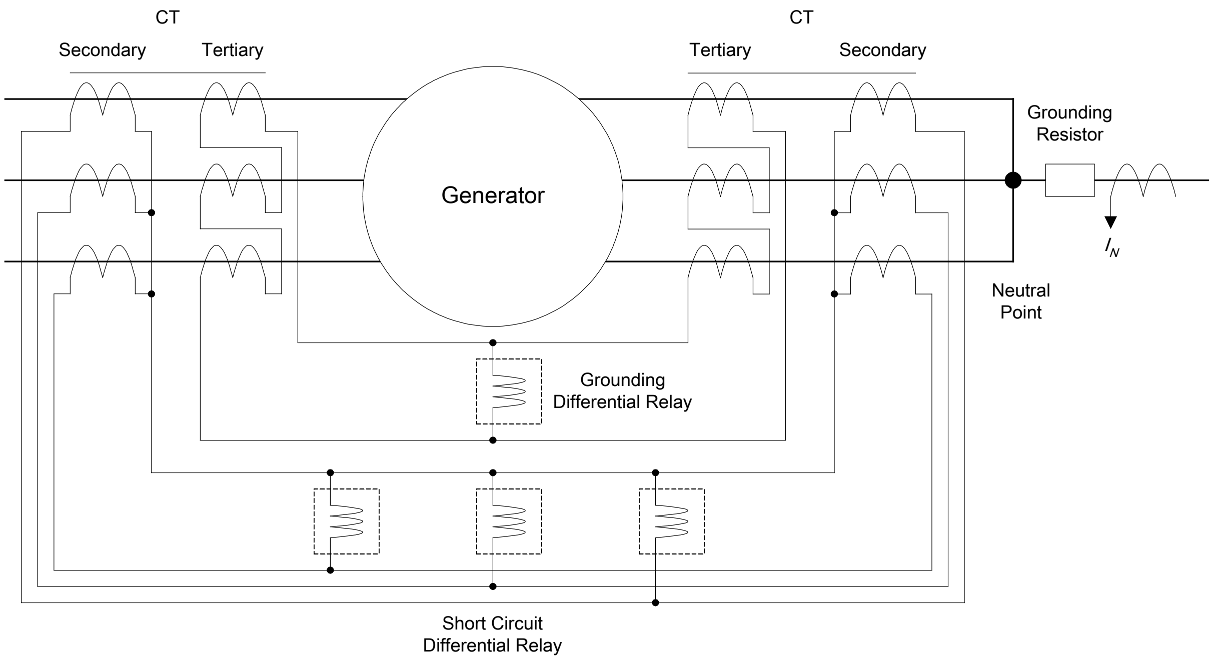


Figure 3.6-2 Protection for Stator with Differential Relays

(b) Protection of Earthing Transformer

An earthing transformer is protected by an overvoltage relay which responds to the secondary side voltage of it as shown in **Figure 3.6-1**. The voltage is zero at usual operations, but at occurrence of an earth fault, it becomes the value corresponding to zero sequence voltage. Therefore, the relay can detect the earth fault. But third harmonic is mainly included in the voltage generated by the generator. The relay needs to have the characteristic which responds to only the fundamental component. Moreover, if large zero sequence voltage arises at an earth fault at the line side of the main transformer, this voltage appears at the generator side through the stray capacity of the transformer, and voltage appears across the earthing transformer. The relay is blocked to prevent an unwanted operation due to this voltage, when the zero sequence voltage on the line side of the main transformer is large.

The above-mentioned relays including the differential relay cannot detect a fault occurred at the winding up to about 10% from the neutral point. The relay to detect a fault near the neutral point may be used, as this measure. The following relays are used for earthing transformer; a relay which detects loss of the 3rd harmonic voltage, or which detect the low frequency current that is always supplied between the neutral point and the earth point from the power source at the occurrence of an earth fault.

(c) Protection of Overheating of the Stator

Overheating of the stator occurs due to overload, a failure of the cooling system, and the insulation aging between laminated cores. A resistance bulb or thermocouple is embedded in the stator winding for this protection. A temperature relay operates by change of the resistance or the generated voltage and is alarmed. Moreover, overload is also protected by overcurrent relay with time delay.

(d) Other Protection

When load is shed at a remote-terminal, the generator continues to charge the lines. In this case, overvoltage across the generator terminals may be caused by self excitation due to capacitive load. The generator should be protected from overvoltage as this measure. VT for overvoltage protection differs from that for automatic voltage regulators.

A distance relay with time delay is applied against the failure of a differential relay, and as backup protection against an external fault. Since fault current from a general generator is below the rated current unless the excitation is strengthened by the automatic voltage regulator even when a phase fault occurs at the generator terminal during no-load rated voltage operation, an overcurrent relay does not have sufficient sensitivity to this purpose.

(3) Protection of the Rotor

(a) Loss of Excitation

A synchronous generator will become an induction generator if it is under loss of excitation. Therefore, the induction generator rotates above the synchronous speed and induced current flows on the rotor. Since the rotor of a steam turbine generator has no damper winding on which the induced current flows, it flows in the iron core, and it makes the rotor overheat quickly. In a salient-pole generator, since the induced current flows into the damper winding, the rotor will be less overheated and 2 to 4 times as much reactive power as the rated capacity of the generator flows into the stator, so it may cause the deterioration of the power system stability and also the overheating of the stator.

Where an undercurrent relay is installed in a field circuit, it may operate unwantedly according to the current induced in a field circuit against an external fault. Therefore, in many cases, loss of excitation is detected by the measured impedance from the voltage and current of the generator terminal. The offset mho relay with the circle characteristics which makes a diameter the following two points, $X_d'/2$ (direct-axis transient reactance/2), and X_d (direct-axis synchronous reactance), as shown in **Figure 3.6-3** is used. The impedance seen by the relay shall move within the operating zone from the load point L at the time of loss of excitation.

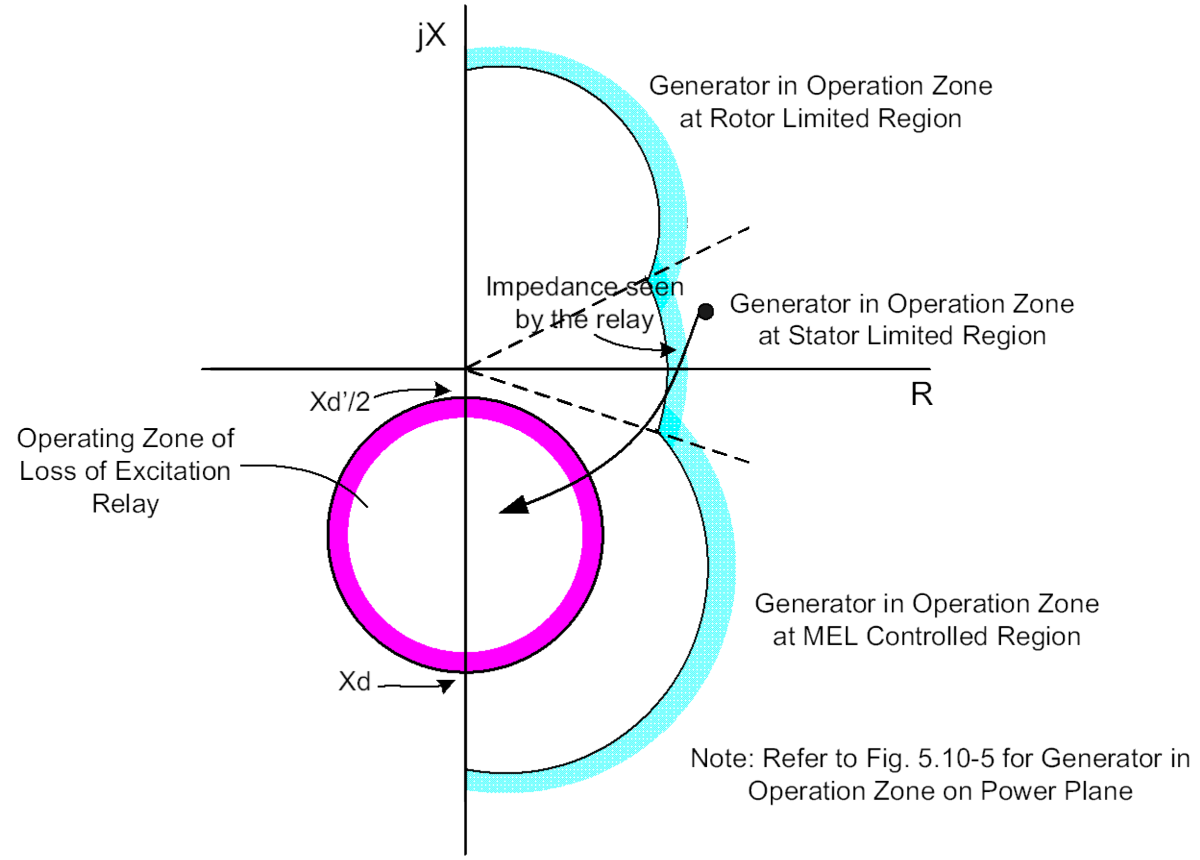


Figure 3.6-3 Loss of Excitation Relay with Offset-Mho Characteristic

(b) Earth Fault Protection for Field Winding

When an earth fault occurs at one point on the field circuit due to a non-earthed field circuit, there will be no need to stop the generator. But, if earth faults occur at two points, as a part of field circuit is bypassed, the rotor will be magnetically unbalanced. As a result, it may cause an excessive vibration, which distorts the rotor axis or destroys the bearing.

Figure 3.6-4 shows an example of earth fault protection of a field winding, whose principle is that the DC voltage rectified from AC voltage is always applied between the field circuit and the earth. When an earth fault occurs, the relay will operate as small current flows into the operation circuit.

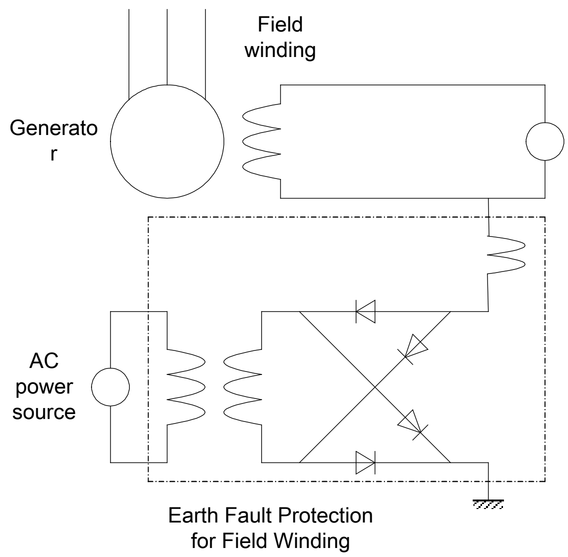


Figure 3.6-4 Example of Earth Fault Protection for Field Winding

(c) Rotor Overheat Protection by Unbalanced Stator Current

The rated values of a synchronous generator are decided based upon the balanced operation. Therefore, if it is operated connecting with unbalanced load or single phase load, negative phase sequence current will flow on the stator. Since the magnetic field due to the negative phase sequence current rotates oppositely to the rotary direction of the rotor, the eddy current with two times of frequency will cause overheating of the rotor whose insulator may be damaged by the rise of temperature. A synchronous generator has the allowable value against negative sequence current. As a protection relay, the negative-phase-sequence overcurrent relay corresponding to this limit is used.

(d) Overspeed Protection

Overspeed occurs mainly by the abnormalities of the governor of the turbine. If the capacity of a generator is small, the generator may be drawn into the speed of another generator. The protection is a centrifugal force switch as mechanical protection and the direct-current-voltage relay with high sensitivity for the tachometer generator as electric protection. The relay should be set for a little bit higher rotation speed than the speed at full-load interception.

3.6.4 Practice of Generator Protection

Table 3.6-4 shows the questionnaire result about the generator protection. In the table, T means a thermal plant, N means a nuclear plant and H means a hydraulic plant. As regarding the capacity for various kinds of plants, that for thermal plants is from 125 MVA to 1000 MVA, that for nuclear plants is 450MA to 1356 MVA, and that for hydraulic plants is from 10MVA to 700 MVA.

There is no big difference in the protection according to the kind of the plants. That is, a generator should be protected from various unusual operations besides a short circuit and an earth fault.

Table 3.6-4 Generator Protection

	Protection relay	AU	CA	CN			ES			FR	IN	JP			KR			MY			PT	SE	UK		
				T	N	H	T	N	H			T	N	H	T	N	H	T	N	H			T	N	H
Inter turn short circuit of armaure winding	Differential relay			×	×	×	×	×	×			×	×	×	×	Not Available	×	×					Not Available	Not Available	
	Check-zone differential relay			-	-	-	-	×	-			×	-	×	-	Not Available	-	-					Not Available	Not Available	
	Distance relay			-	-	-	×	-	×			-	-	-	-	Not Available	-	×					Not Available	Not Available	
	Others			-	-	-	-	-	-			-	-	-	-	Not Available	-	-					Not Available	Not Available	
Grounding of armature winding	Ground overvoltage			×	×	×	×	×	×			×	×	×	×	×	×	×					-	-	
	Differential			-	-	-	×	×	×			-	-	×	-	-	-	-					×	×	
	Others			-	-	-	-	-	-			-	-	-	-	-	-	-					-	-	
Motoring	Power relay			×	×	×	×	×	Not Available			Not Available	Not Available	Not Available	×	×	×	×					Not Available	Not Available	
	Temperature relay			-	-	-	-	-	Not Available			Not Available	Not Available	Not Available	-	-	-	-					Not Available	Not Available	
	Others			-	-	-	-	-	Not Available			Not Available	Not Available	Not Available	-	-	-	-					Not Available	Not Available	
Grounding of field winding	Overcurrent			-	-	-	-	-	-			NA	NA	NA	-	NA	-	NA					NA	NA	
	Others			×	×	×	×	×	×			NA	NA	NA	×	NA	×	NA					NA	NA	
Overvoltage	Overvoltage relay			×	×	×	×	×	×			×	×	×	×	×	×	×					NA	NA	
	Others			-	-	-	-	-	-			-	-	-	-	-	-	-					NA	NA	
Over-excitation	Over-excitation relay			×	×	×	×	×	×			×	×	×	-	×	×	×					×	×	
	Others			-	-	-	-	-	-			×	×	-	-	-	-	-					-	-	
Loss of excitation	Reactive power relay			-	-	-	-	-	-			-	-	×	-	-	-	-					-	×	
	Offset-mho relay			×	×	×	×	×	×			×	×	×	×	×	×	×					×	-	
	Internal angle relay			-	-	-	-	-	-			-	-	-	-	-	-	-					-	-	
	Others			-	-	-	-	-	-			×	×	×	-	-	-	-					-	-	
Out-of-step	Impedance relay			×	×	×	-	-	-			×	×	×	-	-	-	×					Not Available	Not Available	
	Out-of-step relay			-	-	-	×	×	×			×	×	×	×	×	-	×					Not Available	Not Available	
	Others			-	-	-	-	-	-			-	-	-	-	-	-	-					Not Available	Not Available	

<Note> T: Thermal Plant, N: Nuclear Plant, H: Hydraulic Plant

<References>

[1] Horigome et al, ”Reclosing Scheme in Transmission Lines”, OHM, August 1960(in Japanese)
[2] J. Tsukida et al.; "Recent Trends in Transformer Protection Technology in Japan", B5-107, CIGRE SCB5 Colloquium 2005 Calgary, Canada (2005)

4. Special Protection Systems (SPS)

4.1 Classification of SPSs

4.1.1 Classification by Calculation Algorithm

SPSs have been classified according to the calculation algorithm into behaviour-confirmation type systems, behaviour-assumption type systems (online and offline), and behaviour-prediction type systems. **Table 4.1-1** shows the classification of the SPSs according to their calculation algorithm [1].

Table 4.1-1 Classification of SPSs by Calculation Algorithm

Type	Object phenomenon	Control scheme
Behavior confirmation	Out of step	System separation or generator shutdown via out of step relay
		System separation via centralized control
	Abnormal frequency	Load or generator shutdown via frequency relay
	Voltage instability	Load shedding
	Overload cascading	Load shedding or generator shutdown
Behavior assumption (Pre-fault calculation)	Out of step	Generator shutdown based on offline simulation
		Generator shutdown based on online cyclical simulation
	Abnormal frequency	Load shedding and generator shutdown based on frequency predictive calculation
Behavior prediction (Post-fault calculation)	Out of step	System separation or generator shutdown based on real-time predictive calculation

(1) Behaviour-Confirmation Type

This is the most prevalent class. It applies control functions after confirmed occurrence of a disturbance, such as out of step, abnormal frequency, voltage instability or overload cascading, in order to prevent the disturbance from further spreading. All conventional relay-type SPSs belong to this class. Some utilities have used adaptive versions of SPS to prevent the spread of out of step. After confirmation of out of step condition, it collects online information from the substations and performs centralized corrective control.

(2) Behaviour-Assumption Type

This SPS type assumes instability phenomenon following severe contingencies under various system conditions. It predetermines the appropriate control measures. Once an actual contingency occurs, the SPS carries out predetermined control and prevents the power system instability.

The behaviour-assumption type executes control <u>before</u> out of step happens and prevents it from occurring, whilst the behaviour-confirmation type described above implements system separation <u>after</u> out of step occurs and prevents the extension of the abnormal phenomenon. . A typical control scheme of this type which is in common use is generator shedding, or prompt isolation of accelerating generators just after a fault. These schemes use a “pre-fault calculation” simulation to anticipate various severe contingencies and the controls necessary to prevent out of step. Power-system analysis engineers normally carry out this simulation. However, adaptive SPSs have been developed which carry out simulation and decide control automatically according to the on-line information from the existing power systems.

The behaviour-assumption SPS for abnormal frequency is more sophisticated than the behaviour confirmation type such as Under-frequency Relay. As an example, the appropriate amount of generation/loads to be shed against assumed different contingency types are calculated periodically beforehand. When an actual contingency occurs, the SPS promptly executes controls according to the calculation. Thus abnormal frequency conditions can be prevented from occurring.

(3) Behaviour Prediction Type

The behaviour-prediction type could also be called “post-fault calculation type”. It starts calculation after fault occurrence based on real-time measured values, executes predictive control actions and prevents power system instability.

This application is practical only for out of step contingency. After the fault, this type of SPS measures voltage and current during the period when the conditions for an out of step condition are starting to develop. Controls are then implemented according to calculations and predictions, whether or not the fault evolves into a full out of step event. The behaviour-prediction type can also deal with all types of contingencies because it applies controls based on observation of the actual disturbances in addition to the assumed contingencies used in the behaviour –assumption method. On the other hand, the observation dependent control tends to be slower than the behaviour-assumption type.

Figure 4.1-1 through **Figure 4.1-3** show the control scheme of SPSs according to calculation algorithm.

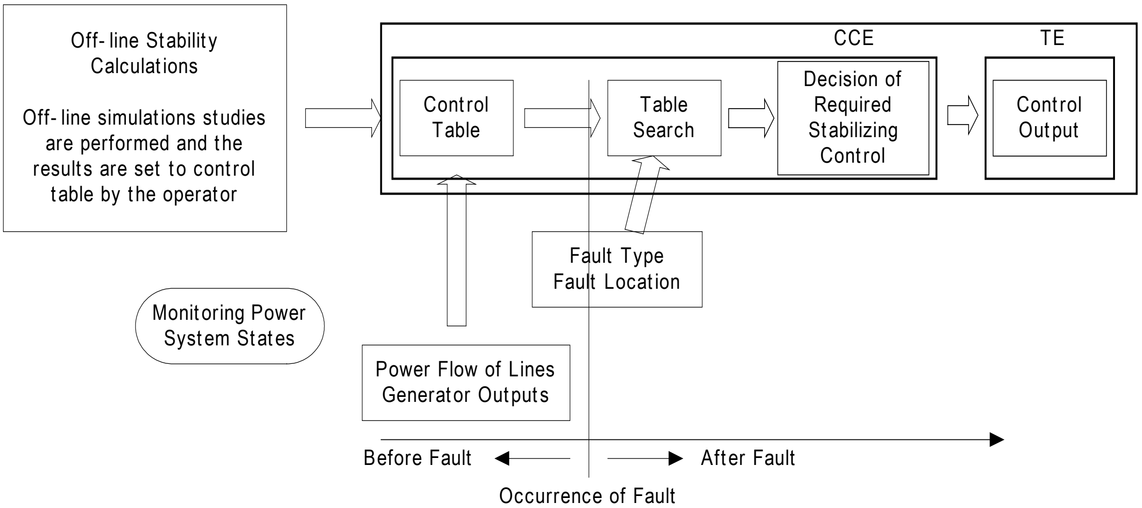


Figure 4.1-1 Behaviour-Assumption Type based on Off-Line Simulation
Note) CCE: Central Control Equipment, TE: Terminal Equipment

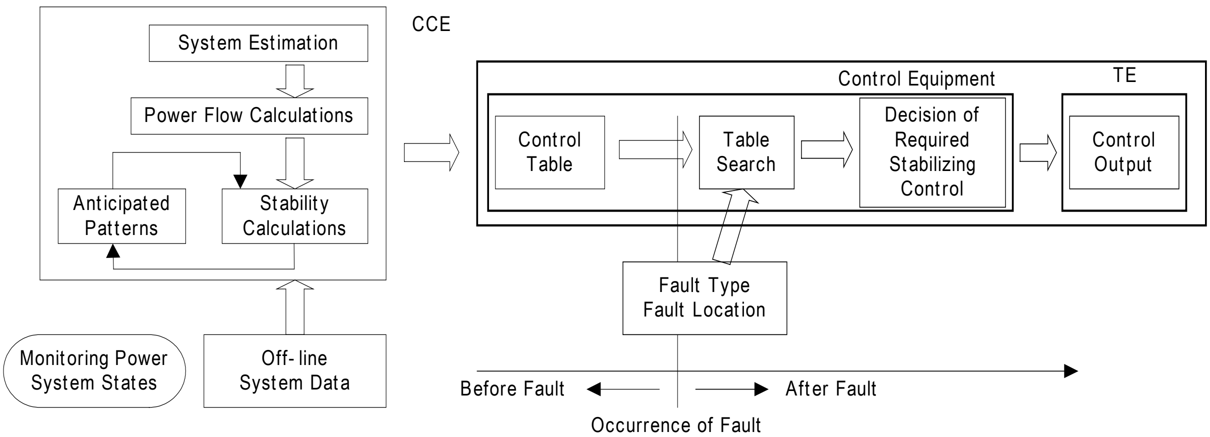


Figure 4.1-2 Behaviour-Assumption Type based on On-Line Simulation
Note) CCE: Central Control Equipment, TE: Terminal Equipment

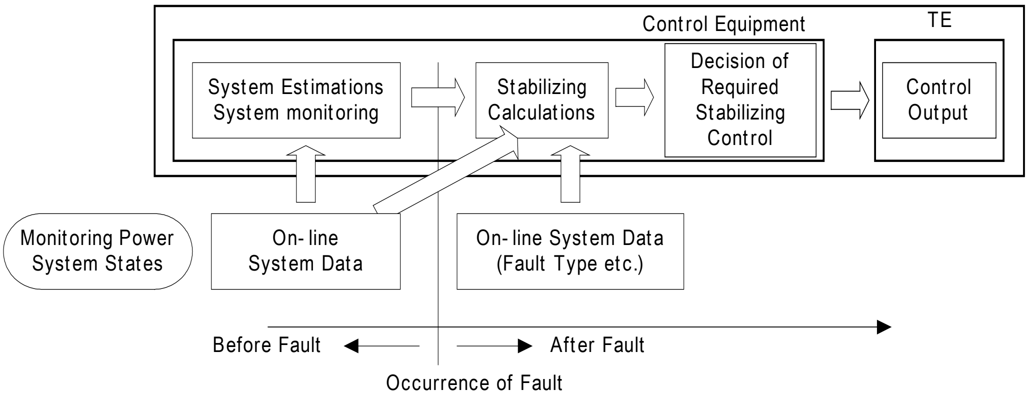


Figure 4.1-3 Behaviour-Prediction Type

Note) TE: Terminal Equipment

4.1.2 Classification by System Structure

SPSs have also been classified according to system structure into wide-area type and stand-alone type [1]. Power systems equipped with SPS fall under the following categories:

- main trunk power system as a whole,
- large-capacity power source system with/without pumped-storage generators and
- tied wide-area power systems.

The purpose of the SPSs applied to large-capacity power source systems is, in most cases, to maintain transient stability. Purposes of the SPSs applied to main trunk power systems or tied wide-area power systems are to maintain stabilities not only in transient domain but also in dynamic domain.

(1) Wide Area Protection (WAP) Type

All of the SPSs applied to main trunk power systems are wide area protection type, in which data terminals are installed in geographically scattered locations and power system data are transmitted to a central unit where computation and control tasks are performed to provide failure extension protection. In order to prevent wide area power system out-of-step, it is necessary to import data such as power flow and generators' operating condition from wide area, and have such data scrutinised by a central unit.

WAP SPSs are also generally applied to large-capacity power source systems. These SPSs target out-of-steps of the power generation systems to the main bulk system. WAP is particularly relevant to large-capacity power source systems which spread over a wide area comprising a large number of generators within it, and it is necessary to acquire a huge amount of data from dispersed sites in order to prevent out-of-step. WAP collects data of voltages, power flows and circuit breaker conditions of each part to the central unit, with potentially well in excess of one thousand individual pieces of data being transmitted.

(2) Stand-Alone Type

In some cases of stand-alone type applications, the offline behaviour-assumption scheme may allow the number of the required power system data points can be reduced because variable conditions of system construction and power flow has been already considered in the settings. In the Behaviour-Prediction scheme, the number of the required data points can also be reduced by using a technique to assume the status of main trunk power systems based on online data obtained after the fault clearance.

4.1.3 Calculation Algorithm and Control Time

Control time achieved by individual SPS system is typically 110~220 ms in the offline behaviour-assumption type relay and 150~270 ms in the online behaviour-assumption type relay after a fault occurrence. There is no significant difference between online and offline types. In the case of behaviour-prediction type relays, control time is 220~350 ms after a fault clearance. Control time of this type is longer than the behaviour-assumption type because it identifies a system failure on the basis of data received after the fault occurrence. It is desirable that a control time should be shorter for a transient stability protection. However, the extent of required shedding as a result of the behaviour-prediction scheme can be minimized by using the post-fault-occurrence data. In comparison, over-shedding is more likely when behaviour-assumption type is used as it must consider the worst case faults conditions.

4.2 Practice of SPSs

Table 4.2-1 shows a questionnaire result about SPS applied in each country. SPSs are generally introduced in consideration of the reliability criteria. Where the system configuration is comparatively simple, and the power system is fixed in operation, the centralized type SPSs which prevent failure extension from out-of-step or abnormal frequency are widely applied.

Table 4.2-1 Practice of SPSs

SPS	AU	CA	CN	ES	FR	IN	JP	KR	MY	PT	SE	UK
Predictive Out-of-Step	-	-	-	-	-		×	×	-		-	-
Out-of-Step	-	-	×	-	×		×	×	-		×	-
Abnormal Frequency	×	×	×	×	-		×	×	×		×	-
Abnormal Voltage	-	×	×	×	×		×	×	×		×	-
Overload	×	×	×	×	×		×	-	×		×	-

4.2.1 Prevention of Out-of-Step

There are several problems in keeping the stability of high density large capacity power systems, for example, when a severe fault happens near a large power source where many generators are concentrated, the generator that has the largest phase angle difference to the main power systems first accelerates and goes to out-of-step, followed by adjacent generators.

In order to prevent this type of out-of-step phenomenon, appropriate power restriction should be done within several hundreds of milliseconds after fault occurrence. **Figure 4.2-1** shows the rotor angle responses for a stable case and for two unstable cases.

In the Stable Case shown, the rotor angle reaches a maximum and reduces to a steady state condition after a few seconds.

In the Unstable Case 1 shown, the angle continues to increase until synchronism is lost. This form is referred to as first-swing instability. These phenomena depend on acceleration of the generator during fault.

In the Unstable Case 2, the system is stable in the first swing but becomes unstable as a power swing continues through several swing cycles or tens of swing cycles, finally resulting in out-of-step. This phenomenon can happen when a power system has long-distance lines, or operating conditions are close to the limits of stability.

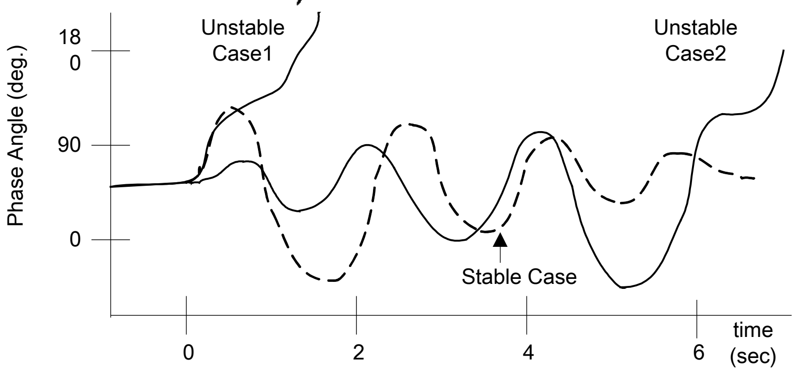


Figure 4.2-1 Rotor Angle Response after a Fault

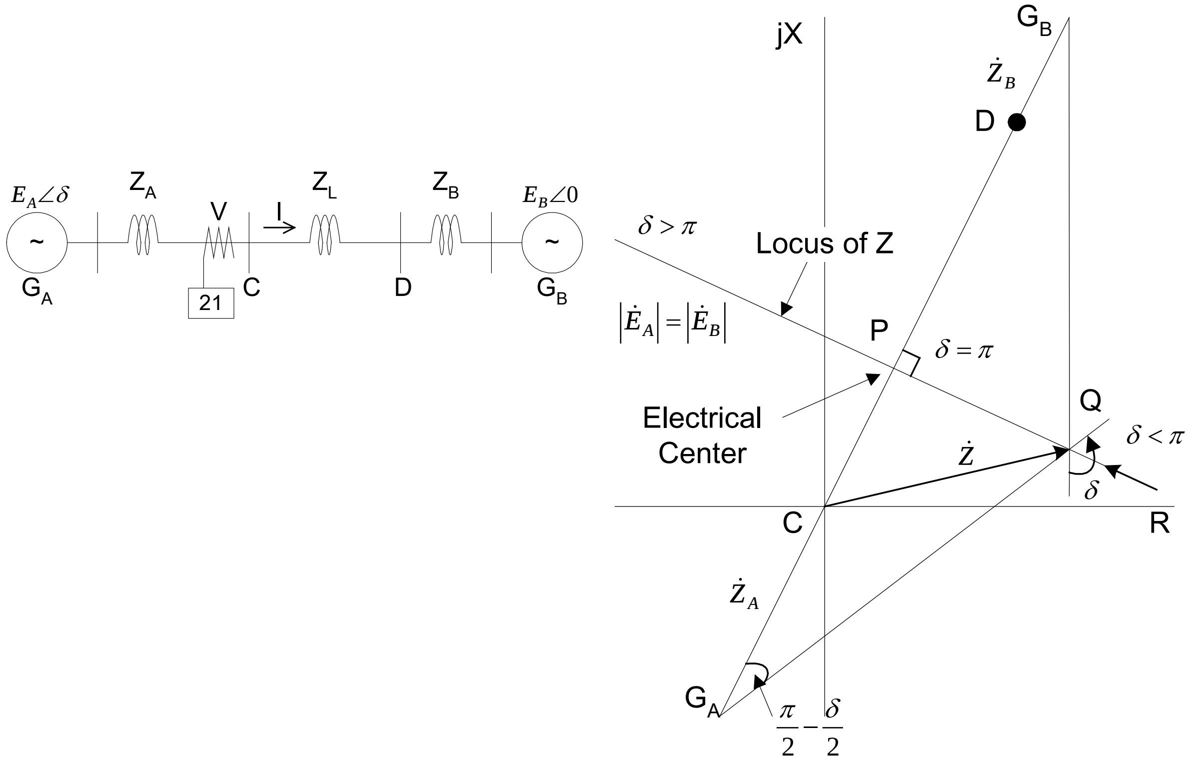
(1) Out-of-Step Relay

The effect of out-of-step phenomenon can be illustrated with the simplified two-machine system and the R-X diagram. In **Figure 4.2-2(1)**, the machines are assumed to be represented by voltages (E_A and E_B, E_A=E_B) of constant magnitudes behind their transient impedances (Z_A and Z_B), and δ represents the angle by which E_A leads E_B. During a swing, the angle δ changes. The locus of apparent impedance Z measured by a relay at bus C is shown in **Figure 4.2-2(2)**. When δ =180 degree, the voltage at the electrical centre (middle of total system impedance) is zero.

Synchronization is still maintained at the beginning of out-of-step in the systems of both sides of the electric centre, when an out-of-step occurs in a power system. System separation near the electrical center of the out-of-step by an out-of-step relay contributes to keeping the stability of both the systems after separation.

There are mainly two detection methods of out-of-step; an impedance locus type and a voltage phase comparison type. The former detects out-of-step on condition that the impedance locus passes through the two domains of the distance relay beyond the definite period of time. In the latter, out-of-step is judged from the voltage phase difference between both ends of a line.

The features of the impedance locus type are the self-end detection and the self-end separation. But if the system configuration is complicated, two or more out-of-step relays may operate due to the difficulty of the detection of the electrical centre and in order to distinguish from a typical short circuit fault or an earthed fault, the time to detect out-of-step is added as shown in **Fig.4.2-3**. For this reason, it cannot detect out-of-step with fast slip. The latter can detect the electrical center at high speed without being influenced by the system condition. But high speed transmission and reception of the voltage phase between the self-end and the remote end with synchronization is required.



(1) Two Equivalent Generator System

(2) Impedance Locus at Out-of-Step

Figure 4.2-2 Impedance Seen by the Distance Relay at C

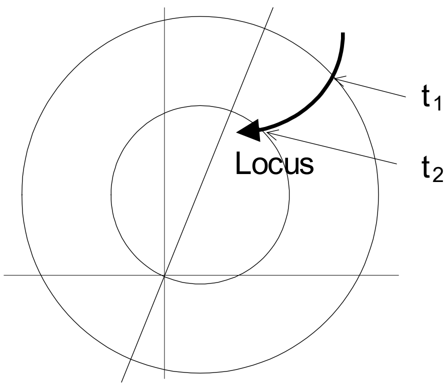


Figure 4.2-3 Confirmation Time for Impedance Locus Detection Type

Table 4-2-2 shows the result of the questionnaire concerning the principle of the out-of-step relays. This result shows Impedance locus type is adopted by most of utilities that are using out-of-step protection. Out-of-step protection is used mostly for EHV network. Japan and Korea are also using the out-of-step protection based on voltage phase comparison. Although it is not shown on this questionnaire, power station or generators of large capacity must be equipped with out-of-step protection.

Table 4.2-2 Principle of Out-of-Step Relays

Protection Scheme	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
Impedance Locus	×	-	-	-	×	×	-					×	-	×	×	-	-	×	×	-	-
Voltage Phase Comparison	-	-	-	-	-	-	-					×	-	×	-	-	-	-	-	-	-
Others	-	-	-	-	×	×	-					-	-	×	-	-	-	-	-	-	-
Not available	×	×	×	×	-	-	×					-	×	-	-	×	×	-	-	×	×

Table 4-2-3 shows the result of the questionnaire concerning the installation points of the out-of-step relays. Out-of-step relays are generally installed at the interconnection points of two utilities for system separation. In Japan and Korea, out-of-step relays are also installed at several points such as important substations in trunk network, intermediate substations in a long distance transmission line, an interconnected point between upper and lower voltage classes and so on.

Table 4.2-3 Installation Points of Out-of-Step Relays

Installation points	AU		CA		CN		ES	FR		IN		JP		KR		MY		PT		SE	UK
	EHV	HV	EHV	HV	EHV	HV	EHV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	EHV
(a)	Not available	Not available	Not available	Not available	×	×	Not available					×	Not available	×	×	Not available	Not available	-	-	Not available	Not available
(b)					-	-						×		×	×			-	-		
(c)					×	×						×		×	×			-	-		
(d)					-	-						×		-	-			-	-		
Others					-	-						×		×	×			×	×		

<Note>
(a) A substation which is interconnected with other utilities
(b) Important substations in trunk network
(c) Intermediate substations in long distance transmission line
(d) Interconnected points between upper and lower voltage classes

Table 4-2-4 shows the result of the questionnaire concerning the confirmation time of the out-of-step relays. We got answers from three countries and it shows the range of time for out-of-step detection is from 40 to 200 ms.

Table 4.2-4 Confirmation Time of Out-of-Step

Voltage Class	AU	CA	CN	ES	FR	IN	JP	KR	MY	PT	SE	UK
EHV (765-187)	NA	NA	200	NA			40-200	50-70	NA	200	NA	NA
HV (below 154)	NA	NA	200				NA	50-70	NA	200		

(2) Pole Slipping Protection

Typical characteristic of the Pole-Slipping protection relay is shown in **Figure 4.2-4**. The characteristic consists of three parts, the lens, the straight line bisecting the lens and the reactance line.

In order to count as a pole slip, the impedance must enter the operating area at point S and leave it on the opposite side of the lens at point R. For this to take place, the centre of the power swing must lie within the generator/transformer unit zone, in which case it is usual to trip the unit after the first slip. If the centre of the power swing is located in the power system, i.e. above the reactance line, tripping is only initiated after a prescribed number of slips.

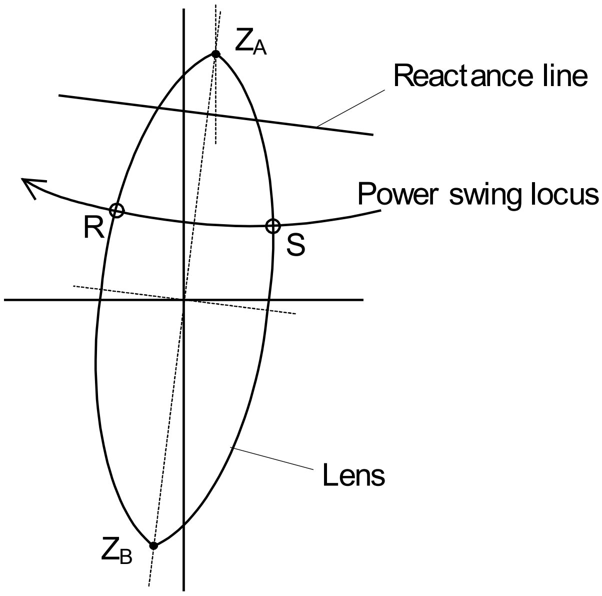


Figure 4.2-4 Typical characteristic of the Pole-Slipping Protection Relay

(3) Experience in France

Cyclopes was developed as the system in France for the purpose of isolation of two south-eastern coherent areas in the French system, identified as having a high risk of synchronism loss. These areas export large amounts of active power, and need loads to be shed frequently, when disconnected from the rest of the system, to prevent induced loss of synchronism.

The functions of Cyclopes [1] as shown in **Figure 4.2-5** are:

- detection of the loss of synchronism;
- tripping of all the lines bordering the homogeneous areas that lose synchronism; and
- if need be initiate load shedding.

The operation principle of this new SPS is that information from the entire power system is processed at one central point. Local measurements on the network are sent to the central point, processed and the affected zone is detected. The central point then commands local substations to isolate the affected zone by opening all of its bordering lines. If necessary, the central point commands HV/MV substations to shed load, so as to prepare the active power balance for the post-islanding sequence, and to maintain a proper frequency range.

When compared to the DRS plan, the co-ordinated SPS "Cyclopes" provides the following improvements:

Phasor detection of the loss of synchronism is closer to the origin of the event and reduces detection delay;

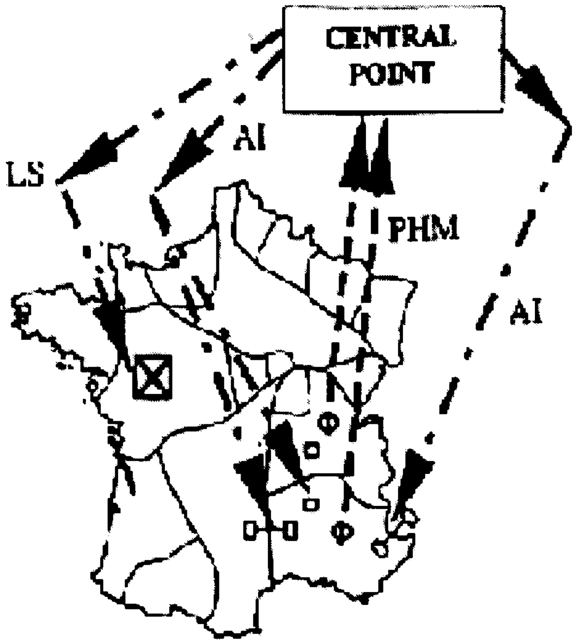
Global processing provides selectivity and accuracy of the actions;

- o Simultaneity and completion of the line tripping process with limited delay preserves the stability of the generators in remote areas;
- o Simultaneity of the load shedding and the line tripping processes keep the rest of the system in a better condition: higher frequency and robustness.

Every part of the SPS needs to be highly reliable and safe to guarantee that the probability of unwanted actions, such as, line tripping or load shedding is acceptable and to ensure proper actions in the event of synchronism loss.

- o Phasor measurements and local pre-processing
- o Information transmission line relayed to the Central Point
- o Real time information process in Central Point

- Order transmission order application (line tripping, load shedding at HV/MV substations)



<Note> PHM: Phase Measurement, AI: Area Islanding, LS: Load Shedding

Figure 4.2-5 Principle of Cyclopes

(4) Experience in Korea

A severe fault near the large capacity generation plants may cause stability problems and the effects of the disturbance tend to cascade into neighbouring areas. When a group of large capacity generating plants is removed from the rest of the system, stability can be analyzed using two equivalent machine systems. One represents a group of generators greatly affected by the disturbance and the other represents the rest of the system. The gross motion between two generators accounts for the mechanism of the system separation. Once this equivalent system is formed, the stability analysis problem becomes well-known equal area criterion. The scheme of "On-line Out of step and Determination of Generation Tripping for Emergency Control of Power System" comprises two steps: on-line out of step prediction by measuring the variation of electric power output from the stations and voltage phasor at the terminal buses, and on-line calculation of generator tripping for emergency control of power system as shown in **Figure 4.2-6**[1].

Using line connection status and current power flow information, Fault Propagation Preventive Controller trips a generator according the control scheme. If there is a power flow interruption via line out, then calculations and reference tables are used to decide how many and which generators should be tripped.

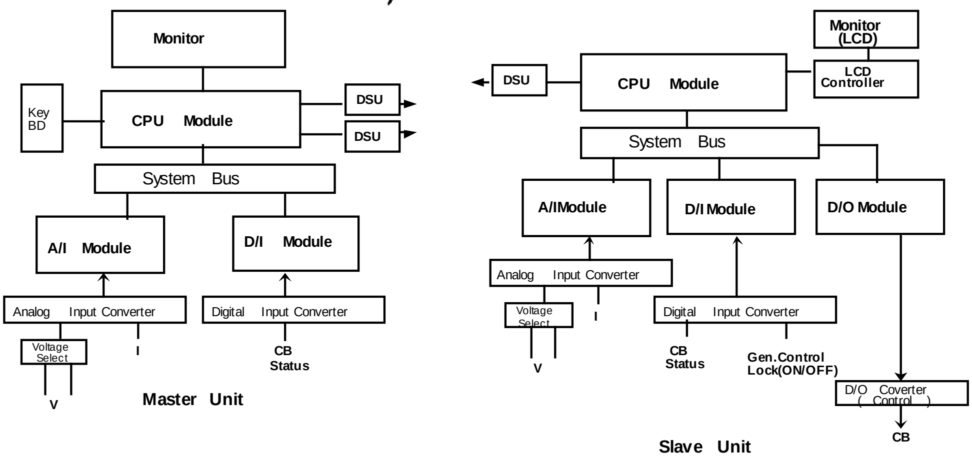


Figure 4.2-6 Block Diagram of FPPC

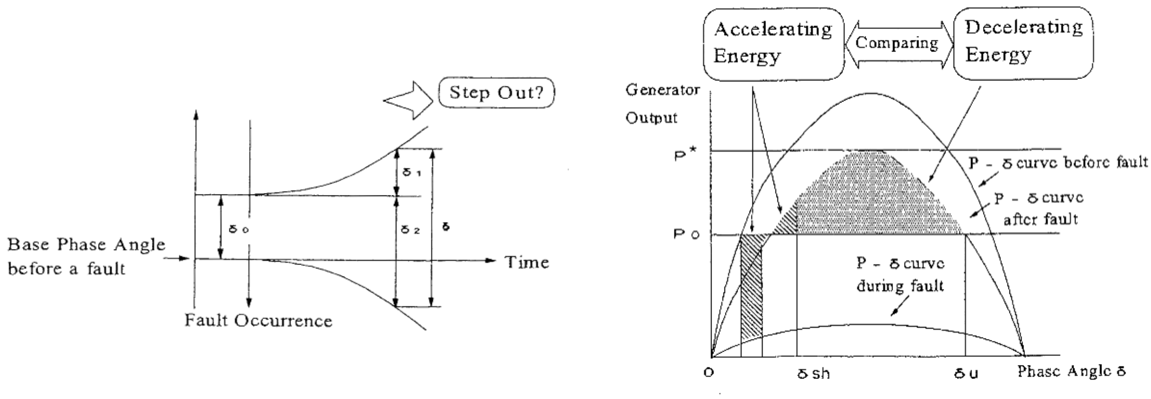
(5) Experience in Japan

In Japan, many applications have been reported regarding behaviour-assumption or behaviour-prediction SPSs. **Table 4.2-5** shows the classification of these out-of-step protection systems with the features such as adaptability and operation.

Table 4.2-5 Classification of out-of-step protection system

Type	System configuration	Features	
		Adaptability	Operation
Behavior assumption (Off-line pre-calculation)	Central control type	Impossible to cope with a fault that is not anticipated Difficult to adapt to the change of power system configuration (It may result over-control) Enormous cases of simulation studies are needed.	System operator can see a control table in advance Operations may be restricted because of severe setting
	Local control type	Control time is short because of its simplicity of calculation As the growth of power systems, reinforcement of CCE may be required As the growth of power systems, additional simulation studies may be required	Manual switching is required in changing controlled objects
Behavior assumption (On-line pre-calculation)	Central control type	Impossible to cope with a fault that is not anticipated Adaptive to the change of power system configuration and operating state of power system Enormous cases of simulation studies are needed, but these are carried by the system High-performance computers are required for CCE As the growth of power systems, reinforcement of CCE is not needed As the growth of power systems, additional simulation is performed by the system	System operator can see the quantity of control in advance Restriction of operation is reduced Manual switching is required in changing controlled objects
Behavior prediction (Real-time calculation)	Central control type	Possible to cope with a fault that is not anticipated Adaptive control to actual phenomena Adaptive to the system configuration and the state of operation of the power system	System operator can not see the quantity of control in advance Restriction of operation is reduced Manual switching is required in changing controlled objects
	Local control type	(Possible to reduce the quantity of stabilizing control) As the growth of power systems, reinforcement of CCE is not needed As the growth of power systems, additional simulation is not required	

Figure 4.2-7 shows the two typical methods of behaviour-prediction type, and **Table 4.2-6** shows seven experiences in which failure extensions were prevented by employing these out-of-step protection systems.



(1) Phase Angle Prediction Method (2) Energy Prediction Method

Figure 4.2-7 Typical Methods of Behaviour-Prediction Type

Table 4.2-6 Experiences of Prevention of Fault Extension

Date System	Interruption cap./time	Summary of the fault (weather or cause)	Operation of SPSs
Aug.21,1982 187kV line	None	Transmission route was disconnected by double-circuit fault. (Physical contact of a carrier car)	Restricting a power source
Sep.7,1983 275kV line	919MW	System separation caused by BFP after a CB failure, losing many loads. (Lightning)	Shedding a generator
Nov.17,1983 187kV line	96MW	System with power sources was disconnected by a double-circuit fault. (Lightning)	Shedding a generator
July 20,1984 275kV line	None	Loss of many loads caused by BFP after a CB failure. (Lightning)	Shedding a generator
May 27,1986 275kV line	40MW 23min	Loss of many loads caused by BFP after a CB failure. (Gas leakage of CB)	Shedding a generator and closing SDR
May 27,1992 500kV line	None	Double-circuit fault on a line connected to a large scale power station. (Lightning)	Shedding a generator by a predictive FEPS
Aug.3,1998 275kV line	None	Overload of transmission line caused by a single fault on the adjacent line. (Lightning)	Restricting a power source

4.2.2 Prevention of Abnormal Frequency

The frequency of power system depends on the speed of the generators connected to power system. The generator speeds will change when there is loss of generation or load, because of imbalance between energy input and output of generator or prime mover. When the input energy is larger than output energy, the frequency increases by increasing speed, and when output energy is larger than input energy, the frequency decreases.

In the system that the power flows from system A to system B via the interconnection, as shown in **Figure 4.2-8**, following the system separation due to tripping of the interconnection lines, the frequency increases in system A due to over generation, and the frequency decreases in system B due to over load.

The abnormal frequency condition often follows this process;

1. occurrence of fault in power system during lightning, storm, or earthquake condition,
2. line/ route cut-off by relay operation, losing some generations or loads in each area, and finally
3. making imbalance condition occurring between the generation and the load.

The failure of generator itself or other apparatus can also be one of causes leading to abnormal frequency.

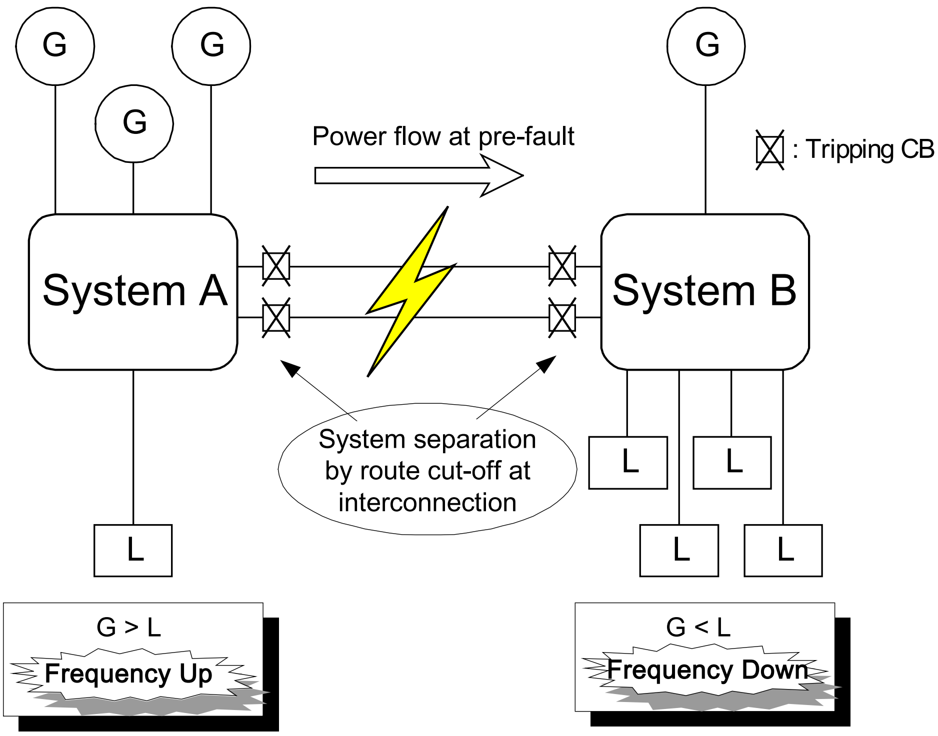


Figure 4.2-8 Example of Abnormal Frequency Condition by System Separation

(1) Experience in Sweden

In Sweden there are four kinds of SPS-functions activated at abnormal frequencies:

1) The Emergency Power EPC functions (part of the HVDC link's control system)
2) Production shedding
3) Start-up of production
4) Load shedding

All HVDC links connecting Sweden with the rest of Europe have EPC functions. The EPC function measures the frequency locally at the converter station and is activated when the frequency reaches or goes below a certain level. The EPC settings make it possible to have more than one level and different size of power change may also be associated with each level. When the function measures a frequency above or below the setting of the EPC function, it automatically changes the power flow over the link, giving more power when the frequency is low and a decrease in power when the frequency is high, thus improving the situation.

The start-up of production involves gas turbines and it is activated at frequencies below 49.7 Hz. The function is used to give automatic support when a disturbance occurs in the system.

Finally, at frequencies below a certain value, disconnecting of load (load shedding) is also used. The load shedding involves load in the southern part of the Swedish Power System.

(2) Experience in Malaysia

In Malaysia there are operating principles for Under-frequency relay and Under-frequency load shedding scheme [3]

1) Under-frequency relay
In general, under-frequency relay operates when:
- Frequency is below setting
- Voltage is above under-voltage setting blocking

In addition, modern under-frequency relaysprovide frequency and rate-of-change of frequency elements. These elements have several protection stages, each of which with its own frequency and rate-of -change of frequency (df/dt) setting, including two adjustable operating times. When the system frequency drops below the setting limit, the protection stage initiates the under-frequency stage. The operating time of any stage is affected by number of cycles used for measurement and an additional timer setting. The df/dt function is not presently utilised in any load shedding scheme in Malaysia.

2) Under-frequency load shedding scheme

The setting of the under-frequency relay is 4-cycle for numerical relay. The tripping signal is wired directly to the trip coil and not to the master trip to assist remote restoration of shed load from National Load Dispatch Centre.

(3) Experience in Japan

Japanese experience includes an event where normal system frequency was maintained by predictive frequency protection following loss of the generation grid connection, and is described as following;

1) Fault occurrences:

First fault 8:51 22, Dec. 2006 Route cut-off at X route of R power plant A by galloping phenomena in wind and snow condition

Second fault 8:52 22, Dec. 2006 Route cut-off at Y route of R power plant B by galloping phenomena in wind and snow condition

2) Preventing failure extension:

For the second fault, the predictive frequency protection shed some loads, because of on-line calculation result that the power loss exceeded permissive limits at second fault timing point. Result of the relay operation succeeded in maintaining normal system frequency in the wide area network, even though the frequency transiently reduced.

3) Coordination between under frequency relay and predictive frequency protection:

In this power network, the under frequency relays had been installed at the interconnection point of adjacent utilities, and the predictive frequency protection was coordinated to operate in advance of under frequency relays in order to maintain the interconnection for adjacent utilities . by appropriate load shedding. Thereafter the frequency in this wide area network kept normal values and the system was operated in a stable condition.

4) Noted Features of this protection:

Commonly this type protection are designed and operated to withstand contingencies such as one route cut-off. Advanced design of this protection is consideration for two route cut-off or faults after faults in multi transmission line connected to large power plant. Power system configuration and fault points are shown in **Figure 4.2-9** and actual frequency record with predictive frequency protection operation and simulation result without predictive frequency protection are shown in **Figure 4.2-10**. Simulation result suggests risk of large scale outage with frequency falling down to 59 Hz or less.

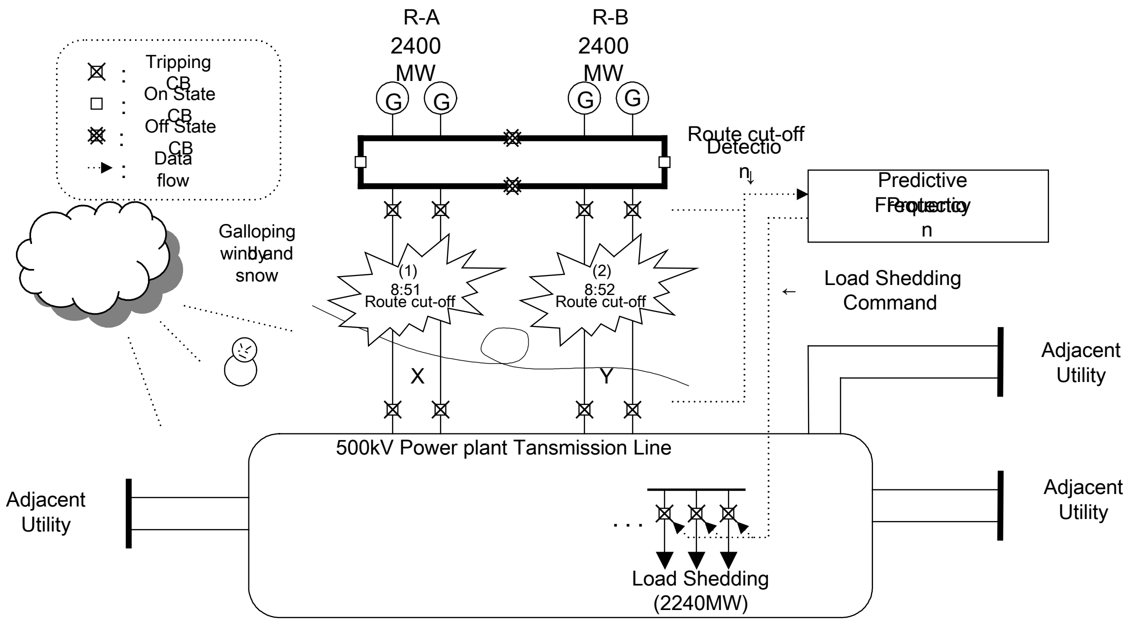


Figure 4.2-9 Power system configuration and fault points

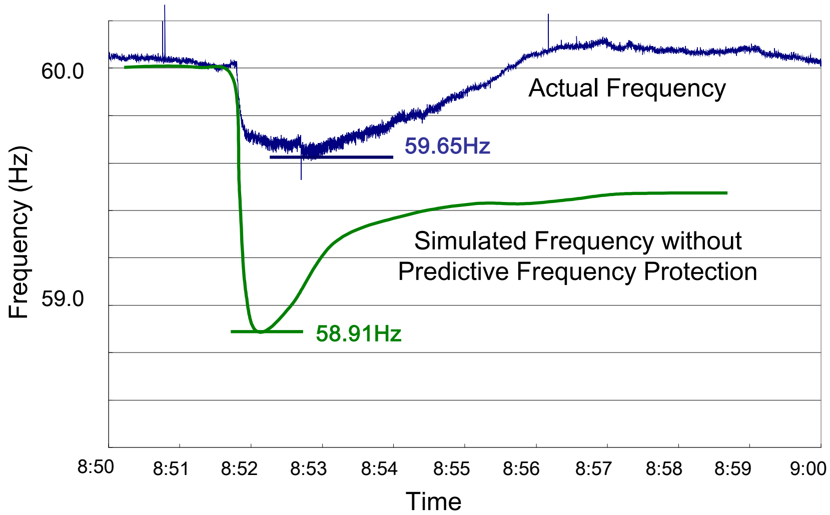


Figure 4.2-10 Actual Frequency Record and Simulation result

4.2.3 Prevention of voltage collapse

(1) Experience in Sweden

There are two important automatic SPS functions installed in the Swedish National Grid. Both measures the voltage at a number of 400 kV stations to detect and prevent a voltage collapse. The risk of voltage collapse in the Swedish grid is present when the power flow from the north of Sweden to the south is excessive. The value depends on the load situation, available lines etc. To prevent this from happening, a signal is send to the EPC function and the power flow is adjusted so that more power is flowing into the south of Sweden via the HVDC links. Thus a voltage collapse is avoided. Note that the first SPS function measures the voltage at the bus bars in four different 400 kV stations to the north of Sweden. It is activated when two stations measure a voltage below 390 kV for a time period of 2 seconds.

The second SPS function is triggered when the voltage in the southern part of Sweden has fallen below 390 kV. After a time delay of 4 seconds, the EPC function for Baltic Cable, SwePol Link and Kontek is activated, resulting in an increase flow of 750 MW into the south of Sweden.

It is important to point out that the HVDC link’s EPC function not only measure frequency, but also voltage, locally at the converter station. Measured values above or below levels defined in the setting of the control system also changes the power flow.

(2) Experience in Saudi Arabia

Refer to **Figure 4.2-11** [1] Simulations indicated that if line from substation 9010 to 9006 was lost and a certain amount of power was imported, then all the power imported to the Qassim network would transfer through 2x350MVA 380/132kV transformers and the extra long 132kV overhead line from substation 9006 to 8808. This would lead to the local generating units reaching their MVAR limit followed by voltage collapse. To prevent such instability, sufficient load must be shed just after a disturbance occurred. Load shedding is performed by under-voltage relays located at substations that would suffer more from a depressed voltage (dead end substations). These relays are set at a 0.85 p.u. voltage with a time delay of 5 seconds in order to inhibit operation under local fault conditions. Additionally, overload relays are located at substation 8808 to monitor the overhead line condition.

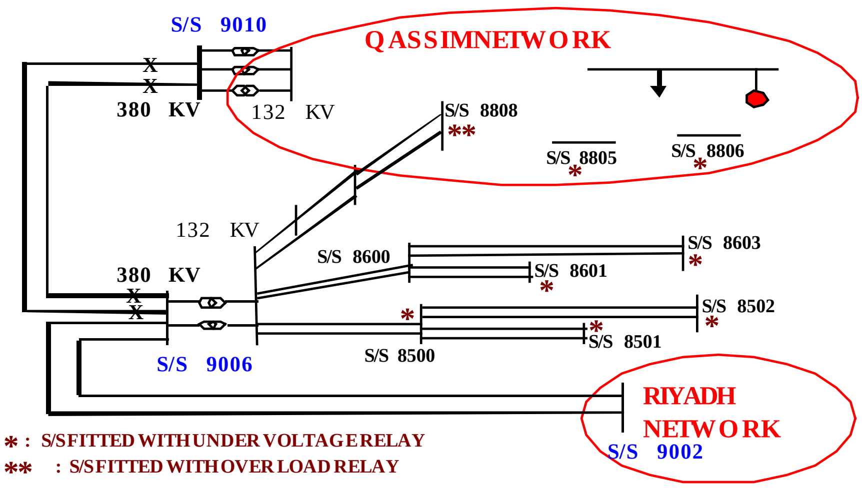


Figure 4.2-11 Outline of Adaptive Power System

4.2.4 Prevention of Overload

Load current on the apparatus such as transmission line or the transformer, will contribute to the rise in temperature normally dissipated by the cooling system and natural cooling. Any apparatus will be thermally overloaded by exceeding the maximum permissible temperature which is considered as withstand value by its design.

Utility companies must consider the new possible load flow scenarios after the commissioning or de-commissioning of power plants and also consider the possible increase of demand in the future. Load flow must be controlled by the power system operator to keep it within the thermal rating of the apparatus on which load flows. However, power plant apparatus might be exposed to the severe natural environment such as thunderstorm, which might cause the sudden interruption of the apparatus. Once the interruption of apparatus happens, load flow on it will be distributed to the neighbouring apparatus to maintain the balance of power flow. This may increase the load current on other apparatus. If this change of the load current is greater than the continuous rating, the temperature of the apparatus will exceed the permissible limit as a thermal overload. Simple example of overload of the parallel transmission line is introduced hereinafter.

(1) Experience in Japan

In this area we described on transmission line overload protection and transformer overload protection, which shed remote loads or remote generators. The overload resolution measures performed in Japan include:

Resolution based on load dispatching instructions by the system operator, such as those for system switching, etc., when the tolerable capacity and tolerable time include a margin for overload. Overload status resolution based on generator output control and load shedding by overload protection when the tolerable time with respect to overload is short. An overload device is shutdown to prevent damage when overload cannot be resolved by the above measures.

Of the above, the relays of Item 2 are classified as fault extension protection relays. **Figure 4.2-12** shows an example of a transmission line and transformer overload protection relay system. In areas with high power station capacity, it is considered that transmission lines will overload when a fault occurs on adjacent lines. As a countermeasure, the SPS controls the generator when overload is detected on the transmission line or transformer circled in the shaded area by means of a definite-time multi-stage overcurrent relay. Other examples include use of a temperature calculation type overload protection relay that operates when a rise in transmission line temperature is calculated from the value of the load current and estimations indicate that the highest operating temperature of the transmission line will soon be reached.

Figure 4.2-13 shows an example of a transformer overload protection relay system. In this system, a control command is issued when transformer overload is detected, changing the control target based on the direction of the current of the transformer. The generator output is reduced or the generator shuts down with an increasing current, or alternatively the generator output is increased or the load is shed with a decreasing current. In this system, a temperature calculation type overcurrent relay is used for detecting overload.

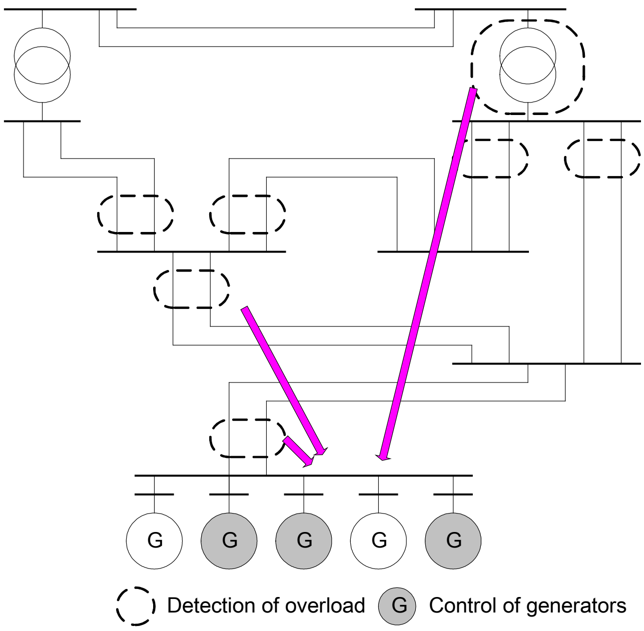


Figure 4.2-12 Example of Overload Protection

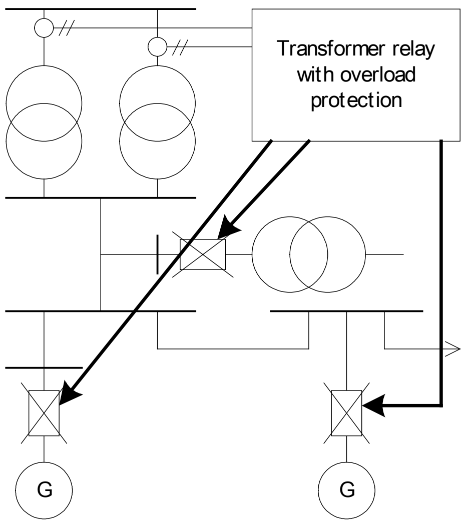


Figure 4.2-13 Example of Overload Protection

<References>

[1] CIGRE Working Group 34.08 Report," ISOLATION AND RESTORATION POLICIES AGAINST SYSTEM COLLAPSE", June 2001

[2] Nordic grid code", Appendix 5 of System Operation Agreement 2004-04-01

[3] " FAILURE EXTENSION PROTECTION SYSTEMS IN JAPAN", CIGRE 2001 SC 34 Colloquium in Sibiu, September 10 - 1,September 2001

[4] "Reliable fault clearance and backup protection", CIGRE SC 34, 1997-08-02

5. Relay Coordination

5.1 Definition of Coordination

Applying protection relays to a power system requires relay setting coordination to enable maximum performance of the power system and to prevent a large-scale blackout. The coordination enables the protection relays introduced into a power system to respond against a fault as well as satisfy the operation conditions. Therefore, there are the following categories in coordination required for a protection relay.

Coordination between the protection relay and another protection relays:
This is a means that the various protection relays applied to a power system are set so as to isolate the minimum extent of the power system necessary to clear the fault.

Coordination between the protection relay and the power system and the primary equipment (high voltage equipment):
The operating time of the protection relay for any fault or load condition should not exceed the withstand capability of the power system (primary equipment).

Coordination within the relay:
Due to the combination of the input conditions and the characteristics of the relay, the relay may fail to operate or have an unwanted operation for a particular power system fault, even though the relay is considered healthy and operating correctly. Although this is considered to be a measure of a protection relay to perform correctly, this "functional coordination" is required to improve the overall operation of the relay. Some examples of functional coordination are shown below.

- Addition of the overcurrent element or the under voltage element in a distance relay
- Coordination of minimum and maximum operating values
- Coordination between an external fault detection element and an internal fault detection element
- Coordination between a mho element and a blinder element in the distance relay
- The discriminating zones for busbar protection
- Inrush current detection
- Blocking functions

These are examples of functional coordination within the relays, which are outside of the scope of this report.

5.2 Unit Protection “Scheme I” and Unrestricted Protection “Scheme II”

5.2.1 Definition of “Scheme I” and “Scheme II”

A fault clearance relay should detect an internal fault within its protective zone. This protection zone is decided by the principle of the protection, the location of the CT, and the setting values for the relay which detects an internal fault at the local end. It is also necessary to take into consideration whether the relay has directional characteristics. In addition, the maximum value of the operating time should be less than the withstand capability of the apparatus and the operation limit in the power system.

Proper coordination between protection relays is required to clear the fault and reduce equipment damage and to minimize outage area. All protection relays applied in the power system should operate systematically according to good coordination for a power system fault, or subsequent to any main protection which fails to operate, or even when the breaker didn't open. In coordination between protection relays, the protective zone of a relay could overlap with that of another adjacent zone relay. By good coordination, all relays can operate so as to become the minimum outage area against any fault. When the protective zone of a relay overlaps with that of another relay, it is necessary to establish correct time coordination and/or sensitivity coordination.

Although protection relays are classified into a fault clearance relay and SPS, coordination is needed when the operating time, the detection time against an event, or the protective zone overlaps with that of another relay.

Fault clearance relays may have clearly defined protection zones such as a current differential relay based on the location of the CTs or interaction of two relays and hence is called Unit/Restricted Protection or "Scheme I" type protection.

Relays where the extent of the protective zone is determined by the setting value like a distance relay or an overcurrent relay are called Unrestricted Protection or "Scheme II" type protection.

The result classified according to the protection system is shown in **Table 5.2-1**. This classification is classified from the necessity for the time coordination or sensitivity coordination between the relay of the self-section and that of the adjoining section. As a result, the former is the group that adds a directional comparison scheme to unit protection defined in IEV 448 and the latter is the group that excludes directional comparison scheme from non-unit protection.

Table 5.2-1 Typical Examples of "Scheme I" and "Scheme II"

Classification	Protection Scheme	Necessity of coordination with the next zone protection
Scheme I	Current differential (Percentage current differential High-impedance current differential Low-impedance current differential) Phase comparison Directional comparison (POP,PUTT,BOP)	Unnecessary
Scheme II	Distance Ground directional Overcurrent Ground overcurrent Ground overvoltage Transverse differential	Necessary

If the power system is protected only by Type I Unit Protection. , since the protective zone of each relay is clear, only one relay which detects the fault inside its zone will operate. Therefore, no additional coordination by time or sensitivity is necessary. However, in this case, when a protection relay or a breaker does not operate correctly to clear the fault there is no inherent backup mechanism and hence additional relays are required.

Unrestricted Type II schemes have the fault coverage zone determined by the setting of the relay. The Relay A in **Figure 5.2-1** is a relay which is classified into "Scheme II" such as a distance relay. For example, if the setting of the Relay A is set to only partially cover the line as for Case 1 , a fault in the near end of the line can be detected but not beyond. If the relay however is set to see faults beyond the far end substation as for Case 2, a fault occurring in the next section can be also detected as back up to the protection located at the far end substation. Some relays such as overcurrent, under voltage or even some impedance based relays may have no inherent directional characteristic and hence may detect a fault in either direction of the power system "in front" of the relay away from the substation or “behind” the relay inside the substation or on another line. Furthermore, as described in **Chapter 3.3**, system conditions may influence the sensitivity of the relay.

The overlapping of protective zones causes the necessity of coordination between the relays as shown in **Figure 5.2-1**, which is described below. **Figure 5.2-1** shows the transmission line protected by a distance relay under the conditions of two different settings or as the case may be for Zone 1 and Zone2 of the distance relay.

In Case 1 the relay setting is relative high which limits the zone of coverage to the near end of the line where the fault value is above the setting.

In Case 2, the relay has a lower setting and hence has an extended zone of fault coverage beyond the far end substation. Consequently the time delay setting on this relay must be coordinated with the operating time of the relays at the far end substation which must be allowed to clear the fault at the far end substation first in order to minimise the extent of power system outage.

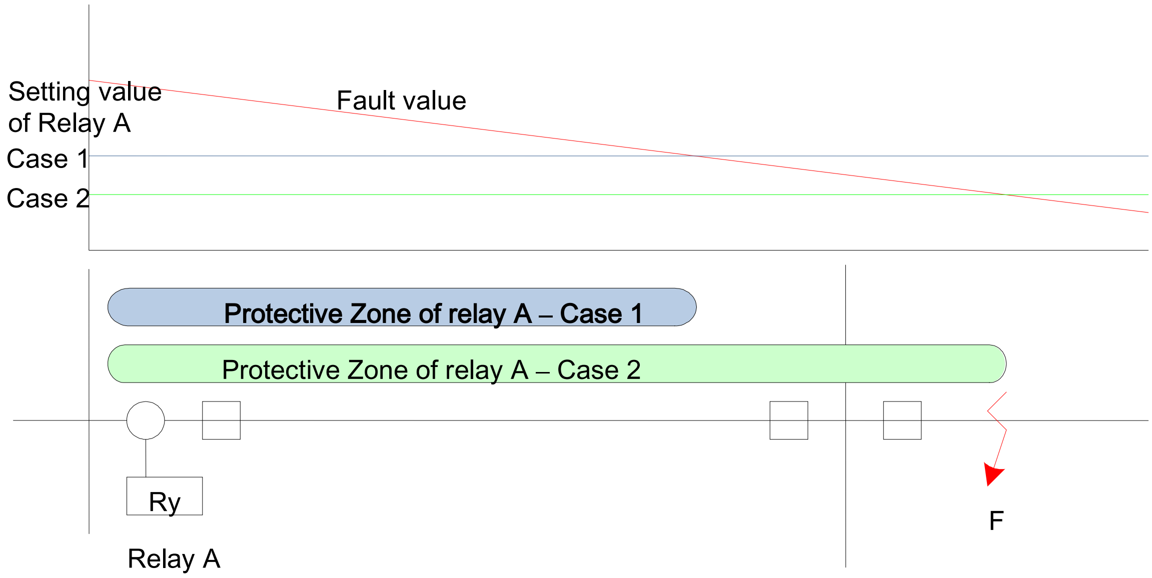


Figure 5.2-1 Change of Protective Zone for “Scheme II” by Change of Setting Value

5.2.2 Coordination of Fault Clearance Relays

The necessity of coordination between fault clearance relays as mentioned above is determined by the protection system characteristic (unit vs. non-unit schemes) applied to the power system. If the power system is protected by "Scheme I" type relays it is clearly distinguishable between internal faults which must be detected and external faults which must not cause operation. However, for protection functions within the "Scheme II" group, a protective zone may overlap another depending on the setting values and power system operation conditions. Where "Scheme I" is applied as the main protection for each equipment and "Scheme II" is applied as the backup protection for each equipment, necessity of coordination between the relays is shown in **Table 5.2-2**.

According to this, coordination is needed between the main protection and the backup protection of the local terminal, between the main protection of the near end and the backup protection of the adjacent section and between the backup protection of the near end and the backup protection of the adjacent section. These examples are described along with the setting criteria issues and approaches for each application in this report.

Table 5.2-2 Example of Coordination between Fault Clearance Relays

		Line Protection		Transformer Protection	
		Main (Scheme I)	Backup (Scheme II)	Main (Scheme I)	Backup (Scheme II)
Busbar Protection	Main (Scheme I)	Unnecessary	Time Coordination	Unnecessary	Time Coordination
	Backup (Scheme II)	Time Coordination	Time Coordination Sensitive Coordination	Time Coordination	Time Coordination Sensitive Coordination
Transformer Protection	Main (Scheme I)	Unnecessary	Time Coordination		
	Backup (Scheme II)	Time Coordination	Time Coordination Sensitive Coordination		
Line Protection	Main (Scheme I)	Unnecessary	Time Coordination		
	Backup (Scheme II)	Time Coordination	Time Coordination Sensitive Coordination		

<Note> Main is of Unit-type and Backup is of Non-unit type schemes.

5.3 Coordination of Line Protection

5.3.1 Coordination between Main and Backup Relays

Assuming that main or primary protection for a transmission line is the differential protection or other in the Scheme I protection category, then failure of this system to clear a fault in the line can be covered by the line backup protection such as distance relay belonging to the Scheme II protection. It is illustrated in **Figure 5.3-1**. The backup distance relay of the line (green or blue colour in the Figure) can also operate instantaneously and so the line fault is quickly cleared, but this is depending on the fault location along the protected line. If the location of the fault is in the zone 1 of the distance relay, then instantaneous trip is initiated If the location of the fault into the protected line is out of the backup relay zone 1 and into the zone 2 reaching, then the zone 2 should operate clearing the fault but not instantaneously. In this case, typical clearing time can be 400 – 500 ms depending on the time setting for the zone 2. As a consequence coordination is not required between the Main and backup protections for faults in the considered line.

Typically the line main protection relay initiates reclosing for faults into the overhead line. Distance protection, as the backup relay, also can be specified to initiate reclosing, but only when its zone 1 has been operated. The type of the employed reclosing system can be single pole, three-pole or multi-pole depending on the practice and criteria of the utility (see **Chapter 3.2.1**).

Directional earth-fault overcurrent function (67N) is provided as a limited earth fault backup protective function for the main line protection system. . Its main purpose is the detection of resistive earth faults and it can be considered as the main line protection for resistive faults (differential protection also can detect this type of faults). In addition, the 67N function also detects solid earth faults operating as backup protection in the case of failure of the main protection system or in the case that distance protection cannot detect this type of faults.

For a single or two phase-to-earth fault, the operation of 67N function typically trips the three poles of the line circuit breaker because this protective function does not have phase selection to know which is the phase or phases that are faulted. The 67N does not initiate reclosing because the 67N actuation cannot guarantee that fault is located only in the first transmission line.; i.e. definitive line circuit breaker three-pole trip is considered. The directional earth-fault overcurrent function is normally neutral voltage polarized and inverse time type curve is set, although definite time or a combination of both can be also used.

Two main setting criteria are applied for 67N function. The first setting criterion is that operating time for faults up to zone 1 reaching of distance protection (backup) is typically 0.2 s to coordinate with the instantaneous time of main and distance protection zone 1. The main and backup line protections with phase discrimination can initiate single pole reclosing for phase-to-earth faults whilst 67N does not initiate reclosing.

The second setting criterion is that 67N function must not operate during the dead time of the reclose relay due to unbalanced line currents when the main protection or distance protection zone 1 initiates a single phase trip and reclose. This is achieved by time coordination or blocking of the 67N during the single phase dead time. Reclosing dead time is analysed in **Chapter 3.2**.

Additional conditions need to be verified when setting 67N functions:

- Coordination with 67N functions of adjacent lines is required. This is normal time coordination
- Low pick-up value it is also convenient to detect very resistive faults. The value needs to be greater than the maximum natural neutral current inherent to the line
- Operating time slightly greater or equal to distance relay zone 2 time (0.35 – 0.4 s) for faults at distance (D) from the line relays location is required. Distance D is as follows:
- $(0.8\text{-}0.85)\cdot L \leq D \leq L$; being (L) the line length

It is not easy to accomplish all main and additional above conditions and could be necessary to sacrifice some of these. In this case each utility will have preferences, priorities or requirements.

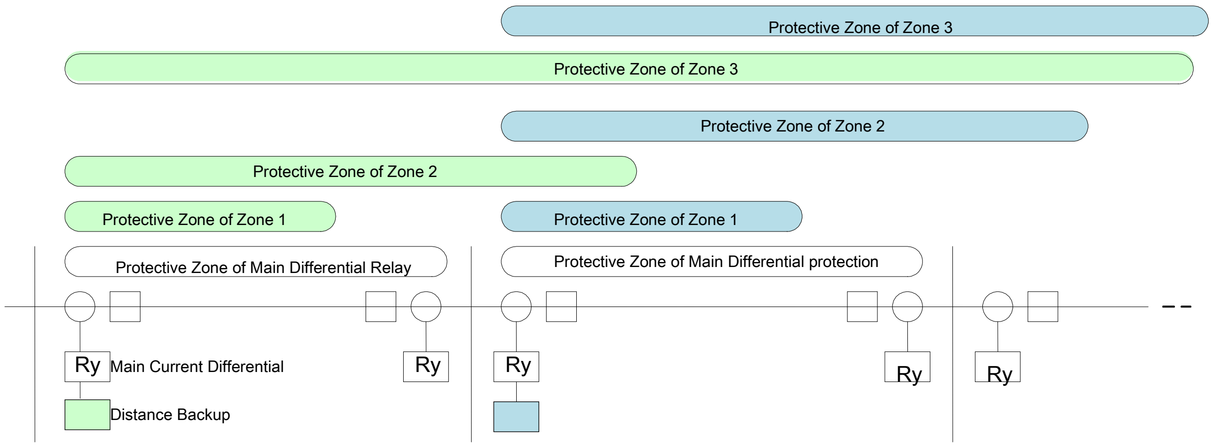


Figure 5.3-1 Protective Zones for Various Kinds of Relays

5.3.2 Coordination between Relays

(1) Necessity of Coordination

Fault clearance relays are installed for all equipment such as a line, a transformer, a busbar, a generator and so on as shown in **Figure 5.3-2**, in order to minimize the outage area in case of a fault occurrence, and therefore only the faulty equipment is tripped. Since the power system is composed of various kinds of interconnected equipment, the protective zone of each fault clearance protection relay must also join and overlap. When the protective zone of a relay overlaps with the relay for the next section of line, perhaps as deliberate back up, time coordination between these relays is required. **Figure 5.3-2** shows the protective zone of the relay Ry-A which must be coordinated with the next adjoining sections of . the far end bus bar protection and Ry-B, Ry-C and Ry-T .

When the Scheme I relay with a defined protective zone is applied for all equipment, coordination between the relays is not necessary to be taken. The existence of the necessity for coordination between relays depends upon the protection relays to be applied.

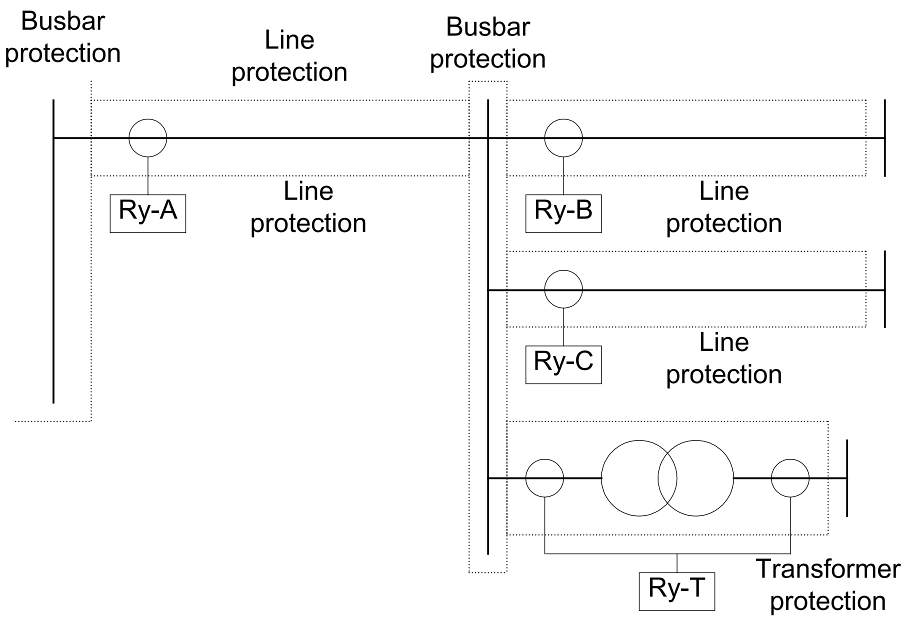


Figure 5.3-2 Protective Zone for Relay at Near End with Adjoining Sections

(2) Coordination Issue of Current Differential Relay for Lines

(a) Coordination Issue

Current differential relay equipment has almost no coordination issue with other protection equipment, because it is a unit-protection scheme. In general, operating time of the current differential relay is satisfactorily fast making no problem with other protection schemes.

(b) Example of Unwanted Operation of Current Differential Relay due to Charging Current

The JN-Line shown in **Fig.5.3-3** is the combination of an overhead line and an underground cable. The underground cable part of the JN-Line 1L was paralleled off. A phase-to-earth fault occurred at the M-Line 2L and it was cleared by the pilot wire relays at M and K terminals. At this time, the JN-Line 1L was unwantedly tripped by the current differential relays at J and T terminals. The power system condition is shown in **Fig.5.3-3** when the current differential relays operated unwantedly against an external fault.

A current differential relay is normally set so that it will not operate due to cable charging current. Since the cable was out-of-operation by scheduled outage, the amount of compensation became error current and it caused the unwanted operation of the current differential relays against the external fault. **Fig.5.3-4** shows the current distribution when the cable part of the 1L is out-of operation. The differential current of the 1L relay and the 2L relay are calculated as follows:

$$I_{d1L} = 25A - 25A = 0A$$
$$I_{d2L} = 175A - 25A = 150A$$

As the current differential relays are set so that it might not operate by charging current. If required at the time of system change, the setting change will be carried out as this measure. The differential current of the 1L relay and the 2L relay are calculated as follows

$$I_{d1L} = 0A - 150A = -150A$$
$$I_{d2L} = 150A - 150A = 0A$$

In this case, charging current caused unwanted operation of the current differential relays for the JN-line 1L. If required at the time of the power system change, the setting change became carried out as this measure.

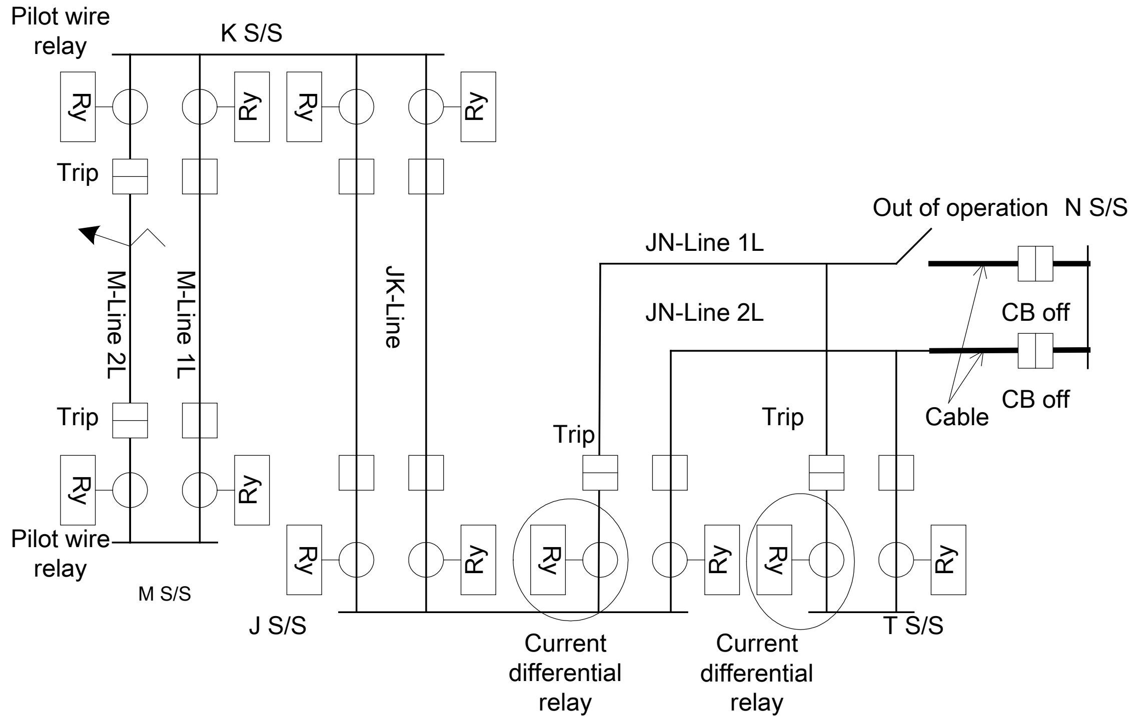


Figure 5.3-3 Power System Condition at Occurrence of Unwanted Operation of the Current Differential Relay

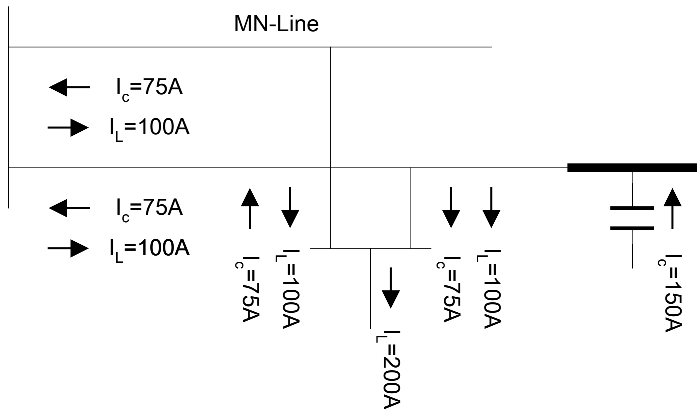


Figure 5.3-4 Current Distribution

(3) Coordination Issues of Overcurrent Relay

(a) Coordination in Loops with Multiple Current Sources

For looped transmission systems with multiple sources, the setting and coordination process is much more complex. All overcurrent relays must be directional and each pair of relays must be coordinated, moving around the loop in both directions. Moreover, at points where external sources are interconnected with the loop, the relays of that interconnection must also be coordinated with those within the loop.

To illustrate the problems of coordinating overcurrent relays in a system with multiple current sources, consider the loop system with multiple sources as shown in **Figure 5.3-5**. Assuming each line section having an impedance of j0.1 per unit, the impedance from R to Q through bus G is j0.2 and that from R to Q through buses T and H is j0.3. Consider the currents only on the branch

R-G-Q. The sources at S and at U are assumed to be equal. For faults at or near bus G it is possible to coordinate relays 4 and 2, or 1 and 3 since they see the same fault current because bus G is equidistant from the two sources. For faults farther removed from bus G coordination is possible, since the relays closest to the fault will trip first, seeing a higher current, thereby making the fault radial from the opposite end.

There is no best starting point for coordinating multiple loop systems. and it may require several attempts of “cutting” the network and trying the coordination to realize complete coordination although generally it is useful to . start at the point where the largest external current source is connected, if there is one largest source. This cut and try procedure described above is time consuming and tedious with no guarantee to find a solution that will working all cases. If this cannot be resolved, then it is necessary ot introduce different protection systems such as Scheme I in order to break the interdependencies between each section of line and relay coordination.

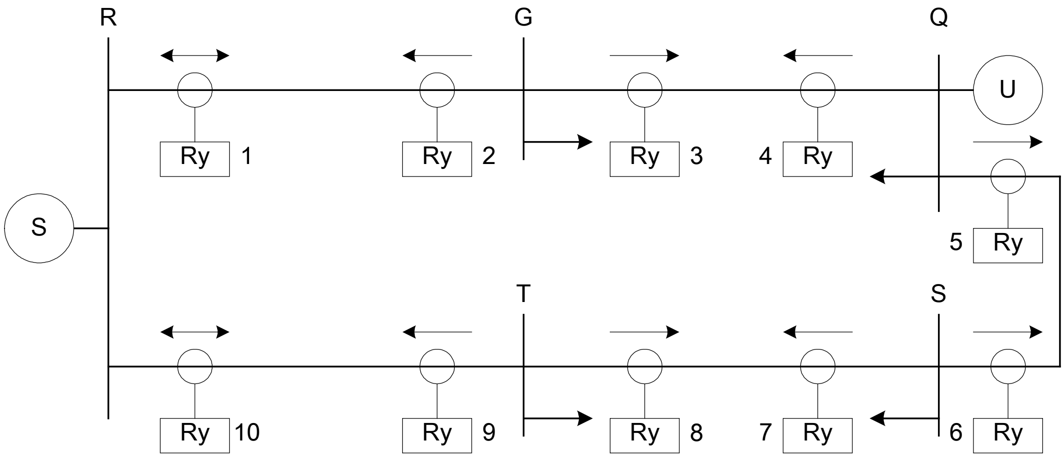


Figure 5.3-5 Loop System with Two Sources

(b) Examples of Miscoordination between Overcurrent Relays in 33kV Transmission System

In the power system shown in **Figure 5.3-6**, a fault occurred on the 33kV H line. One of the two transformers at W substation was out of operation at that time. Time of overcurrent relay OC-1 was set to provide protection of the transformer HV winding but was sensitive enough to detect the fault on line H. OC-1 had fixed operating time (blue line) which for the particular fault was shorter than the IDMT curve of OC-4 (red IDMT curve) for a fault of that magnitude. Therefore, under the setting condition as shown by the solid line for OC-4 in **Figure 5.3-7**, overcurrent relay OC-1 will operate faster than OC-4 against a fault near the end of H line. The miscoordination caused the expansion of blackout besides the blackout of H line. Time of OC-4 was reviewed as shown by the green dotted line in **Figure 5.3-7**.

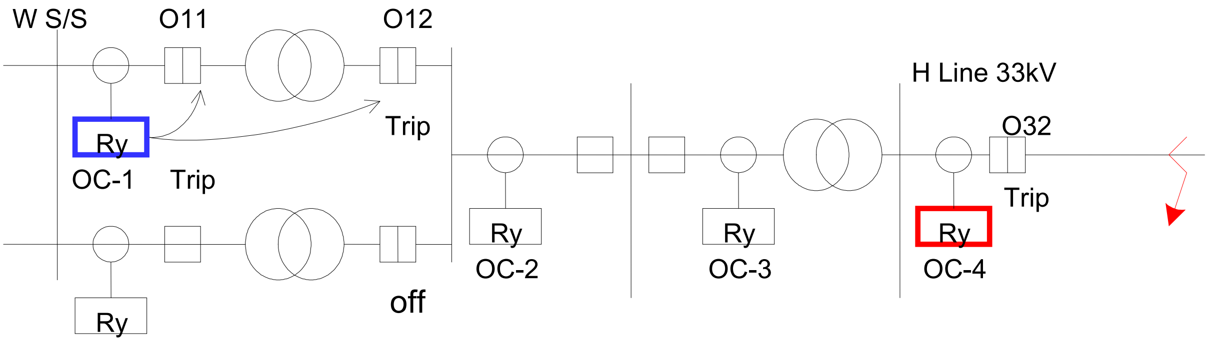


Figure 5.3-6 Power System Condition at Occurrence of Fault at End of Line

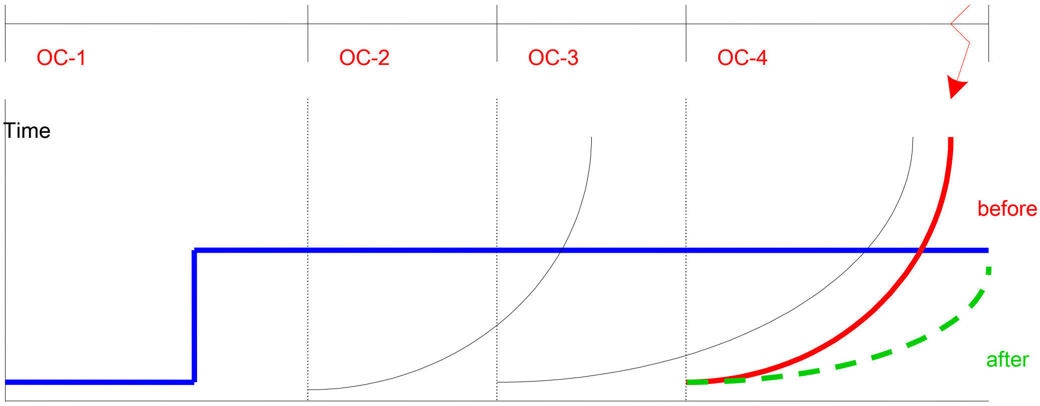


Figure 5.3-7 Coordination Diagram

(4) Coordination Issues of Distance Relay

(a) Coordination between Zones of Distance Relays

Zone 1 of distance relays in transmission system overheads lines is set typically to 80-85% of the protected line impedance and with instantaneous operating time. This setting criterion is required in order to assure sensitive coordination with instantaneous zone 1 of remote distance relays and with the main protection (Scheme I) of the next sections also. In this way close-in faults in remote lines such as B-C, connected to the remote bus B, are not detected by the local relay Ry-A (**Figure 5.3-8**). The *15-20%* resultant margin of the reach setting on the protected line impedance is enough to guarantee the sensitive coordination with Ry-B distance relay zone 1 of the remote line B-C.

$$Z_1 = 0.8\, Z_{line}$$

The application of relay distance Zone 2 in transmission system overhead lines is to detect faults at any point of the protected line. The ohmic setting of the reaching is calculated to it and as a direct consequence; faults at the remote bus are also detected by zone 2 providing so backup protection to the busbar differential protection.

The zone 2 setting criterion of distance Ry-A in **Figure 5.3-9** is to have sensitive coordination with the zone 2 of all line remote relays of the next section such as, for example, the Ry-B that is the only shown in the Figure. To achieve this, the ohmic setting of the reaching of Ry-A zone 2 is typically set to the impedance value of the protected line A-B plus *50-65%* of the impedance of the shortest line connected to the remote bus B:

$$Z_2 = Z_{line} + 0.65\ Z_{shortest\ remote\ line}$$

The resultant above Z_2 value shall be larger than or equal to *115-120%* of the protected line impedance A-B in order to can guarantee fault detection at any point of the protected line when current and voltage transformer and relay measurement errors are expected:

$$Z_2 \geq 1.2\ Z_{line}$$

This resultant reaching value for Z_2 is a minimum setting and as a consequence, a minimum backup for faults in remote lines, such as the B-C shown, is achieved. On the other hand, the indicated setting is very conservative to coordinate (to have selectivity) because "infeed or branch effect" (see **Chapter 3.1.3**) of remote lines and transformers connected to the remote bus B is not considered, when faults at these remote lines are postulated. A larger reach can be set if "infeed effect" is taken account. Computer programs will be necessary to optimize the setting of distance relays zone 2 in order to increase the setting taking into account remote lines and transformers "infeed effect".

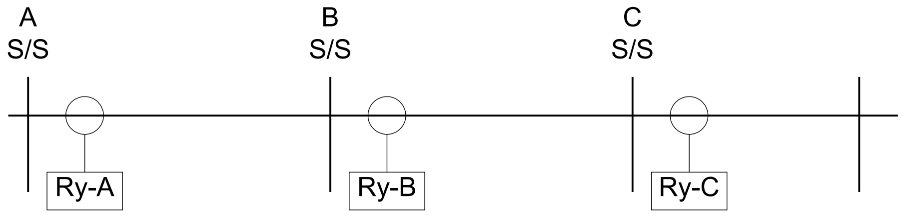


Fig.5-3-8 Power System to Coordinate between Relays

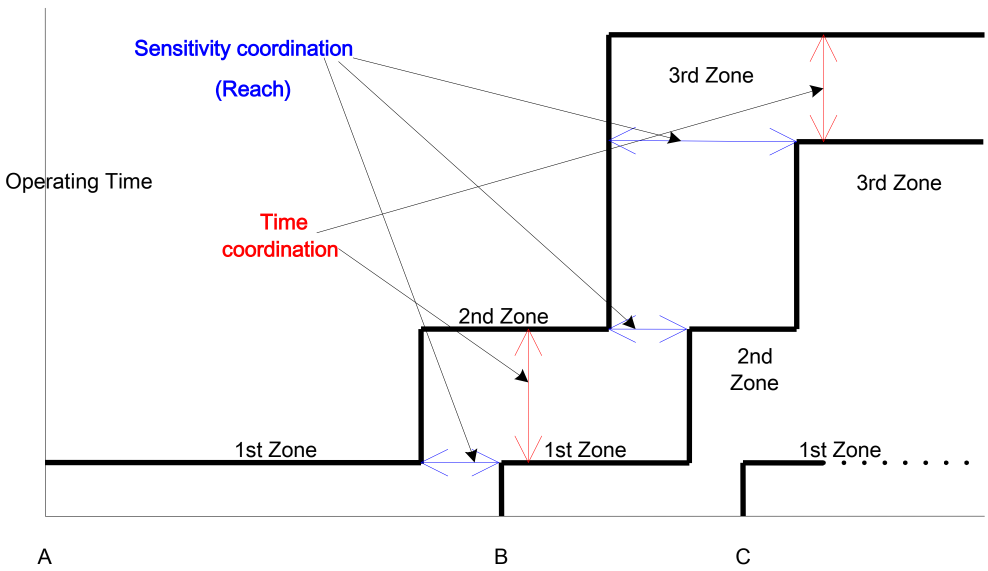


Figure 5.3-9 Coordination between Distance Relays

Coordination problems with remote relays zone 2 setting, such as Ry-B shown, arise when remote lines connected to the remote bus B in **Figure 5.3-10** are very short, i.e. typically the impedance is lower than 15-20% of the protected line A-B. In these special cases, specific setting considerations are to be provided; such as to minimize the reaching of zone 2 as much as possible (110-112% of the protected line impedance if the current and voltage transformers and relay errors permit do it).

For phase-to-earth faults at zone 2 locations but in remote lines such as the BC, the setting of the zero-sequence compensation factor k_0 is normally set equal to the zone 1 k_0 factor; i.e. to the same value as the k_0 factor of the protected line. This is because remote lines connected to B have a similar or equal k_0 factor value to the protected line.

Typical delay time setting of Ry-A zone 2 is 0.35 - 0.4 s. This delay time value is necessary to achieve time coordination with the breaker failure protection at the remote B substation which will normally be set to 0.175-0.2 s. The zone 2 setting must also provide time coordination with the time setting of the remote busbar coupling relay (double busbar arrangement assumed) that it is generally set at approximately 0.2 s. The resultant coordination margin of 0.2 s has generally been proven to be sufficient to achieve time coordination when modern digital relays and circuit breakers are used.

Zone 3 of Ry-A in **Figure 5.3-10** is overlapping the zone 1 and partially the zone 2 of the relay Ry-B. As a consequence it is set to have time coordination with zone 2 of remote relays such as Ry-B and also to achieve time coordination with the remote B busbar coupling relays (when applicable) for faults at whichever location in remote lines such as the B-C shown. To guarantee this, the Ry-A zone 3 reaching is typically set to 110-120% of the impedance that results to add the impedance of the protected line A-B and the impedance of the longest remote line connected to the remote bus B. It is formulated as follows:

$$Z_3 = 1.1\left(Z_{line} + Z_{longest\ remote\ line}\right)$$

In reality this setting cannot assure the detection of faults near to the end of the B-C line because of the “infeed effect” on the faulted line B-C of the remote lines connected to B (not shown in the Figure). Also, the “infeed effect” of the remote power transformers if existing in B, mean that the local relay Ry-A underreachs for faults in line B-C but near the substation C. The above calculation, although simple, is not optimized and generally shorter reaches for zone 3 are used with the result that distance relay Ry-A will not provide complete back up of the remote Ry-C for line fault locations. The above setting will normally coordinate with the zone 2 setting of all remote relays such as Ry-B in **Figure 5.3-10**.

As with zone 2, computer programs will be necessary to optimize the setting of distance relays zone 3 in order to increase the setting taking into account remote lines and transformers “infeed effect”.

Zone 3 reach must be set to permit the maximum line load current without trip. To accomplish this, an overload factor is assumed, t.ypically 115%-120% of the actual load current and at reduced voltage of 0.85 p.u. This setting criterion is conservative and it can be formulated as follows:

$$Z_{\min imum-load} = 0.85\,U_n \,/\left(\sqrt{3}\cdot 1.15\cdot I_n\right)$$

$Z_{minimum\text{-}load}$: Minimum load impedance i.e. for maximum load current
U_n: Nominal system voltage
I_n: Maximum permissible continuous line load current

The load current in front and behind the relay will generally sit in the region defined by the angle α which is typically assumed to be in the range: $-(35 \text{ to } 45)^o \leq \alpha \leq (35 \text{ to } 45)^o$ and $(135 \text{ to } 145)^o \leq \alpha \leq (215 \text{ to } 225)^o$. In order to accommodate out of step detection, it may be necessary to include a margin on the above zone $Z_{minimum\text{-}load}$. The zone 3 region must not overlap the load area. Quadrilateral characteristic distance relays have specific settings for resistive phase-to-earth faults reach which are generally set as $R_f = 20\,\Omega$, but other larger values can be used if no interference exists with the maximum load region.

Delay time setting for zone 3 is typically set in the range ***0.6 - 1.5 s*** depending on the utility practice. Time coordination with zone *2 (0.35-0.4 s)* is so guaranteed. Higher values are used when the zone 3 reach is set to detect faults on the secondary winding of the transformers. This large time value for the zone 3 delay time provides coordination margin in order to have selectivity with overcurrent relays of transformers for faults on the secondary side of the transformer.

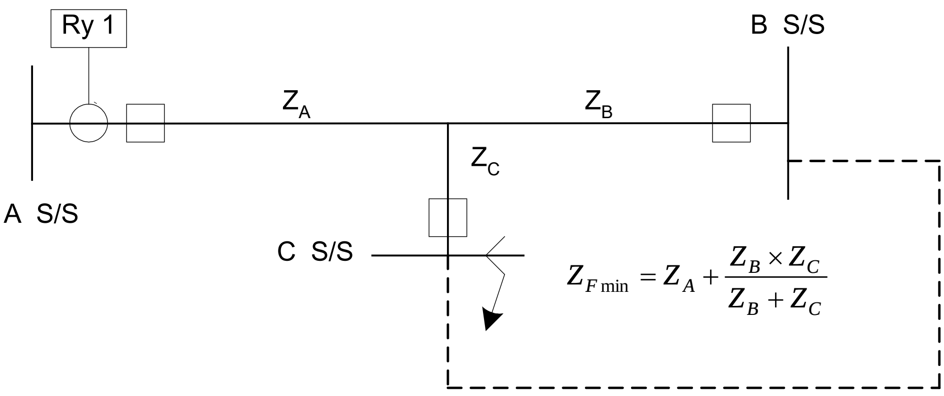


Figure 5.3-10 Minimum Impedance at Shortest Remote End Busbar Fault

(b) Coordination in Three-Terminal Line by Distance Relay

For distance protection coordination within zone setting and time setting of each relay located each remote terminal must be considered. And for some arrangements of 3 terminals, the requirements of distance protection coordination can make primary protection quite difficult and/or limited. In the case of distance protection with 3 terminals line, zone 1 setting should be 80 - 90 % of shortest line length of any remote terminal, according to requirement that zone 1 must not operate at any remote end busbar fault. Thus high-speed coverage of the line is limited to smaller zone.

Figure 5.3-10 shows a minimum impedance at C substation busbar fault for distance relay Ry1 with severe conditions, on the supposition that C substation is connected to B substation solidly, and in this case, the important point is that the impedance at C substation busbar fault for distance Ry1 relay is smaller than line length between A substation and C substation.

In the case that the impedance between C substation and B substation is known as Z_{BC}, the impedance at C substation busbar fault for distance relay Ry1 is following equation.

$$Z_{F\min} = Z_A + Z_C \frac{Z_B + Z_{BC}}{Z_B + Z_{BC} + Z_C}$$

In the parallel line, that with severe conditions is following formula. Refer to **Figure 5.3-11**.

$$Z_{F\min} = Z_A + Z_C \frac{2Z_B + Z_C}{2Z_B + 2Z_C}$$

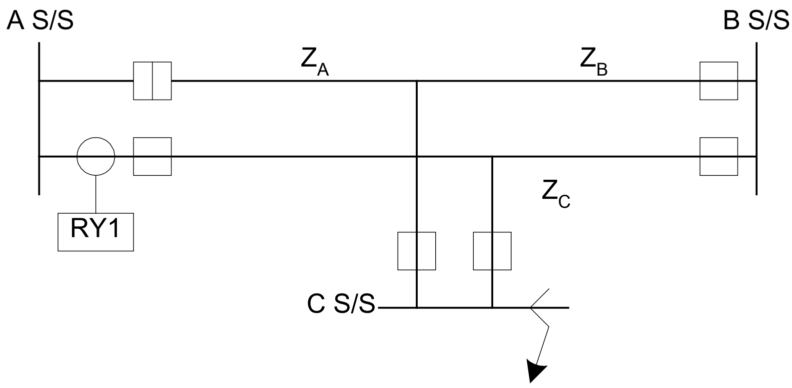
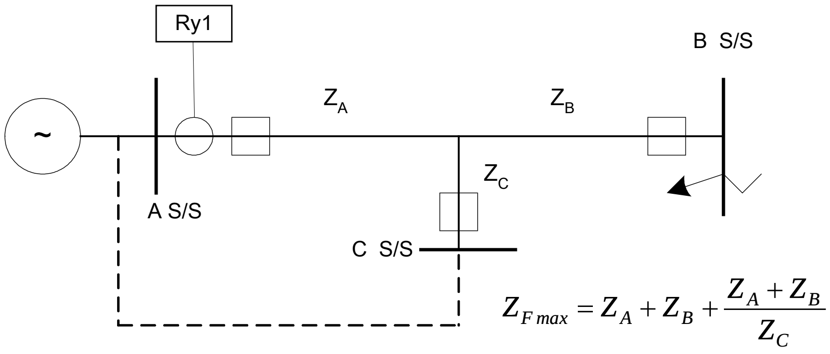


Figure 5.3-11 Minimum Impedance Seen by RY-1 in Parallel Line

As zone 2 must operate for any remote end busbar fault, the zone 2 setting must be longer than longest line length of any remote terminal including consideration of the effective impedance seen by the relay due to the infeed effect. **Figure 5.3-13** shows the example of infeed effect with the condition that the power sources of A substation and B substation have the same impedance.



$$Z_{F\,max} = Z_A + Z_B + \frac{Z_A + Z_B}{Z_C}$$

Figure 5.3-12 Maximum Impedance Seen by Ry1 at Longest Remote End Busbar Fault

In the case that the source impedance of A substation and C substation is known as Z_{SA} and Z_{SC}, the impedance at B substation busbar fault for relay Ry1 is following formula.

$$Z_{Fmax} = Z_A + Z_B + Z_B \frac{Z_A + Z_{SA}}{Z_C + Z_{SC}}$$

In the case of parallel line and C substation with no source, that is following formula. Refer to **Figure 5.3-13**.

$$Z_{Fmax} = Z_A + Z_B + Z_B \frac{Z_A}{Z_A + 2Z_C}$$

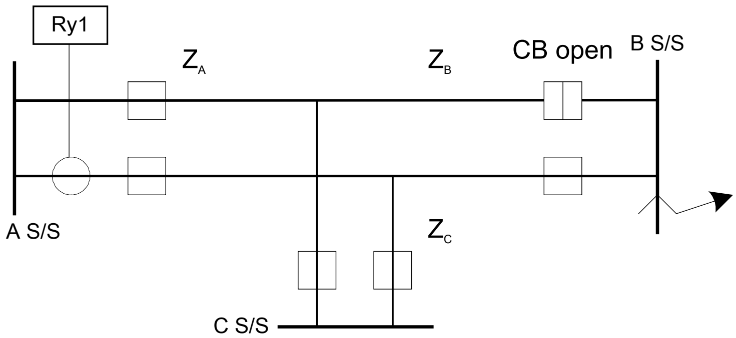


Figure 5.3-13 Maximum Impedance Seen by Ry1 in Parallel Line

In the case of **Figure 5.3-14**, current can flow out C substation for an internal line fault near the B substation. Thus distance relay Ry2 at C substation will see the internal fault as an external fault and will not operate until after CB B has opened.

In example of **Figure 5.3-15**, Ry1 zone 1 at A substation is set to 80 % of the length of the line to C substation, which is shortest length of the two remote substations. Ry1 zone 2 is set between 120 - 150 % of length to B substation which means it also extends beyond the reach of the Ry2 zone 1 at substation C. This also means that zone 2 of Ry1 relay overlaps zone 2 of Ry2 and hence the zone 2 timers must be coordinated such that Ry2 zone 2 will operate faster than Ry1 zone 2.

Thus protection of tapped and multi-terminal lines is more complex and requires specific data on the line impedances, location and type of tap or terminal, and fault data with current distributions for the various system and operating conditions. Most often except for small transformer load taps, these types of line are more easily protected by differential protection although requiring a communications link to do so.

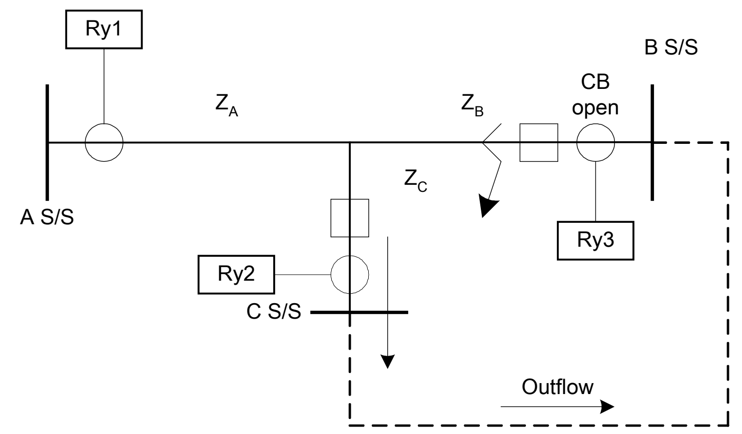


Figure 5.3-14 System Condition with Maximum Outflow at Internal Fault in Multi-Terminal Line

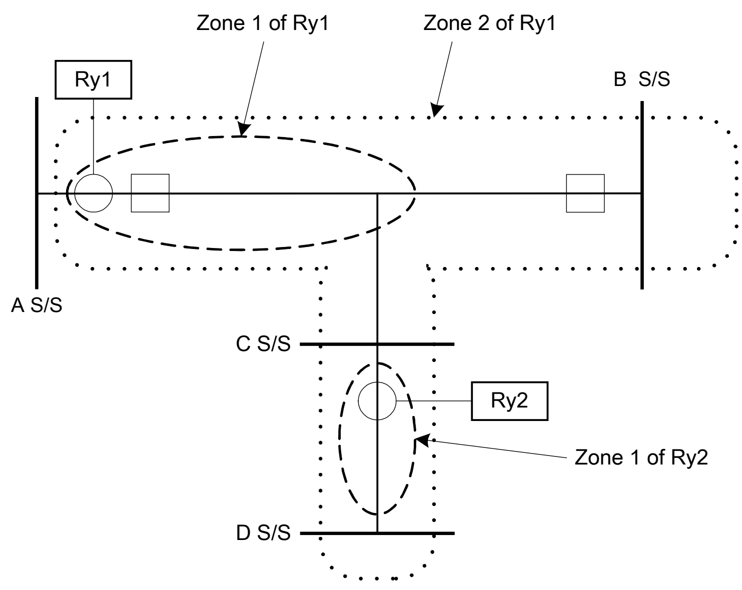


Figure 5.3-15 Example of Coordination Issue for Three-Terminal Line

(c) Coordination in Long-Short Line by Distance Relay

Distance protection must consider coordination of the zone reach setting and time setting of each relay located at each remote terminal as described in **Chapter 3.1.3**. The requirements of distance protection coordination may make backup protection quite difficult and/or limited for some line length arrangements.

As zone 2 must operate for remote end busbar faults as discussed in **Chapter 3.1.3**, zone 2 should cover all the protected line plus 20 - 50 % of the next shortest line in order to guarantee fault detection at any point of protected line when current and voltage transformer and relay measurement errors are expected.

In example of **Figure 5.3-16**, zone 2 of the distance relay Ry1 at A substation is set to 120 - 150 % of length to B substation, with the result that it covers beyond the zone 1 of the distance relay Ry2 at B substation and extends further beyond C substation. This also means that zone 2 of Ry1 relay overlaps zone 2 of Ry2 and hence the zone 2 timers must be coordinated such that Ry2 zone 2 will operate faster than Ry1 zone 2.

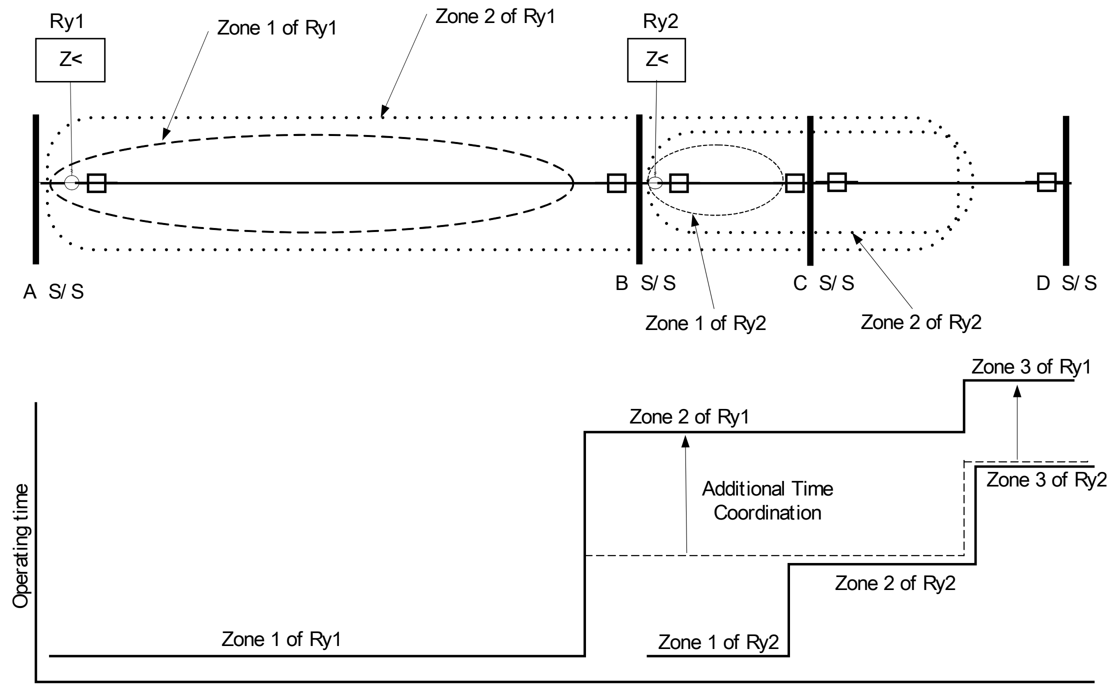


Figure 5.3-16 Example of Coordination Issue of Distance Protection for Long-Short Line

(d) Mutual Coupling

For significant mutually coupled transmission lines, which share the same right of way or have multi-circuit towers for all or a portion of the line length, a large measurement error might occur because the earth-fault current in the faulted line induces a voltage in the unfaulted line and it could cause maloperation of earth-fault distance relays.

Consider a parallel circuit in **Figure 5.3-17** that has common positive- and zero-sequence sources. In this case both lines terminate at a common bus at both ends of the lines and there are common sources of earth-fault current for both lines. For the fault at the location *h*, the apparent impedance seen by the earth-fault distance relay at AR is

$$Z_{AR} = hZ_{L1}\left(\frac{I_{AR} + k_{SA}I_{GA0} + k_{MA}I_{GB0}}{I_{AR} + k_{CA}I_{GA0}}\right) = hZ_{L1}\left(\frac{I_{ARM}}{I_{ARC}}\right)$$

Where,

$$I_{GA0} = 3C_{AO}I_{a0} = residual\ current\ in\ line\ A\ at\ relay\ AR$$

$$I_{GB0} = 3C_{BO}I_{a0} = residual\ current\ in\ line\ B\ at\ relay\ BR$$

$$k_{SA} = \frac{Z_{A0} - Z_{A1}}{3Z_{A1}} \qquad k_{MA} = \frac{Z_{M0}}{3Z_{A1}}$$

$$C_{A0} = \frac{I_{AR0}}{I_{a0}} \quad C_{A1} = \frac{I_{AR1}}{I_{a1}} \quad C_{A2} = \frac{I_{AR2}}{I_{a2}}$$

$$C_{B0} = \frac{I_{BR0}}{I_{b0}}$$

Let’s defining the current ratio

$$Measurement\ index = 1 - measurement\ error = \frac{I_{ARM}}{I_{ARC}} k_e$$

For accurate distance measurement, the measurement index *Ke* must be as close to unity as possible. If this term can be forced to a value of unity, the distance measurement will be exactly right. However, since the denominator may not equal the numerator, there may be an error in the distance measurement. The error is a function of the constants k_{SA} and k_{CA} as well as the parameters associated with the mutual coupling of the nearby line, namely, k_{MA} and I_{GB0}. Consequently, the relay underreaches when I_{GB0} is in phase with $I_{AR}+ I_{GA0}$ and overreaches when I_{GB0} is out of phase with $I_{AR}+ I_{GA0}$. It has been known that underreaching as much as 25% may occur. Large overreach errors will occur under certain switching conditions.

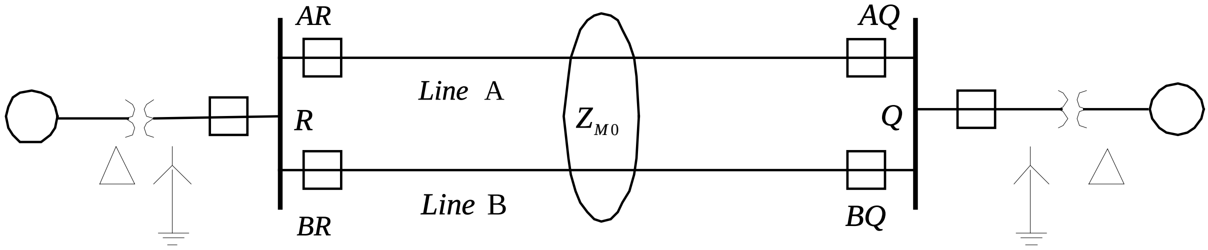


Figure 5.3-17 Parallel Line with Common Sources for Both Positive- and Zero-Sequence Networks

(e) Examples of Miscoordination

1) Miscoordiation due to Branch Effect

Figure 5.3-18 shows a part of the power system in Okinawa electric power company. A single line to ground fault occurred at the lightning arrester that protected the start-up transformer at 'M' power station and evolved to a three phase to ground fault. The transformer protection didn't operate due to CT saturation and therefore, it was not cleared by the transformer protection. The remote back protection at the 'I' end operated, but the remote backup protection at 'N' and 'T' ends didn't operate because of the setting in which branch effect wasn't taken into consideration. As a result, some 70% of this transmission network was blacked out.

Figure 5.3-19 shows the impedances seen by the relay at each substation which were analyzed by numerical simulation. The relay at N substation that should operate as a remote backup protection, but it didn't operate due to branch-effect. The relay at T substation under-reached by branch-effect as well (The dotted lines in **Figure 5.3-20** are the setting conditions at the time of the occurrence of the fault.). The large-scale blackout was brought because the fault was finally cleared by the remote backup relay at I substation. As a result, the setting values of the distance relays were improved to be the solid lines in **Figure 5.3-20**. The setting values are set in consideration of the branch effect.

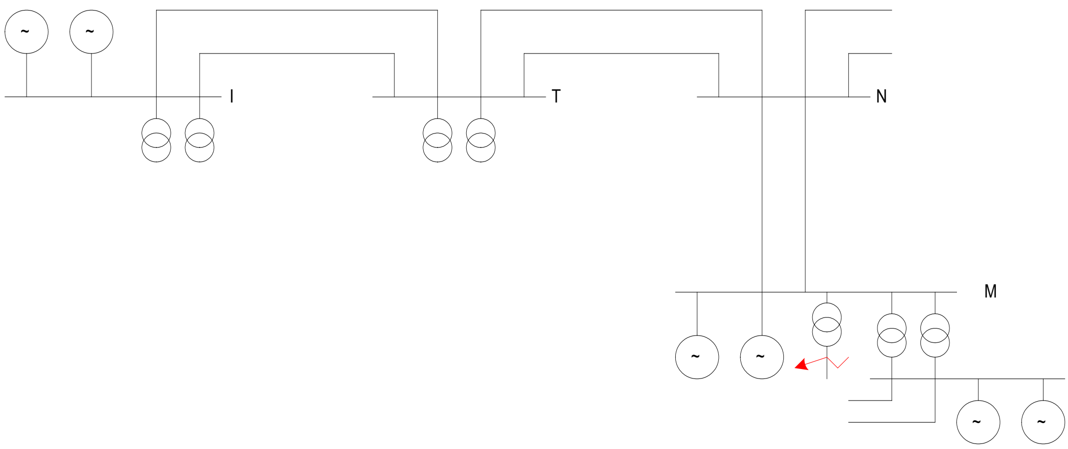


Figure 5.3-18 Condition of the Power System at Occurrence of the Fault

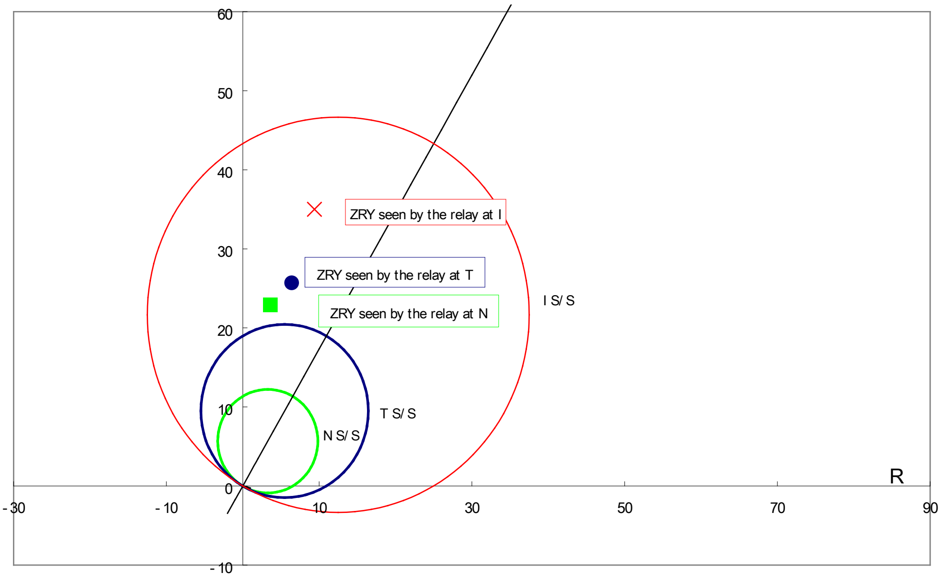


Figure 5.3-19 Impedance Seen by the Relays

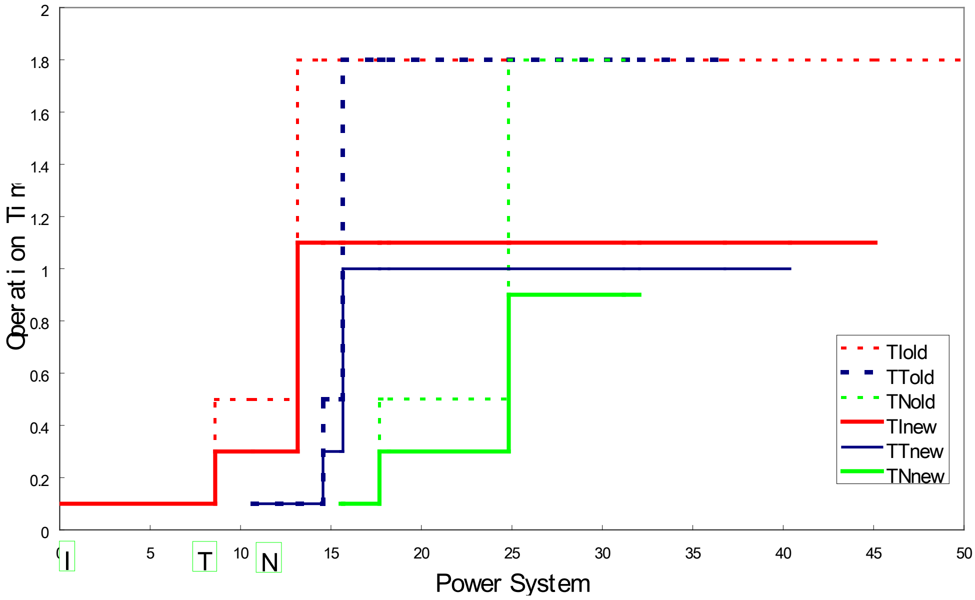


Figure 5.3-20 Coordination Diagram

2) Overreach against a Phase-to-Phase Fault at the Busbar

Figure 5.3-21 shows the radial power system with one generator system. This parallel line is protected by the distance relays. The zone 1 of the 'ca' phase element of the distance relay at the sending end operated unwantedly at the occurrence of phase-to-phase fault of phases 'ab' at the busbar of the receiving end. Since the setting of the mho relay which is a directional element was large due to the large short circuit capacity of the substation busbar, it operated unwantedly due to the over-reach of the lead phase as shown in **Figure 5.3-22**. The setting value was set so that the direction element might not over-reach as this measure.

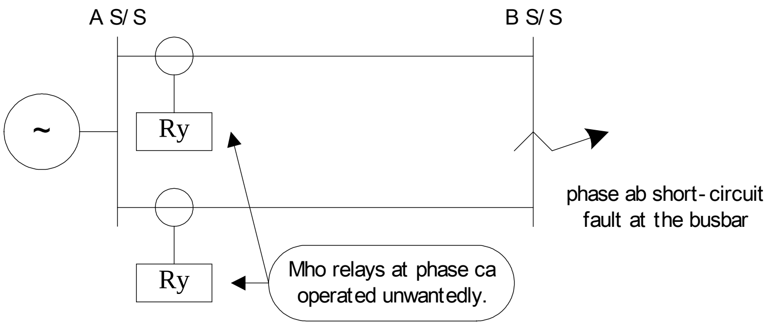


Figure 5.3-21 Faulted Power System

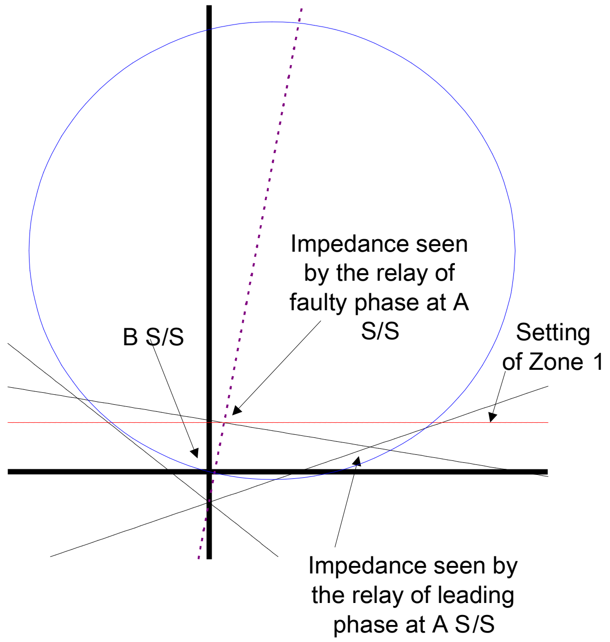


Figure 5.3-22 Impedance Seen by the Relay against the Remote-End Busbar Fault

5.3.3 Blocking of Transverse Differential Relay against a Busbar Fault

Parallel lines sharing the same towers may be protected by transverse differential relays. Transverse differential relays do not require a telecommunication link (as per general current differential relays) in order to protect parallel lines. The transverse differential relay uses voltage and current from the local end only to determine which is the faulty line.

In the case where the parallel lines are connected with a double busbar substation when a busbar fault occurs affecting one line, the remaining current flow in the other line will be seen as a transverse differential current which would cause trip of the second line as well. In order to avoid this unwanted operation, the transverse differential relay is blocked by the busbar protection trip.

5.4 Coordination of Busbar Protection

5.4.1 Coordination between Main and Backup Relays for Busbar

Where double busbar arrangement substation with coupling circuit breaker is applied, the protection for the buses coupling circuit (distance or overcurrent) can be considered as a partial backup function of busbar differential relay. For faults on bus 1 or bus 2 with failure of the respective differential relay, the coupling protection is capable to operate isolating the faulted bus from the healthy bus. As indicated in Chapter 3.3, the operating time is set to approximately 0.2 s as a definite time setting.

5.5 Coordination of Transformer Protection

Large transformers are generally protected by current differential relays which do not need any special coordination as Scheme I relays. In this report, only coordination between backup protection for transformers and other protection is considered.

5.5.1 Overcurrent Protection

Backup overcurrent protection located at the high voltage side is intended to detect all terminal faults of a transformer. Hence the pick-up setting must be less than the minimum fault current for a fault on the low voltage terminal. If overcurrent backup is intended to detect faults on the feeders on the lower voltage, the faults at the far end of the feeder must be assumed for minimum fault current. As these are Scheme II protections with unrestricted zone of operation other than by pick up setting sensitivity, coordination with the main protection of the LV feeders is required.

High set overcurrent protection is intended to detect faults on the bushing of the high voltage side and to trip quickly. It is sometimes categorised as main protection rather than backup protection. The pick-up setting must be greater than both the maximum inrush current or be immune to transformer inrush currents. The setting must also be greater than the maximum fault current at lower voltage side so as not to detect faults on the feeder of the lower voltage side.

When overcurrent backup is intended to detect faults on the low voltage side it should be used with delay timer as mentioned above. In that case it is possible to set pick up setting smaller than the magnitude of the maximum inrush current if the timer is long enough to avoid unwanted operation considering attenuation of inrush current. The setting philosophy for overcurrent backup protection is shown in **Figure 5.5-1**.

The magnitude of the inrush current varies with the capacities of transformers and with the earthing methods etc. Generally the per unit inrush current magnitude becomes smaller and the time constant of DC component of inrush current is longer for larger transformers but must be verified by the manufacturer for each transformer in order to know the exact value of inrush current.

If single phase auto reclosing is applied to feeder protection the delay timer for zero sequence overcurrent must be longer than the dead time added to the short circuit period in order not to operate during the dead time.

Overcurrent backup is provided on the lower voltage side of the transformer either as the backup protection for the lower voltage lines and bus bars or as backup to the transformer protection itself. In addition, the difference in fault current magnitude on the high voltage side to lower voltage circuit should be considered for the setting. If the backup OC must not operate for the external fault in lower voltage circuit, the pick-up setting must be greater than the magnitude of the maximum fault current at the lower voltage circuit. This may make it difficult to choose the pick-up setting.

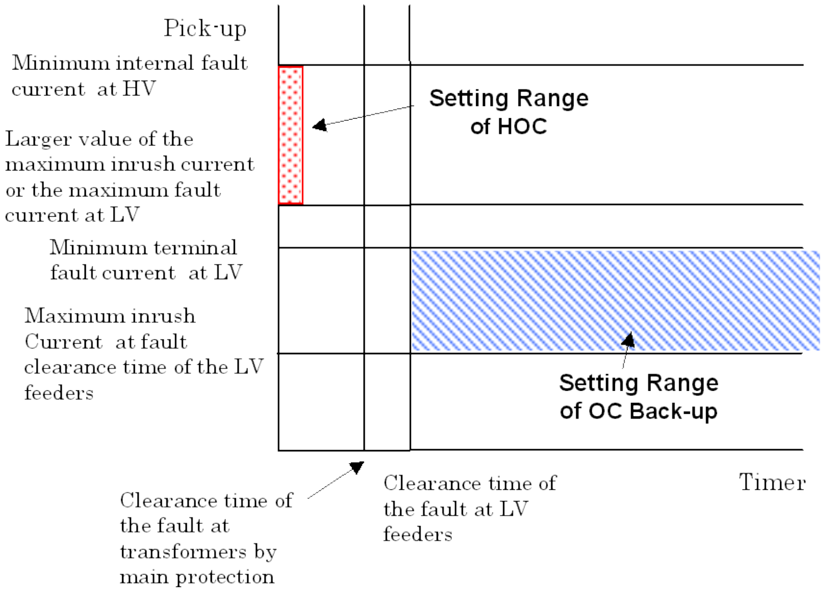


Figure 5.5-1 Setting Range of OC Backup

5.5.2 Distance Protection

If zone 1 is set to detect only internal faults, for example it is set to 80% of the transformer impedance, it is possible to apply distance protection as second main protection without any delay timer. In this case, zone 2 will cover the whole transformer and the feeders. (If there are any sources on the LV side distance protection can be installed either on the LV side or on both sides.) It should be noted that the phenomena of faults on the LV side (HV side if distance protection is allocated on the LV side) is different from the phenomena of normal line faults. Therefore some additional consideration is necessary for schemes or for settings.

(1) Star-Delta Configuration

Figure 5.5-2 shows fault current when a phase-to-earth fault occurs in Delta side at star-Delta configuration transformer. (For simplicity voltages at both side is assumed as the same)

It is clear that no zero-sequence current flows in star side and the fault looks like a phase-to-phase fault on the star side, although the actual fault in delta side is a phase-to-earth fault. Depending on the impedance of the earthing transformer, it can be difficult for distance protection to detect the fault. **Figure 5.5-3** shows the fault current distribution for a phase-to-phase fault on the delta side of a star-delta transformer.

It is also clear that no zero-sequence current flows in star side although the fault is similar to a phase-to-earth fault on the star side. Consequently it may be necessary to require operation of the earth fault overcurrent element in addition to the phase-to-earth distance element in order to confirm the fault is an earth fault. That logic is needed to be removed from the distance protection for transformer backup.

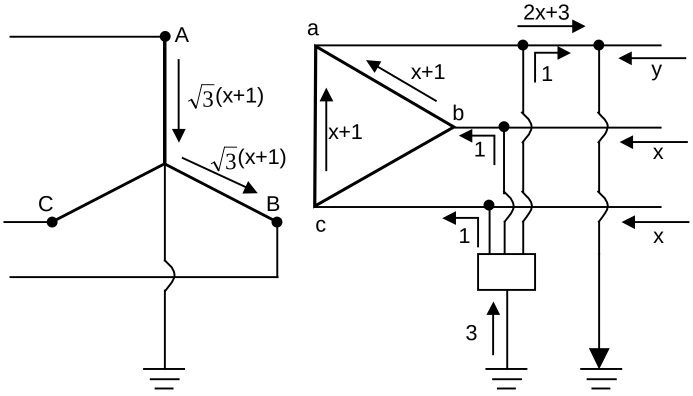


Figure 5.5-2 Fault Current at Phase-to-Earth at Delta Transformer Side

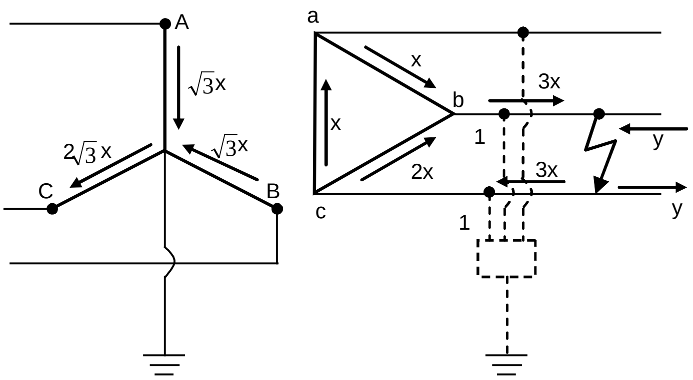


Figure 5.5-3 Fault Current at Occurrence of Phase-to-Earth Fault at Delta Transformer Side

(2) Auto-Transformer (Including Star-Star Configuration)

Figure 5.5-4 shows example of the fault current when a phase-to-earth fault occurs at lower voltage side of an auto-transformer. The direction of the fault current can be different with the parameters and with fault points.

Faulted phase and fault mode is identical in both sides. However zero sequence current in high voltage side and the zero sequence current in low voltage side are different. Therefore phase-to-earth distance measurement may have an error for phase-to-earth faults because of incorrect zero sequence compensation. It is necessary to take the current from earthing point or from delta windings in order to measure the distance correctly by zero-sequence compensation.

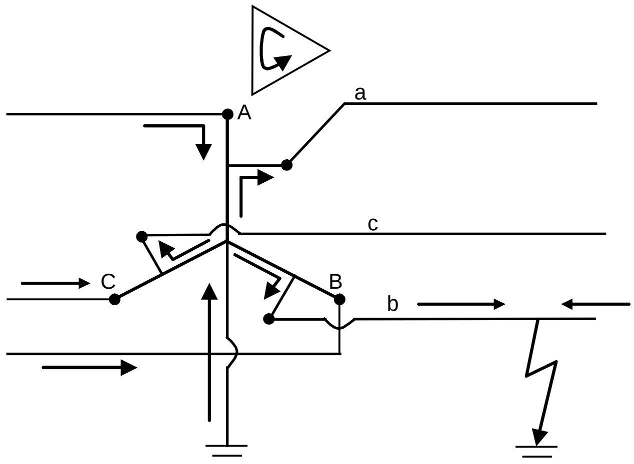


Figure 5.5-4 Fault Current at Occurrence of Phase-to-Earth Fault at Delta Transformer Side

(3) Remote Busbar Backup Protection by Transformer Backup Distance Relay

Transformer backup distance relays (zone 2) are sometimes applied for remote busbar backup protection as shown in **Figure 5.5-5**. There is no significant difference from the remote backup of line protection except as mentioned in section (2). However, it should be noted that zone 2 may cover significantly beyond the B substation along the lines to C and D substations because the impedance of the transformer is quite large. This is a similar condition to a long line with no transformer between A and B followed by short lines B-C and B-D. Therefore the coordination between this zone2 and the line protection should be carefully considered.

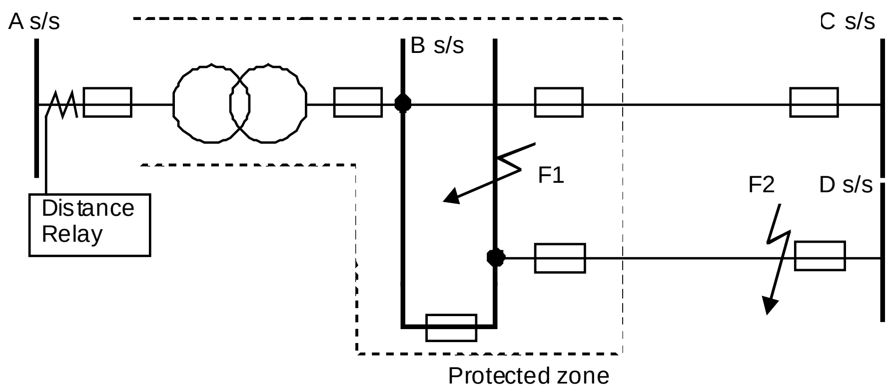


Figure 5.5-5 Busbar Remote Backup Protection

5.5.3 Earth Fault Overcurrent Protection for Transformers

(1) Definition of Neutral Current Protection and Purpose of This Section

In this report NCP (Neutral Current Protection) for transformers is defined as earth-fault protection using the neutral current of the transformer as shown in **Figure 5.5-6**.

NCP is sometimes applied as final backup protection for feeders. However it is difficult to coordinate NCP with feeder protection, which could cause problems. In this report, the points to be considered for the coordination between NCP and feeder protection is summarised. In this report NCP is assumed as IDMT type because coordination of IDMT is more complicated than definite time delay type and the principle for IDMT type is relatively easily applied to definite time delay type.

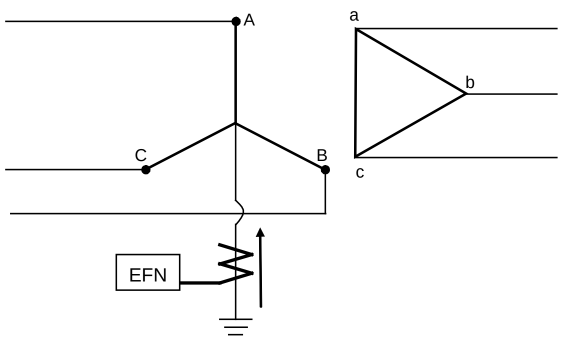


Figure 5.5-6 Definition of NCP Relay

(2) General Principles for the Setting of NCP

a) NCP must not be operated by inrush current

b) NCP should be sensitive enough to detect a fault as a backup protection and should operate after the line protection. The requirements of NCP for the maximum fault resistance to be detected and zone to be protected should be clarified for which has a higher priority of operation or non-operation as follows:

b-1) The setting is sensitive enough to detect an earth fault with the maximum fault resistance (Smaller than the fault current for the maximum resistance at the farthest point to be protected)

b-2) The setting is high enough not to operate for a fault with the minimum fault resistance that NCP must not operate for, at the nearest point to be protected

5.6 Coordination between Line Protection and Busbar Protection

5.6.1 Coordination Issues with Line Protection

If busbar protection fails to operate, zone 2 of remote-end distance relay and directional relays will provide backup protection. A disadvantage of this solution is apart from the long trip time (busbar protection will clear a fault in about 100 ms and distance protection will clear a fault in about 500 ms) is that all lines will be disconnected to the remote stations and thereby removing more transmission lines and loads than is actually necessary, in particular, when it is tapped lines.

The backup fault clearance time is about 500 ms. Therefore, the high voltage equipment should be designed to withstand full fault current during 0.5 seconds. A failure to operate of a busbar protection results in a contingency that is more severe than generally anticipated in the system planning criteria and in the technical specifications for the generating units. Generally the larger generators have undervoltage relays that disconnect the generator from the network in case of failure of the busbar protection to operate.

5.6.2 Coordination between Bus Coupler Protection and Local Distance Protection

When a fault happens within the reach of zone 1 of line distance relay, both line distance relay and bus coupler protection relay, to which either overcurrent relay or distance relay is applied, will pick up. Obviously zone 1 of line distance relay should trip the breaker faster than the bus coupler gives the trip command.

Time coordination of the buscoupler protection must consider the tripping time of the zone 1 of the distance relay, the circuit breaker operational time and the reset time of bus coupler protection relay itself.

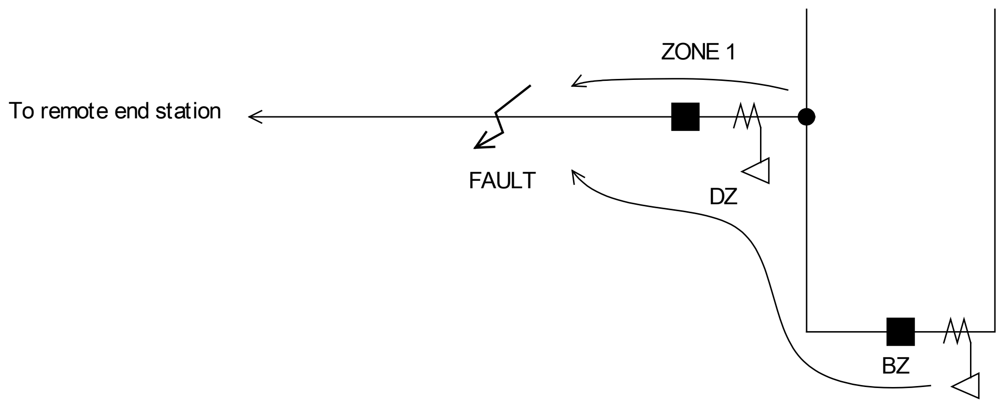


Figure 5.6-1 Coordination between Bus Coupler Protection and Line Distance Protection

5.6.3 Coordination between Coupling Circuit Breaker Relays and Line Distance Relays

Reference to **Figure 5.7-16** it is also necessary for the following explanations. Overcurrent relays have been extensively used in the past to protect the coupling circuit at double busbar substations. Typically overcurrent and earthfault inverse time functions were used. Distance relays are applied at many applications where busbar VTs are available. Overcurrent and earthfault functions are also used but with combined inverse and definite time protection functions where busbar VTs are not installed.

Coupling circuit breaker BZ protection function acts as a partial backup protection on the differential busbar relay. Faults at one bus with failure of the corresponding differential busbar relay permits the coupling circuit breaker protection to quickly detect the fault and trip the coupling circuit breaker. This actuation permits the healthy bus to remain in service.

When definite time overcurrent function is used as protection, this is typically set to detect fault at buses. The overcurrent pick-up value ($I_{pick\text{-}up51}$) is calculated as the minimum two-phase short-circuit at busbar ($I_{cc\_ph\text{-}ph}$). Some safety margin (K) is to be used:

$$I_{pick\text{-}up51} = K \cdot I_{cc\_ph\text{-}ph} \qquad K = 0.85\text{-}0.9 \text{ (Safety margin)}$$

For earthfault function the setting criterion for pick-up ($I_{pick\text{-}up51N}$) is to apply a safety margin (K) to the minimum short-circuit neutral (residual) current ($3I_o$), for single phase-to-earth or double phase-to-earth faults ($3I_{o\_\mathrm{ph\text{-}gnd}}$) at busbar location:

$$I_{pick\text{-}up51N} = K \cdot 3 \cdot I_{o\_pg\text{-}gnd}$$

The delay time is usually set to 0.2 s. This delay time needs to be set to assure time coordination with line instantaneous distance relays (backup or Scheme II protection) and with line main protection (Scheme I). However this time setting also needs to be coordinated with remote distance relays zone 2 time in order to guarantee selectivity when protective/communication failure is postulated or for faults in busbar with simultaneous failure of the busbar differential protection. Zone 2 time is usually set at 0.4 s and the resultant 0.2 s coordination margin is adequate when modern digital relays and circuit breakers are employed.

The inverse time operation curve for coupling circuit protection is normally set to coordinate with zone 2 of line distance relays. In **Figure 5.6-1** time coordination is required with zone 2 of DZ for faults at whichever location of all lines such as the illustrated. For this, it is necessary to select the pick-up value and the time characteristic in such a way that the resultant operating time be 0.6-0.65 s for faults at 80-85% of the line length.

Coordination with overcurrent relays in busbar coupling circuit is not an easy task. Two problems arise:

- Different length of lines connected to the substation
- Different potential short circuit current magnitudes depending on the generation scenarios throughout the day.

A good alternative to overcurrent relay is the use of distance relay in the busbar coupling circuit. Coordination is more easy and secure using distance relay than overcurrent relays. The use of this relay in transmission power system is quickly increasing at some countries.

Three busbar potential transformers are required to feed the distance protection in addition to the three current transformers for the busbar coupling circuit. Two forward zones and two reverse zones are usually considered although the best solution is to use an impedance type characteristic; i.e. with the centre of the circles for zone 1 and zone 2 located in the origin of the R-X diagram.

With mho type characteristic, zones 1 and 2 are set forward and zones 3 and 4 are set reverse. Zones 1 and 3 are equally set to detect faults at busbar; in this way the reach to be set is calculated to not overreach the distance relay zone1 impedance of the shortest line that is connected to the substation. For zones 1 and 3 the operating time is set at 0.2 s in order to have time coordination with main and backup instantaneous line protections for line faults close to the substation.

Zones 2 and 4 are equally set to coordinate with line distance relay zone 2 for faults at all lines that are connected to the substation; i.e. all lines such as the illustrated in **Figure 5.6-1**. To achieve this, the operating time of the busbar coupling circuit breaker distance protection is set at 0.6 s value if the zone 2 of the line distance relays is set at 0.4 s. Sometimes it is necessary to sacrifice the fault detection at all point of the lines by zones 2 and 4 of the coupling circuit breaker protection at specific line fault locations, if selectivity has to be guaranteed. Inversely coordination could be sacrificed if the fault detection at all points along the line needs to be guaranteed. The number of protective devices and number of communication systems will be the factors that determine if complete fault detection or selectivity is to be sacrificed.

5.6.4 Coordination between Bus Coupler Protection and Remote End Distance Protection

When a fault happens on the busbar while the main protection is blocked, zone 2 of line distance relay at remote end substation will detect this fault. If the transmission line is double circuit, both distance relays at remote end on each circuit will pick up. Unless the bus coupler protection trips faster than distance relay at remote end, distance relays at remote end will trip both circuits. It will result in the separation of network, and may cause the complete shut down of the substation at the worst case as shown in **Figure 5.6-2**.

To prevent this, bus coupler distance relay should trip faster than remote-end zone 2 distance relay, in such the way, time coordination must be carried out.

Typically, the tripping time of bus coupler distance relay is 240 ms and that of the zone 2 of line distance relay is 340 ms. For the above time coordination, circuit breaker tripping time and the reset time of distance relay must be taken into account.

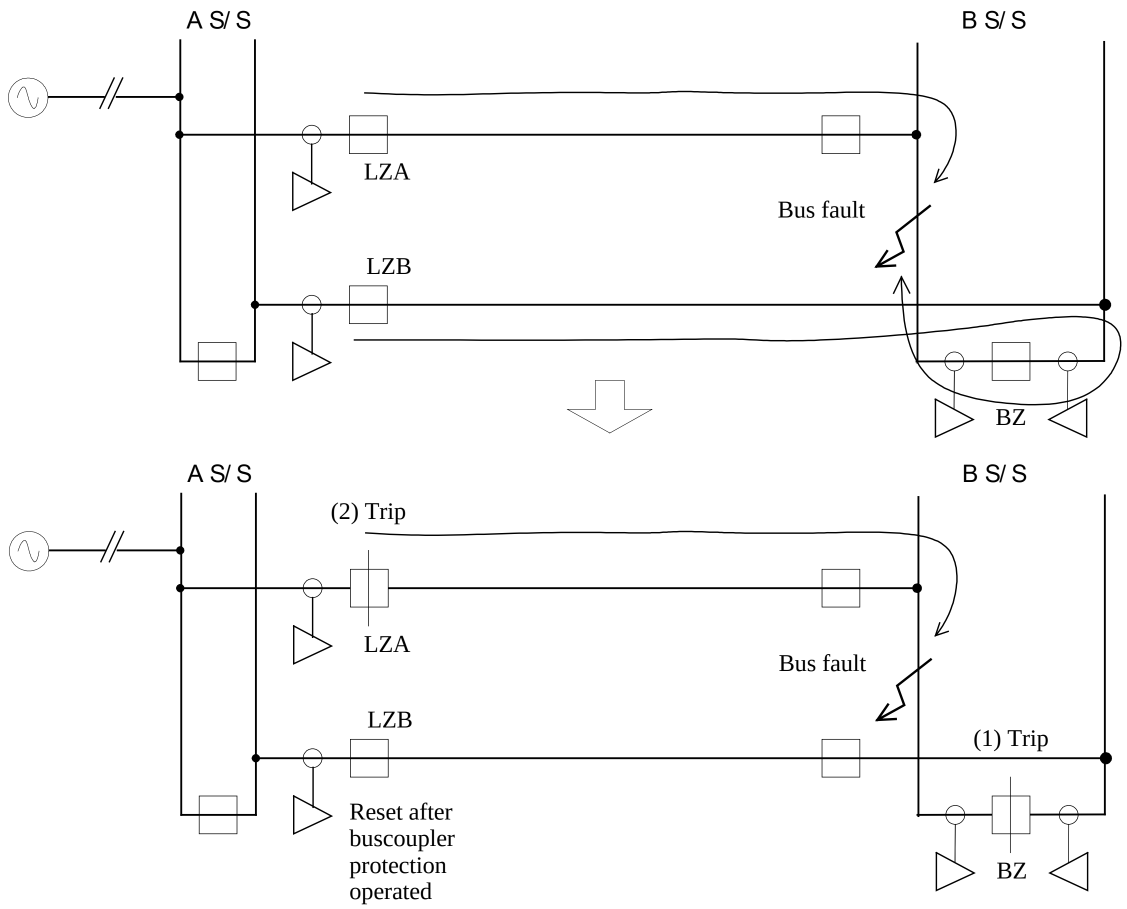


Figure 5.6-2 Coordination between Bus-Coupler Protection and Remote Line Distance Protection

5.7 Coordination between Line Protection and Transformer Protection

5.7.1 Basic Coordination between Distance Relay for Line and Overcurrent Relay for Transformer

Generally speaking, it is not easy to coordinate overcurrent relay with distance protection because the principle of the operation is different. The operating zone of overcurrent relays varies with the source impedance etc, although the operating zone of distance protection is fixed. However it may be also difficult to avoid the miscoordination because overcurrent is applied for backup protection for transformers quite widely and zone 3 of line protection is also applied widely. **Figure 5.7-1** shows an example in which coordination between the distance relay at A substation and OC relay at B substation should be considered.

F1 and F2 are assumed as the fault at bushing of transformer at B substation side and B(L) substation respectively. Usually F1 is in the protected zone of zone 2 of the distance relay and F2 is outside of zone2 and in the zone 3. In order to minimize de-energized zone, overcurrent backup needs to operate earlier than the distance relay as shown in **Figure 5.7-2**. T2 and T3 are operating time of distance relay for zone 2 and zone 3 respectively.

Therefore the timer should be set so that the operating time for the minimum fault current at F1 is shorter than T2 and the operating time for the minimum fault current at F2 is shorter than T3.

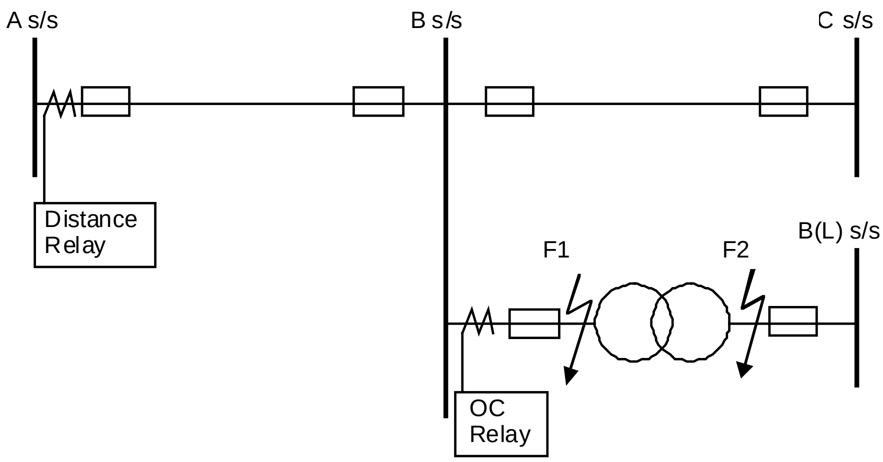


Figure 5.7-1 Fault Current at Occurrence of One-Line-to-Earth Fault at Delta Transformer Side

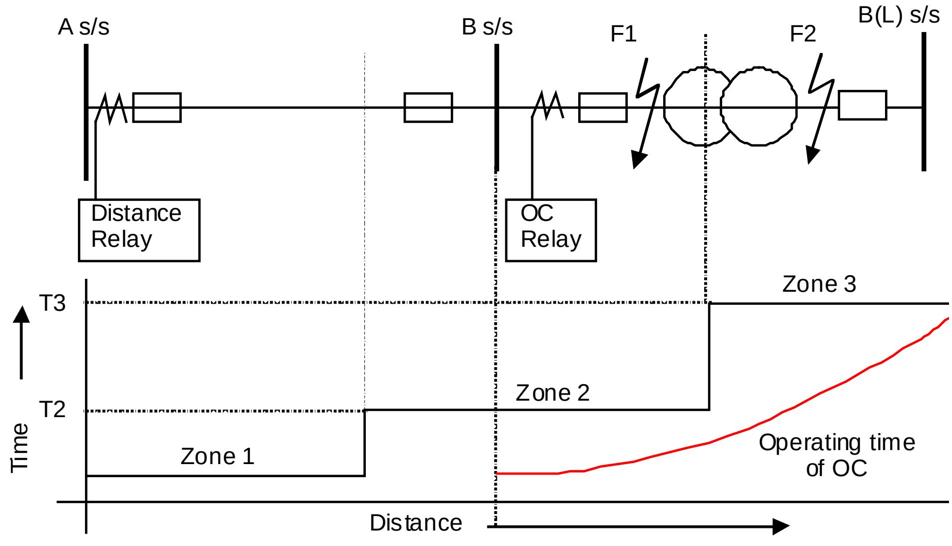


Figure 5.7-2 Coordination between Distance Protection and Overcurrent Protection

5.7.2 Basic Coordination between Earth Fault Overcurrent Protection for Transformer and Distance Protection

Firstly, it is necessary to decide the maximum fault resistance that the distance protection should detect. Distance protection must operate faster than earth fault overcurrent protection using neutral current of a transformer (NCP) for every fault which the distance protection should detect (**Figure 5.7-3**). Therefore the following should be confirmed.

1) Operating time of NCP for a fault which gives the maximum fault current (e.g. fault point is closest to B substation, Minimum source impedance), should be longer than the fault clearance time by the final distance backup protection. (e.g. Zone 3)

2) However, condition "A" would be impractical in some cases. Alternatively if the following condition is possible, the coordination should be good enough in practice.

I) Operating time of NCP for a fault which gives the maximum fault current (e.g. fault point is closest to B substation, Minimum source impedance), should be longer than the fault clearance time by zone 2 distance backup protection.
II) Operating time of NCP for a fault at the remote busbar which gives the maximum fault current for the fault in an adjacent line, should be longer than the fault clearance time by the final distance backup protection (e.g. Zone 3).

3) Sufficient sensitivity to detect the fault at the farthest point to be protected, with the maximum fault resistance to be detected

4) Operating time must be slower than the dead time of auto-reclosing when single phase auto-reclosing is applied. Or it must be insensitive enough not to detect the $3I_0$ caused by the unbalanced condition These conditions must be checked for every distance relay which is allocated to feeders connected to a busbar.

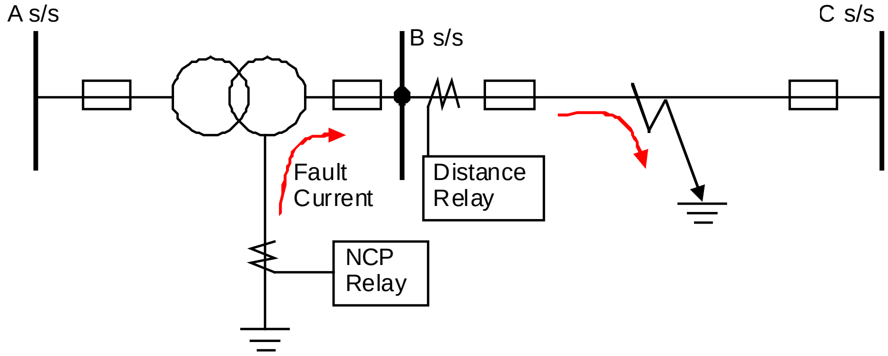


Figure 5.7-3 NCP Relay and Distance Relay

5.7.3 Basic Coordination between Earth Fault Overcurrent Protection for Transformer and Feeder Overcurrent Protection

In this section overcurrent is assumed as backup feeder protection. Therefore we are concerned with the coordination between backup protections. Since generally the effect of tripping of a transformer is larger than the tripping of a line, neutral current protection should operate only when the overcurrent backup doesn’t operate. The simplest method for the coordination of neutral current protection as final feeder backup is to set the sensitivity low enough not to operate for inrush and set the timer much slower than the overcurrent’s operating time. If this is difficult because of the requirements from the point of view of the operation of the network, then coordination would be so complicated as to be difficult to find a solution which can be applied for any cases under any conditions. Nevertheless it is useful to give the general idea which can be applied for many cases in this report.

(1) In Case Only Load is Connected

Fault current flows in the three phase circuit as shown in **Figure 5.7-4**. As demonstrated in the figure, fault current in the faulted phase is larger than the fault current which the neutral current protection relay detects. It is usual that the neutral current protection is more sensitive than the overcurrent backup, however this difference in the measured fault currents should be taken into consideration for the margin of the sensitivity in order to realise better sensitivity coordination. This is generally easy to do because the pick-up setting of the overcurrent backup must be larger than maximum load current. This can be explained using a sequence network model as shown in **Figure 5.7-5**.

The impedance of the load is so large that it can be expressed as an open circuit. The neutral current protection relay detects $3I_0$ and the overcurrent backup in the faulted phase detects I_F which is equivalent to $I_1+I_2+I_0$. It is clear that $I_F>3I_0$ in this case because all current in the positive sequence circuit and the negative sequence circuit goes through the side in which the relay is connected. The difference between $3I_0$ and I_F varies depending on the ratio of I_0 between B substation side and C substation side. It is important to ensure that the overcurrent backup operates faster than the neutral current protection for faults close to B substation.

When N transformers are connected to the B substation the current that each neutral current protection detects becomes *1/N* of the total $3I_0$. Therefore, the setting of the neutral current protection needs to be *1/N* of the result derived from the above explanation.

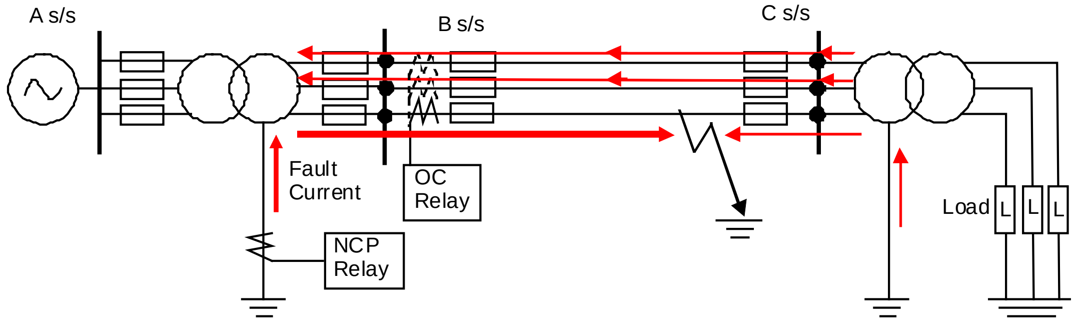


Figure 5.7-4 NCP Relay and OC Relay (One-End Infeed)

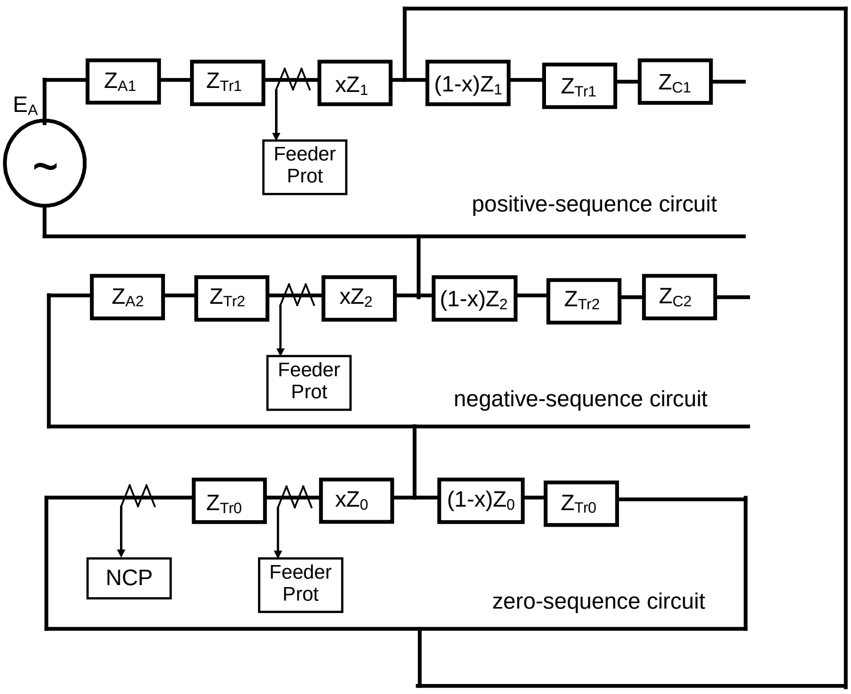


Figure 5.7-5 Equivalent Sequence Network Connecting NCP Relay and OC Relay (One-End Infeed)

(2) In Case There Are Generators on Both Sides

When there are generators on both sides as shown in **Figure 5.7-6** the equivalent sequence network becomes **Figure 5.7-7**. In this case, the relationship between the magnitudes of $3I_0$ and I_F in the faulted phase is unknown, being determined by the fault points and by the impedance of the network including the reverse impedance behind A substation and C substation. The effect of the reverse impedance becomes large when the protected line is short and small when the protected line is long.

For example, if a total of 10 units of fault current are split into 9 and 1 units in the zero sequence circuit for B substation side and C substation side respectively and are split into 7 and 3 units in the positive and negative circuits, I_F will be 23 (=9+7+7), $3I_0$ will be 27. Therefore $3I_0$ is larger than I_F. However, on the contrary, if fault current is split into 1 and 9 units for B substation side and C substation side respectively in the zero sequence circuit and is split into 3 and 7 units in the positive and negative circuit, I_F will be 7 (=1+3+3), $3I_0$ will be 3. Therefore $3I_0$ is smaller than I_F. Therefore it is not simple to determine the sensitivity of the neutral current protection and the overcurrent protection. For coordination it is important to ensure that neutral current protection operates after the overcurrent protection even for the case that $3I_0$ is larger than I_F.

When N transformers are connected to B substation the current that each neutral current protection detects becomes *1/N* of total $3I_0$. Therefore the setting of the neutral current protection needs to be *1/N* of the result derived from the above explanation.

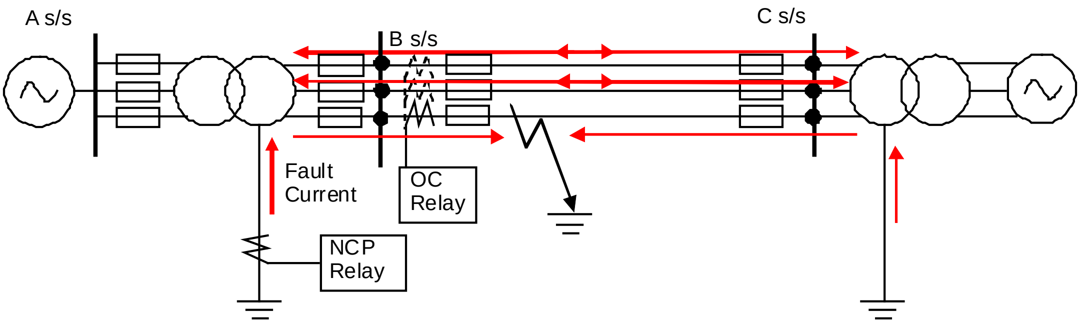


Figure 5.7-6 NCP Relay and OC Relay (Both-End Infeed)

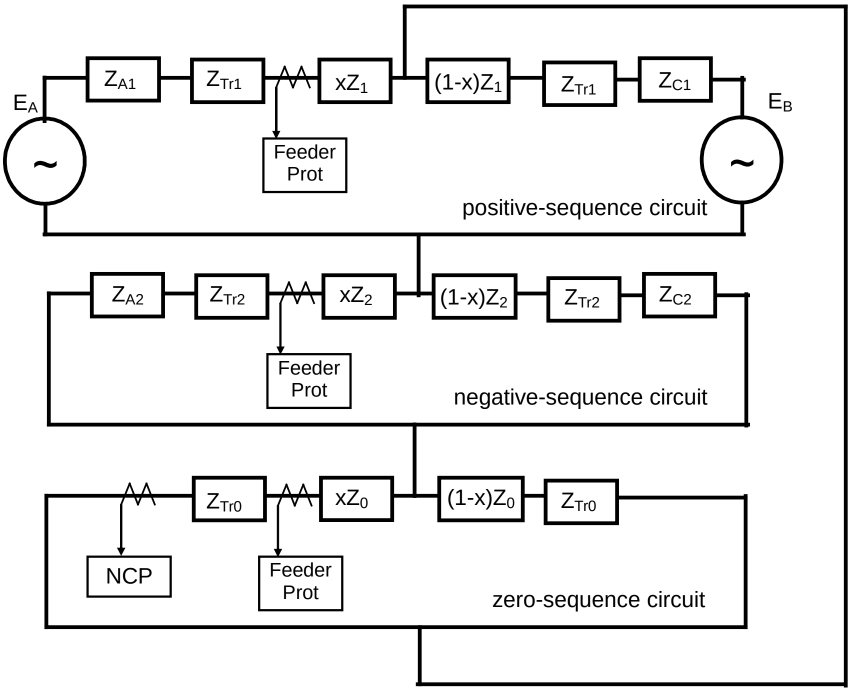


Figure 5.7-7 Equivalent Sequence Network Connecting NCP Relay and OC Relay (Both-End Infeed)

(3) In Case of Double Lines

In case of double lines as shown in **Figure 5.7-8**, coordination is more complicated because there is a current from/to the parallel line. When a fault is close to B substation as shown in the figure, OC Backup detects the fault current including a flow from the parallel line, which should be larger than the current which neutral current protection detects. Conversely, if the fault point is close to C substation, the fault current is split between the parallel lines so that the fault current that the overcurrent backup detects will be smaller than the fault current that the neutral current protection detects. The precise calculation is too complicated to be done by hand because many factors such as mutual impedance, reverse impedance etc. affect the result. Therefore computer simulation would be required in order to ensure that the neutral current protection operates after overcurrent even for the case that $3I_0$ is larger than I_F.

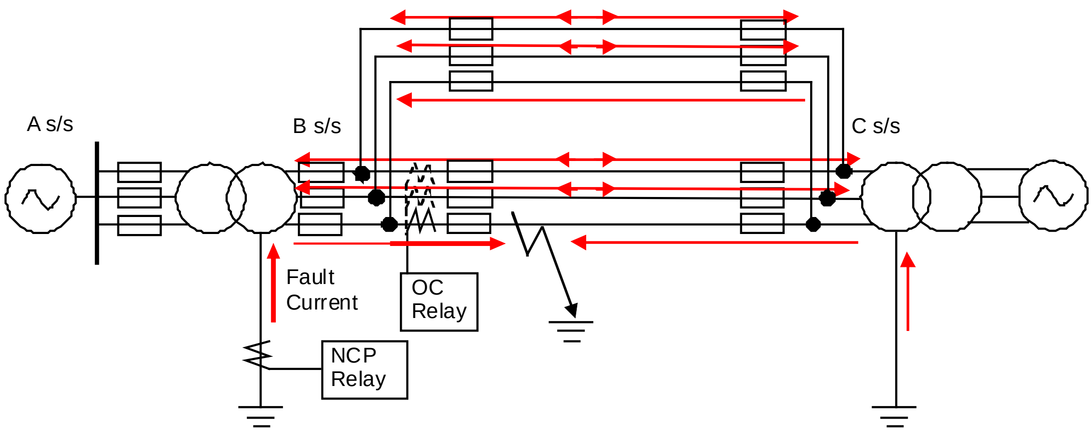


Figure 5.7-8 NCP Relay and OC Relay (Double Line Application)

5.7.4 Basic Coordination between Earth Fault Overcurrent Protection for Transformer and Earth Fault Overcurrent Protection for Feeder Protection

When an earth fault relay is applied to line backup protection as shown in **Figure 5.7-9**, it is also necessary to consider the coordination between the neutral current protection relay and the earth fault relay.

In this case an equivalent circuit is used for protection by both relays as shown in **Figure 5.7-10**. Therefore coordination is not as complicated as between neutral current protection and overcurrent protection. However the following conditions must be noted.

1) When *N* transformers are connected to the B substation the current that each neutral current protection detects becomes *1/N* of total $3I_0$. Therefore the setting of the neutral current protection needs to be *1/N* of the result derived from the above explanation.
2) In case of double lines as shown in **Figure 5.7-11**, in-feed effect and out-feed effect must be considered.

Generally the in-feed effect and out-feed effect can be summarised as follows:

For a fault close to B substation, the earth fault relay detects larger current than the current detected by neutral current protection relay because of the in-feed effect from the parallel line. For a fault close to C substation, EF relay detects smaller current than the current detected by neutral current protection relay because of the out-feed effect. Typically, the fault current that the earth fault relay detects for a fault further than C substation is almost half of the current that neutral current protection detects. This can be drawn as shown in **Figure 5.7-12**.

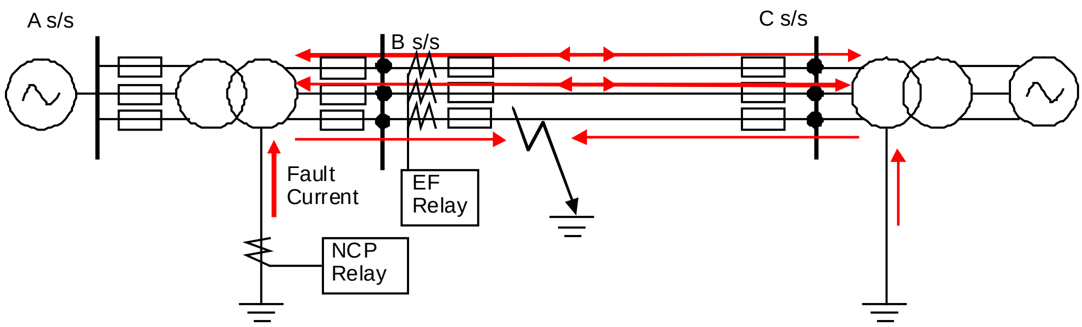


Figure 5.7-9 Neutral Current Protection Relay and the Earth Fault Relay

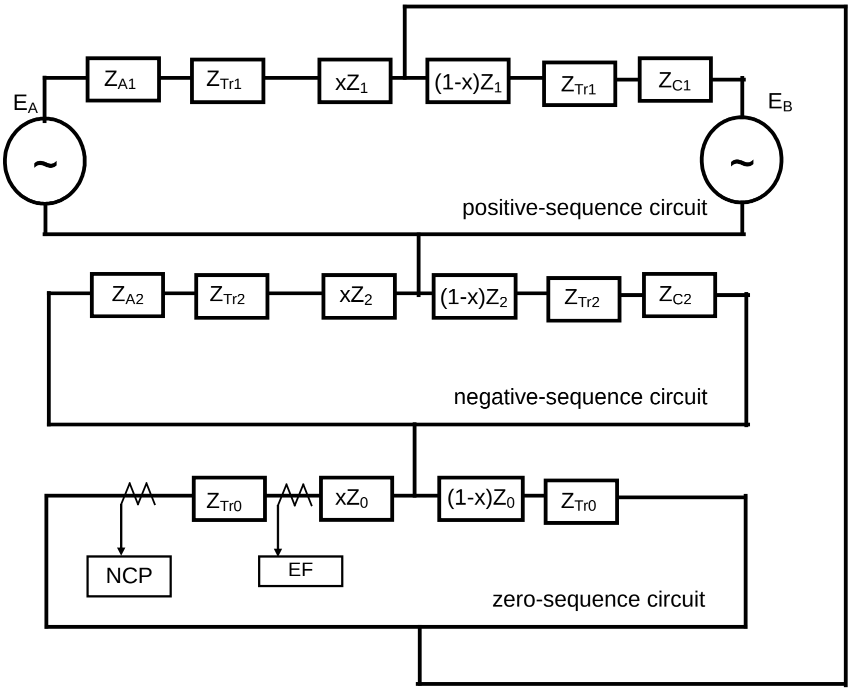


Figure 5.7-10 Equivalent Circuit Connecting Neutral Current Protection Relay and the Earth Fault Relay

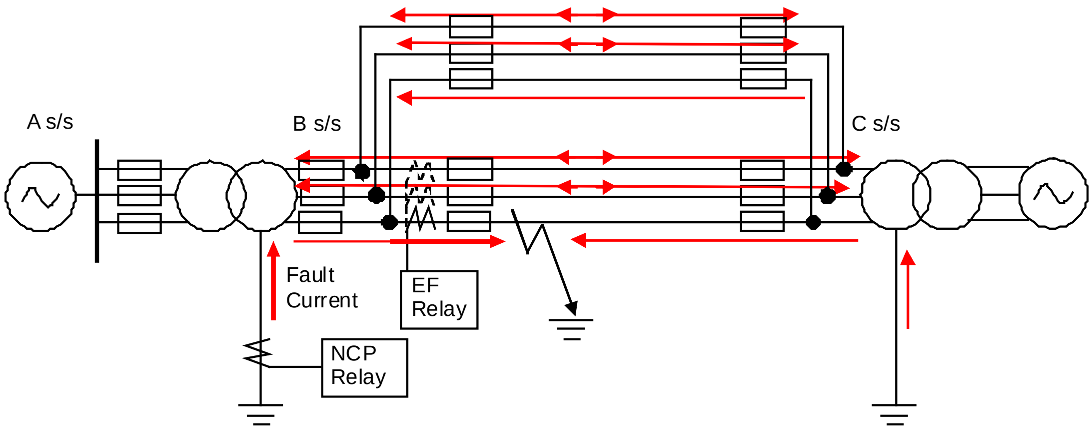


Figure 5.7-11 Neutral Current Protection Relay and the Earth Fault Relay Applied to Double Line

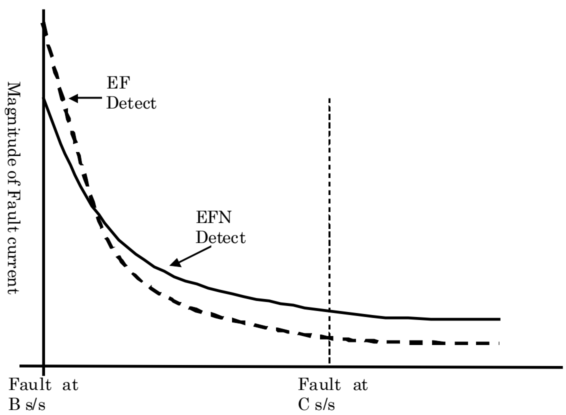


Figure 5.7-12 Relationship of Fault Currents Detected by Neutral Current Protection Relay and the Earth Fault Relay

5.7.5 Practical Coordination between Distance, Overcurrent, and Neutral Current Protection for Line Fault or Busbar Fault

(1) Protection Settings & Coordination Requirements for Overcurrent N-T Dedicated to Radial Lines

(a) Setting Criterion

A phase-to-earth fault on the high voltage bus at substation D in **Figure 5.7-13** generates the maximum $3I_0$ contribution measured by each of the neutral current protection for the transformer. In the figure, Tx_{pL}, Tx_{nL} and Tx_{nT} mean timers for overcurrent, earthfault line protection and for neutral current protection respectively.

The ($3I_0$) contribution of each transformer at substation D provided that each have an equal per unit impedance is calculated based on the number of available transformers (*n*) according to: $3I_0/n$ where I_0 is the total zero sequence current provided from the short circuit data.

Each transformer has a neutral current protection relay which measures $3I_0/n$. The pick-up setting of the neutral current protection must be able to detect minimum phase-to-earth faults at the far end of the line.

The instantaneous element of the neutral current protection relay must be disconnected or adjusted with a safety factor greater than the maximum ($3I_0$) contribution for a phase-to-earth fault at the high voltage side of substation D.

The time delay of the distance protection at substation "A" or "C" must be faster than all neutral current protection relays at location "D"

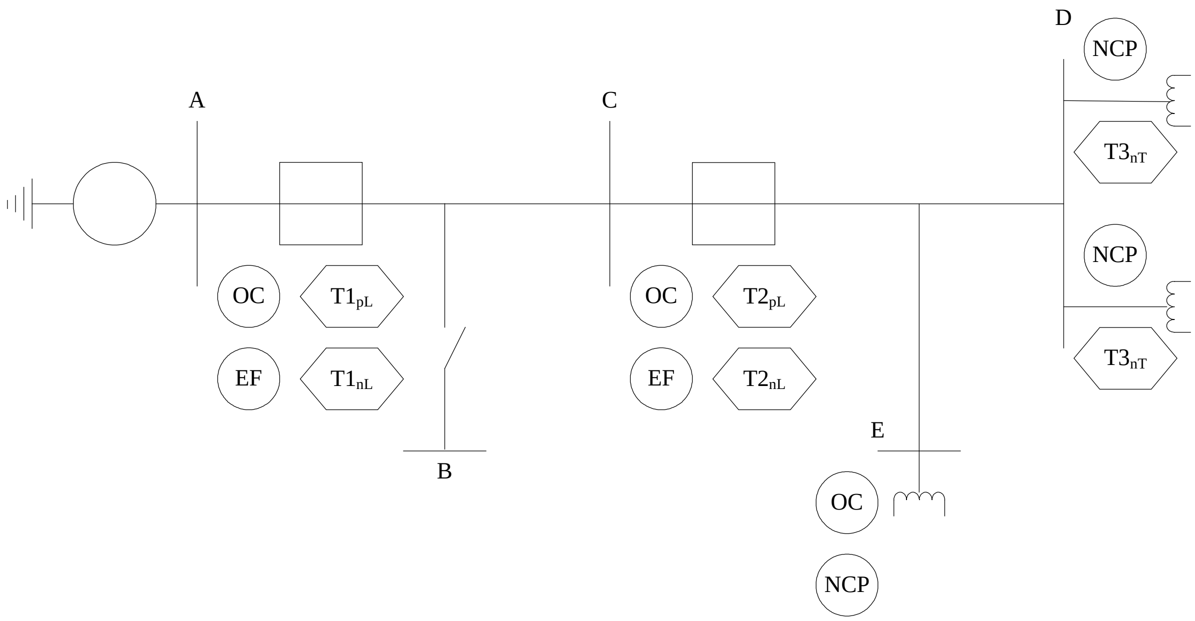


Figure 5.7-13 Example 1

(b) Coordination Criterion for Substation "D"

From **Figure 5.7-13** above, all upstream and downstream phase and earth fault current contributions must be evaluated and analysed.

All neutral current protection relays at substation D must be considered as backup to overcurrent relays and earthfault relays at substation C.

All neutral current protection relays of substation D must be set slower than all overcurrent and earthfault relays provided at substation C or A for any line faults. Operating of each protection should be as follows.

$$T1_{pL} < T3_{nT} > T1_{nL}$$

It must be verified that coordination exists for an upstream phase-to-earth fault at substation C. Also, verify that proper coordination is implemented between the neutral current protection of substation D and the residual line overcurrent protection at substation C. In this case, the residual overcurrent protection at substation C measures the total zero sequence current contribution from substation D.

$$T3_{nT} > T1_{nL} > T2_{pL} \text{ and } T2_{nL}$$

For transformer faults at substations E and D, verify that overcurrent and earthfault relays at substation C coordinate adequately with protection relays in substations E and D.

(2) Protection Settings & Coordination Requirements for Overcurrent N-T Dedicated to Multi-Terminal Sources

(a) Setting Criterion

The sum $\sum 3I_0$ of all zero sequence contributions of four substations A, B, D, E from the above **Figure 5.7-14** defines the phase-to-earth fault level on line DE near substation D. The following steps are useful for protection coordination:

- The ($3I_0$) contribution of each transformer at substation D provided that each have an equal per unit impedance is calculated based on the number of available transformers ***(n)*** according to:

  $$(3I_0 / n)$$

  where I_0 is the total zero sequence current provided from the short circuit data.

- Each transformer has a neutral current protection relay which measures $(3I_0 / n)$.The pick-up setting of the neutral current protection relay has a typical pick-up of *50%* of transformer rated current. However, this pick-up must be able to detect minimum phase-to-earth faults at the extreme end of the line. The relay has a backup role to eliminate all faulted contributions in case of failure for fast fault elimination from distance protections provides at each source of the network. The time dial setting is determined according to the listed criterion below.

- The instantaneous element of the neutral current protection relay must be disconnected or adjusted with a safety factor greater than the maximum (*3I0*) contribution for a phase-to-earth fault at the high voltage side of substation D.

- The time delay of the distance protection at substation "A" or "B" must be faster than all phase and earth-fault overcurrent protection elements.

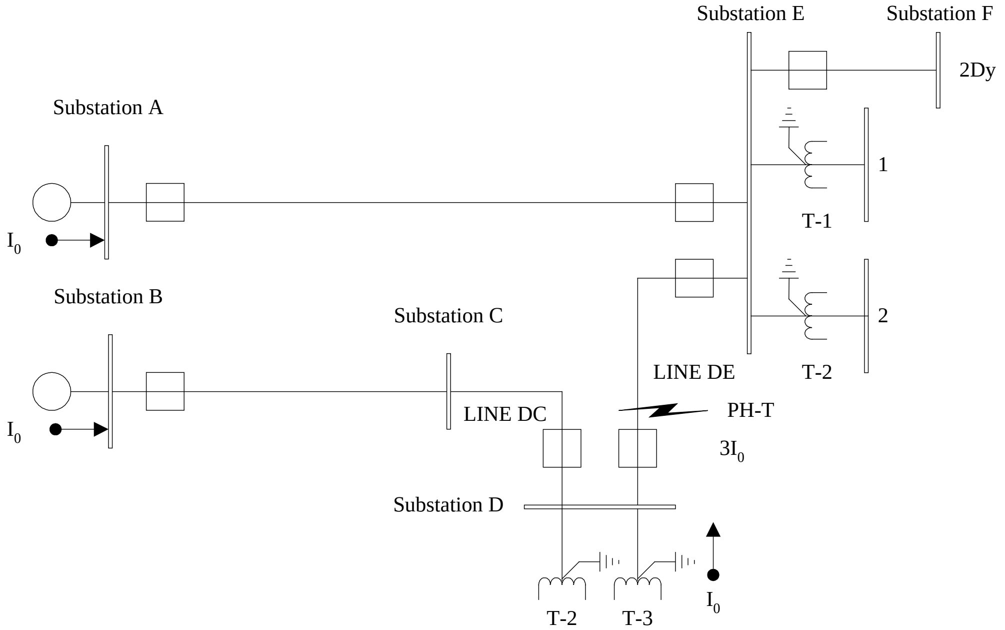


Figure 5.7-14 Example 2

(b) Coordination Criterion for Substation "D"

Short-circuit analysis from sources "A" and "B" will determine if there is a need for directional overcurrent protection.

Ensure that all neutral current protection relays are set slower than the longest overreaching elements (e.g. Zone 3) provided at each source of all remote ends of the network.

Ensure that all overcurrent and earthfault relays of the faulted line have slower time settings compared to the remote distance overreaching time delay (e.g. Zone 3 timer).
Ensure that all earthfault relays of the faulted line (DE) are set faster than the neutral current protection relays of the power transformers.

$$T1_{nL} < T3_{nT}$$

Ensure that all earthfault relays of the healthy line (DC) are set slower than all overcurrent elements of the faulted line (DE) but faster than the neutral current protection elements of the transformers.

$$\mathrm{T2}_{\mathrm{nL}} > \mathrm{T1}_{\mathrm{nL}} \quad and \quad \mathrm{T2}_{\mathrm{nL}} < \mathrm{T3}_{\mathrm{nT}}$$

$$Hence \quad T1_{nL} < T2_{nL} < T3_{nT}$$

Ensure that all overcurrent relay of the faulted line (DE) are faster than the neutral current protection relays of the power transformers.

$$\mathrm{T1}_{\mathrm{pL}} < \mathrm{T3}_{\mathrm{nT}}$$

Ensure that all overcurrent elements of the healthy line (DC) are set slower than the overcurrent and earthfault relays of the faulted line (DE)

$$T1_{pL} < T2_{pL} > T1_{nL} \quad and \quad \mathrm{T2}_{\mathrm{pL}} < \mathrm{T3}_{\mathrm{nT}}$$

Verify and analyse the different fault current contributions in order to make sure that coordination is still feasible under the condition that circuit breaker at Substation E is either on or off. Avoid the miss-coordination between the transformer's neutral current protection relays and the faulted line overcurrent/earthfault relays.

(c) Coordination Criterion for Substation "E"

From **Figure 5.7-15**, the coordination steps are identical to what was discussed for substation D.

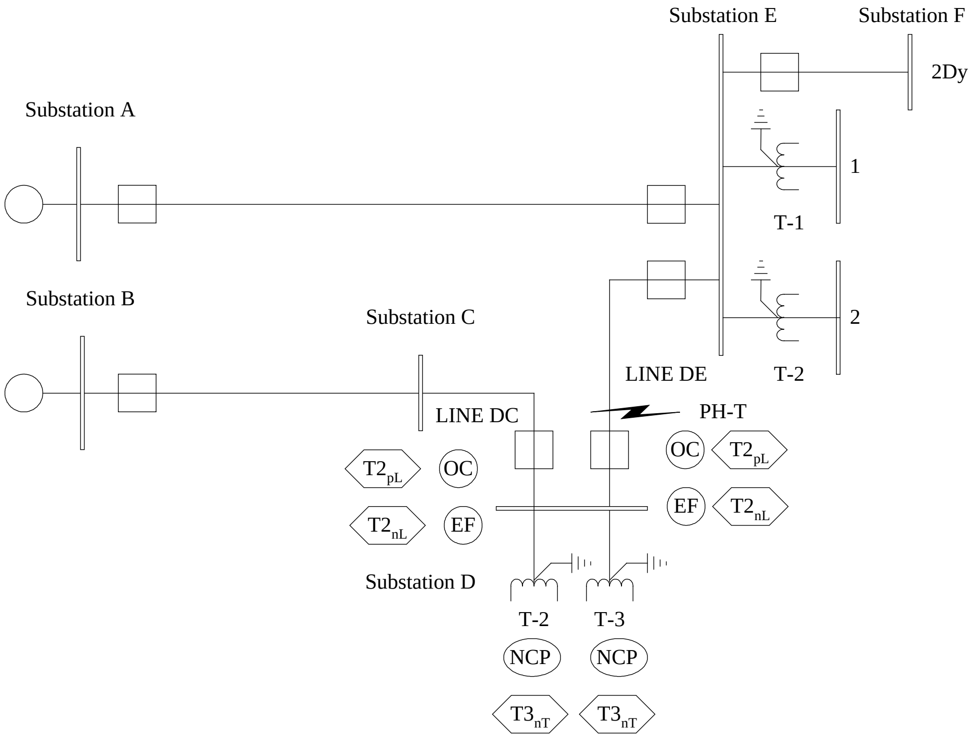


Fig.5.7-15 Example 3

5.7.6 Practical Coordination between Distance Relays and Overcurrent Relays for Transformers

Figure 5.7-16 illustrates the usual case that will be analysed at the following paragraphs. Transformers T1 and T2 can be distribution or transmission transformers. Faults such as F1 or F2 at busbar, shall be detected by backup time delayed overcurrent and/or earth fault functions located at the opposite side of transformer. Depending on the type of short circuit, either the time delayed overcurrent or earthfault will be responsible to detect the fault. Sometimes the zone 3 reach setting permits the detection of the specified faults. In these cases coordination by time between the third zone of relay Ry-A and time delayed overcurrent, earthfault functions is necessary. Normally when T1 and T2 are transmission system transformers the operating time for overcurrent and/or earthfault overcurrent functions is in the interval 0.4 – 0.6 s for F1 or F2 faults, while the operating time set for zone 3 is 0.8s or 1 s. The resultant time margin of is very adequate to achieve coordination and to have the required selectivity.

Time coordination between the zone 3 of Ry-A and transformer 51 and/or 51N overcurrent functions located at the same side as the Rx-A it is possible if the setting is such that the operating time for overcurrent functions is in the interval (0.4 – 0.8 s). If line distance relay's zone 3 set time is 1 s or more then coordination is guaranteed.

It is common for some utilities to set the time delayed overcurrent and earthfault transmission power system transformer functions of the same side as Ry-A to operate at a value in the interval (0.6, 0.8 s) for faults as F1, F2. With this criterion, coordination does not exist between overcurrent functions at both sides of transformer. This type of coordination could be desirable but cannot be mandatory in all cases because it is not necessary to have selectivity and it can be permitted to do not accomplish it.

If T_1 and T_2 are distribution transformers, the nominal voltage at the opposite side of transformers can be typically in the range 22 -132 kV. In these applications the operating time for time delayed overcurrent and/or earthfault functions is in the interval 0.7 – 0.8 s (particularly when the voltage is 22 - 66 kV) while the operating time that is set for line distance relay's zone 3 could be 1 s as a minimum. The minimum resultant margin of 0.3 – 0.2 s is adequate to achieve coordination and to have selectivity; however coordination between Rx-A third zone (1 s) and transformer time delayed overcurrent and/or earthfault functions located at the same side as the Rx-A it is only possible if the operating time of these overcurrent functions is also in the interval (0.7, 0.8 s). In these cases there is no coordination between overcurrent functions at different sides of transformer, but selectivity is not affected; selectivity is not lost at F1, F2 fault scenarios. The simultaneous trip of circuit breakers at both sides of transformer can be undesirable if the time to reenergize the transformer needs to be minimized.

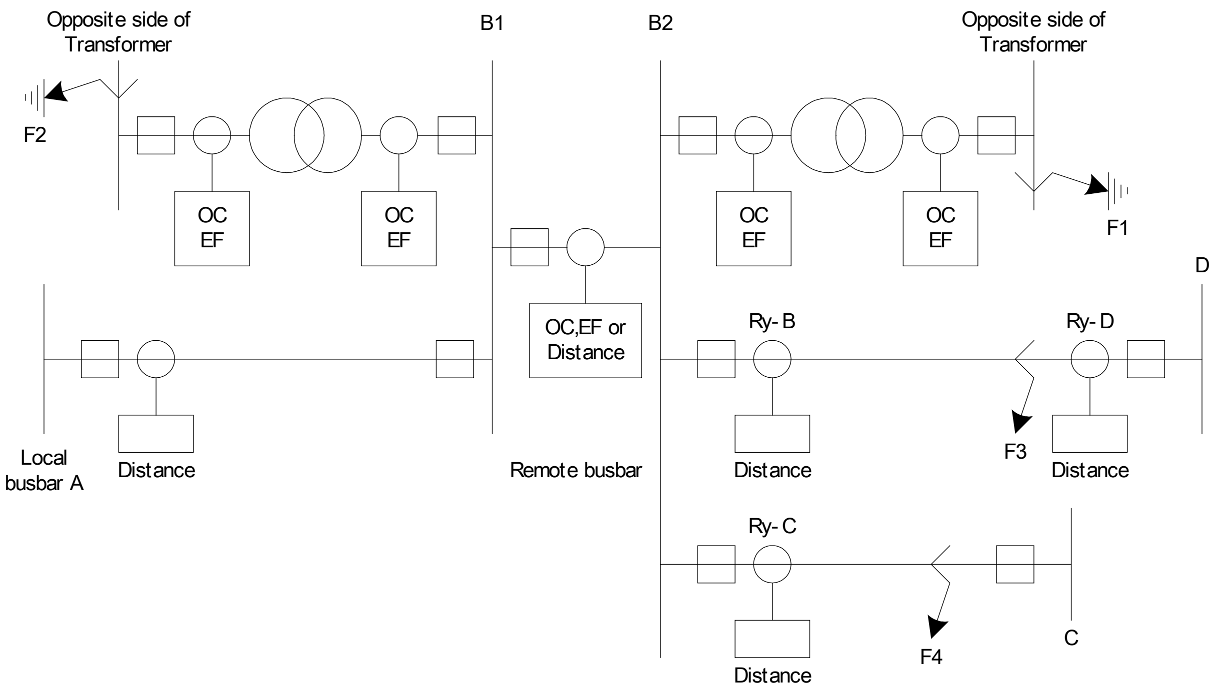


Fig.5.7-16 Coordination between Distance Relays and Overcurrent Relays

5.8 Coordination between Busbar Protection and Transformer Protection

5.8.1 Coordination between Overcurrent Relays for Transformer and Busbar Coupling Circuit Protection

For faults on bus B2 in **Figure 5.7-16** assuming failure of bus B2 differential protection, the coupling circuit protection acts at the set value of 0.2 s providing isolation of the healthy bus B1. It is necessary that overcurrent functions of transformer do not operate for the specified fault in order to guarantee selectivity. This is accomplished by setting at 0.4 s as the minimum permissible operating time value for the transformer definite time overcurrent function. This is the applied setting criterion to save selectivity.

For faults at zone 1 limit, or near to the lines end, such as F3 and F4 shown in **Fig. 5.7-16**, the coupling circuit protection has to operate at 0.6 - 0.65 s if failure of line relays is assumed. In this case, it is necessary that the overcurrent functions of transformer operate at 0.8 - 0.85 s as a minimum time in order to guarantee time coordination between both relays and to have good selectivity.

As above indicated, inverse time functions are typically used as backup overcurrent functions in transformers, in order to detect faults at the end of the lines or faults such as F3 or F4 shown in the above referenced Figure. It is not easy to guarantee complete selectivity at all power system scenarios; this is because the operating time of inverse time overcurrent functions is very dependent of the system short circuit power and this is greatly dependent of the power system scenario. It is normal that a big increase in the operating time of these protective functions can occur at times of low power generation of the power system. Selectivity can be not satisfied if faults arise at these times. Many computer calculations are required to adequately set inverse time overcurrent and neutral current protection functions taking account peak and valley power system scenarios and also considering cases where an overhead line or transformer is not connected to the substation.

Overcurrent functions are also set to protect the through fault withstand capability curve of transformer. This curve is supplied by the transformer manufacturer or provided from IEC or ANSI standards. Normally this is not the limiting setting criterion of the inverse time overcurrent function, but always checking is necessary after the setting has been decided in order to guarantee the necessary transformer thermal protection for through faults.

An additional check is also required to verify that no undesired trip occurs at no load transformer connection to the power system. To accomplish it, the selected inverse time curve and pick-up value, shall assure the not operation for the transformer inrush current.

Other coordination problems appear when overcurrent and neutral current protection are used as backup functions. These problems are derived of not directional characteristic of these overcurrent functions. For example, the overcurrent and neutral current protection T2 transformer relay at the side of bus B1 in **Fig. 5.7-16** will detect faults at bus B2 and also will detect faults such as F1, F3 and F4. Coordination with the coupling circuit breaker protection is necessary and setting to accomplish it is applied as above indicated.

On the other hand, faults such as F2 illustrated in the referred Figure are also detected and coordination with the coupling circuit protection of bus B1 it is also required. This double requirement shall be mandatory when the setting is calculated and other time many computer calculations are required to make a very good setting.

The above indicated difficulties, when 51/51N functions are used as transformer backup protective functions in meshed networks, drive to consider the substitution of these devices by distance relay for transformers. Two important advantages are obtained with this:

- Great independence of operation related to the power system scenario
- Directionality in fault detection

At present, this option is used by some utilities in the transmission power system transformers, but probably at future will be considered as the preference for the backup protection of all 400 / 220 kV transformers.

5.9 Coordination of Breaker Failure Protection

5.9.1 Coordination between Zone 2 for Line and Overcurrent at CB Failure against Adjacent Section Fault

Circuit breaker failure protection can be considered as backup for line, busbar, transformer, reactor and capacitor bank relays when the indicated power system element circuit breaker fails to open if short-circuit is present. As an example, if the fault is not cleared by the Ry0 relay and its assocated circuit breaker, the circuit breaker fail protection must operate to clear the fault by the two breakers on the incomers to the substation but before operation f the zone 2 elements aof Ry2 and Ry3.

Then 150ms < Tc < 260ms

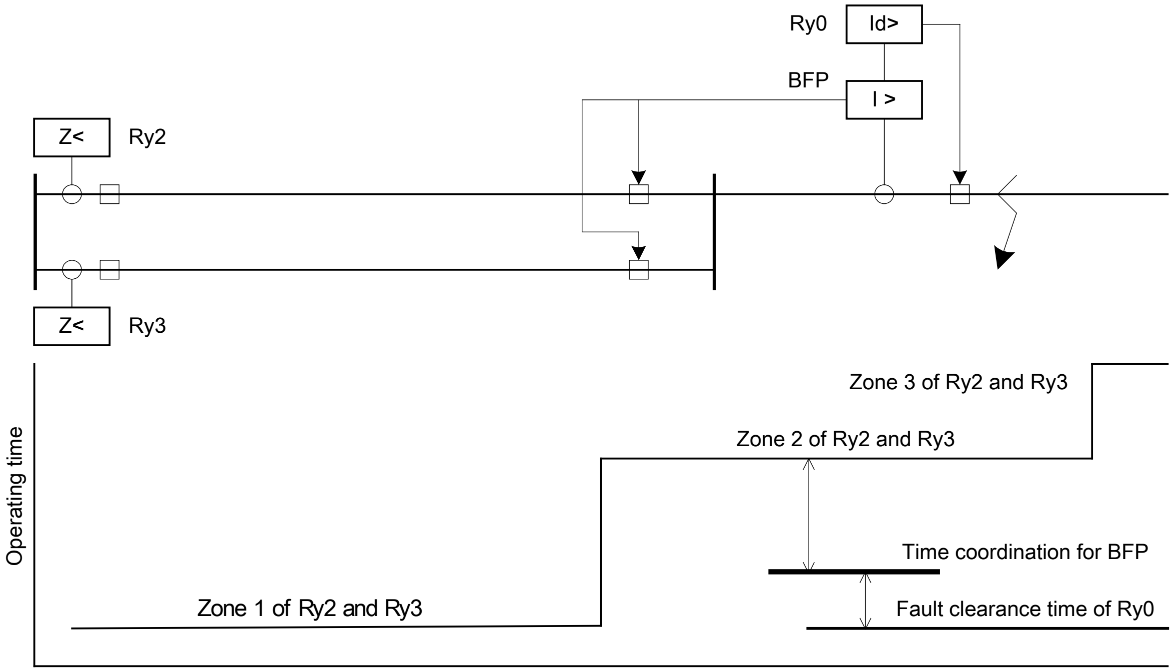


Figure 5.9-1 Example of Coordination Issue between Line Protection with Distance Relay and CBF against Adjacent Section Fault

5.9.2 Coordination between Zone 2 for Line and overcurrent with Splitting Protection at CB Failure against Adjacent Section Fault

As mentioned in **Chapter 3.5**, circuit breaker failure protection shall be considered to operate faster than other backup protection.

- The fault clearance time T_m for main relay at local substation is put at 70ms that consisting 30ms for operating time of differential relay Ry0 and 40ms for CB clearance time.
- The fault clearance time T_b for backup relay is put at 0.34s for 2nd zone of distance relay Ry2, Ry3.
- The opening time of bus-coupler by splitting protection Ry1, “splitting protection have large zone setting for splitting parallel line to individual system”, is put at *0.24s*.

Then the fault clearance time T_c of CBF over-current relay is set at 0.2s as following equations.

Tm + Resetting time of main relay < Tc - Fault clearance time of CB
70ms +40ms < Tc - 40ms
150ms < Tc
Tc + Resetting time of CBF relay < Tb - Fault clearance time of CB
Tc + 40ms < 340ms - 40ms
Tc < 260ms

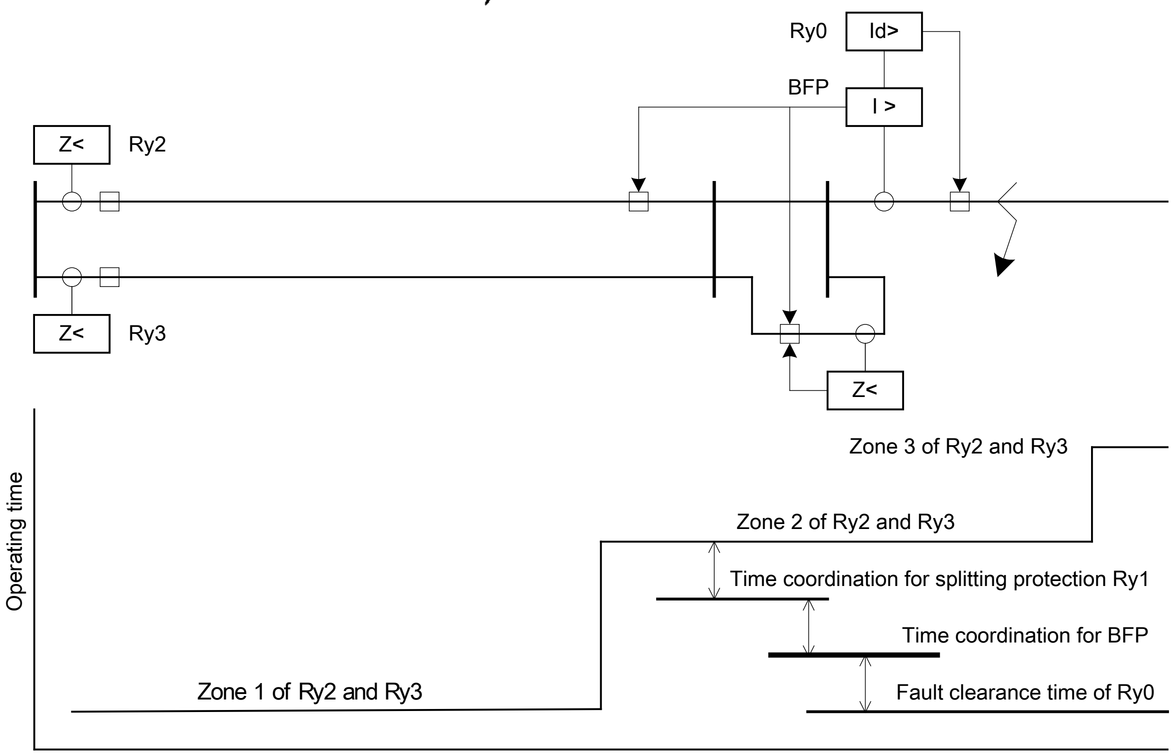


Figure 5.9-2 Example of Coordination between Line Protection with Differential Protection and Circuit Breaker Failure Protection in Double Busbar against Adjacent Section Fault

5.10 Coordination of Generator Protection

5.10.1 Coordination between Generator Protection and Generator Control

Coordination between generator protection and generator control systems can be classified into four generator functions during normal and abnormal operating condition, as follows:

1) Voltage Regulation - concerns the generator and its excitation system, such that the generators are design to operate over a range of terminal voltages
2) Speed Regulation - concerns the generator's turbine and its fuel systems
3) Overcurrent/Overload
4) Synchronism

Such consideration can be summarized in **Table 5.10-1**:

Table 5.10-1 Generator Protection and Control Coordination under Voltage Regulation Issues

Control System		Protection System		Coordination Remarks
Settings	Parameter	Settings	Parameter	
Off-load Tap Changer of Unit Transformer	Tap setting	None	None	Only device testing
Load Drop Compensation	LDC=V/(XT)	None	None	Setting of LDC should be verified by testing: (1)
V/H Exciter control characteristic	· Pickup · Time characteristics	Over-excitation (V/Hz)	· Pickup · Time characteristics (Inverse characteristic)	Manufacturer's transient and steady-state V/Hz capability curves of generator, unit transformer and excitation transformer.
Under-excitation	Minimum excitation limiter control characteristics (instantaneous)	Loss of Excitation or Field Failure	· Xd' · Xd (2)	Coordination curves required
Rotor overload (minimum field current) control	· Pickup · Time characteristics	Field Winding Overload	· time delay · Pickup · Time characteristics	Rotor windings and exciter overload capability curves. Coordination curves

<Note> (1) V: p.u. change in terminal voltage on breaker opening, I_R: reactive current before breaker opening, X_T: p.u. unit transformer reactance

(2) X_d': transient reactance, X_d : synchronous reactance

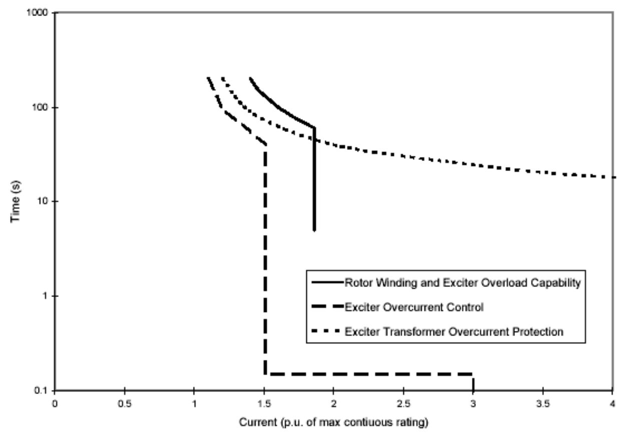


Figure 5.10-1 Dynamic Overload Capability of Generator Excitation System

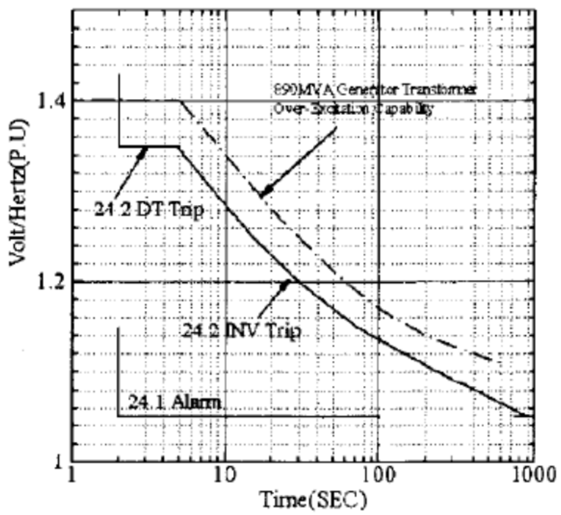


Figure 5.10-2 Coordination between 24T and Generator Transformer V/Hz Capability

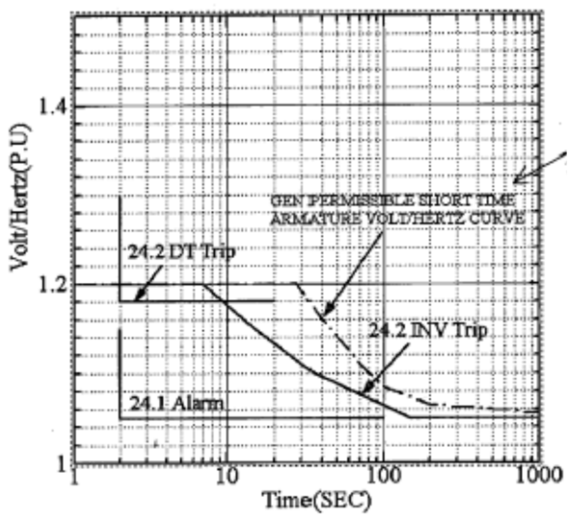


Figure 5.10-3 Coordination between 24G and Generator V/Hz Capability

Table 5.10-2 Generator Protection and Control Coordination under Speed Regulation Issues

Control System		Protection System		Coordination Remarks
Settings	Parameter	Settings	Parameter	
Frequency limits	To be advised	Under-frequency	To be advised	Coordination curves required
		Over-frequency	To be advised	Coordination curves required
Speed droop	Droop	None	None	Only device testing
Acceleration/ Deceleration Ramp Rate	To be advised	None	None	
Governor Control Mode	Speed or Power Control	None	None	Only device testing
	Frequency deadband			
Turbine Over-temperature	• Pickup • Time characteristics	Turbine Over-temperature	• Pickup • Time characteristics	Coordination curves required
Overpower	To be advised	None	None	Only device testing

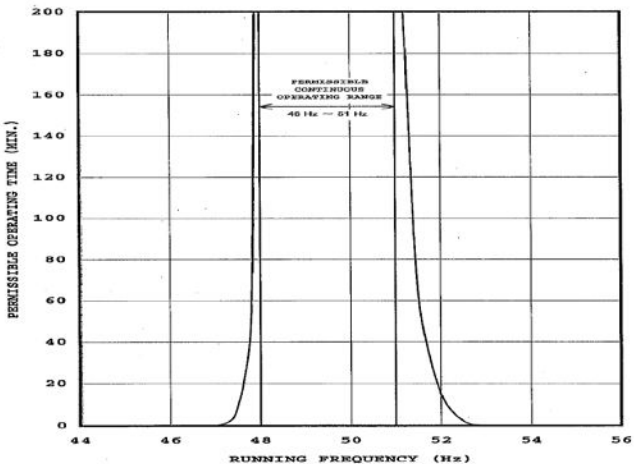


Figure 5.10-4 Frequency Deviation Capability of a Generator

Table 5.10-3 Generator Protection and Control Coordination under Overcurrent/Overload Issues

Control System		Protection System		Coordination Remarks
Settings	Parameter	Settings	Parameter	
None	None	Negative Phase Sequence	To be advised	Coordination with single-phase autoreclosing dead time
None	None	Backup Short Circuit	To be advised	Coordination with system protection
OEL, UEL	To be advised	Stator Overload	To be advised	Coordination curves required
MEL	To be advised	Rotor Overload	To be advised	Coordination curves required

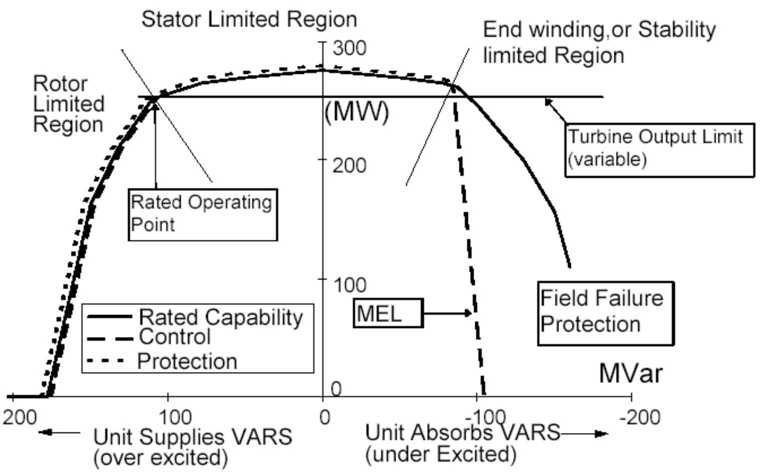


Figure 5.10-5 Generator Capability, Protection and Control Limits (See Figure 3.6-3)

Table 5.10-4 Generator Protection and Control Coordination under Synchronism Issues

Control System		Protection System		Coordination Remarks
Settings	Parameter	Settings	Parameter	
Automatic Synchronizer	・Mode of synchronizing - SYNC or DL or DB ・dU ・df	None	None	Only device testing
None	None	Pole Slipping	・Xd',Xd ,Xs (1) ・Time delay(s)	Coordination with system protection

<Note> (1) X_d': transient reactance, X_d: synchronous reactance, X_s : system reactance

5.10.2 Coordination between Generator Protection and System Protection

Coordination between generator protection and system protection can be classified into those responsive during fault conditions and those under abnormal system conditions. They can be summarized in **Table 5.10-5**.

Tab.5.10-5 Summary of Coordination between Generator Protection and System Protection

	Protection Type	Main 1	Main 2	Backup	Need Coordination
Faults	Inter-turn short circuit of armature winding	87G	21ZG-1	21ZG-2 87OG	21Z to coordinate with generator transformer protection
	Grounding of armature winding	64G	59NG		
	Grounding of field winding	64F		59F	
Abnormal conditions	Motoring	32G-1	32-2		
	Over-excitation	24G-1	24G-2		
	Overvoltage	59G-1	59G-2		
	Loss of excitation	40G			
	Out-of-Step	78G			
	Underfrequency	81UF-1	81UF-2		Coordinated with underfrequency protection
	Overfrequency	81OF-1	81OF-2		
	Current Unbalance	46G-1	46G-2		Consideration under single-pole autoreclosure operations
	System Faults			51V	Need to coordinate with system protection

5.10.3 Coordination between Generator Protection and Line Protection

Although the coordination between main protection for line and main generator protection is not necessary, it is necessary for the coordination between backup protection for generator and the backup protection for line or transformer such as an overcurrent relay or a distance relay. Time coordination is required so that the backup generator protection doesn't operate faster than the backup line protection for a line fault.

When there is a short line connecting to the network, the coordination may become difficult. When a fault at the power system side is cleared by the backup protection, the time of voltage sag will become longer than that compared with the fault clearance time by main protection interception, so the auxiliary equipment of a generator is influenced during this period. Some of auxiliary equipment may trip due to detection of undervoltage with time delay. The time delay of the backup protection of the power system side should not exceed that of the auxiliary equipment. It is necessary for the setting of the time delay to fully take into consideration the characteristics of the auxiliary equipment [1].

Negative-phase-sequence relays are installed in order to prevent overheating of the rotor according to negative-phase-sequence current. However these relays must be set so as not to operate for negative phase sequence currents created during single pole reclosing or multi-pole reclosing which would cause unwanted operation of the relay [1].

5.10.4 Examples of Miscoordination between Generator Protection and Other Protection

(1) Unwanted Operation of the Percentage Differential Relay for the Step-Up Transformer due to Under-Frequency in the Islanded System

After the 66kV A-lines were tripped simultaneously as shown in **Figure 5.10-6**, the No.1 **-** No.3 generators at the X power station were under isolated operation, and under-frequency and under-voltage occurred. Consequently, the No. 1 step-up transformer would be over-excited, and the percent differential relay operated unwantedly due to the rapid increase of the differential current. The causes of no-operations of the percentage differential relays of No. 2 and No. 3 transformers were presumed to be differences in the exciting current of the transformers and differences in the frequency characteristics of the relays.

In order to prevent isolated operation at an early stage as much as possible as this measure, the settings of the frequency relays were changed from 47.5Hz, 8 seconds to 47.5 Hz, 2 seconds.

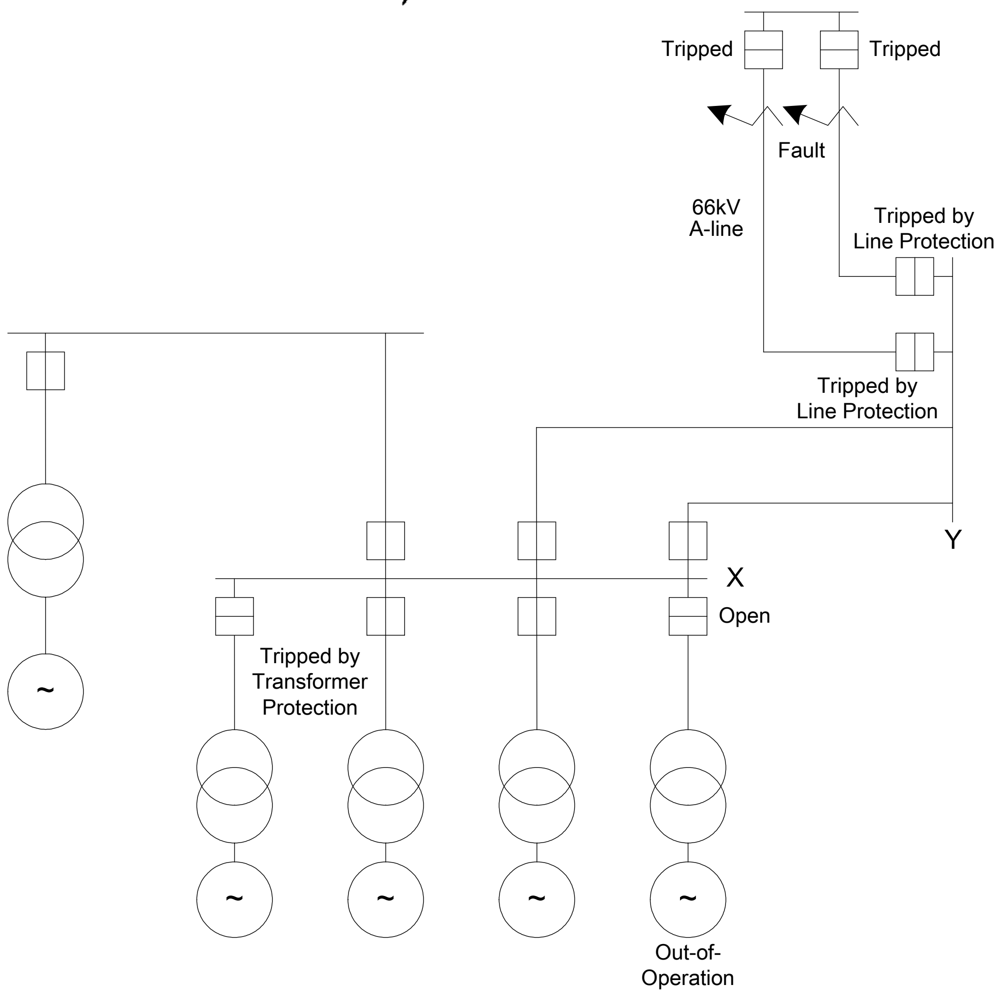


Fig.5.10-6 Power System

(2) Breakage of the Arrester due to Overvoltage Caused by Series Resonance during Double Phase-to-Earth Fault

The arrester of A substation was damaged due to the short-time AC overvoltage by series resonance during two phase to ground fault in the G line of the 66kV system shown in **Figure 5.10-7**.

This cause was presumed as follows:

- The backup relay for phase fault at the C substation operates according to two-line earth fault near the E substation and No.2 line of the G line was tripped at the C switching station.
- Higher harmonic current from the generator of the B power plant caused series resonance by the inductance of the lines and the electrostatic capacity of the generator and the transformer.
- Series resonance caused overvoltage, and AC overvoltage was applied during short-time across the phase B arrester in the No.2 line side.
- The element of the phase B arrester in the No.2 line side at the A power plant was damaged due to transient overvoltage.
- Breakdown discharge occurred in the phase B arrester due to recharging.
- The pressure relief device operated due to the rise of the internal pressure of the arrester.

It was presumed arc discharged across the gap from the trace of the arc at the insulating tube side.

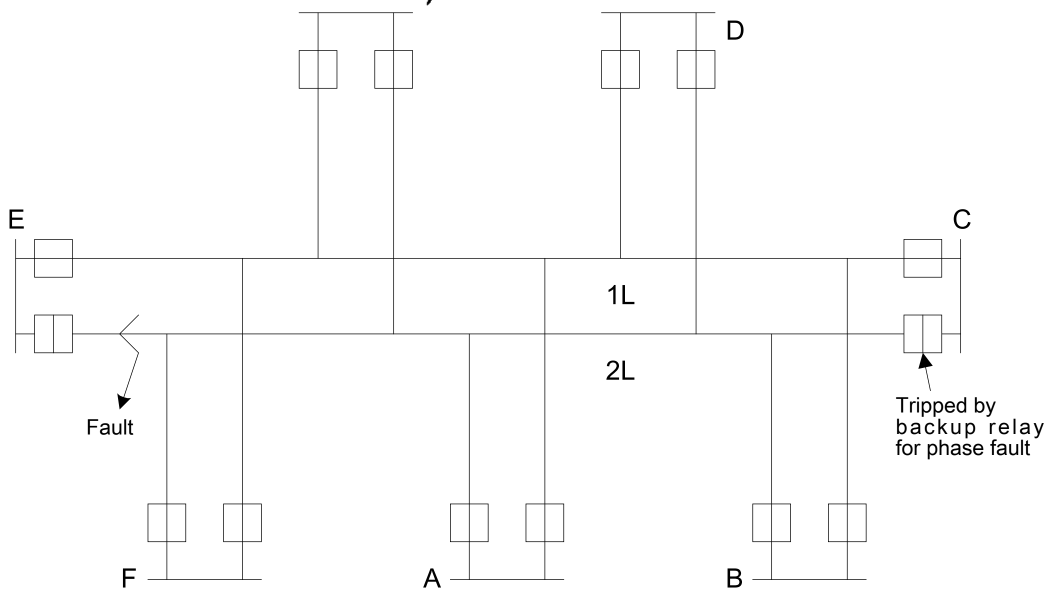


Figure 5.10-7 Power System

(3) Miscoordination between the Overcurrent Relay for the Main Transformer and the Generator and the Loss of Excitation Relay

Undervoltage of the backup battery in the automatic voltage regulation board at the A power plant *(2400kW)* occurred. Consequently the voltage regulation system failed with the excitation system value set to the value at the occurrence of the event. At the time, since the exciting current was small and the terminal voltage of the generator was low, the generator fell into leading power factor operation and large reactive current flowed, which caused the incorrect operation of the overcurrent relay of the main transformer. In addition, since the overcurrent relay for the main transformer operated before the generator overcurrent relay due to the mal-coordination between the overcurrent relay for the main transformer and that for the generator, further tripping ocurred. In addition, an undercurrent relay with the time delay for 6 seconds was used as the loss of excitation relay.

Subsequently, the setting of the generator overcurrent relay was improved and the loss of excitation relay was changed to a relay with offset mho characteristics.

<References>

[5] [1] Protective Relaying Committee, "The Coordination between System Protection & Generator Protection", CRIEPI Report 184001, April, 1984 (in Japanese)

6. Coordination of the SPS

6.1 Coordination between a SPS and a Fault Clearance Relay

6.1.1 Coordination Issues

Coordination issues can exist for triggering of the SPS operation and effects of its operation on the power system phenomena.

(1) Trigger of the SPS Operation

In many cases, SPS operations are triggered by operation of the fault clearance relays. If the aim of the SPS is to cope with transient stability problem, high-speed trigger is needed, and in some cases, the time delay between fault clearance relays initiating the signal and SPSs receiving it can be important to be minimised.

(2) Effect on the Power System Phenomena

The following coordination issues can exist on the SPS for transient stability; remedial actions of the SPS are significantly dependent on whether a fault was cleared by main or backup protection.

It is sometimes question which may be advantageous: Intentional generator shedding with SPS after reclosing- failure or unintentional generator drop after omitting a reclosing.

6.1.2 Coordination between a SPS and a Fault Clearance Relay

(1) Power-Swing Blocking

When power swing which sometimes occurs after clearing a fault is large and continues for a long time, the distance relay which measures the electrical impedance from the installation point may operate unwantedly. Therefore, power-swing blocking may be added to a distance relay to prevent an unwanted operation. In particular, this circuit is added to the zone 1 of a distance relay in many cases, to prevent an unwanted operation when the impedance locus moves within the protective zone because the zone 1 relay usually operates instantly. In many cases, power swing blocking is added to a distance relay for a short circuit fault, but it may be added to that for an earth fault when power swing will occur after a phase-to-earth fault.

Table 6.1-1 shows the application situation of power swing blocking. According to this table, it is widely adopted in the main transmission systems in many countries. Application of power swing blocking is very rare in lower voltage power systems.

As an example, power swing function is normally included in distance relay and also in line differential relay used in the 400 kV and 220 kV Spanish transmission systems , typically set to block all distance zones (zone 1, 2 and 3). It is necessary to coordinate the power swing function and zone 3 (the zone with the largest coverage) as well as between power swing function and the minimum line load impedance area (maximum load area). **Figure 6.1-1** graphically shows the operation areas or zones. AB and CD are the internal blinders of internal zone ABCD. This area is calculated to be external at the largest zone; i.e. typically the zone 3.

External blinders EF and GH need to be set not to intersect with the line load area (See the referenced Figure). Some safety margin it is also used. This margin, to define the external blinder, is normally 90% of minimum load impedance at 45º load impedance angle.

Table 6.1-1 Application of Power Swing Blocking

Power swing blocking	CA		ES		FR		JP		KR		MY		PT		SE		UK	
	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV	EHV	HV
Zone 1							△										×	
Zone 1 & Zone 2								Not available	×						Not available			
All Zones			×				△				×		×					

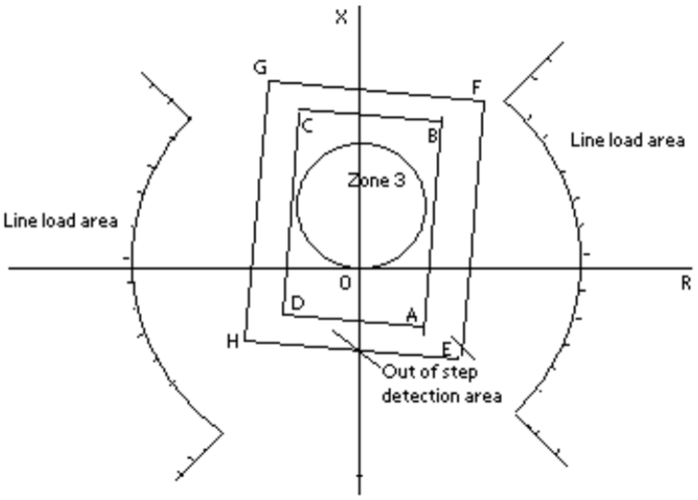


Figure 6.1-1 Operation area

(2) Line Overvoltage and Distance Zone 3

Multifunction relays protecting 400 kV and 220 kV transmission system overhead lines typically include an overvoltage function to protect the insulation of the substation equipment. The function is typically set at 120% of the nominal system voltage and definite time value around 1 s or more is normally set. This operating time shall permit time coordination with zone 3 of distance relays. The minimum admissible coordination time interval of 0.2 s (coordination time margin) is necessary for single phase-to-earth faults when the voltage phase-to-earth can be increased at healthy phases at some substation over 20% of nominal system voltage; so time coordination is achieved.

6.2 Coordination between SPSs

6.2.1 Coordination Issues

The following coordination issues can arise between SPSs.

(1) Trigger of SPS Operation

Two or more different SPSs can be triggered by the same incident, such as protection relay operation or some abnormal phenomena. In this case, coordinated operation between the two SPSs is needed. In the decentralized UFR system, coordinated actions are realized by making different setting among each device.

(2) Operating Time

In the case two different-purpose SPSs are installed in the same power system, it is sometimes a good solution to make operating time difference for coordinated operations.

(3) Decision for Remedial Actions

Example is the case of two SPSs for transient stability, one covers large scale thermal/nuclear power plants and the other covers pumped-storage power plants. The former SPS changes threshold level for deciding remedial actions whether pumped-storage plant is operating or not, considering effect of the actions of the latter SPS.

(4) Shedding Targets

Example is the case of two SPSs where one is for transient stability, the other is for frequency stability, having common shedding targets for their choices. Shedding targets are selected in advance of fault occurrence on some assumption. Selected targets with the SPS for transient stability are sent to the SPS for frequency stability beforehand and the latter SPS selects the same targets preferentially to avoid over-shedding the targets.

6.2.2 Practice of Coordination between SPSs

Coordination methods between SPSs are classified as **Table 6.2-1**.

Tab.6.2-1 Practice of Coordination between SPSs

Coordination category	Purpose	methods
Operating value or OperatingTime Coordination	Prevention for over shedding caused by simultaneous start-up of multiple devices of same kinds sytems	Setting Value
Control Calculation Coordination	Prevention for Over or Under Shedding when two devices are started and shedding command is impacted by the shedding performed by the other device.	Operation of the other device is estimated based on startup signal delivery and electrical input data, and the shedding effect is reflected in the control calculation.
Selection Coordination of Shedding Target	Prevention for Over or Under Shedding caused by duplicate selection when two devices with the same shedding target are started.	The selection of the other device is recognized and the shedding target is selected based on shedding target information delivery and the setting value.

(1) Coordination between Behaviour-Confirmation Type and Behaviour-Assumption Type or Behaviour-Prediction Type

(a) Outline of Behaviour-Assumption Type against Abnormal Frequency

An SPS known as System Stabilizing Controller (SSC) to maintain frequency stability is used in a Japanese utility. The SSC recovers the frequency of the islanded power system when a parallel-line is simultaneously tripped by a severe fault. **Figure 6.2-1** shows the outline of the SSC. In this figure, line AB and line BC are double-circuit-lines, but the power system would be split if a severe double-circuit fault occurs on these lines. When Network I or Network II in the figure is islanded, the frequency of the power system will go up or go down in accordance with the amplitude and the direction of the pre-fault power flow in the faulted lines. The SSC will shed the loads or the generators to keep the frequency within the normal range when the power system could be islanded. Basically, the SSC will shed the same amount of the generators or the loads equal to the pre-fault power flow in the faulted lines.

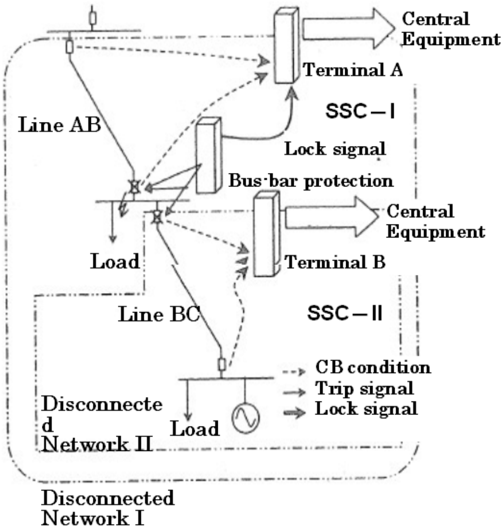


Figure 6.2-1 Outline of SSC

(b) Coordination between SSC and UFRs

Underfrequency relays (UFRs) are locally equipped to shed the loads independently when the frequency drop would go below a certain level. The SSC will operate together with the UFRs. In this case, the SSC is designed as main protection and the UFRs are designed as backup protection. The functions of these two are closely related. The target frequency of the SSC, which is the frequency of the power system after load-shedding, is usually set lower than the rated frequency to reduce the amount of the shedding loads. The target frequency of the SSC is usually set higher than the setting value of the UFR so that the UFR could not operate considering the successful control of the SSC. The relation is shown in **Figure 6.2-2**.

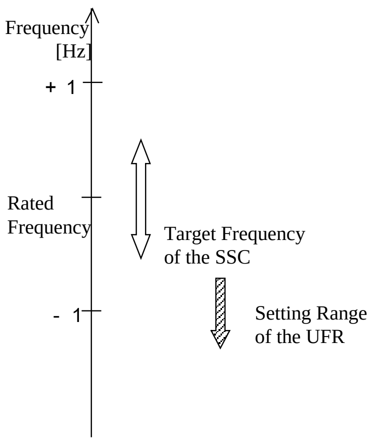


Figure 6.2-2 Coordination between SSC and UFR

(c) Coordination of SSC at operation of Busbar Protection

When bus-bar protection operates, some routes would be interrupted simultaneously. In this case, there is a possibility of simultaneous operation of the some SSCs, so coordination between SSCs is required to avoid over-control. In case of the operation of the busbar protection in **Figure 6.2-1**, SSC-I would shed some loads for the islanded Network-I as the double-circuit Line AB is simultaneously tripped, and SSC-II would shed some loads for the islanded Network II as the double-circuit Line BC is simultaneously tripped. When the busbar protection at B substation operates, the power systems are separated at both Line AB and Line BC, so both SSC-I and SSC-II would be triggered and cause excessive load shedding. To avoid this over-control, the operation signal of the bus-bar protection is sent to the SSC-I to block the control of SSC-I, and the SSC-II would perform the remedial control alone.

(2) Coordination between SPSs with Different Purposes

(a) Coordination between SSC and TSC

The SPSs installed by certain purpose in each protected section. And they operate individually in normal condition. But, in the case that two SPS systems start to control same generator plants or loads, it should be controlled with coordination.

As example, the coordination between predictive out-of-step protection and predictive abnormal frequency protection is described as following where a transient stability control relay system (TSC) and a predictive abnormal frequency protection relay (SSC) are installed in the same system.

The TSC limits the power supply at the time of a predicted severe fault, and the SSC limits the power supply and load in the islanding system at the time of system islanding due to a power system separation fault. Both TSC and SSC, however, have the same power supply shedding target. Here, in cases where a severe fault other than power system separation occurs, causing islanding as a result of missing high-speed reclosing, both systems operate resulting in the potential for excessive power supply shedding if coordination with respect to power supply shedding target selection is not achieved. Thus, the system is designed so that the shedding target information for each fault point determined based on advance calculation is sent from TSC to SSC, enabling the prioritized selection of the sent shedding target at the time the shedding target is selected by SSC. This prevents output of the shedding command from both systems to the same shedding target, thereby preventing overshedding (See **Figure 6.2-3**).

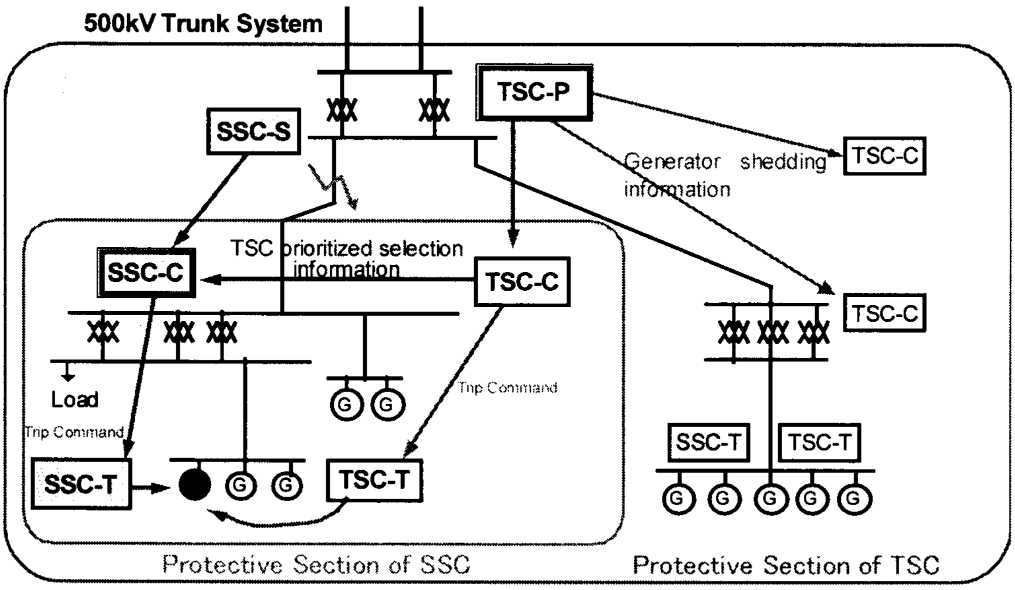


Figure 6.2-3 Coordination between SPSs with Different Purposes

(b) Coordination between the Frequency Relay System and Overload Protection Relay Systems

If the active power balance control is conducted due to the balance of total active power within the separated power system, overload might occur in the separated power system. At this time, if the overload protection system would shed some generators or some loads in the isolated power system, there is a possibility that the active power balance might collapse and the isolated power system might go unstable. As this countermeasure, the frequency relay system has the function to change the controlled objects to prevent from overload within the isolated power system during the operation process of the controlled objects.

(3) Coordination between SPSs with Different Calculation Methods

The SPSs installed by certain purpose in each protected section. And they operate individually in normal condition. But, in the case that two SPS systems start to control by same point fault, it should be controlled with coordination.

As example, the coordination between a predictive out-of-step protection relay installed for a large-capacity power supply group, and a predictive out-of-step protection relay installed for the pump group described as following;

The following describes an example where a predictive out-of-step protection relay is installed for a large-capacity power supply group eccentrically located on the east side of the system and the pump group eccentrically located on the west side of the system, respectively. When both systems are activated as a result of a severe fault in the main system, control calculations that reflect the effect of the control of the other system must be performed. Thus, when it has been assessed that pumping is in progress in the power supply side relay system, the system assesses that the pump side relay system is implementing control and must adopt a method for compensating its own controlled variable calculation in anticipation of the effect. The phase differential with the main system is used in the controlled variable calculation and, since data transmission is not performed between the two systems, the pumping operation status is detected based on the trend of the phase angle of the main system at about 50ms after fault elimination, applying compensation for only the phase angle differential compensation portion given by the setting value.

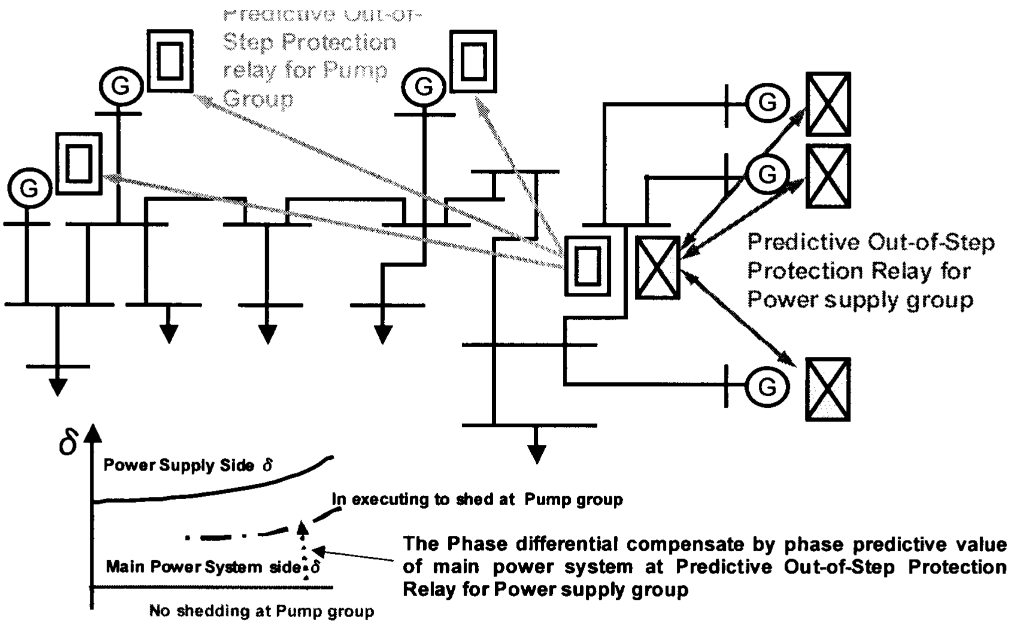


Fig.6.2-4 Coordination between SPSs with Different Calculation Methods

7. Conclusion

Protection system depends not only on the reliability and technical excellence of its components but also on the adequacy of the functions to the application for which they were designed. Protection system, as many other systems, is not made by ideal entities, but by dispersed, discrete and non error-free ones. These devices, or more generally functions need to be linked with each other in an organized manner in order to allow the Protection System acting as a whole and in a selective way. Protection coordination is the technique, art or process that makes this possible.

Due to the recent complexity of the power system and severe requirement to it, protection coordination becomes more difficult and more sophisticated. Under such circumstances, protection coordination was chosen as the main scope of this working group.

From around the world, many specialists of protection engineering joined to this working group, and through their endeavour to achieve the goal, lots of actual schemes applied in the world and coordination studies were presented with detailed sequences of the coordination between protective relaying devices and functions, illustrating with concrete situations.

The report also presents the results of a worldwide questionnaire regarding protection system functions breakdown by power system components, voltage level, Main and Backup, including Special Protection Schemes applications. These are also very vital information to support this working report. The members had lots of discussions in order to choose and converge various ideas from the world into the statement presented before.

This was also tough coordination. It is impossible to pick up all schemes or ideas presented by participants. If some of them are omitted in this report, it does not mean they are not valid.

We know each utility or manufacturer owns concrete philosophy to establish integrity of power system protection by using their techniques. However, we are sure the objectives of protection coordination are the same.

This report introduces protection principles and coordination issues together with countermeasures actually applied in the world. Further, this report covers general protection theories, even though main theme of this report is protection coordination, and this would also be helpful.

We are confident that this report will give the vital information to the readers, especially those who are working with protection relays. We are very pleased if readers make full use of this information presented in this report and establish the best protection coordination to fit their power systems. The power system is a very organic entity, and therefore there may be many solutions, but any schemes introduced in this report have been used before, and the successful operations were proved.

The choice of topics presented in this report is based on the opinions of the members with many years of experience in power system protection. This report is presented in a way, which enables readers to find out their requiring topic easily. It is with this hope and intention in mind that members of this working group have written this report.

Acknowledgement

We received much meaningful information from many colleagues as well as WG members and we have learned a lot about the protection systems or the coordination issues from those results. As to the results of the questionnaire in the report, when two or more replies could be obtained from one country, it displayed as a reply from one country. Moreover, the results of the questionnaire for HV systems may be insufficient from the reason why some electric power companies or ISO don't have the transmission systems for all voltage classes. However, we fully appreciate their concerns about sincerely filling out the questionnaire although they were busy.

We thank heartily for all WG members and our friends here.

Finally, our sincere thanks to our colleagues who contributed to the questionnaire presented in this report are introduced;

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Kansai Electric Power Company, Inc., JP
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