

Fundamentals of Power System Protection

Y.G. Paithankar

S.R. Bhide



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FUNDAMENTALS OF POWER SYSTEM PROTECTION
Y.G. Paithankar and S.R. Bhide

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Preface

Power System Protection is a fascinating subject. A protection scheme in a power system is designed to continuously monitor the power system to ensure maximum continuity of electrical supply with minimum damage to life, equipment, and property. While designing the protective schemes, one has to understand the fault characteristics of the individual power system elements. One should also be knowledgeable about the tripping characteristics of various protective relays. The job of the protection engineer is to devise such schemes where closest possible match between the fault characteristics and the tripping characteristics is obtained. The design has to ensure that relays will detect undesirable conditions and then trip to disconnect the area affected, but remain restrained at all other times. However, there is statistical evidence that a large number of relay trippings are due to improper or inadequate settings than due to genuine faults. It is therefore necessary that students should be equipped with sound concepts of power system protection to enable them to handle unforeseen circumstances in real life.

Whenever a tripping takes place it has all the elements of intrigue, drama, and suspense. A lot of detective work is usually undertaken to understand the reason behind the tripping. It needs to be established why the relay has tripped. Whether it should have tripped at all. What and where was the fault? These are some of the questions required to be answered. This is because a power system is a highly complex and dynamic entity. It is always in a state of flux. Generators may be in or out of service. New loads are added all the time. A single malfunction at a seemingly unimportant location has the potential to trigger a system-wide disturbance. In view of such possible consequences, a protective system with surgical accuracy is the only insurance against potentially large losses due to electrical faults.

Protective relays are meant to mitigate the effects of faults. This text treats the entire spectrum of relays, from electromechanical to the state-of-the-art numerical relays, for protection of transmission lines, turbo-alternators, transformers, busbars, and motors. However, it is ironic that every additional protective relay also increases the possibility of disturbance by way of its (relay's) own malfunction. This is possibly an area where protection tends to become an art. The protection engineer has to strike a balance between the threat perception and the security offered by the protective scheme.

The book is focused on teaching the fundamental concepts and the related design aspects of protective relay schemes. Written in a simple, clear and down-to-earth style, this state-of-the-art text offers students of electrical engineering a stimulating presentation that is both friendly and refreshingly simple.

The text contains a wealth of figures, block diagrams, and tables to illustrate the concepts discussed. The graphics are extensively annotated. The students are urged to spend some time to read the annotations on the figures, so that learning becomes easy and concepts are reinforced.

Though the book's audience consists mainly of final year electrical engineering students, the practising engineers, interested in learning the fundamental concepts of power system protection, will also find it useful. The authors will gratefully receive suggestions and comments from the readers for improvement of the book.

**Y.G. PAITHANKAR
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1

Introduction

1.1 Dependence of Modern Society on Electric Supply

The modern society has come to depend heavily upon continuous and reliable availability of electricity—and a high quality of electricity too. Computer and telecommunication networks, railway networks, banking and post office networks, continuous process industries and life support systems are just a few applications that just cannot function without a highly reliable source of electric power. And add to this, the mind-boggling number of domestic users of electricity whose life is thrown out of gear, in case the electric supply is disrupted. Thus, the importance of maintaining continuous supply of electricity round the clock cannot be overemphasized.

No power system can be designed in such a way that it would never fail. So, one has to live with the failures. In the language of protection engineers, these failures are called *faults*. There is no negative connotation to the word *fault* in this context. What is more important is, how to prevent the faults and how to mitigate the consequences of the faults. The ill effects of faults are minimized by quickly isolating the faulty element from the rest of the healthy system; thus limiting the disturbance footprint to as small an area in time and space as possible.

1.2 Faults and Abnormal Operating Conditions

1.2.1 Shunt Faults (Short Circuits)

When the path of the load current is cut short because of breakdown of insulation, we say that a 'short circuit' has occurred. The insulation can break down for a variety of reasons, some of which are listed in Section 1.2.2. Figure 1.1 shows a single line-to-ground fault on a transmission line due to flashover of spark gap across the string insulator.

Such faults due to insulation flashover are many times temporary, i.e. if the arc path is allowed to deionize, by interrupting the electrical supply for a sufficient period, then the arc does not re-strike after the supply is restored. This process of interruption followed by intentional re-energization is known as *reclosure*. In low-voltage systems up

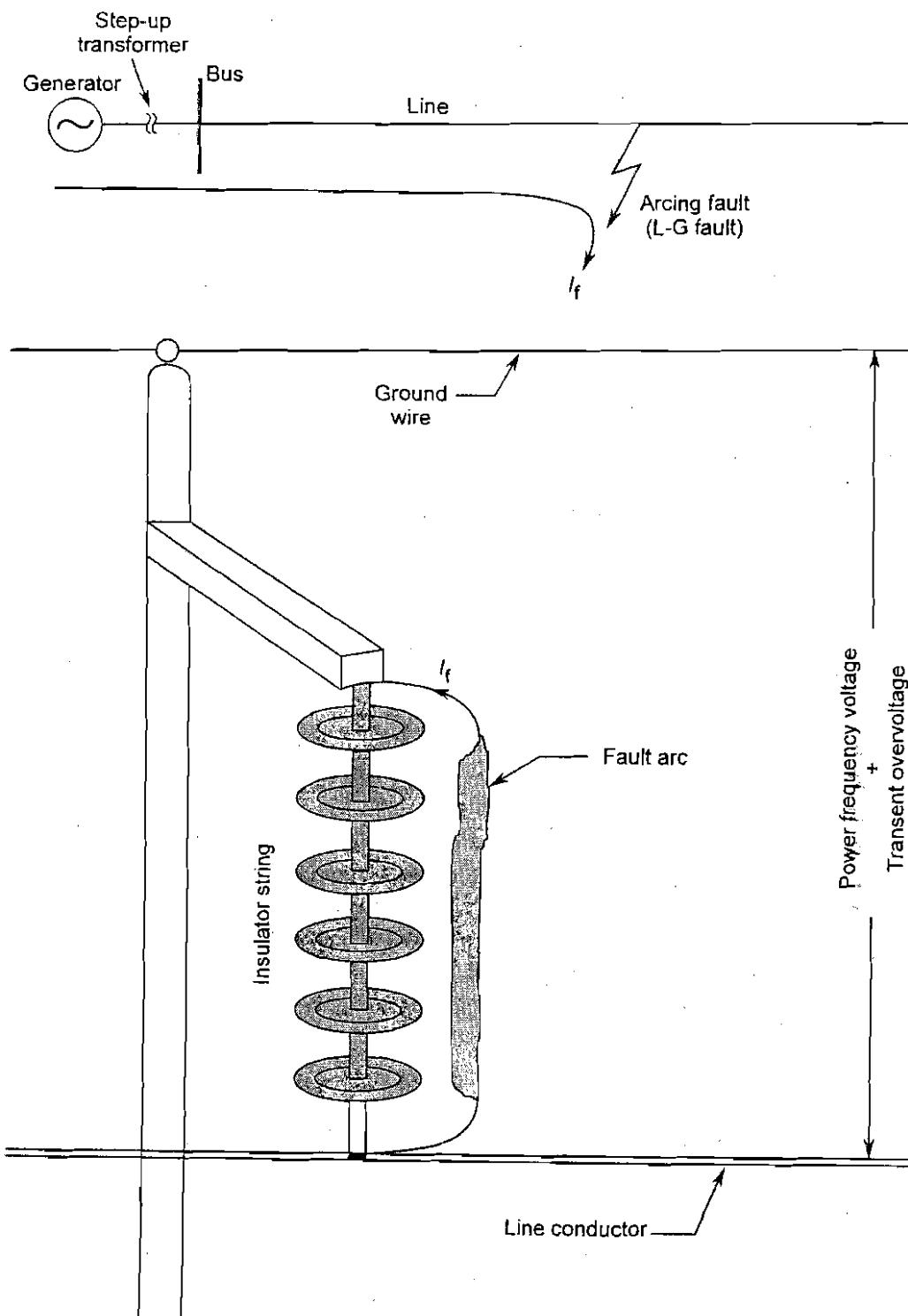


Figure 1.1 Single line-to-ground fault due to flashover of insulator string.

to three reclosures are attempted, after which the breaker is locked out. The repeated attempts at reclosure, at times, help in burning out the object which is causing the breakdown of insulation. The reclosure may also be done automatically. In EHV systems,

2. breaker lock out

where the damage due to short circuit may be very large and the system stability at stake, only one reclosure is allowed.

At times the short circuit may be total (sometimes called a *dead short circuit*), or it may be a partial short circuit. A fault which bypasses the entire load current through itself, is called a *metallic fault*. A metallic fault presents a very low, practically zero, *fault resistance*. A partial short circuit can be modelled as a non-zero resistance (or impedance) in parallel with the intended path of the current. Most of the times, the fault resistance is nothing but the resistance of the arc that is formed as a result of the flashover. The arc resistance is highly nonlinear in nature. Early researchers have developed models of the arc resistance. One such widely used model is due to Warrington, which gives the arc resistance as:

$$R_{\text{arc}} = \frac{8750(S + 3ut)}{I^{1.4}}$$

where

S is the spacing in feet

u is the velocity of air in mph

t is the time in seconds

I is the fault current in amperes.

1.2.2 Causes of Shunt Faults

Shunt faults are basically due to failure of insulation. The insulation may fail because of its own weakening, or it may fail due to overvoltage. The weakening of insulation may be due to one or more of the following factors:

- Ageing
- Temperature
- Rain, hail, snow
- Chemical pollution
- Foreign objects
- Other causes

The overvoltage may be either internal (due to switching) or external (due to lightning).

1.2.3 Effects of Shunt Faults

If the power system just consisted of isolated alternators feeding their own loads, then the steady-state fault currents would not be much of a concern. Consider an isolated turboalternator with a three-phase short circuit on its terminals as shown in Figure 1.2. Assuming the internal voltage to be 1 p.u. and a value of synchronous impedance, $X_d' = 2$ p.u., the steady-state short-circuit current would only be 0.5 p.u. which is too small to cause any worry. However considering subtransient impedance, $X_d'' = 0.1$, the subtransient current would be 10 p.u. We must not, however, forget that in an

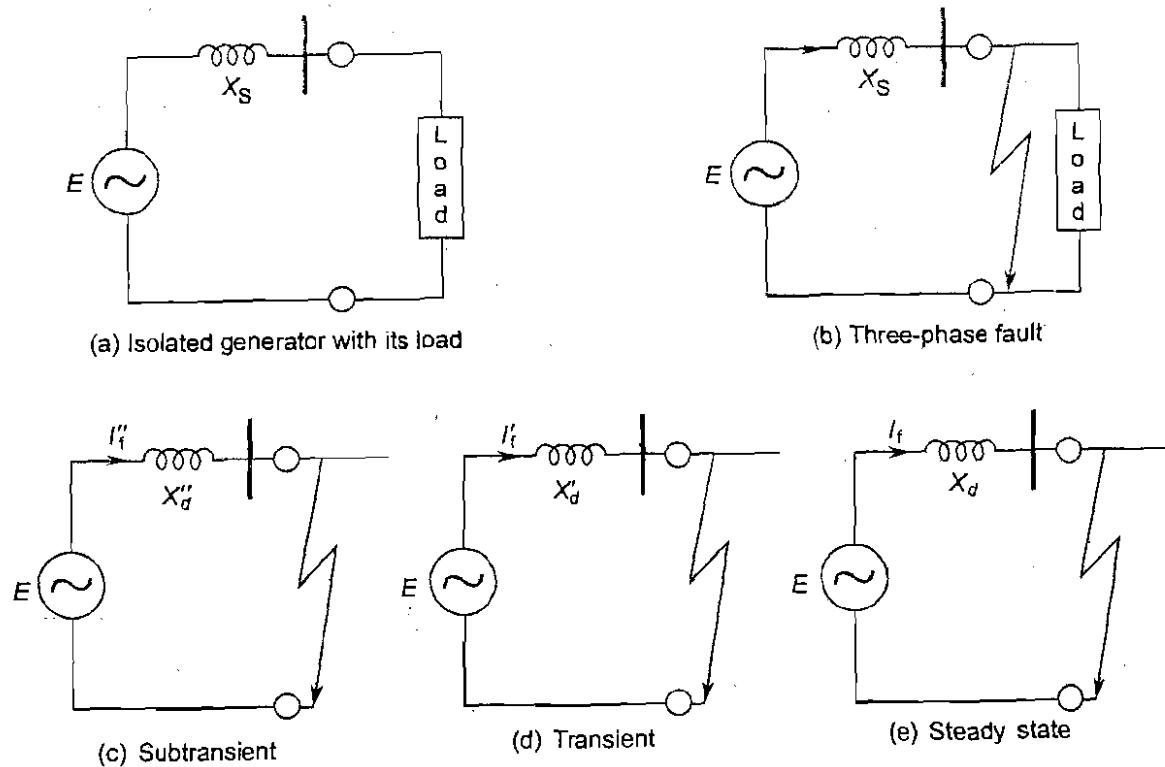


Figure 1.2 Isolated generator experiences a three-phase fault.

interconnected power system all the generators (and even motors) will contribute towards the fault current, thus building up the value of the fault current to couple of tens of times the normal full-load current.

Faults, thus, cause heavy currents to flow. If these fault currents persist even for a short time, they will cause extensive damage to the equipment that carry these currents. Over-currents, in general, cause overheating and attendant danger of fire. Overheating also causes deterioration of the insulation, thus weakening it further. Not so apparent is the mechanical damage due to excessive mechanical forces developed during over-current. Transformers are known to have suffered mechanical damage to their windings, due to faults. This is due to the fact that any two current-carrying conductors experience a force. This force goes out of bounds during faults, causing mechanical distortion and damage.

Further, in an interconnected system, there is another dimension to the effect of faults. The generators in an interconnected power system must operate in synchronism at all instants. The electrical power output from an alternator near the fault drops sharply. However the mechanical power input remains substantially constant at its pre-fault value. This causes the alternator to accelerate. The rotor angle δ starts increasing. Thus, the alternators start swinging with respect to each other. If the swing goes out of control, the alternators will have to be tripped out. Thus, in an interconnected power system, the system stability is at stake. Therefore, the faults need to be isolated as selectively and as speedily as possible.

1.3 Classification of Shunt Faults

1.3.1 Phase Faults and Ground Faults

Those faults, which involve only one of the phase conductors and ground, are called **ground faults**. Faults involving two or more phase conductors, with or without ground, are called **phase faults**.

Power systems have been in operation for over a hundred years now. Accumulated experience shows that all faults are not equally likely. Single line to ground faults (L-G) are the most likely whereas the fault due to simultaneous short circuit between all the three lines, known as the **three-phase fault** (L-L-L), is the least likely. This is depicted in Table 1.1

Table 1.1 Fault statistics with reference to type of fault

Fault	Probability of occurrence (%)	Severity
L-G	85%	Least severe
L-L	8%	
L-L-G	5%	
L-L-L	2%	Most severe
Total	100%	

Further, the probability of faults on different elements of the power system are different. The transmission lines which are exposed to the vagaries of the atmosphere are the most likely to be subjected to faults. Indoor equipment is least likely to be subjected to faults. The fault statistics is shown in Table 1.2.

Table 1.2 Fault statistics with reference to power system elements

Power system element	Probability of faults (%)
Overhead lines	50
Underground cables	9
Transformers	10
Generators	7
Switchgear	12
CT, PT relays, control equipment, etc	12
Total	100%

The severity of the fault can be expressed in terms of the magnitude of the fault current and hence its potential for causing damage. In the power system, the three-phase fault is the most severe whereas the single line-to-ground fault is the least severe.

1.3.2 Phasor Diagram of Voltages and Currents During Various Faults

A fault is accompanied by a build-up of current, which is obvious. At the same time there

is a fall in voltage throughout the power system. If the fault is a metallic fault, the voltage at the fault location is zero. The voltage at the terminals of the generator will also drop, though not drastically. If the source is ideal, there will be no drop in voltage at the generator terminals. Normally the relay is away from the fault location. Thus, as seen from the relay location, a fault is characterized by a build-up of current, and to a certain extent, collapse of voltage.

Figure 1.3 depicts various ground faults as well as phase faults.

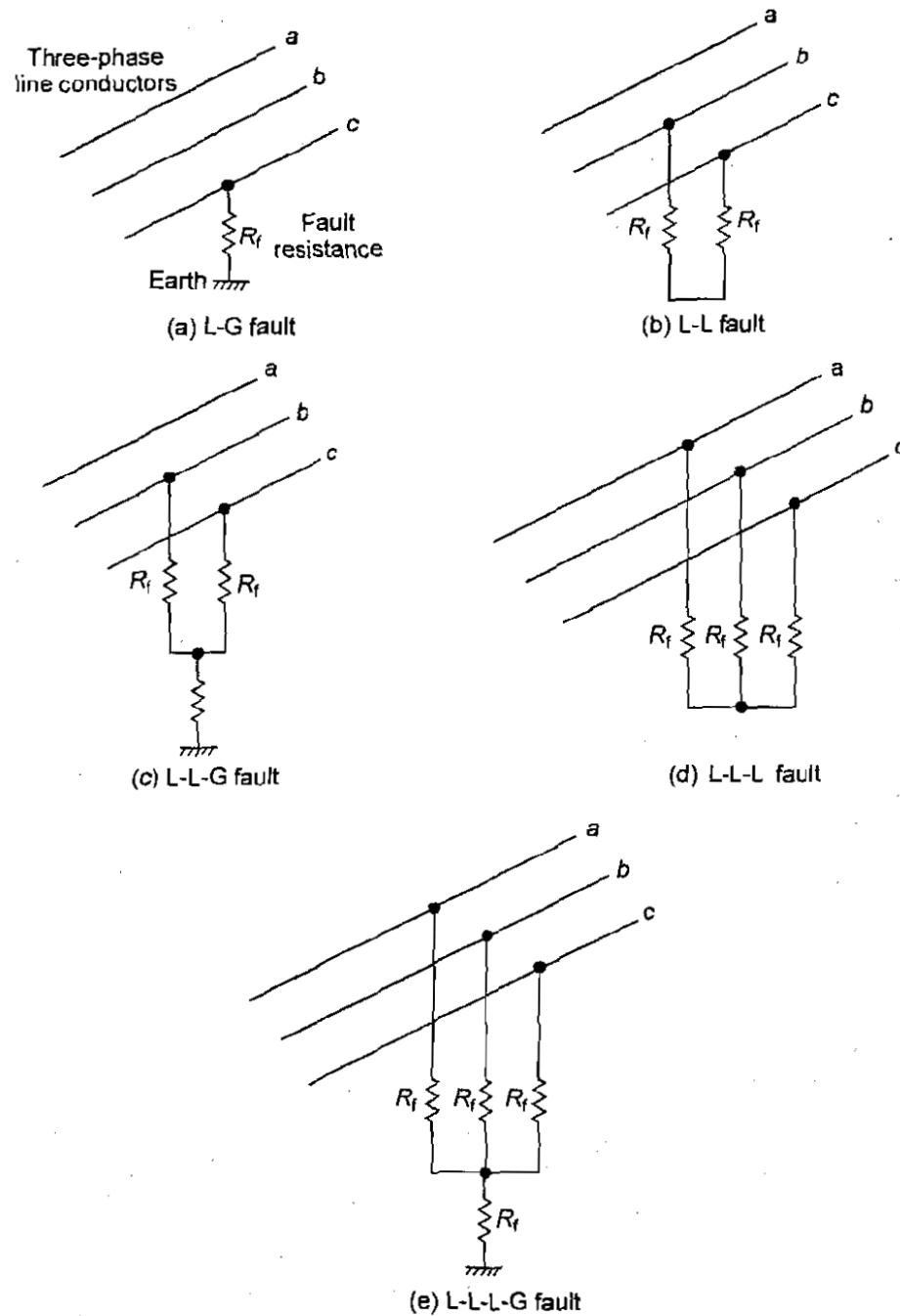


Figure 1.3 Various ground faults and phase faults.

Figure 1.4 depicts a radial power system with a fault near the remote end of the transmission line. It can be seen from the phasor diagram that the voltage at the relay location during fault is less in magnitude than that during the pre-fault condition and also lags its pre-fault value. In order not to clutter the diagram, only phase a voltage is shown. In Figure 1.5, the distortion in voltages during all the 11 shunt faults are considered.

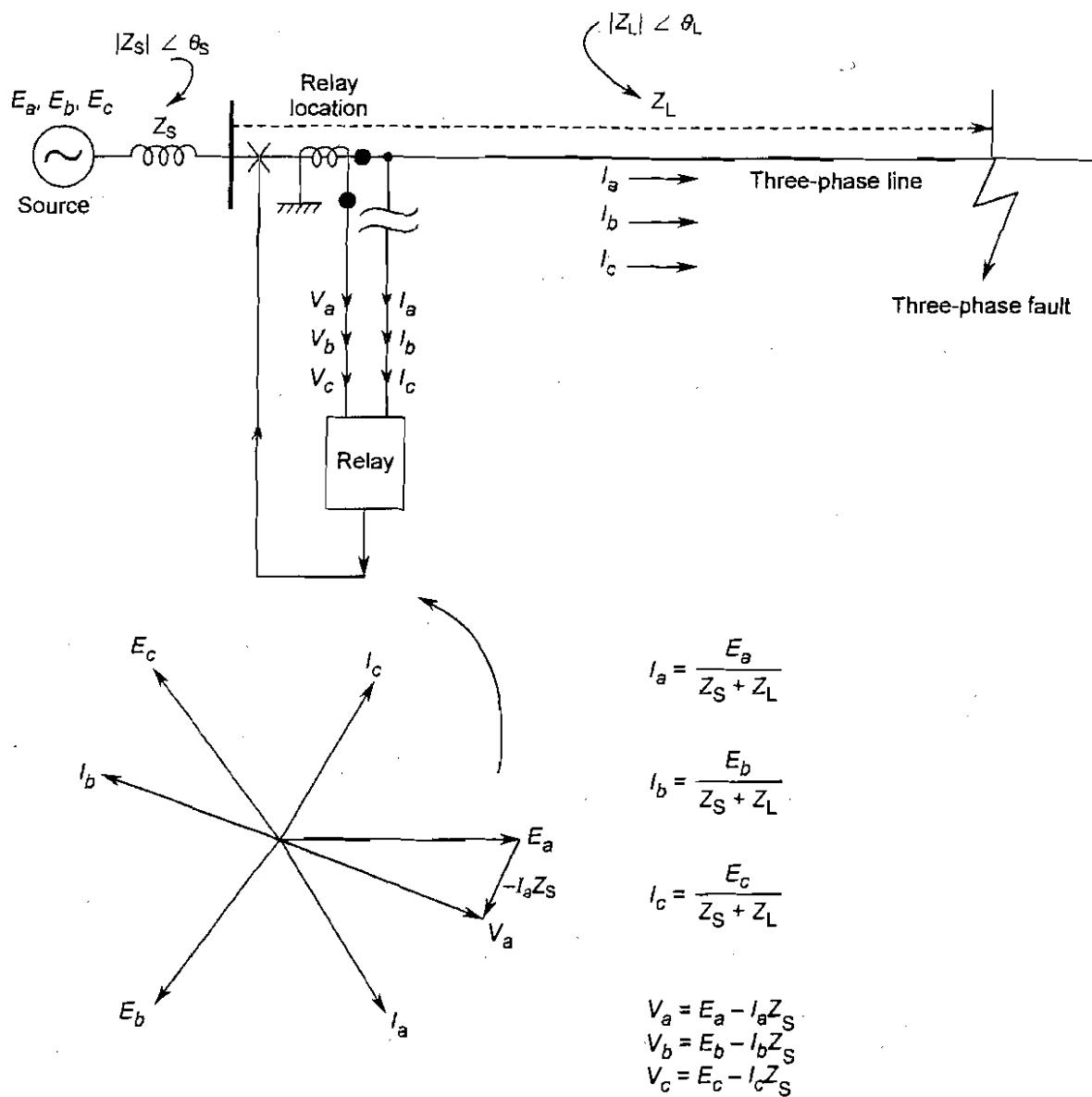


Figure 1.4 Fall of voltage at the relay location shown on single-line diagram of a three-phase system.

1.3.3 Series Faults

Series faults are nothing but a break in the path of current. Normally such faults do not result into catastrophes except when the broken conductor touches other conductor or

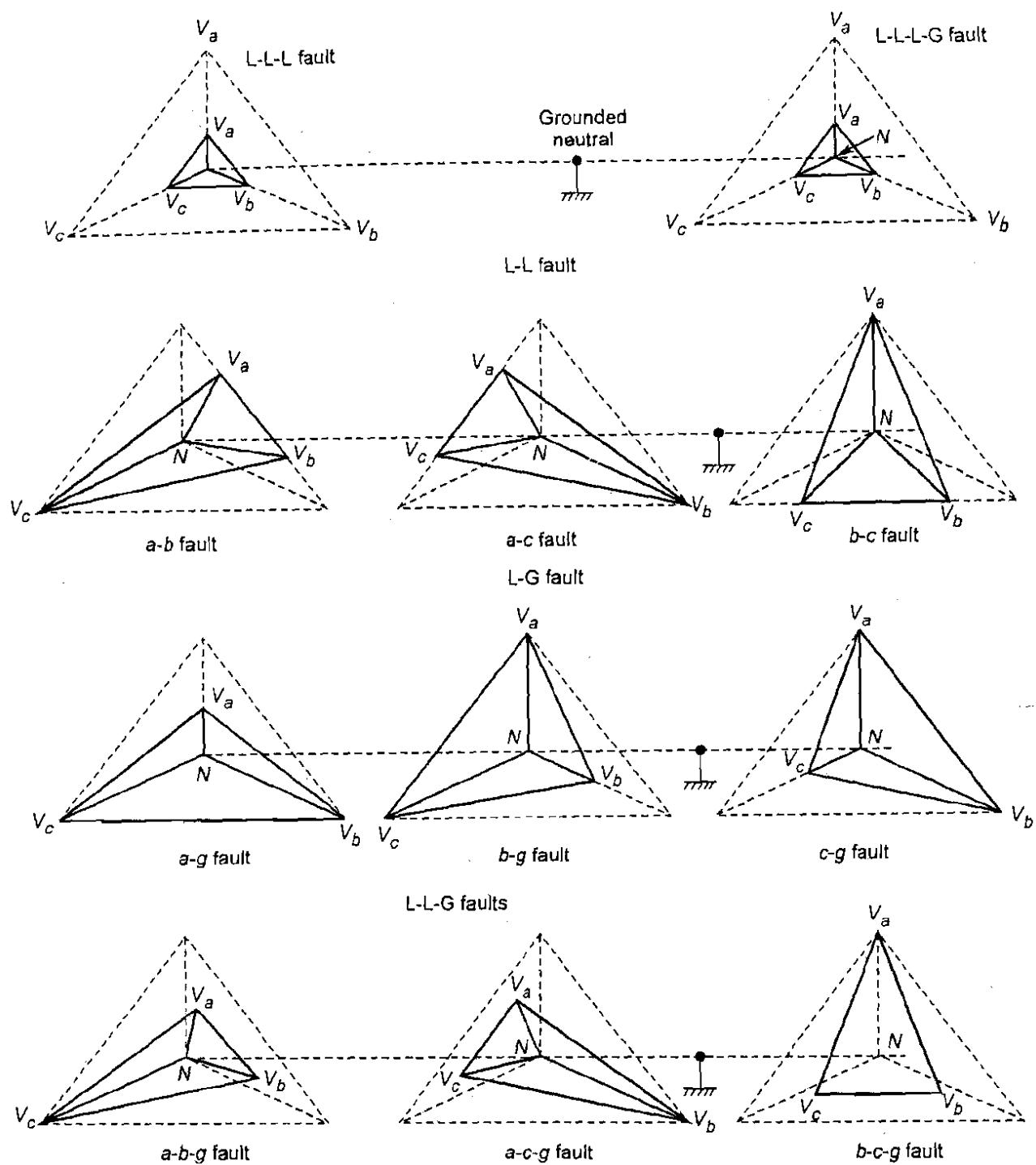


Figure 1.5 Voltages at the relay location during various faults.

some grounded part. It is observed in practice that most of the open conductor faults sooner or later develop into some or the other short-circuit fault. However, there are some instances where an open circuit can have dangerous consequences. For example, the secondary circuit of a current transformer and the field circuit of a dc machine if open circuited, can have dangerous consequences.

1.4 Abnormal Operating Conditions

The boundary between the normal and faulty conditions is not crisp. There are certain operating conditions inherent to the operation of the power system which are definitely not normal, but these are not electrical faults either. Some examples are the magnetizing inrush current of a transformer, starting current of an induction motor, and the conditions during power swing.

1.4.1 Should Protective Relays Trip During Abnormal Operating Conditions?

How the protective system should respond to the abnormal operating conditions needs careful consideration. It may or may not be required to take cognizance of the abnormal operating condition. Some examples of abnormal operating conditions are starting currents of motors, inrush currents of transformers and stable power swings. Magnitude-wise, these currents may qualify as faults, but there is no need to provide protection from them. Thus, the protective system must be able to discriminate between the normal operating conditions, abnormal operating conditions, and faults.

1.4.2 Can Protective Relays Prevent Faults?

It can be seen from the above discussion that protective relays cannot prevent faults. To a certain extent, faults can be prevented by using the properly designed and maintained equipment. However, it is not possible to totally prevent the occurrence of faults.

1.4.3 What are Protective Relays Supposed to Do?

The protective relays are supposed to detect the fault with the help of current and voltage transformers, and selectively remove only the faulty part from the rest of the system by tripping an appropriate number of circuit breakers. This, the relay has to do with utmost sensitivity, selectivity and speed. In a power system, faults are not an everyday occurrence. A typical relay, therefore, spends all of its life monitoring the power system. It must, therefore, be ready all the time in anticipation of a fault. It is said that a relay operates far more number of times during testing and maintenance than during actual fault! Thus, relaying is like an insurance against damage due to faults.

1.5 Evolution of Power Systems

Power systems have evolved from isolated generators feeding their own loads to huge interconnected power systems spanning an entire country. The evolution has progressed from low-voltage systems to high-voltage systems and low-power handling capacities to high-power handling capacities. The requirements imposed on the protective system are closely linked to the nature of the power system.

1.5.1 Isolated Power System

The protection of an isolated power system is simpler because firstly, there is no concentration of generating capacity and secondly, a single synchronous alternator does not suffer from the stability problem as faced by a multi-machine system. Further, when there is a fault and the protective relays remove the generator from the system, the system may suffer from a blackout unless there is a standby source of power. As shown in Section 1.2.3, the steady-state fault current in a single machine power system may even be less than the full-load current. Such a fault will, however, cause other effects like speeding up of the generator because of the disturbed balance between the input mechanical power and the output electrical power, and therefore should be quickly attended to. Although, there are no longer any isolated power systems supplying residential or industrial loads, we do encounter such situations in case of emergency diesel generators powering the uninterrupted power supplies as well as critical auxiliaries in a thermal or nuclear power station.

1.5.2 Interconnected Power System

An interconnected power system has evolved because it is more reliable than an isolated power system. In case of disruption in one part of the system, power can be fed from alternate paths, thus, maintaining continuity of service. An interconnected power system also makes it possible to implement an economic load dispatch.

The generators in an interconnected system could be of varied types such as turboalternators (in coal fired, gas fired or nuclear power plants), generators in hydroelectric power plants, wind-powered generators, fuel cells or even solar-powered photovoltaic cells.

Figure 1.6 shows a simple interconnected power system. Most of the generators operate at the voltage level of around 20 kV. For bulk transmission of power, voltage levels of the order of 400 kV or higher are used. At the receiving end, the voltage is stepped down to the distribution level, which is further stepped down before it reaches the consumers.

It can be seen that the EHV lines are the *tie* lines which interconnect two or more generators whereas the low voltage lines are radial in nature which terminate in loads at the remote ends.

There is interconnection at various EHV voltage levels.

1.5.3 Negative Synergy of an Interconnected System

There are other undesirable effects of interconnection. It is very difficult to maintain stability in a massively interconnected system. Disturbances quickly propagate throughout the system endangering the integrity of the whole system. Possibility of cascade tripping due to loss of stability is always looming large. In addition to the angle stability problem, an interconnected system also suffers from the voltage stability problem. Further, undesirable effects, such as harmonic distortion, propagate throughout the system rather than remain localized. Also, there is the possibility of cyber-attacks and acts of malicious hacking, which have a greater footprint in the case of an interconnected

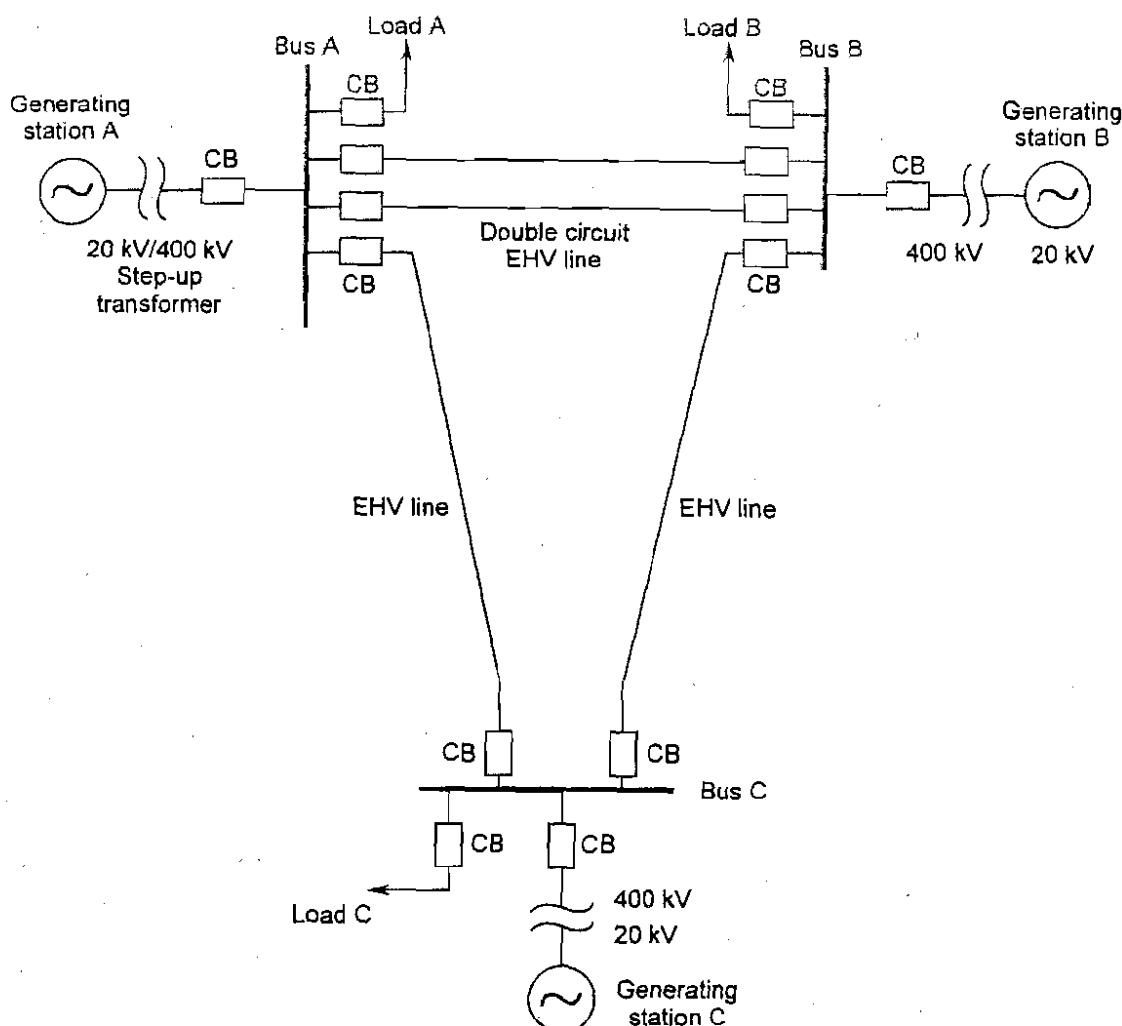


Figure 1.6 Single-line diagram of a simple interconnected power system.

power system. This can be called the *synergy*, of the negative type, which inevitably accompanies the interconnection. However, these are the perils of the so-called modern way of life that we have adopted and have to be taken as an opportunity to devise newer and novel methods of protection.

1.5.4 Various States of Operation of a Power System

A power system is a dynamic entity. Its state is likely to drift from one state to the other as shown in Figure 1.7. When the power system is operating in steady state, it is said to be in the normal operating state. In this state, there is enough generation capacity available to meet the load, therefore, the frequency is stable around the nominal frequency of 50 Hz or 60 Hz. This state is also characterized by reactive power balance between generation and load. This is reflected as a flat voltage profile with normal voltage throughout the system. The above is almost a theoretical proposition and a real power system rarely finds itself in this state.

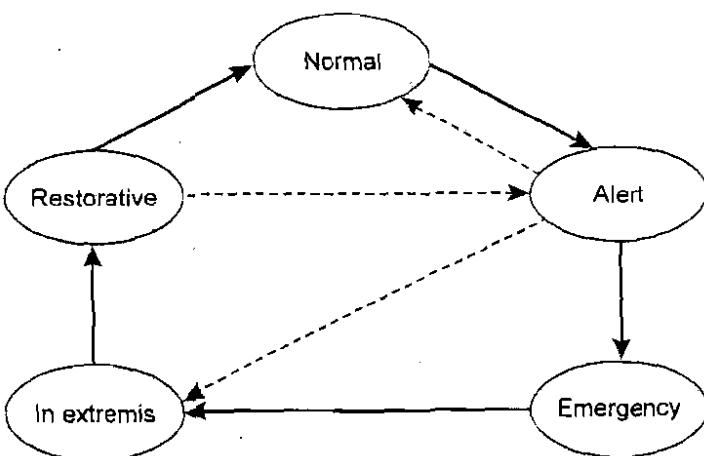


Figure 1.7 Various states of the power system.

Another possible state of the power system is the alert state. In this state, all the parameters are within the limits but a major disturbing event is imminent, for example, a mighty storm, accompanied by lightning, which threatens to put some major EHV tie line out of service. From this state the system may hurtle into the *in-extremis* state, as a result of major tripping, after passing through an *emergency* state. In the emergency state there could be overloading in certain tie lines, the system frequency may take a significant plunge or may surge and the voltage profile may be far from flat. The emergency situation may lead to total ac failure as a result of cascade tripping. This is indeed the nightmare and the system controllers at the load dispatch centres try their best to avoid it.

What has all these states of the power system to do with relaying? A little thought will show that on the one hand relaying is profoundly affected by the state of the system while on the other, the system's fate is decided by the settings of the relays. Ideally, relay settings must be live to the system state and must change so as to operate in the best interest of system stability and security. There are, however, certain other ground realities which prevent us from implementing a totally adaptive online relay setting philosophy. The relay engineers want their protective system to be as simple as possible. There is overwhelming evidence that the simpler the systems are, the more reliable they are. Thus the relay engineers follow the KISS philosophy; Keep It Simple, Stupid!

1.5.5 From Natural Monopoly to the Deregulated Power System

The electrical power system was always considered to be a natural monopoly. Recently, however, the world over, there is a paradigm shift. The industry is being deregulated. In this scenario, big electric utility companies are no longer monopolizing the generation of electric power. The field is open for smaller players. The customers have a choice to buy electricity from the cheapest bidder (albeit through the distribution company). This has opened many technical and administrative issues which, up till now, were non-existent. The relaying engineer cannot remain unaffected by this change which is sweeping through the power industry. We shall, however, not discuss this aspect further in this introductory text.

1.6 A Protection System and Its Attributes

Figure 1.8 shows a protection system for the distance protection of a transmission line, consisting of a CT and a PT, a relay and its associated circuit breaker. Every protection system will have these basic components. (In non-directional over-current protection, as well as in differential protection, the PT will not be required.) The CT and the PT are briefly discussed in Section 1.7.

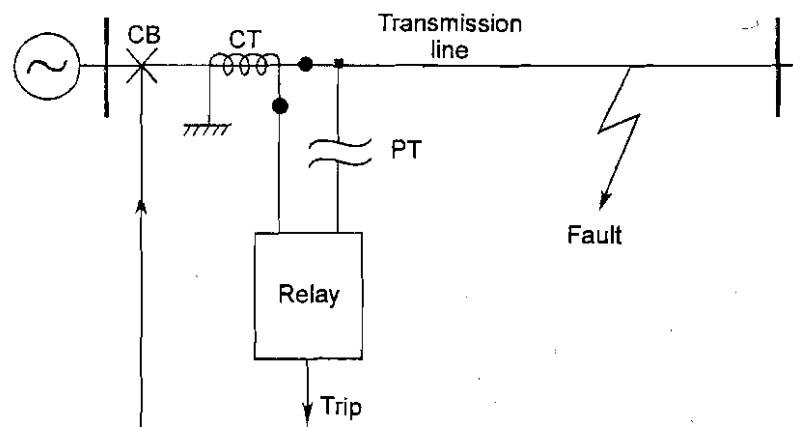


Figure 1.8 The protection system.

At this stage, we can consider the relay as a black-box having current and voltage at its input, and an output, in the form of the closure of a normally-open contact. This output of the relay is wired in the trip circuit of the associated circuit breaker(s) so as to complete this circuit. The relay has another user settable input which is the setting of the relay. The relay carries out the processing of information provided by the CT and the PT in accordance with some predetermined logic to arrive at a discriminant, and compares it with the settings to take a trip/no-trip decision. The conceptual diagram of a generalized relay is shown in Figure 1.9.

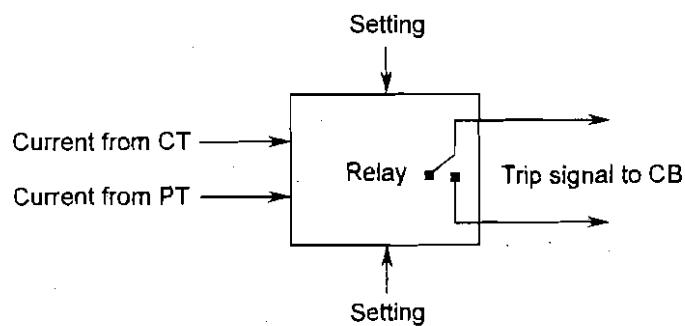


Figure 1.9 Conceptual diagram of a relay.

Without entering into the discussion about how it is to be achieved, it is possible at this stage to enumerate certain general properties that a protective system should possess. This is more or less like a wish list, in the mind of a protection engineer.

1.6.1 Sensitivity

The protective system must be alive to the presence of the smallest fault current. The smaller the fault current it can detect, the more sensitive it is.

1.6.2 Selectivity

In detecting the fault and isolating the faulty element, the protective system must be very selective. Ideally, the protective system should zero-in on the faulty element and isolate it, thus causing minimum disruption to the system.

1.6.3 Speed

The longer the fault persists on the system, the larger is the damage to the system and higher is the possibility that the system will lose stability. Thus, it helps a lot if the entire process of fault detection and removal of the faulty part is accomplished in as short a time as feasible. Therefore, the speed of the protection is very important. It must, however, be mentioned that speed and accuracy bear an inverse relationship! The high-speed systems tend to be less accurate. This is for the simple reason that the high-speed system has lesser amount of information at its disposal than a slow-speed system. The protection engineer has to strike a balance between these two incompatible requirements.

1.6.4 Reliability and Dependability

A protective system is of no use if it is not reliable. There are many ways in which reliability can be built into the system. Good engineering judgement plays a great part in enhancing the reliability of the protective system. In general, it is found that simple systems are more reliable. Systems which depend upon locally available information, tend to be more reliable and dependable than those that depend upon the information at the remote end. However, in spite of best efforts to make the system reliable, we cannot rule out the possibility of failure of the (primary) protection system. Therefore, we add features like back-up protection to enhance the reliability and dependability of the protective system.

1.7 System Transducers

Current transformers and voltage transformers form a very important link between the power system and the protective system. These transducers basically extract the information regarding current and voltage from the power system under protection and pass it on to the protective relays. While doing this, they insulate the low-voltage protective system (both personnel and protective apparatus) from the high-voltage power system.

1.7.1 Current Transformer

The current transformer has two jobs to do. Firstly, it steps down the current to such levels that it can be easily handled by the relay current coil.

The standard secondary current ratings used in practice are 5 A and 1 A. This frees the relay designer from the actual value of primary current. Secondly, it isolates the relay circuitry from the high voltage of the EHV system. A conventional electromagnetic current transformer is shown in Figure 1.10. Ideally, the current transformer should faithfully transform the current without any errors. In practice, there is always some error. The error creeps in, both in magnitude and in phase angle. These errors are known as *ratio error* and *phase angle error*.

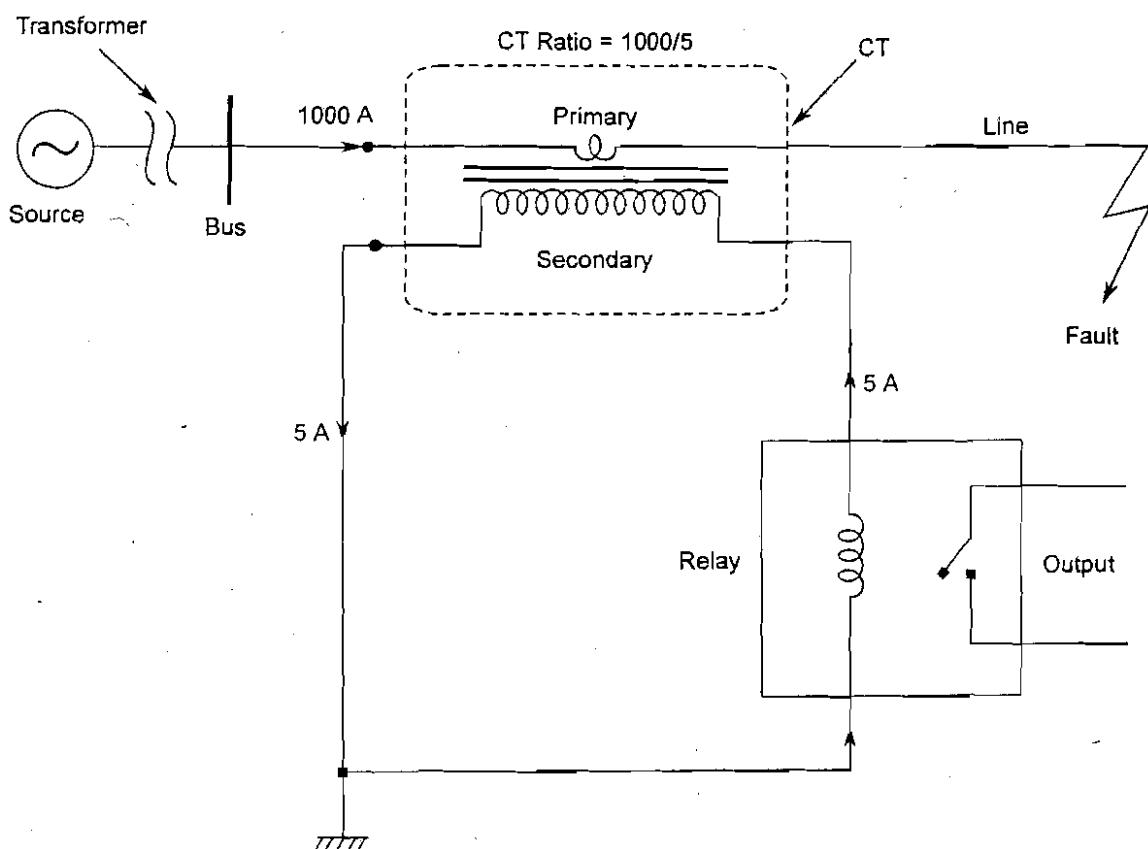


Figure 1.10 Current transformer.

It may be pointed out here, that current transformers are used for metering purposes as well. However, there is a very important difference between a metering CT and a protection CT. A metering CT is so designed (proportioned) that in case of faults, it will saturate and thus save the instrument connected to its secondary from damage due to excessive current. On the other hand, a protective CT is designed to faithfully reproduce the largest fault current. The operating points, on the excitation characteristics, for the two types of CTs are shown in Figure 1.11. Further treatment of CT errors is given in Appendix 1.

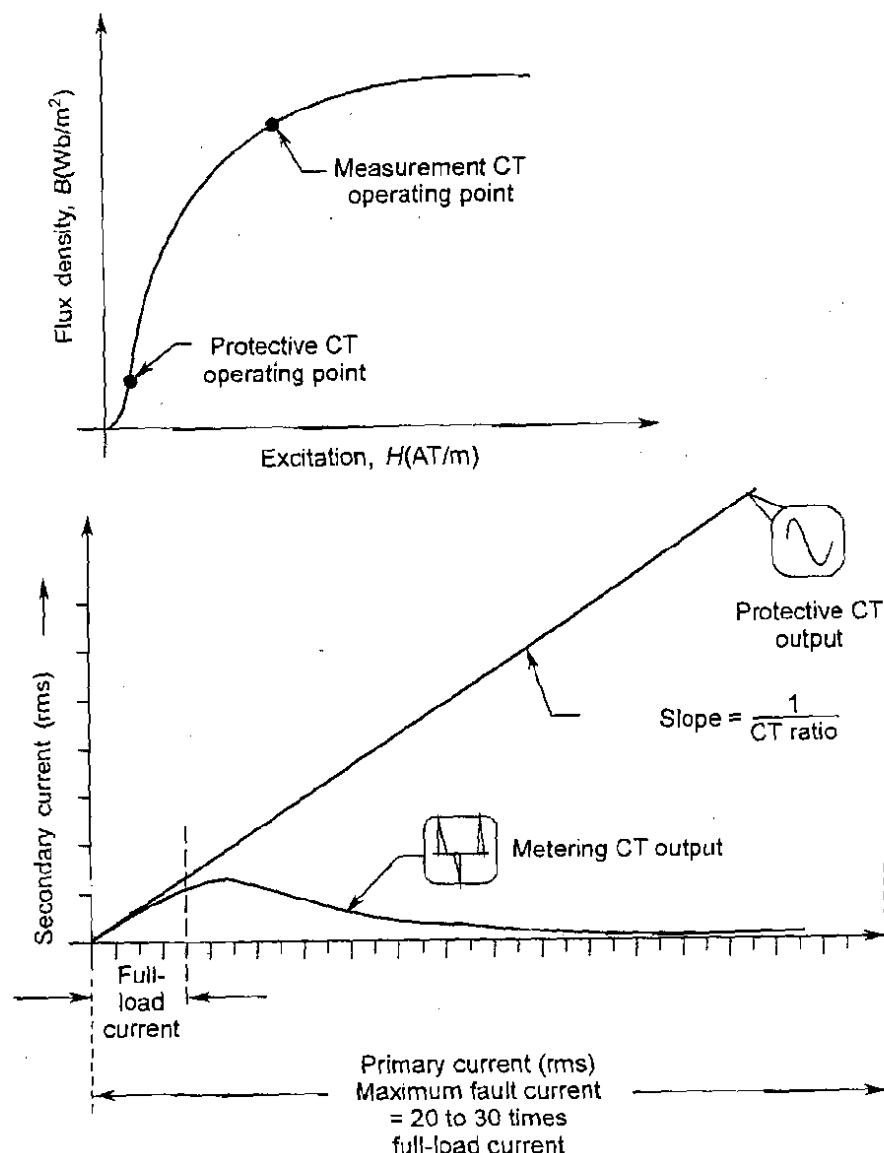


Figure 1.11 Protective CT vs measurement CT.

1.7.2 Voltage Transformer

The voltage transformer steps down the high voltage of the line to a level safe enough for the relaying system (pressure coil of relay) and personnel to handle. The standard secondary voltage on line-to-line basis is 110 V. This helps in standardizing the protective relaying equipment irrespective of the value of the primary EHV adopted.

A PT primary is connected in parallel at the point where a measurement is desired, unlike a CT whose primary is in series with the line in which current is to be measured. A conventional electromagnetic VT is shown in Figure 1.12. The VT also suffers from ratio and phase angle errors. Further treatment of VT errors can be found in Appendix 1.

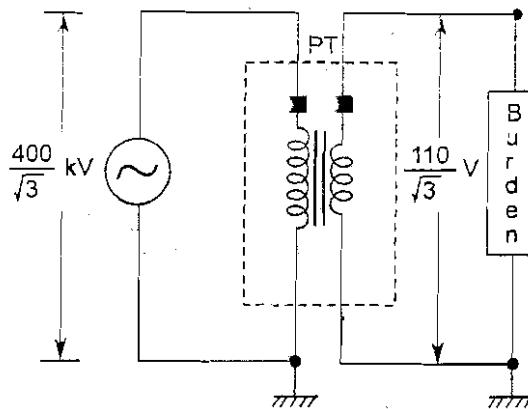


Figure 1.12 Potential (voltage) transformer (PT or VT).

Another type of VT that is commonly used in EHV systems is the Capacitive Voltage Transformer or CVT. This is dealt with in Appendix 1.

1.7.3 Circuit Breaker

The circuit breaker is an electrically operated switch, which is capable of safely making, as well as breaking, short-circuit currents. The circuit breaker is operated by the output of the associated relay. When the circuit breaker is in the closed condition, its contacts are held closed by the tension of the closing spring. When the trip coil is energized, it releases a latch, causing the stored energy in the closing spring to bring about a quick opening operation.

1.7.4 Trip Circuit of a CB

The circuit breaker contacts are in a closed position by the force of a spring. Energy is stored in the spring during the closing operation. In order to trip the circuit breaker, it is necessary to release a latch either manually or by energizing the trip-coil of the circuit breaker. The trip-battery supplies energy to the trip-coil for this operation. The relay output contact is wired in series with the trip-battery and the trip-coil. Thus when the relay operates, the trip-coil gets energized and the circuit breaker quickly parts its contacts. The mechanical arrangement is quite complicated and only its essence is depicted in Figure 1.13.

1.7.5 Organization of Protection

The protection is organized in a very logical fashion. The idea is to provide a ring of security around each and every element of the power system. If there is any fault within this ring, the relays associated with it must trip all the allied circuit breakers so as to remove the faulty element from the rest of the power system. This 'ring of security' is called the *zone of protection*. This is depicted in Figure 1.14 with the help of a simple differential relay for the protection of a transformer. Without going into the detailed working of the differential relaying scheme, we can make the following statements:

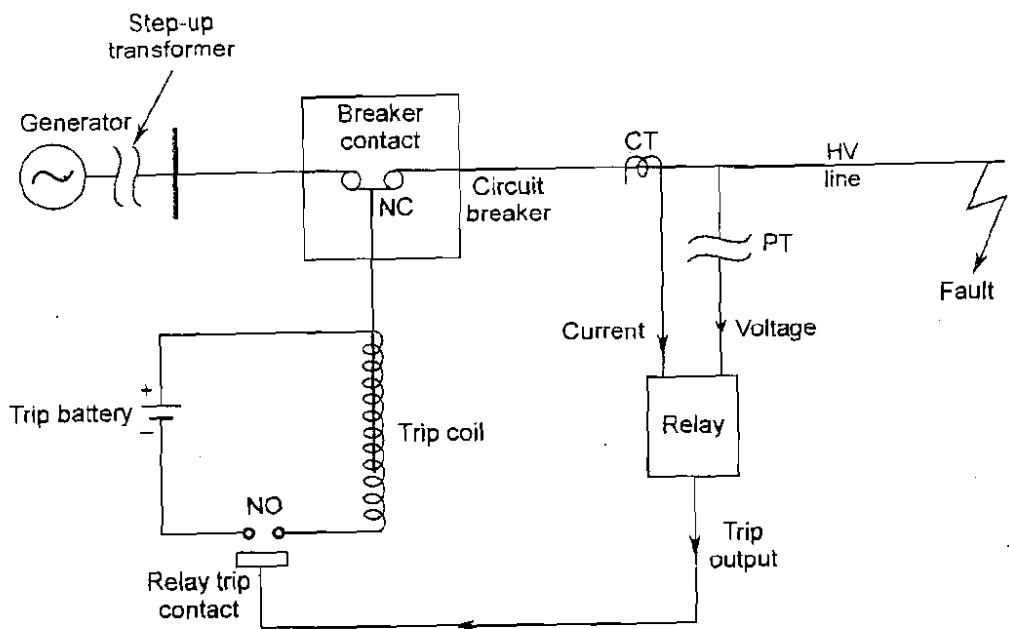


Figure 1.13 Trip circuit of a circuit breaker.

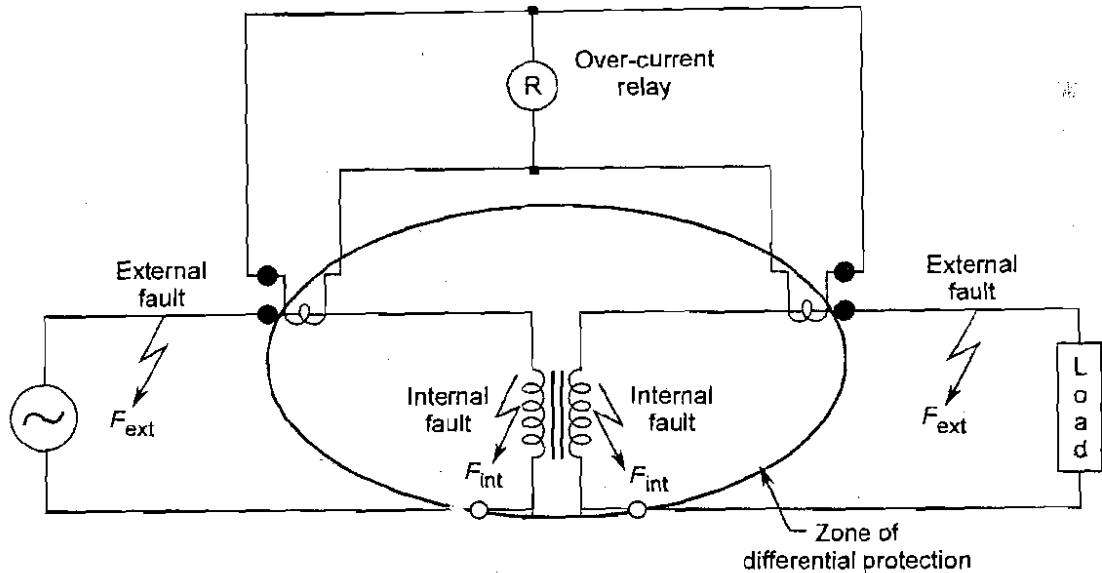


Figure 1.14 Zone of protection, external and internal faults.

Faults within the zone are termed **internal faults** whereas the faults outside the zone are called **external faults**. External faults are also known as **through faults**. Ideally, a relay looking after the protection of a zone should operate only for internal faults. It should restrain from operating for external faults. The farthest point from the relay location, which is still inside the zone, is called the **reach point**. The distance between the relay location and the reach point is termed the **reach of the relay**.

It might be mentioned here, in passing, that though the zone of protection, as a notion, is a very clearly marked out area, in practice, it may become fuzzy and keep on expanding and contracting. How far the zone is crisply carved out depends upon the relaying principle used. In general, it can be said that the differential relaying gives a much more crisply carved out zone than over-current or distance relaying. Directional relaying creates a zone with infinite reach in the tripping direction.

1.7.6 Zones of Protection

Various zones, for a typical power system, are shown in Figure 1.15. It can be seen that the adjacent zones overlap, otherwise there could be some portion which is left out and

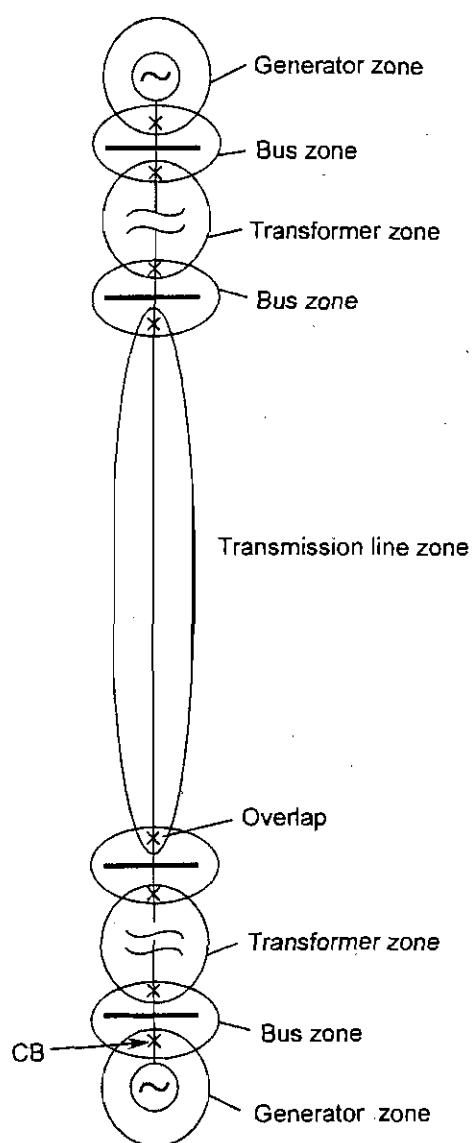


Figure 1.15 Various zones of protection for a power system.

remains unprotected. At the same time, it must be realized that if the fault takes place in the overlapped portion, more than the minimum number of circuit breakers will trip, causing a major dislocation to the system. Each of the zones may be implemented using a different relaying principle. All the zones, in practice, may not be as well marked out as they are shown in the figure and may contract or expand depending upon the various system conditions.

1.7.7 Primary and Back-up Protection

As already mentioned there are times when the primary protection may fail. This could be due to failure of the CT/VT or relay, or failure of the circuit breaker. One of the possible causes of the circuit breaker failure is the failure of the trip-battery due to inadequate maintenance. We must have a second line of defence in such a situation. Therefore, it is a normal practice to provide another zone of protection which should operate and isolate the faulty element in case the primary protection fails. A little thought will convince the reader that the back-up protection should not have anything in common with the primary protection. It should also preferably be located at a place different from where the primary protection is located. Further, the back-up protection must wait for the primary protection to operate, before issuing the trip command to its associated circuit breakers. In other words, the operating time of the back-up protection must be delayed by an appropriate amount over that of the primary protection. Thus, the operating time of the back-up protection should be equal to the operating time of primary protection plus the operating time of the primary circuit breaker.

Consider the radial system shown in Figure 1.16. Relay B, in conjunction with circuit breaker CB_B , provides primary protection to the line section B-C. Relay A with circuit breaker CB_A provides back-up protection to the section B-C. Consider a fault in section B-C as shown in Figure 1.16.

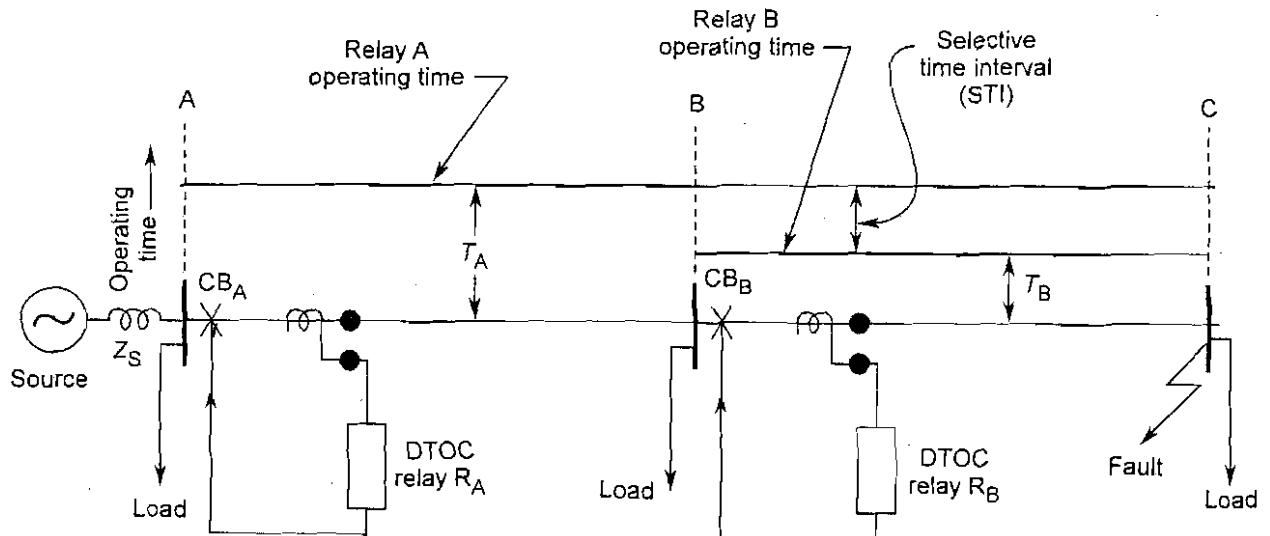


Figure 1.16 Primary and back-up protection.

When a fault takes place, both the primary relay R_B and the back-up relay R_A , start operating simultaneously. In case the primary protection (provided by $R_B + CB_B$) operates successfully, the line B-C gets de-energized but the loads on buses A and B remain unaffected. Therefore, the back-up protection (provided by $R_A + CB_A$) resets without issuing a trip command. The sequence of events in such a case is depicted in Figure 1.17. However, in case the primary protection fails to operate, the back-up which is already monitoring the fault, waits for the time in which the primary would have cleared the fault and then issues the trip command to its allied circuit breakers.

When the back-up operates, the time for which the fault persists is longer and disruption to the loads also lasts longer.

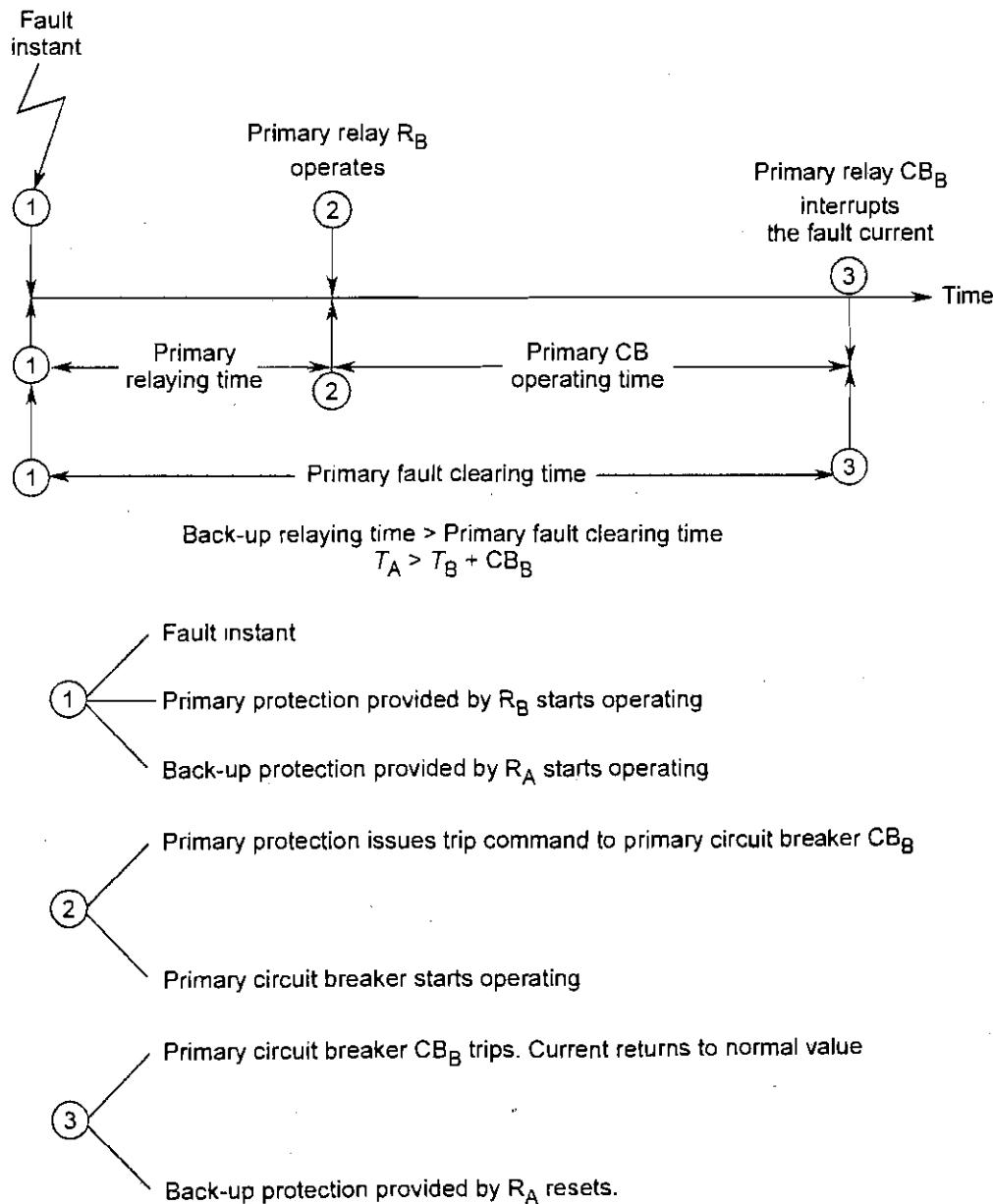


Figure 1.17 Primary and back-up protection: sequence of events: normal operation.

1.7.8 Maloperations

There should be proper coordination between the operating time of primary and back-up protection. Figure 1.18 shows an instance of loss of selectivity between the primary and back-up protection. It can be seen that the back-up protection in this case issues trip command to its breaker without waiting for the primary protection to do its job. This results in operation of both the primary and the back-up, resulting in a longer and unnecessary disruption to the system. It is said that with every additional relay used, there is an increase in the probability of maloperation.

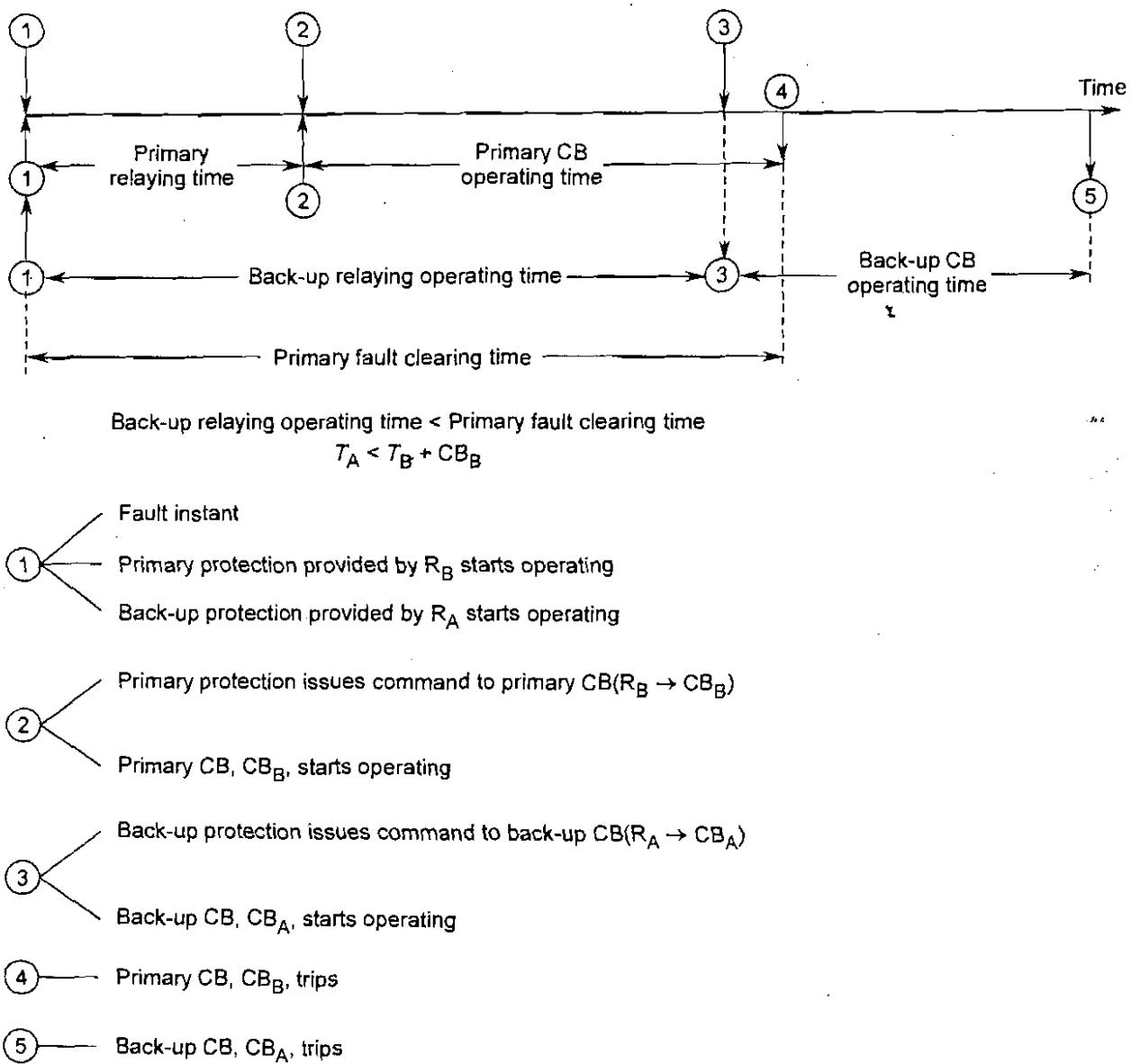


Figure 1.18 Primary and back-up protection: sequence of events: loss of selectivity.

1.8 Various Power System Elements That Need Protection

The power system consists of alternators, busbars, transformers for transmission and distribution, transmission lines at various voltage levels from EHV to 11 kV, cables, induction and synchronous motors, reactors, capacitors, instrument and protective CTs and PTs, various control and metering equipment, etc. Each of these entities needs protection. Each apparatus has a unique set of operating conditions. For example, while the transmission line is spread out geographically over a very long distance, the transformer windings are localized to comparatively much smaller space. While the alternator is a huge rotating mass with mechanical coupling to the turbine and electrical coupling to the power system, the busbars present an entirely different scenario as far as protection is concerned. Thus each apparatus needs a different kind of protective system targeted to its unique set of anticipated faults and abnormal operating conditions. This makes the field of power system protection a medley of relay operating principles and schemes. However, it is possible to sort out this seemingly kaleidoscopic situation by either focusing on the power system element that one is trying to protect or by focusing on the protection principle involved. Both approaches are complementary and both should be used.

1.9 Various Principles of Power System Protection

The most visible effect of fault is a sudden build-up of current. Thus, *over-current* relaying is the most natural principle of relaying. However, fault current magnitude is a function of type of fault and the source impedance. The source impedance, which depends upon the number of generating units that are in service at a given time, keeps changing from time to time. Therefore, the reach as well as the operating time of over-current relaying keep changing from fault to fault, and time to time.

This has led relay engineers to think of other principles of protection. Another very natural and appealing principle is the *differential* protection. It is based on the premise that the current entering a protected section must be equal to that leaving it. Any discrepancy between the two indicates the presence of a fault. However, it is impractical to apply this principle to a transmission line because the ends are far apart and it is not easy to compare information at the two ends.

To get over the above problem, a *distance* relay compares voltage with current at the same end. This, in effect, measures the impedance between the relay location and the fault point. Since impedance of a transmission line can be considered to be directly proportional to the distance along the line, this type of relaying is known as *distance* relaying.

In case of a double-end feed system, or parallel lines, or a ring main system, a fault gets fed from both sides. In order to be selective, the relay must be sensitive to the direction of fault power flow. The relays which exhibit such property are termed *directional* relays. The entire gamut of protection can be captured in Table 1.3.

Table 1.3 The gamut of power system protection

<i>Apparatus</i>	<i>Principle</i>	<i>Non-directional over-current</i>	<i>Directional over-current</i>	<i>Differential</i>	<i>Distance</i>
Alternator	Primary Protection		✓	✓	✓
Busbar	Primary Protection			✓	
Transformer	Primary Protection			✓	
Transmission Line	Primary Protection	✓	✓		✓
Large Induction Motor	Primary Protection	✓		✓	

The cells of the Table 1.3, where the *principle* meets the *protected*, in fact form the subject matter of the book. In chapters to come, we will try to fill up these cells or try to understand why some of the cells remain vacant!

Review Questions

1. Power systems are moving towards increasing complexity and demand equally complex protection. Discuss.
2. Compare an isolated power system and an interconnected power system. How do their protection requirements differ?
3. A single synchronous alternator does not suffer from loss of stability. Discuss.
4. What do you mean by zone of protection?
5. What do you mean by an internal and an external fault?
6. What is a through fault?
7. Why are adjacent zones made to overlap?
8. Why zone boundaries, in practice, tend to float?
9. Explain the terms sensitivity and selectivity with respect to their use in the protective relaying field.
10. Why is speed of protection so important?
11. Why is back-up protection needed?
12. What do you mean by maloperation of a relay?
13. What do you mean by maloperation due to loss of selectivity between the primary and the back-up relaying?
14. What are the advantages of high-speed protection?
15. What are the pitfalls of high-speed protection?
16. Give an estimate of circuit breaker operating time.
17. Give an estimate of relay operating time.

Problems

1. The percentage impedance of a transformer is 8%. Determine the short-circuit current for a three-phase short circuit on the secondary terminals of the transformer.
2. In the diagram of Figure 1.16, $T_B = 0.2$ s. If the circuit breaker operating time is 0.5 s, determine the operating time of relay R_A so that there is no loss of selectivity.
3. In the diagram of Figure 1.16, the operating time of relay $R_B = 0.3$ s, operating time of relay $R_A = 0.6$ s. The circuit breaker operating time is 0.5 s. Investigate whether there will be any loss of selectivity between the primary and the back-up protection.
4. The load current in a system is 100 A. The short-circuit current for the smallest fault is 1000 A. An over-current relay capable of carrying a current of 5 A continuously is to be used.
 - (a) Suggest a suitable CT ratio.
 - (b) What will be the relay current for the smallest fault?
 - (c) Will the protective CT be able to faithfully reproduce the fault current?

2

Over-current Protection of Transmission Lines

2.1 Introduction

As already pointed out, the most obvious effect of a shunt fault is a sudden build up of current. Therefore, it is only natural that the magnitude of current be utilized as a positive indication of existence of a fault. It is no wonder, therefore, that the over-current protection is the most widely used form of protection. In many situations, it may be the only protection provided. This type of protection which depends on only the magnitude of the current, without taking any cognizance of its phase angle, is known as the *non-directional over-current protection*.

However, many times it is required to discriminate between faults *in front* of the breaker and faults *behind* the breaker. This is possible only if we take into account, not only the magnitude of the current but also its phase with respect to the voltage at the relay location. In such cases, the protection is known as the *directional over-current protection*. A little thought will convince the readers that a directional over-current protection affords greater selectivity than a non-directional over-current protection.

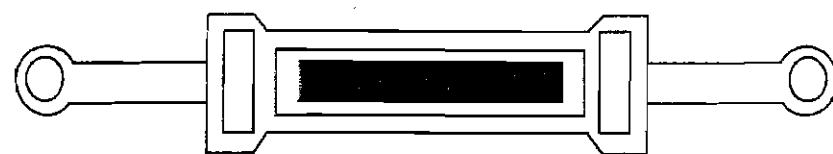
We must not forget that any type of protection is first a concept. Then, it needs to be implemented. The vehicle of implementation is the *relay*. We can thus imagine a non-directional over-current relay, which provides the non-directional over-current protection and so on.

Historically, however, fuses have preceded the over-current relays for providing over-current protection. We will, therefore, take a brief look at fuses in the next section.

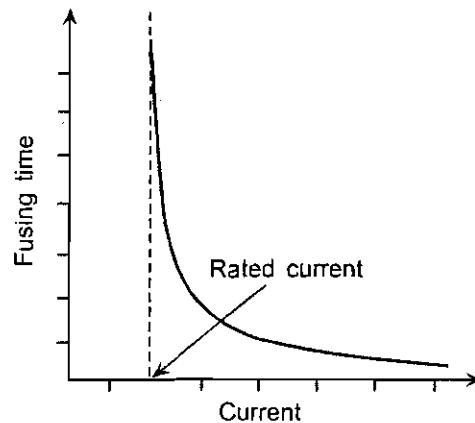
2.2 Fuse

Fuses are the oldest protective devices that have survived from the dawn of the age of electricity to the present times. This can be attributed to their intuitive simplicity. The fuse allows the normal current to flow but melts itself out, thus breaking the circuit, when the current exceeds a certain magnitude for a certain amount of time. It combines the functions of sensing, comparing, and interrupting the current into one. Figure 2.1(a) depicts the external appearance of a high rupturing capacity (HRC) fuse. The current

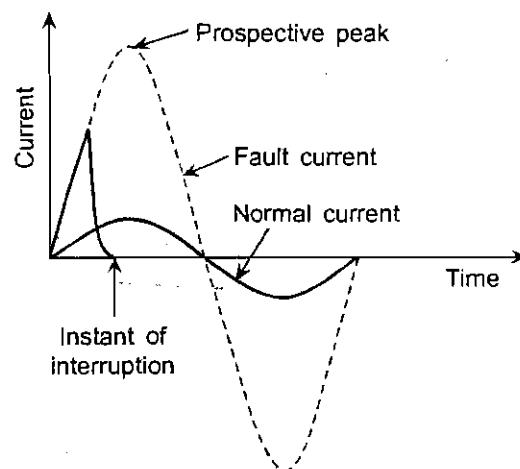
versus time characteristic of a fuse is shown in Figure 2.1(b). The waveform of the short-circuit current interrupted by a fuse is shown in Figure 2.1(c), where it can be seen that the fuse interrupts the current even before it attains its peak value.



(a) External appearance of a HRC fuse



(b) Time-current characteristic of a fuse



(c) Short-circuit current interrupted by a fuse

Figure 2.1 High rupturing capacity (HRC) fuse.

2.3 Thermal Relays

Thermal relays, of the bimetallic type, work on the principle of strain generated due to unequal linear expansion of two different metals as a result of heat generated by the

passage of the fault current. Figure 2.2(a) shows a bimetallic relay consisting of strips AB and CD of two different materials. Both the strips get heated up by the same amount but are deformed by differing amounts. Figure 2.2(b) shows the relay operation. The material with higher coefficient of expansion is at the outer surface of the curve while that with lower coefficient is at the inner surface.

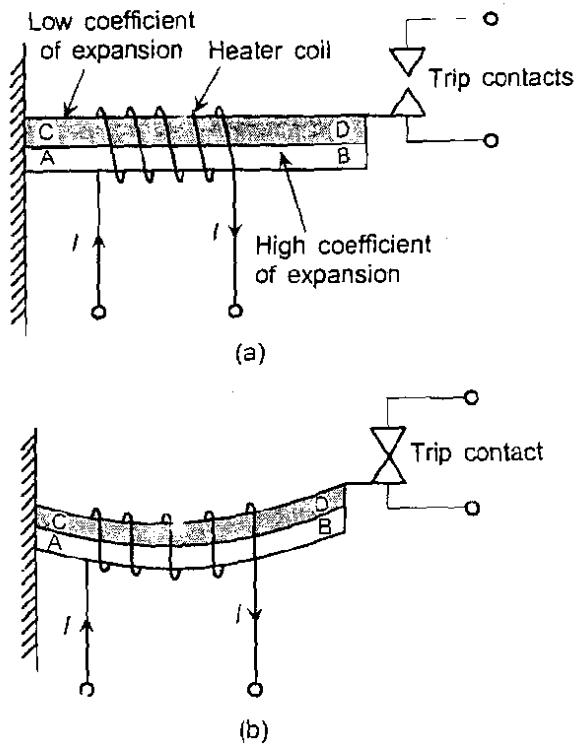


Figure 2.2 A bimetallic relay

Since the heating effect is proportional to the square of the current, the energy dissipated is given by $(I^2R)t$, where t is the time for which the current flows through the relay.

Since accumulation of sufficient amount of heat depends on the thermal inertia of the relay, which tends to be rather large, these relays are used where very quick operation is not called for. A typical application of the thermal relay is to provide protection against prolonged overloading of motors. The thermal overload relay thus lets the motor supply overload for a preset amount of time before tripping it off.

2.4 Over-current Relay

An over-current (OC) relay has a single input in the form of ac current. The output of the relay is a normally-open contact, which changes over to closed state when the relay trips. The relay has two settings. These are the time setting and the plug setting. The time setting decides the operating time of the relay while the plug setting decides the current required for the relay to pick up. The name *plug setting* comes from the

electromechanical over-current relay. In these relays, we have to insert a shorting plug in a plug-setting bridge, so as to change the number of turns of the operating coil to get a particular pick-up value. The same terminology continues to be used in the modern relays. The block diagram of an OC relay is shown in Figure 2.3.

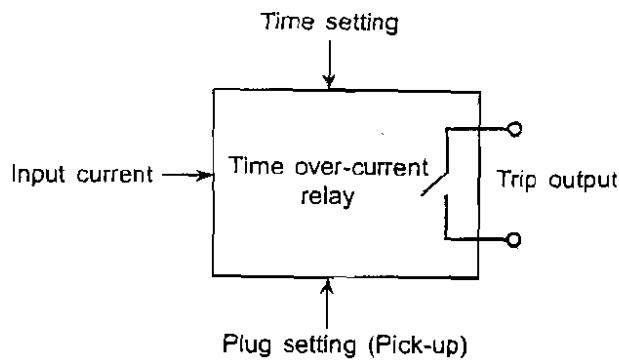


Figure 2.3 Block diagram of an over-current relay.

The plug-setting multiplier, PSM, is defined as follows:

$$\boxed{PSM = \frac{I_{\text{relay}}}{PS}}$$

where I_{relay} is the current through the relay operating coil and PS is the plug-setting of the relay. The value of PSM tells us about the severity of the current as seen by the relay. A PSM less than 1 means that normal load current is flowing. At $PSM > 1$, the relay is supposed to pick up. Higher values of PSM indicate how serious the fault is.

For example, let us consider a 1.0 A relay (i.e. a relay with current coil designed to carry 1.0 A on a continuous basis) whose plug has been set at 0.5 A, i.e. at 50%. Assume that, for a certain fault, the relay current is 5.0 A. The relay, therefore, is said to be operating at a PSM of $(5.0/0.5) = 10$.

2.4.1 Instantaneous OC Relay

It is to be noted that the word *instantaneous* has a different connotation in the field of power system protection. *Instantaneous* actually means *no intentional time delay*. Howsoever fast we want the relay to operate; it needs a certain minimum amount of time. The operating time of an instantaneous relay is of the order of a few milliseconds. Such a relay has only the pick-up setting and does not have any time setting. The construction and the characteristics of an instantaneous attracted armature type relay is shown in Figure 2.4, wherein it can be seen that as the armature of the relay gets attracted towards the coil, the air-gap becomes smaller, and hence the reluctance becomes smaller. This results in increased flux which causes the force on the armature to build up (force being proportional to the square of the flux density). This is a positive feedback action which results in the armature moving quickly in an instantaneous snap action. The operating torque on the armature is proportional to the square of the current.

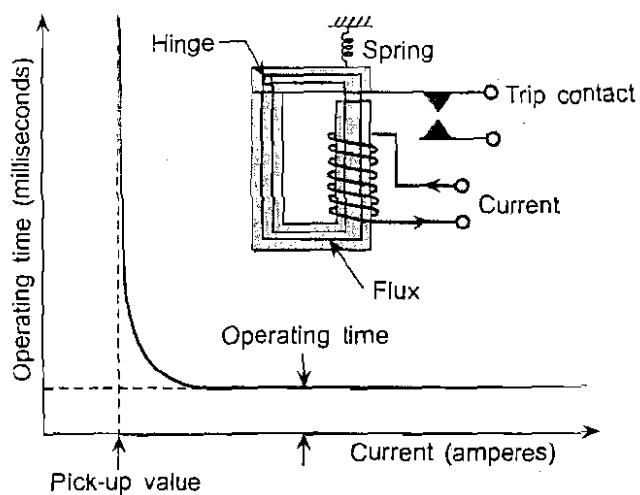


Figure 2.4 Instantaneous over-current relay characteristic.

2.4.2 Definite Time Over-current Relay

A definite time over-current relay can be adjusted to issue a trip output at a definite (and adjustable) amount of time, after it picks up. Thus, it has a time-setting adjustment and a pick-up adjustment. The characteristic and the block diagram are shown in Figure 2.5.

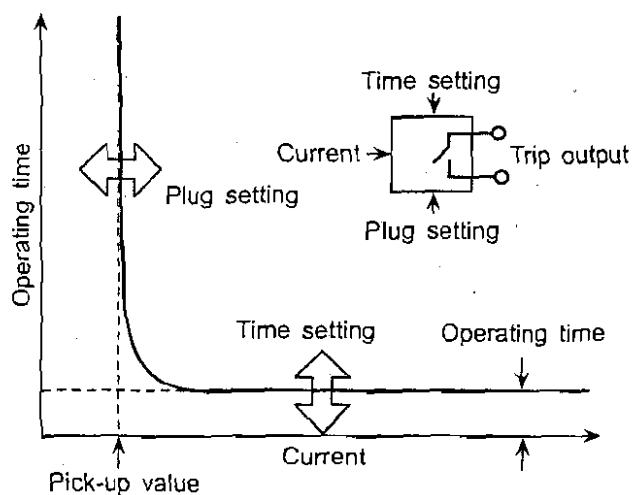


Figure 2.5 Definite time over-current relay characteristic.

2.4.3 Inverse Time Over-current Relay

Inverse time characteristic fits in very well, with the requirement that the more severe a fault is, the faster it should be cleared to avoid damage to the apparatus. This type of characteristic is naturally obtained from an electromechanical relay, which has led to its widespread use and standardization. With the advent of microprocessor-based relays, it is now possible to generate any imaginable time-current characteristic. However, in order to maintain compatibility with the very large number of electromechanical relays, still in

service, certain inverse time characteristics, described in the next section, have been standardized.

Inverse definite minimum time (IDMT) over-current relay

This is possibly the most widely used characteristic. The characteristic is inverse in the initial part, which tends to a definite minimum operating time as the current becomes very high. The reason for the operating time becoming definite minimum, at high values of current, is that in the electromechanical relays the flux saturates at high values of current and the relay operating torque, which is proportional to the square of the flux, does not increase substantially after the saturation sets in. Such a characteristic came about because of the limitation of the electromechanical technology. Ideally, we may demand that the operating time be inverse in nature throughout the operating range. The mathematical relation between the current and the operating time of IDMT characteristic can be written as

$$t_{op} = \frac{0.14 \text{ (TMS)}}{(PSM)^{0.02} - 1}$$

where PSM is the plug-setting multiplier and TMS is the time-multiplier setting of the relay. Thus, the operating time is directly proportional to the TMS and inversely proportional to the PSM. The characteristics of the IDMT relay are shown in Figure 2.6.

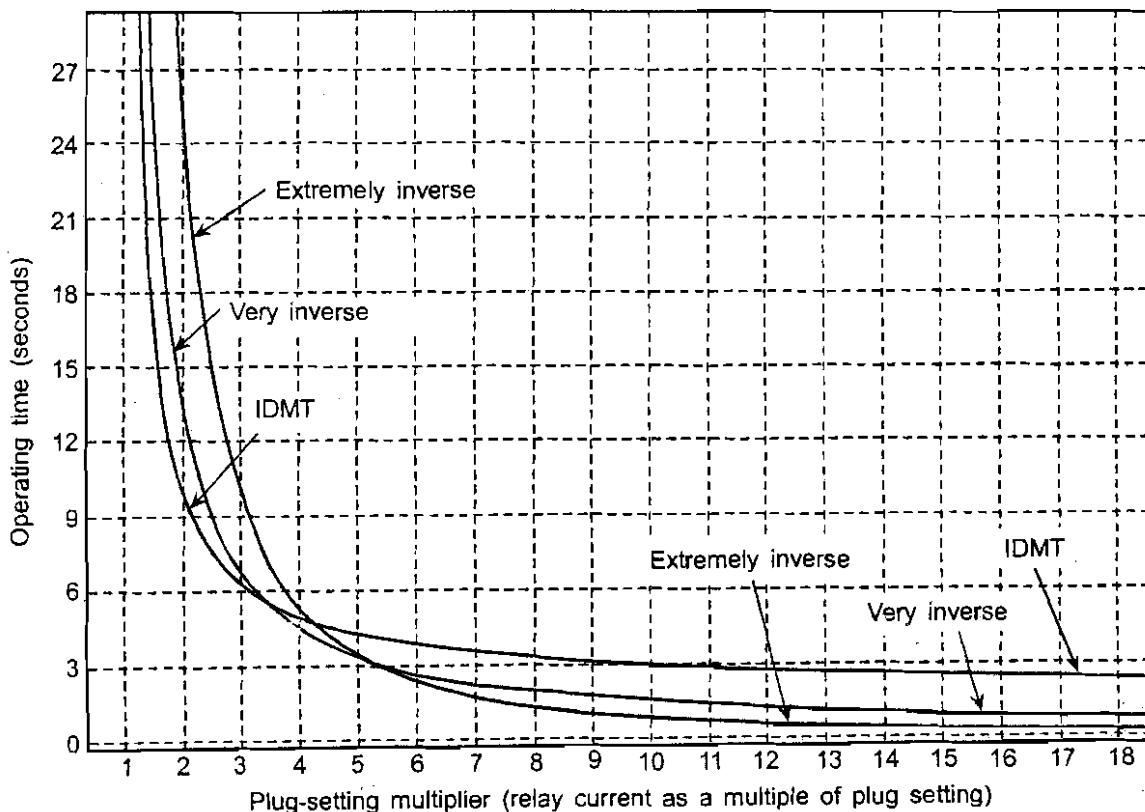


Figure 2.6 Inverse definite minimum time relay characteristics (TMS = 1.0).

Very inverse time over-current relay

The inverseness of this characteristic is higher than that of the IDMT characteristic. The mathematical relation between the current and the operating time of such a characteristic can be written as

$$t_{op} = \frac{13.5 \text{ (TMS)}}{(\text{PSM}) - 1}$$

The characteristic of the relay is shown in Figure 2.6.

Extremely inverse time over-current relay

The inverseness of this characteristic is higher than that of the *very inverse* characteristic. The mathematical relation between the current and the operating time of such a characteristic can be written as

$$t_{op} = \frac{80.0 \text{ (TMS)}}{(\text{PSM})^2 - 1}$$

The characteristic of the relay is shown in Figure 2.6.

2.5 Implementation of Over-current Relay Using Induction Disk

In order to understand the working of an induction disk type relay, let us first see how torque can be produced by two alternating fluxes acting on a common metallic but non-magnetic rotor. Figure 2.7 shows two alternating fluxes ϕ_1 and ϕ_2 having a phase difference of θ between them.

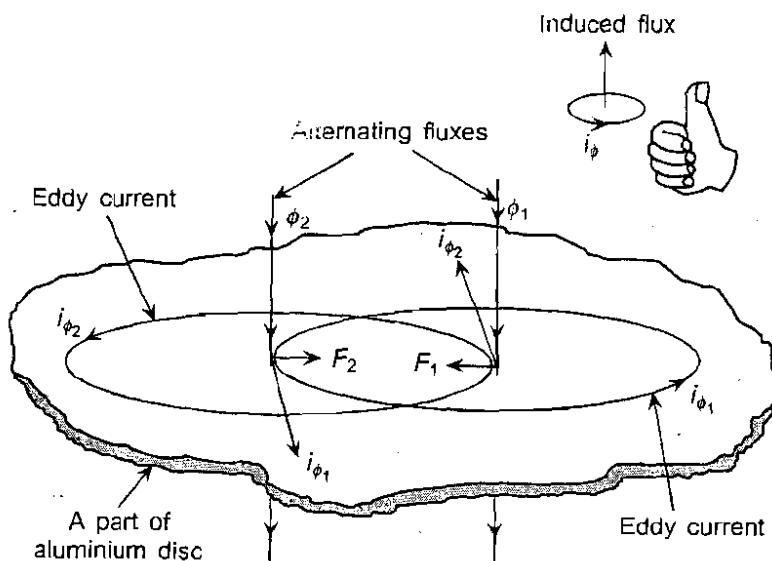


Figure 2.7 Operating principle of induction disc type relay.

Thus, we have

$$\phi_1 = \phi_{m_1} \sin \omega t$$

$$\phi_2 = \phi_{m_2} \sin (\omega t + \theta)$$

Each flux induces a voltage in the disc, and hence gives rise to induced currents i_{ϕ_1} and i_{ϕ_2} . Assuming that the eddy current path has negligible inductance, we can write

$$i_{\phi_1} \propto \frac{d\phi_1}{dt} = \omega \phi_{m_1} \cos \omega t$$

$$i_{\phi_2} \propto \frac{d\phi_2}{dt} = \omega \phi_{m_2} \cos (\omega t + \theta)$$

As shown in Figure 2.7, ϕ_1 interacts with i_{ϕ_2} to produce force F_1 . Likewise ϕ_2 interacts with i_{ϕ_1} to produce a force F_2 . Assuming ω to be constant, we have

$$F_1 = \phi_1 i_{\phi_2} \propto \phi_{m_1} \phi_{m_2} \sin \omega t \cos (\omega t + \theta)$$

$$F_2 = \phi_2 i_{\phi_1} \propto \phi_{m_1} \phi_{m_2} \sin (\omega t + \theta) \cos \omega t$$

The net force ($F_2 - F_1$) is thus, given by

$$F_2 - F_1 \propto \phi_{m_1} \phi_{m_2} [\sin (\omega t + \theta) \cos \omega t - \cos (\omega t + \theta) \sin \omega t]$$

which simplifies to

$$F_2 - F_1 \propto \phi_{m_1} \phi_{m_2} \sin \theta$$

The following important conclusions can be drawn from the above expression for torque:

- Two alternating fluxes with a phase shift are needed for torque production, i.e. a single alternating flux would not produce torque.
- Maximum torque is produced when two alternating fluxes are shifted in phase by 90° .
- The resultant torque is steady, i.e. it is not a function of time, as time t is not involved in the expression for torque.

Since in an over-current relay, there is only one input quantity, it will not be possible to produce torque unless two fluxes shifted in phase are produced.

The above principle has been used in the induction disc type over-current relay whose construction is shown in Figure 2.8. Herein two fluxes shifted in time phase are obtained from the input current, by using a shading coil. The flux in the shaded coil lags the main flux. The torque thus produced by the interaction of the two fluxes, neglecting saturation, is proportional to I^2 since each of the flux is proportional to I . This is the deflecting torque $T_{\text{deflecting}}$. The spiral spring provides the control torque $T_{\text{controlling}}$. The control torque can be considered to be directly proportional to the angle δ , through which the back-stop has been retarded from the trip position. The permanent magnet provides the damping torque, which is active only when the disc is in motion and is thus proportional to the rate of change of angle $d\delta/dt$. The torque equation can therefore be written as

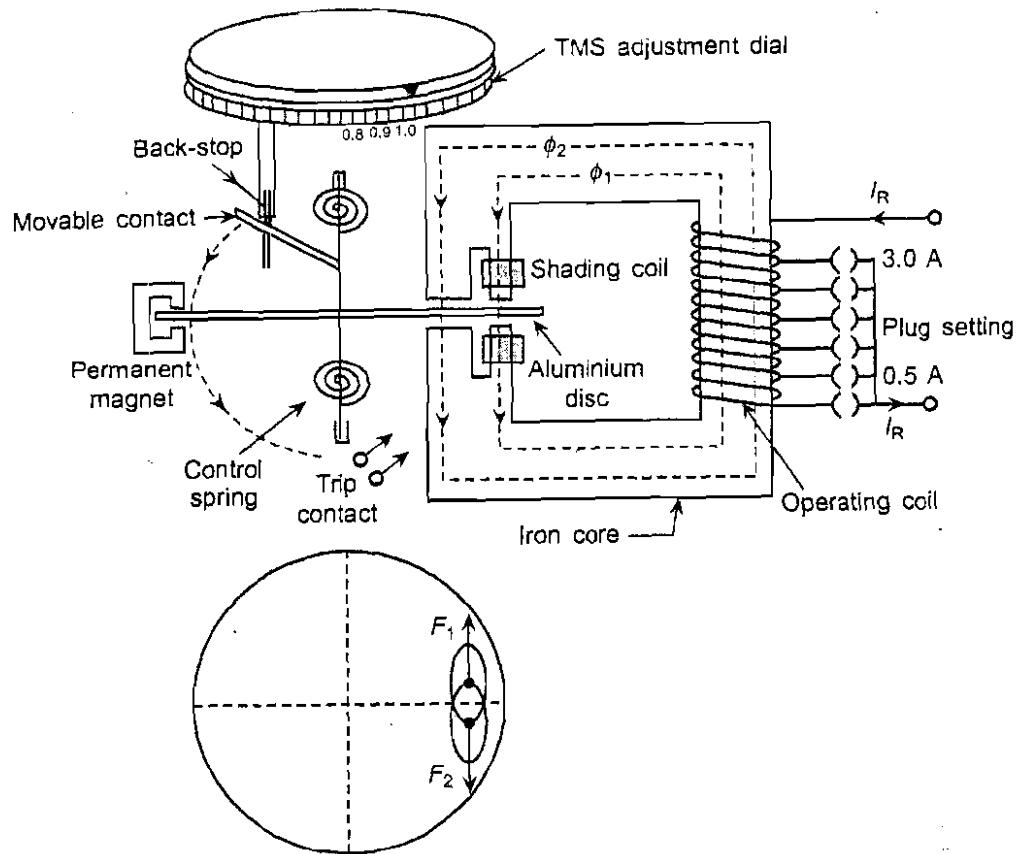


Figure 2.8 Construction of an induction disc relay.

$$T_{\text{deflecting}} > T_{\text{controlling}} + T_{\text{damping}}$$

or

$$KI^2 > S\delta + D \frac{d\delta}{dt}$$

where K is deflection constant, S is the spring constant, and D is the damping constant. All these constants depend upon the design of the relay.

When the disc is on the verge of deflection, we can equate the torques and write

$$\frac{d\delta}{dt} + K_1\delta - K_2I^2 = 0, \quad K_1 = \frac{S}{D} \text{ and } K_2 = \frac{K}{D}$$

The solution of the above equation is of the form

$$\delta = K_3 e^{-t} - K_4$$

where K_3 and K_4 are functions of K_1 and K_2 , i.e. S , D and I^2 . Now,

At $t = 0; \delta = \delta_{\text{initial}}$

At $t = t_{\text{op}}; \delta = 0$

We can find the operating time by finding the value of time t for which δ becomes zero. The value of δ_{initial} is decided by the time-multiplier setting.

The exact analysis of the dynamics of induction disc is quite involved. However, it can be noted that by proper design of the magnetic circuit a wide range of characteristics from extremely inverse to definite time can be obtained.

2.6 Application of Definite Time OC Relays for Protection of a Distribution Feeder

Consider a three-phase feeder as shown in the single-line diagram of Figure 2.9, with two line sections AB and BC. Assume that DTOC relays are used at buses A and B. There are loads at all the three buses.

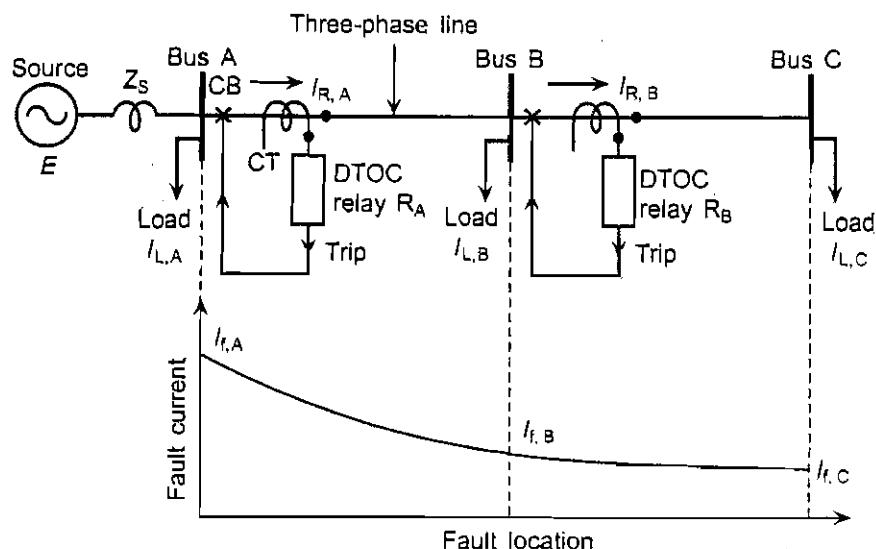


Figure 2.9 Application of DTOC relays for feeder protection.

The protection problem can be stated as follows:

Given the magnitudes of all the loads and the fault currents at all the buses, how to set the DTOC relays at buses A and B so that the entire feeder gets over-current protection arranged as primary and back-up protection.

The first step in designing the over-current protection is to select the ratios for all the CTs. The secondary current of the CT is decided by the rating of the relay current coil. The CT primary current is decided by the maximum load current to be carried by the CT primary. Next we have to do the relay setting. It may be noted that *setting* of the relay, where the DTOC relays are involved, means:

1. How to select the pick-up value of the relay?
2. How to set the operating time of the relay?

How to select the pick-up value of the relay?

The setting problem has been pictorially depicted in Figure 2.10.

We can set the pick-up value of the relay, keeping in mind, that the relay should allow normal load as well as a certain degree of overload to be supplied. Thus the pick-up value

of the relay should be more than the allowable maximum load. At the same time, the relay should be sensitive enough to respond to the smallest fault. Thus, the pick-up value should be less than the smallest fault current. Therefore, we can write the following rule, as far as setting the pick-up value of the OC relay is concerned:

$$I_{L, \text{max}} < I_{pu} < I_{f, \text{min}}$$

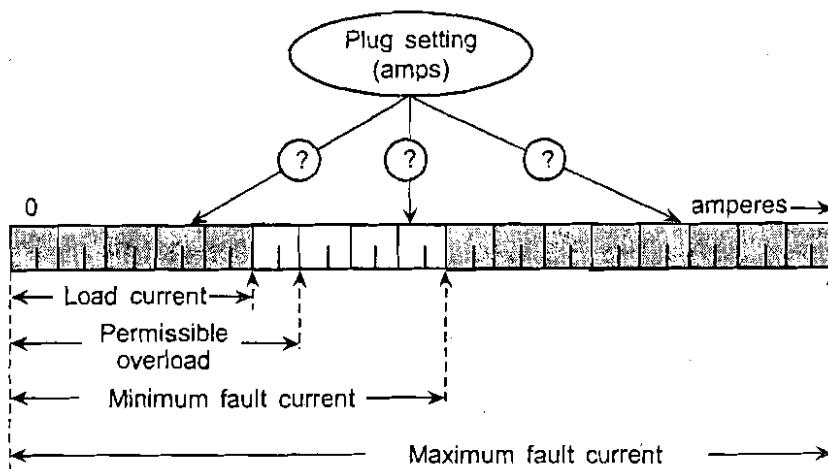


Figure 2.10 The plug setting of DTOC relays.

How to set the operating time of the relay

Here we are guided by the principle that a relay must get an adequate chance to protect the zone under its primary protection. Only if the primary protection does not clear the fault, the back-up protection should initiate tripping. Thus as soon as the fault takes place, it is sensed by both the primary and the back-up protection. Naturally, the primary protection is the first to operate, its operating time being less than that of the back-up relay. Figure 2.11 shows the relationship between the operating time of the primary relay and that of the back-up relay. We have to allow for the overshoot of the primary relay, so that there is proper coordination between the primary and the back-up. Overshoot time

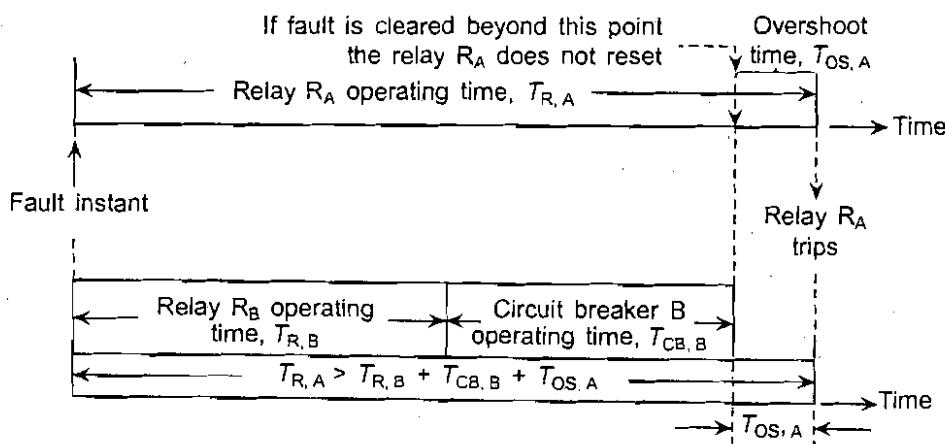


Figure 2.11 The time setting of DTOC relays.

is defined as the time for which the relay mechanism continues to move, even after the operating coil has been de-energized. Overshoot is because of the moment of inertia of the moving system.

In the light of the above discussion, the correct procedure would be to start the setting from the tail end of the feeder system. The relay, which is at the end of the radial feeder, can be made to operate without any delay, as it does not have to coordinate with any other relay. In the given example of Figure 2.9, let us assume that the operating time of R_B is set to 0.1 s. Thus relay R_A should wait for 0.1 s plus, a time equal to the operating time of circuit at bus B ($T_{CB,B}$) plus overshoot time of relay A ($T_{OS,A}$). Thus, we can write

$$T_{R,B} = 0.1 \text{ s (fastest)}$$

$$T_{R,A} = T_{R,B} + T_{CB,B} + T_{OS,A}$$

Assuming CB operating time = 0.5 s and overshoot time = 0.2 s, we have

$$T_{R,A} = 0.1 + 0.5 + 0.2 = 0.8 \text{ s}$$

The time step between the operating times of the two relays, which is equal to the sum of the operating time of the circuit breaker at B and the overshoot time of relay A, is essential for maintaining selectivity between relays at A and B. Hence this interval is referred to as the *selective time interval* (STI). The worksheet for the settings of the relays thus can be written as shown in Table 2.1.

Table 2.1 Purpose and setting of relays

<i>Relay</i>	<i>Purpose</i>	<i>Pick-up value</i>	<i>Time setting</i>
R_B	Primary protection of section BC <i>Note:</i> R_B is at the tail end of the system	$I_{L,C} < I_{pu,R,B} < I_{f,C,min}$	Fastest $T_{R,B} = 0.1 \text{ s}$
R_A	Back-up protection of section BC	$(I_{L,B} + I_{L,C}) < I_{pu,R,A} < I_{f,C,min}$	$T_{R,A} = T_{R,B} + T_{CB,B} + T_{OS,A}$ = 0.1 + 0.5 + 0.2
	Primary protection of section AB		= 0.8 s

Note that the setting process has to be started from the relay which is at the tail end of the system. This is because this relay is not at all constrained by selectivity problems. All other upstream relay settings are tied up with their downstream neighbours.

The result of this setting process is shown in Figure 2.12. It can be seen from this figure that as the fault moves towards the source, the fault currents become larger and the fault clearing time also becomes longer. This is because the relays nearer the source are deliberately delayed so that they are selective with relays downstream. Thus, the relay nearest to the source is the slowest. This is not desirable. It can be shown that a significant improvement in fault clearing time, as we move towards the source, is obtained if we use the Inverse Definite Minimum Time (IDMT) relays.

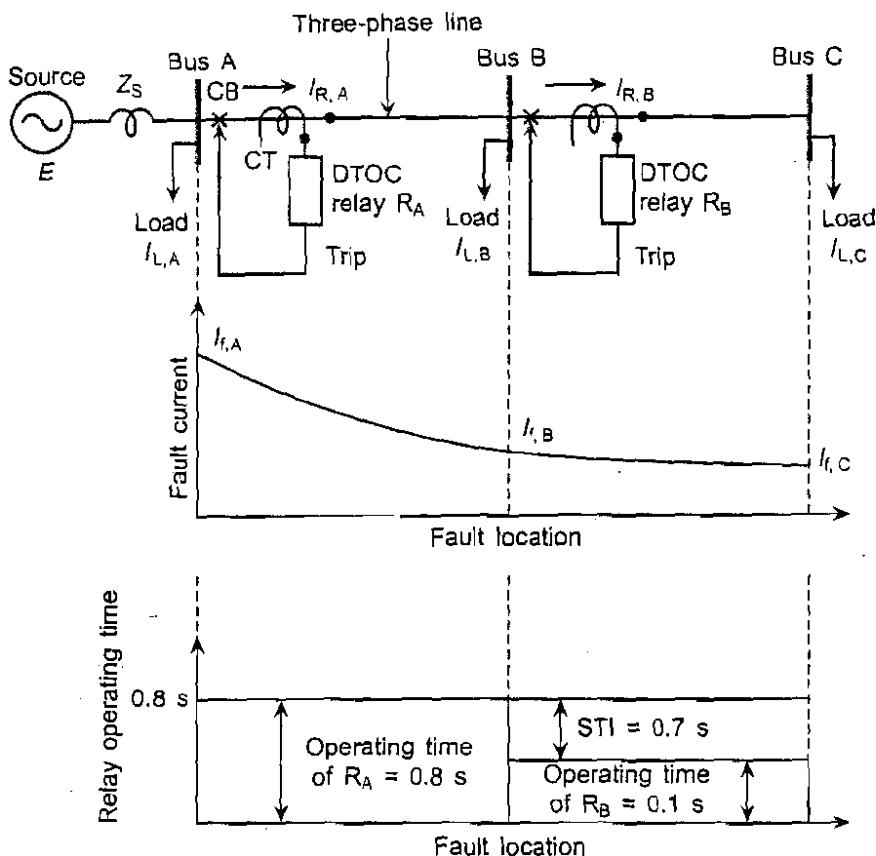


Figure 2.12 Setting of DTOC relays for OC protection of a feeder.

2.7 Application of Inverse Definite Minimum Time Relay on a Distribution Feeder

Consider a radial feeder with two buses A and B where IDMT OC relays are to be used (Figure 2.13). It should be noted that:

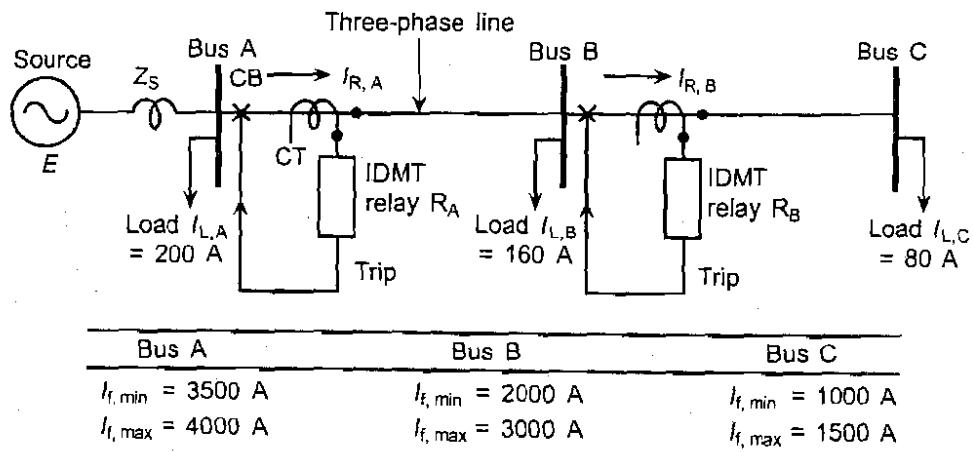


Figure 2.13 Setting of IDMT OC relays.

- The purpose of relay R_B is to provide primary protection to line BC.
- The purpose of relay R_A is to provide primary protection to line AB and back-up to line BC.

We start the setting process from the tail end of the system.

(a) Deciding the CT ratios and plug settings:

- At relay B, the maximum load current, assuming 25% overload is:

$$80 \text{ A} + (0.25 \times 80 \text{ A}) = 100 \text{ A}$$

Assuming 1 A relay to be used, the CT ratio can be selected to be 100 : 1. The plug setting PS can be done at 100%, i.e. PS = 1.0 A.

- At relay A the maximum load current, assuming 25% overload is:

$$(160 + 80) + 0.25(160 + 80) = 300 \text{ A}$$

Assuming 1 A relay to be used, the CT ratio can be selected to be 300 : 1. The plug setting can be done at 100%, i.e. PS = 1.0 A.

(b) Deciding the time-multiplier settings: Starting from the most remote relay R_B

- Since R_B does not have to maintain selectivity with any other relay, it can be made to operate the fastest. Thus the TMS of R_B can be selected as 0.1.
- Now, to maintain selectivity between R_A and R_B , the following constraint must be met:

Operating time of R_A for maximum fault at B	=	Operating time of R_B for maximum fault at B	+	Circuit breaker B operating time	+	Overshoot time of R_A
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The operating time of R_B for maximum fault just beyond bus B can be found from

$$T_{R,B} = \frac{0.14(\text{TMS})}{\text{PSM}^{0.02} - 1}$$

For maximum fault at B, fault current = 3000 A on primary side which becomes $(3000/100) = 30$ A secondary. Since plug setting is done at 1.0 A,

$$\text{PSM} = \frac{I_{\text{relay}}}{\text{PS}} = \frac{30}{1} = 30$$

The TMS of R_B has already been set at 0.1. Substituting these values, we get

$$T_{R,B} = \frac{0.14(0.1)}{30^{0.02} - 1} = 0.1988 \approx 0.2 \text{ s}$$

Let $T_{CB,B} = 0.5$ s. Then,

$$T_{R,B} + T_{CB,B} = 0.7 \text{ s}$$

This value of 0.7 s is the desired operating time of R_A . Assuming overshoot time of R_A to be 10% of 0.7 s, i.e. $T_{OS,A} = 0.07$ s.

Thus, we get the required operating time of R_A for maximum fault at bus B:

$$T_{R,A, \text{ max fault at B}} = 0.2 + 0.5 + 0.07 = 0.77 \text{ s}$$

The TMS of R_A can be found from the following expression for the operating time of R_A :

$$0.77 = \frac{0.14 \text{ (TMS)}}{\text{PSM}^{0.02} - 1}$$

We have, for R_A , for the above condition, $\text{PSM} = I_{\text{relay}}/\text{PS} = (3000/300)/1 = 10$

Hence, for R_A

$$\text{TMS} = 0.77 \frac{(10^{0.02} - 1)}{0.14} = 0.26$$

This finishes the setting of both the relays.

We can verify that the selectivity for minimum fault at bus B is automatically maintained.

Minimum fault current for fault at bus B = 2000 A. Relay B current corresponding to this is $2000/100 = 20$ A. Since plug setting is 1 A, this translates into a PSM of 20. For relay R_B , $\text{TMS} = 0.1$. Thus, operating time of R_B for minimum fault at bus B will be:

$$T_{R_B, \text{min fault at B}} = T_{R_B} = \frac{0.14(0.1)}{20^{0.02} - 1} = 0.226$$

and

$$T_{CB,B} = 0.5 \text{ s}$$

Expected operating time of R_A for this fault should be greater than

$$0.226 + 0.5 + 0.1(0.226 + 0.5) = 0.726 + 0.0726 = 0.7986 = 0.8 \text{ s (approx.)}$$

Now, let us find out the actual operating time of R_A for minimum fault at bus B:

$$\text{Minimum fault current} = 2000 \text{ A}$$

Relay R_A current corresponding to this is: $2000/300 = 6.66 \text{ A}$

Since plug setting is 1 A, this translates into a PSM of 6.66. For relay R_A , $\text{TMS} = 0.26$. Thus the operating time of R_A for minimum fault at bus B will be:

$$T_{R_A, \text{min fault at B}} = T_{R_A} = \frac{0.14(0.26)}{6.66^{0.02} - 1} = 0.94 \text{ s}$$

This value of 0.94 s is greater than the minimum operating time of 0.8 s, required for maintaining selectivity between R_A and R_B .

The results can be listed as follows:

Relay	CT ratio	Plug setting	TMS
R_B	100 : 1	1 A	0.1
R_A	300 : 1	1 A	0.26

The sketch of fault clearing time as a function of fault location for IDMT relays is shown in Figure 2.14.

We can deduce the following general rules from the above setting exercise:

- Start the setting from the relay at the tail end of the system.
- Plug setting should be such that: $I_{L, \text{max}} < \text{PS} < I_{f, \text{min}}$ at the end of next section i.e. for plug setting consider **minimum** fault current at the **end** of the **next** section.

- TMS should be decided such that the selectivity with the next relay downstream is maintained for maximum fault current at the beginning of the next section.

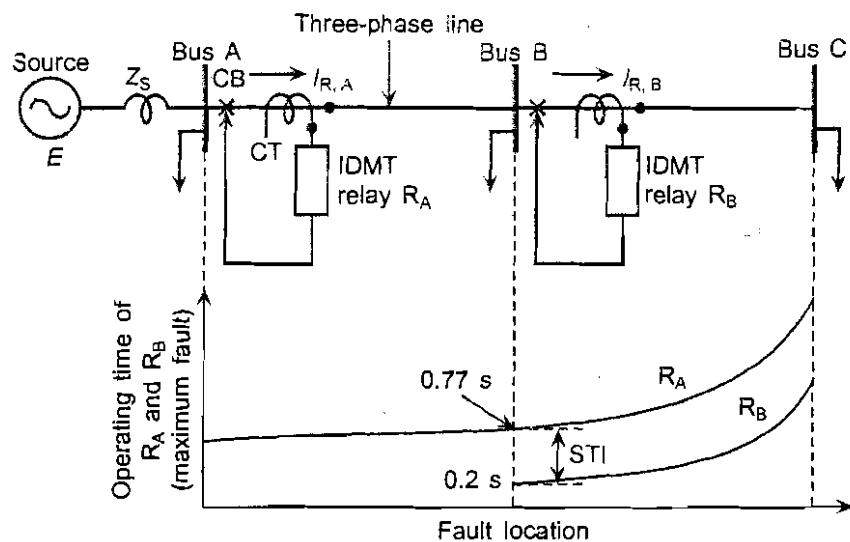
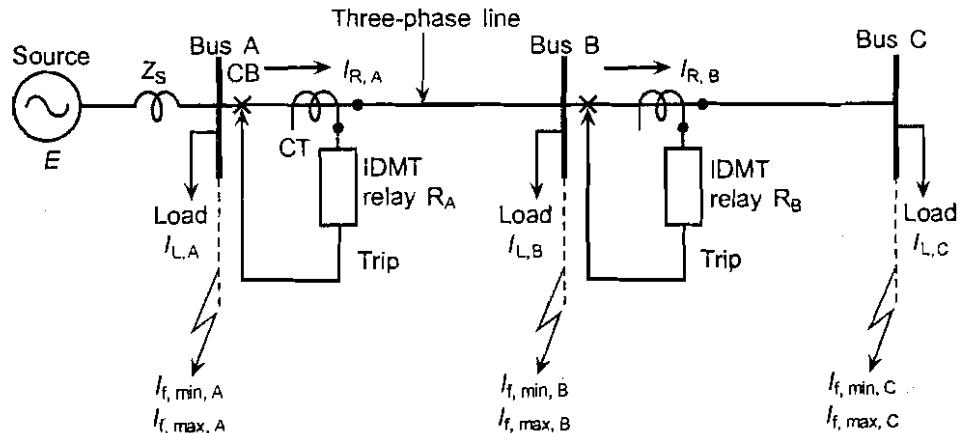


Figure 2.14 Variation of fault current against fault location for IDMT relays under maximum fault condition.

These rules are shown in Figure 2.15 for a simple system consisting of two buses. The same principle can be extended to an n bus system. In fact, a computer algorithm can be developed to automate this task in case of a large system.



Plug setting of R_B should be such that:

$$I_{f,\min,C} > \text{PS of } R_B > (I_{L,C} + \text{Overload})$$

TMS of R_B can be set at the smallest value of 0.1.

Plug setting of R_A should be such that:

$$I_{f,\min,C} > \text{PS of } R_A > [(I_{L,B} + I_{L,C}) + \text{Overload}]$$

TMS of R_A should be such that:

$$\begin{array}{lcl} \text{Operating time of } R_A \\ \text{for } I_{f,\max,B} \end{array} = \begin{array}{l} \text{Operating time of } R_B \\ \text{for } I_{f,\max,B} \end{array} + \begin{array}{l} \text{Circuit breaker B} \\ \text{operating time} \end{array} + \begin{array}{l} \text{Overshoot} \\ \text{time of } R_A \end{array}$$

Figure 2.15 Rules for setting IDMT OC relays.

2.7.1 Choice Between IDMT and DTOC Relays

It can be seen that IDMT relays offer significant improvement in fault clearing times over DTOC relays. A question that naturally arises is: if this is so, there should be no need to use DTOC relays. However, there are situations where IDMT relays do not offer significant advantages over DTOC relays. For example, consider a system where $Z_S \gg Z_L$. Since the fault current as a function of fault location is proportional to

$I_f = \frac{E}{Z_S + Z_L} \approx \frac{E}{Z_S}$, it would remain more or less constant throughout the length of the feeder, therefore, the inverseness of the IDMT characteristics cannot be exploited. In such situations, DTOC relays being cheaper may be preferred. Such feeders are also described as electrically short in length, irrespective of their physical length. Thus we can say that DTOC relays are suitable for lines which are short in length.

It is a practice to recommend DTOC relays when $\frac{Z_S}{Z_L} \geq 2$. See Figure 2.16.

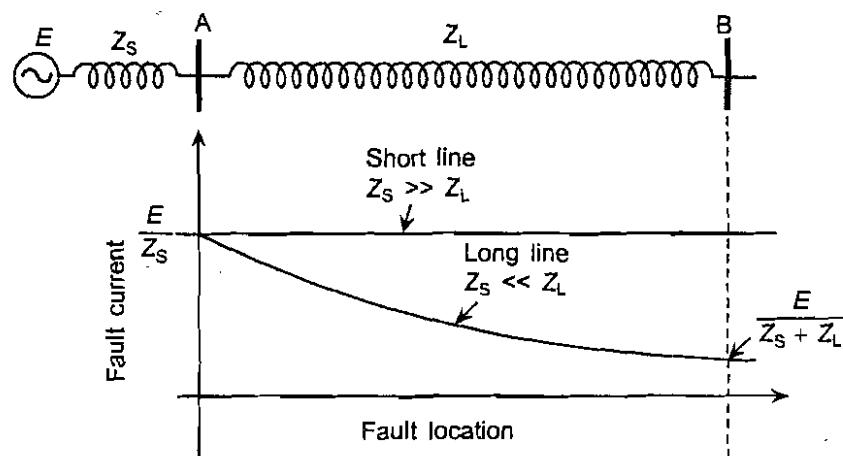


Figure 2.16 Choice between DTOC and IDMT relays.

2.8 Protection of a Three-phase Feeder

Up to this point we have shown three-phase feeders with the help of a single-line diagram. The single-line diagram hides the complexity of the three-phase system. The three-phase system is subject to *phase faults* as well as *ground faults*. For providing complete protection to a three-phase feeder, we can begin with three relays connected to three CTs as shown in Figure 2.17. As can be seen from Table 2.2, all the 11 numbers of shunt faults are catered for by the three relays.

The relays at bus A will be coordinated with those at bus B using the procedure illustrated in Section 2.7.

It may be pointed out here, that fault current for a single line to ground fault, depends upon the system grounding as well as the tower footing resistance. Therefore, it may happen that the fault current for a single line to ground fault, may be less than the load current. In such cases, it will not be possible to cater to such faults if we use the

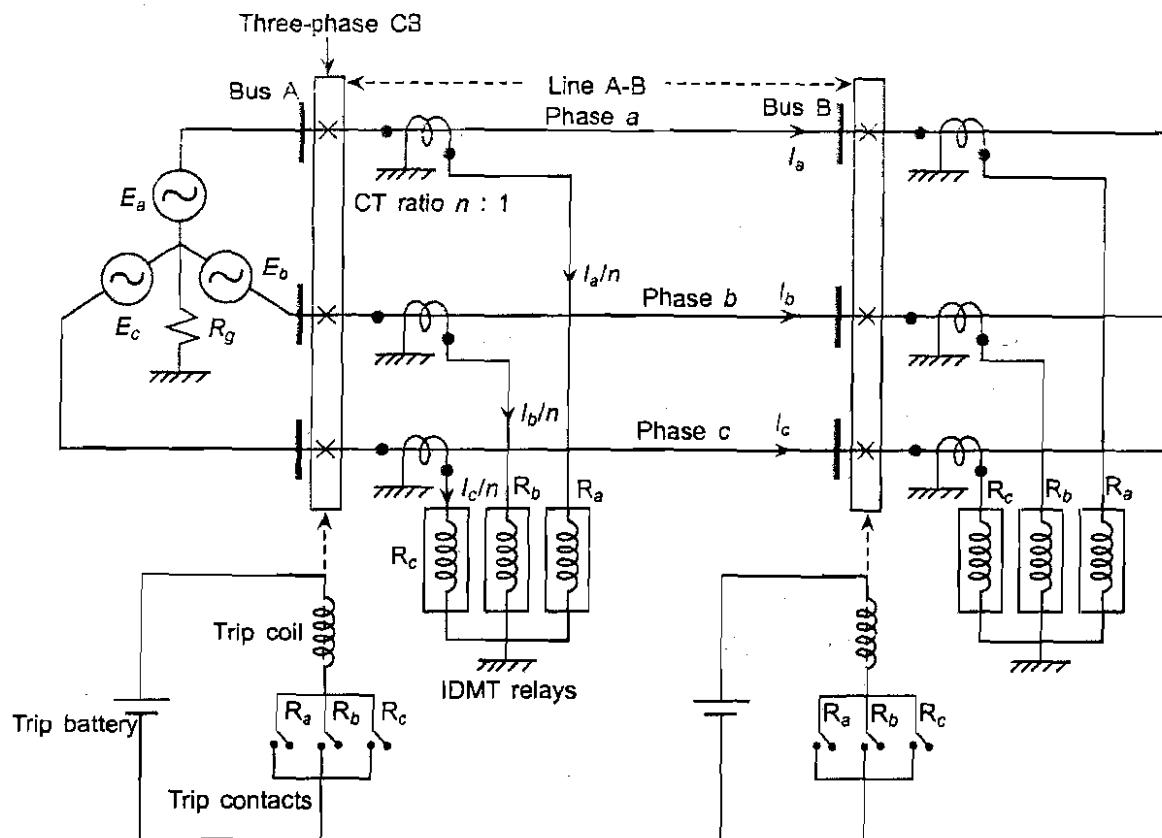


Figure 2.17 OC protection of a three-phase feeder.

Table 2.2 Protection of a three-phase feeder

Fault	Relays which will operate	
	Three-phase fault relays of Figure 2.17	Two-phase fault + one ground fault relay of Figure 2.18
a-g	R_a	R_a , R_g
b-g	R_b	R_g
c-g	R_c	R_c , R_g
a-b	R_a , R_b	R_a
b-c	R_b , R_c	R_c
c-a	R_c , R_a	R_c , R_a
a-b-g	R_a , R_b	R_a , R_g
b-c-g	R_b , R_c	R_c , R_g
c-a-g	R_a , R_c	R_a , R_c , R_g
a-b-c	R_a , R_b , R_c	R_a , R_c
a-b-c-g	R_a , R_b , R_c	R_a , R_c

scheme shown in Figure 2.17. A little thought will show that if we connect an OC relay in the residual current path as shown in Figure 2.18, it will be blind to the load current (which is balanced three-phase current) and see only the ground fault currents. The current in this path will be zero or near zero during normal balanced load conditions as

well as during a three-phase fault. Thus, the setting of this relay, which is in the residual current path, can be made independent of load current and can indeed be much smaller than the load current.

Further, as illustrated in Figure 2.18, it is not necessary to use all the three relays for detection and protection against phase faults. We can get rid of any one phase fault relay without affecting the performance of the scheme. In Figure 2.18, the relay in the phase b has been removed.

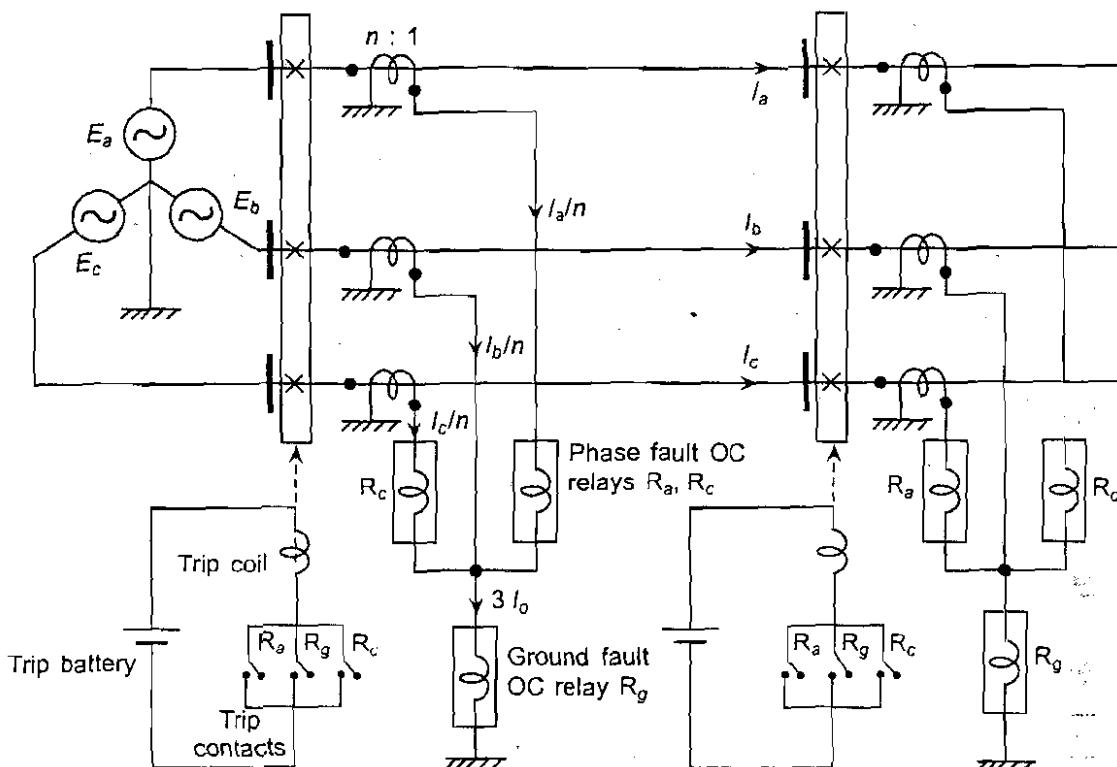


Figure 2.18 Two-phase fault relays and one ground fault relay for OC protection of a three-phase feeder.

Table 2.2 shows the operation of relays for all the 11 shunt faults for OC schemes of Figure 2.17 and Figure 2.18, which shows that all the 11 shunt faults are catered for by these schemes.

2.9 Directional Over-current Relay

Figure 2.19 shows a double-end-fed power system. The zones to be generated by the relays are also shown. Consider that we have only over-current relays at our disposal. Will it be possible to implement the desired zones using simple over-current relays? In order to answer this question, let us focus on OC relays at bus C. Note that OC relays operate on the magnitude of fault current and cannot sense the direction of the fault.

Consider fault F_a . As per the desired zones, only CBs 4 and 5 should trip. However, it can be easily seen that if plain OC relays are used, CBs 3, 4, 5, and 6 will all trip as

the fault will be seen by OC relays at these locations. Thus, the desired zones are not generated. The desired relay response is shown in Table 2.3 with respect to faults F_a and F_b .

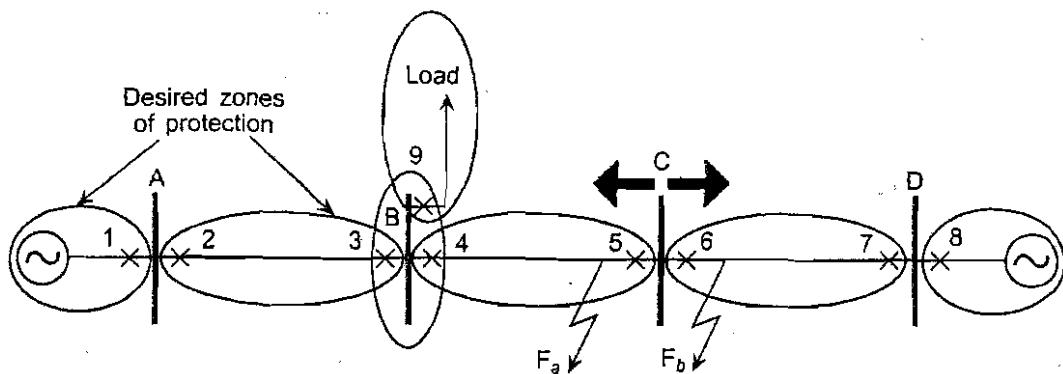


Figure 2.19 Need for directional relay.

Table 2.3 Response of OC relays to generate desired zones of protection

<i>Fault</i>	<i>Direction of fault power flow at bus C as seen from 5</i>	<i>Desired response of OC relay at 5</i>	<i>Direction of fault power flow at bus C as seen from 6</i>	<i>Desired response of OC relay at 6</i>
F_a	Away from bus C	Trip	Towards bus C	Restrain
F_b	Towards bus C	Restrain	Away from bus C	Trip

Thus it can be seen from Table 2.3, that whenever the fault power flows away from the bus, it is desired that the OC relay should trip. It should restrain if it sees the fault power flowing towards the bus.

2.9.1 Other Situations Where Directional OC Relays are Necessary

There are other situations where it becomes necessary to use directional relays to supervise OC relays. One such situation is a single-end-fed system of parallel feeders, shown in Figure 2.20, where a fault on any of the parallel lines is fed not only from the faulted line but from the healthy line as well.

If directional relays are not provided, in conjunction with OC relays, then the desired zones will not be generated. This will result in both lines being tripped out for any fault on any one of the lines.

It may be noted that directional relays with tripping direction away from the bus will be required at locations '2' and '3' in Figure 2.20. However, at locations '1' and '4', non-directional over-current relays will suffice. Since directional relay units cost more and also need the provision of PTs, they should be used only when absolutely necessary.

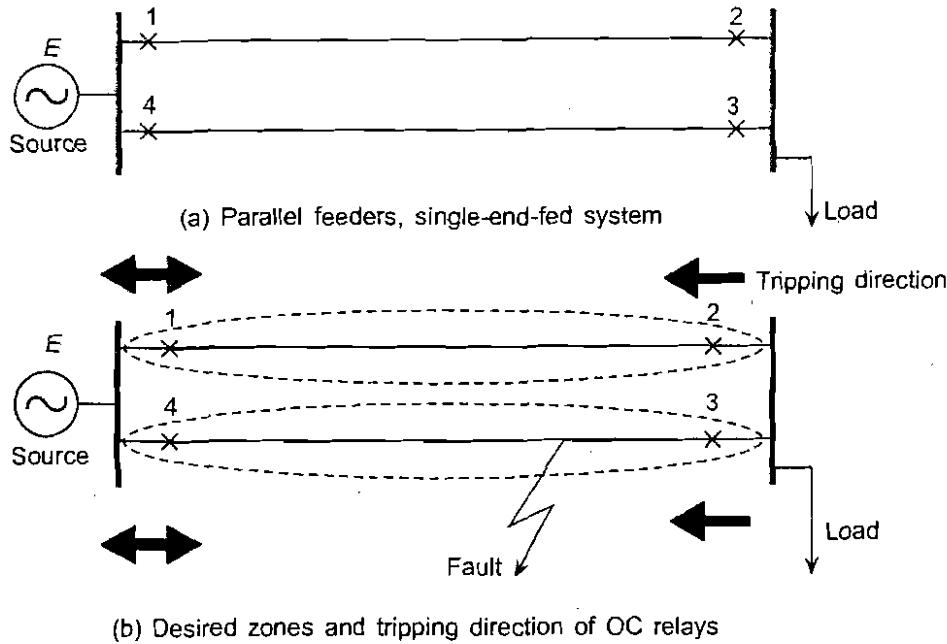


Figure 2.20 Single-end-fed parallel feeder needs directional OC protection.

Consider the ring main feeder system shown in Figure 2.21. This is another situation where directional supervision of OC relays is called for. It is well known that the ring main feeder allows supply to be maintained to all the loads in spite of fault on any section of the feeder. A fault in any section causes only the CBs associated with that section to trip out, and because of the ring topology, power flows from the alternate path.

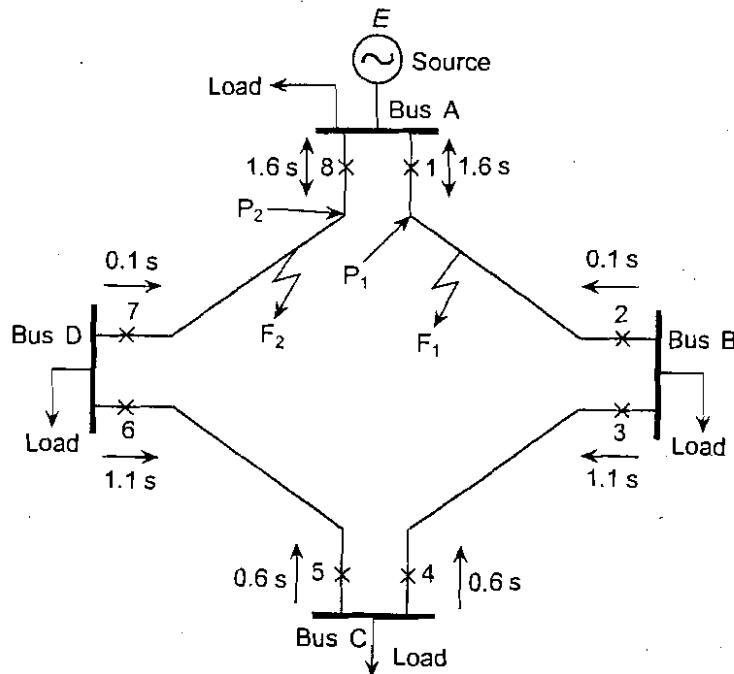


Figure 2.21 Protection of ring feeder using directional OC relays.

Characteristics of directional relay

A directional relay can be compared to a contact making wattmeter. A wattmeter develops maximum positive torque when the current and voltage supplied to the current coil and the pressure coil are in phase. If we define the maximum torque angle (MTA) as the angle between the voltage and current at which the relay develops maximum torque, then a wattmeter can be called a directional relay with MTA of zero degree.

The phasor diagram for a directional relay is depicted in Figure 2.23.

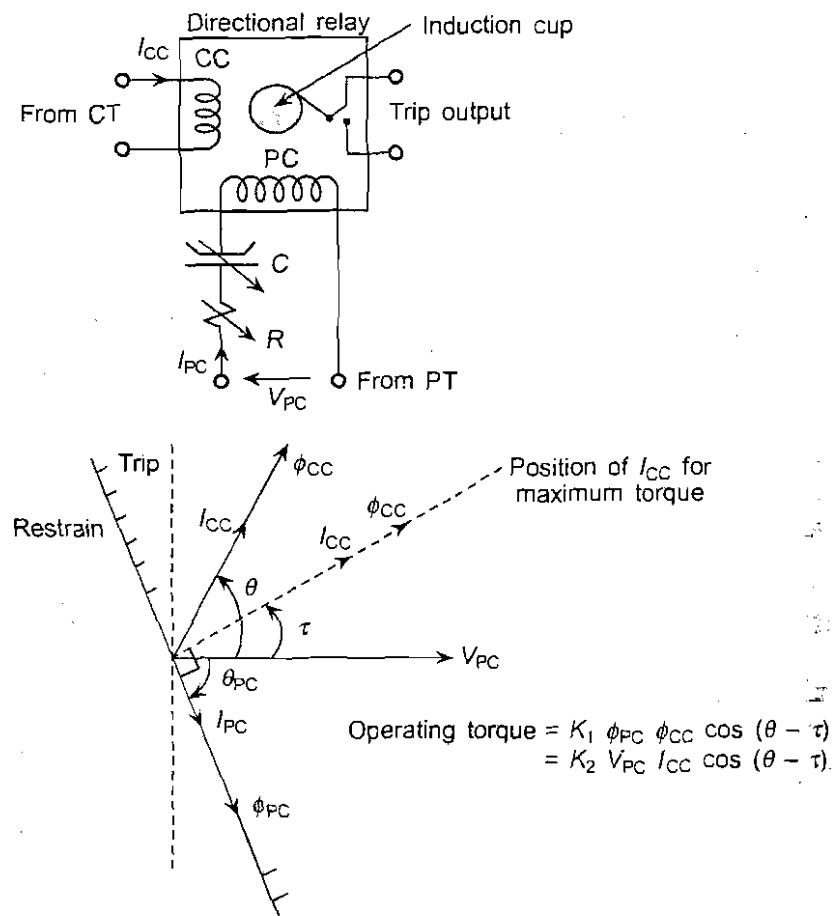


Figure 2.23 Phasor diagram for a directional relay based on induction principle.

V_{PC} is the voltage applied to the pressure coil. The current drawn by the pressure coil I_{PC} lags the voltage by a large angle θ_{PC} .

As the fault moves from the forward to the reverse direction, the current undergoes a large change in its phase whereas the phase of the voltage does not change substantially. Thus, voltage signal is the reference against which the phase angle of the current is measured.

Now, in a relay based on induction principle, the two fluxes responsible for torque production, ϕ_{PC} and ϕ_{CC} should be shifted in phase by 90° , for them to produce maximum torque. The torque becomes zero when the current phasor is $\pm 90^\circ$ away from the MTA

position. This gives the direction of the current phasor for maximum torque, the maximum torque angle τ , and the boundary between tripping and restraining regions on the phasor diagram.

The operating torque of the directional relay can be expressed as:

$$\text{Operating torque } T_{\text{operating}} \propto \phi_{\text{PC}} \phi_{\text{CC}} \sin (\theta + \theta_{\text{PC}})$$

From phasor diagram it can be seen that:

$$\theta_{\text{PC}} + \tau = 90^\circ$$

$$\therefore \theta_{\text{PC}} = 90^\circ - \tau$$

$$\begin{aligned} \therefore T_{\text{operating}} &\propto \phi_{\text{PC}} \phi_{\text{CC}} \sin (\theta + 90^\circ - \tau) \\ &\propto \phi_{\text{PC}} \phi_{\text{CC}} \sin [(\theta - \tau) + 90^\circ] \\ &= K_1 \phi_{\text{PC}} \phi_{\text{CC}} \cos (\theta - \tau) \end{aligned}$$

Since $\phi_{\text{PC}} \propto V_{\text{PC}}$ and $\phi_{\text{CC}} \propto I_{\text{CC}}$

$$T_{\text{operating}} = K_2 V_{\text{PC}} I_{\text{CC}} \cos (\theta - \tau)$$

From the phasor diagram, it can be easily seen that the maximum torque angle τ is given by

$$\tau = 90^\circ - \theta_{\text{PC}}$$

Since the pressure coil is highly inductive, the value of θ_{PC} is of the order of 70° to 80° . This gives MTA of 20° to 10° . However, θ_{PC} and hence τ can be adjusted to any desired value if an external resistance or capacitance is introduced into the pressure coil circuit.

2.9.3 Application of Directional Relay to a Three-phase Feeder

In case of application of directional relays to a three-phase feeder, phase faults need to be considered separately from ground faults. There are various possibilities of energizing these relays; hence the various alternatives need to be carefully considered. The directional relay must meet the following requirements:

1. The relay must operate for forward faults.
2. The relay must restrain during reverse faults.
3. The relay must not operate during faults other than for which it has been provided, i.e. the relay must not maloperate.

Directional phase fault protection

Consider a directional relay for protection against all phase faults involving phase a , i.e. $a-b$, $a-b-g$, $a-c$, $a-c-g$, $a-b-c$, and $a-b-c-g$ faults. Let us consider an $a-b$ fault. It is logical to choose current I_a to energize the current coil. However, the choice of voltage to be applied to the pressure coil is not immediately apparent. Figures 2.24 and 2.25 explore the possibility of using voltage V_{ab} and V_{ca} for the pressure coil of the directional relay catering to phase faults involving phase a . From Figure 2.24, it can be seen that the voltage V_{ab} tends to collapse during $a-b$ fault. Further, the angle between V_{ab} and I_a during

fault is substantially large. For the MTA angle shown, the relay does not develop positive torque during forward fault. From these figures, it can be easily seen that both these voltages are not suitable, as they do not meet the requirement set out in Section 2.9.3.

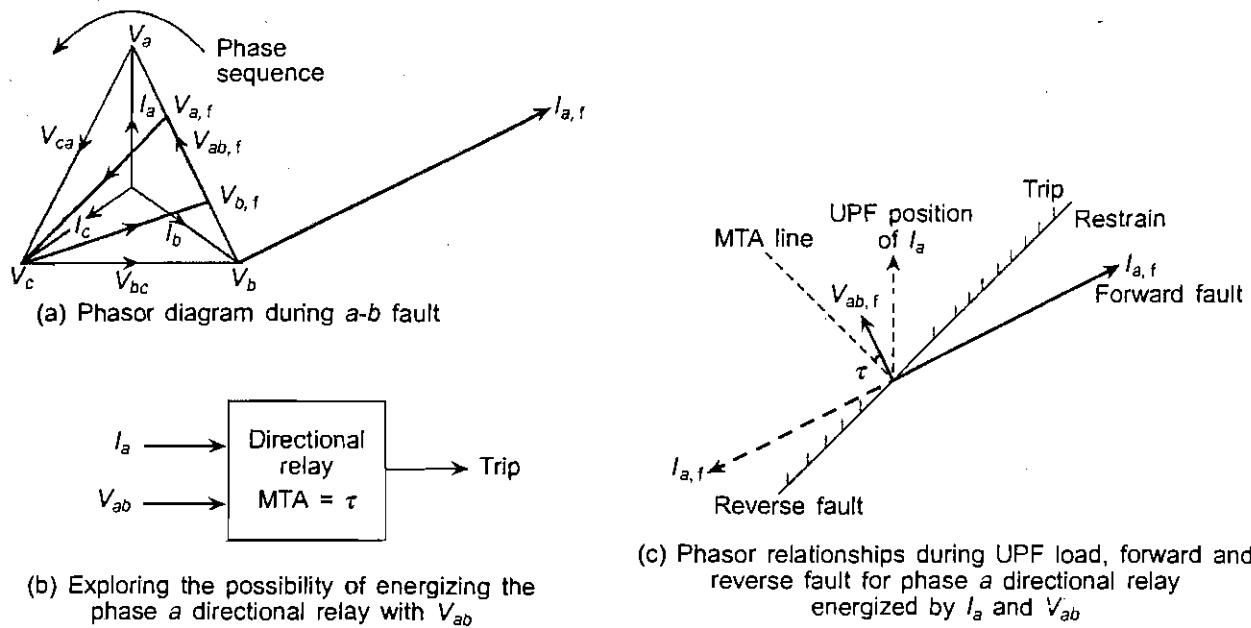


Figure 2.24 Exploring the possibility of energizing the pressure coil of phase *a* directional relay with voltage V_{ab} .

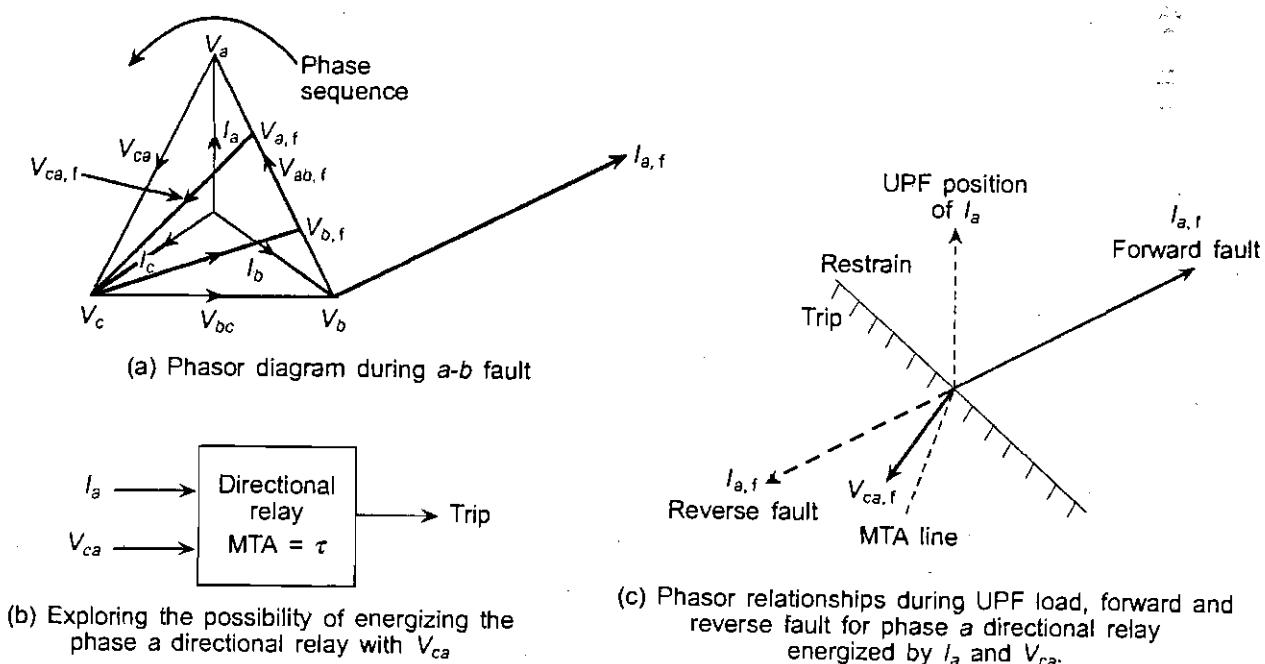


Figure 2.25 Exploring the possibility of energizing pressure coil of phase *a* directional relay with voltage V_{ca} .

Figure 2.26 shows that the voltage V_{bc} happens to be the correct choice. Since the unity power factor (UPF) position of I_a leads V_{bc} by 90° , this connection is known as the 90° connection.

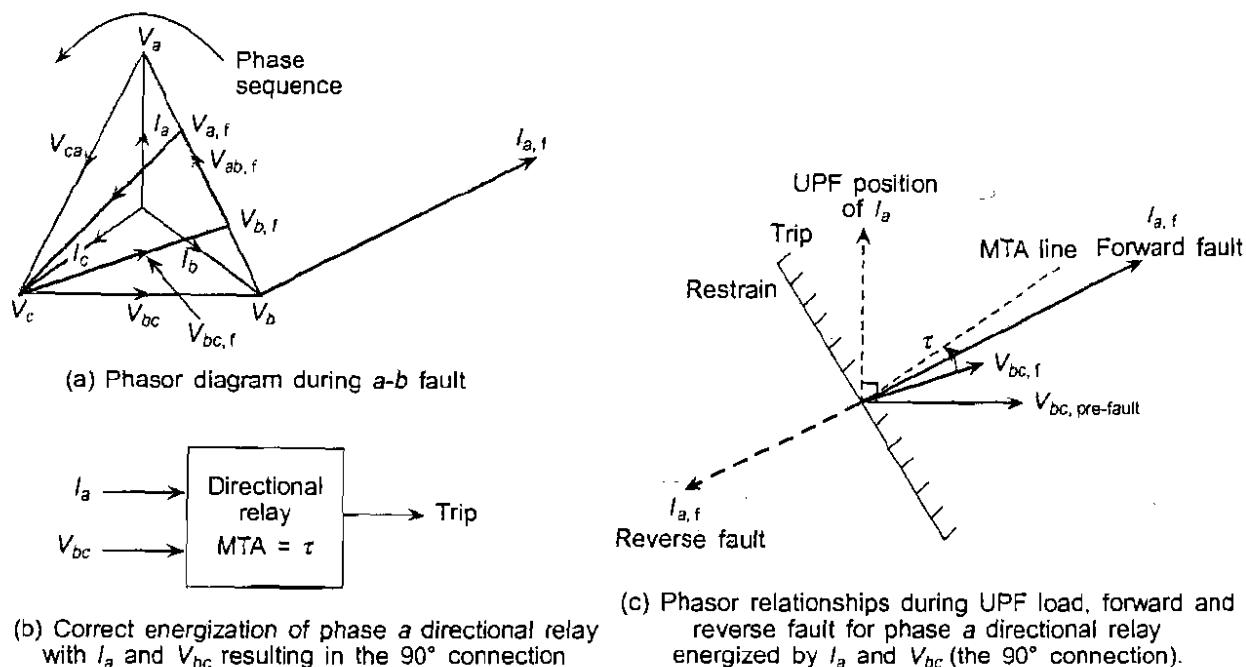


Figure 2.26 Correct energization of directional relay: 90° connection.

The 30° and the 60° connections

As already pointed out there are other possibilities for energizing the voltage coils of directional relays. However, all the possible voltages may not meet the requirement of no maloperations. Hence, the choice has been narrowed down to three. The other two possible voltages, for phase a directional relay, are V_{ac} and $(V_{ac} + V_{bc})$. These are known as the 30° and the 60° connections because of the angular relationship between the unity power factor (UPF) position of I_a and these voltages during the pre-fault condition.

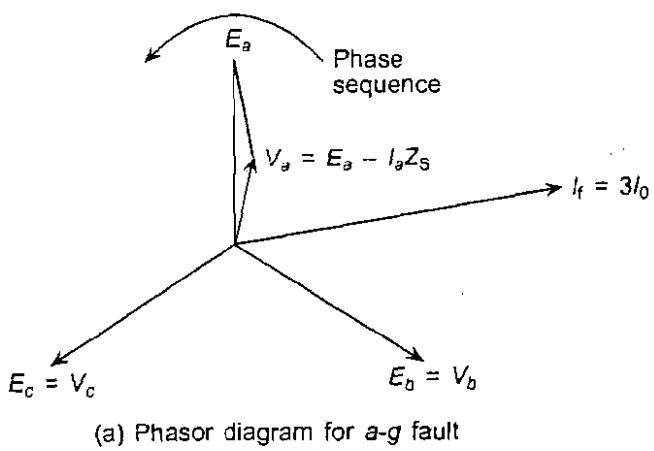
Table 2.4 summarizes various combinations of voltages and currents to be fed to directional phase fault relays catering to phase faults involving the three phases, for the 90° , 30° and 60° connections.

Table 2.4 Summary of phase fault relay excitation

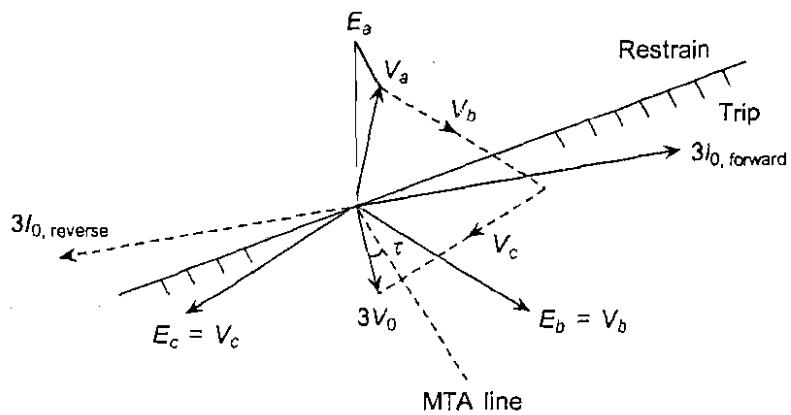
Type of connection	Phase faults involving phase, a		Phase faults involving phase, b		Phase faults involving phase, c	
	Current	Voltage	Current	Voltage	Current	Voltage
90°	I_a	V_{bc}	I_b	V_{ca}	I_c	V_{ab}
30°	I_a	V_{ac}	I_b	V_{ba}	I_c	V_{cb}
60°	I_a	$V_{ac} + V_{bc}$	I_b	$V_{ba} + V_{ca}$	I_c	$V_{cb} + V_{ab}$

Directional ground fault protection

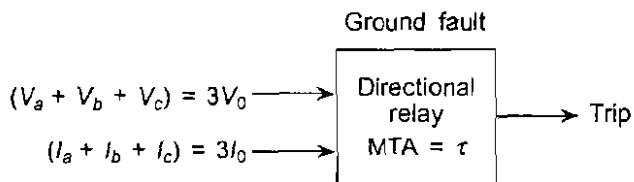
The directional ground fault relay develops correct tripping tendency when fed by the residual current I_0 and residual voltage V_0 . This is shown in Figure 2.27.



(a) Phasor diagram for a-g fault



(b) Phasor relationships between actuating quantities during forward and reverse faults



(c) Directional ground fault relay energized by residual voltage and current

Figure 2.27 Directional ground fault relay energization.

2.9.4 Directional OC Protection of a Three-phase Feeder

Figure 2.28 shows a three-phase feeder protected by directional relays supervised by OC relays.

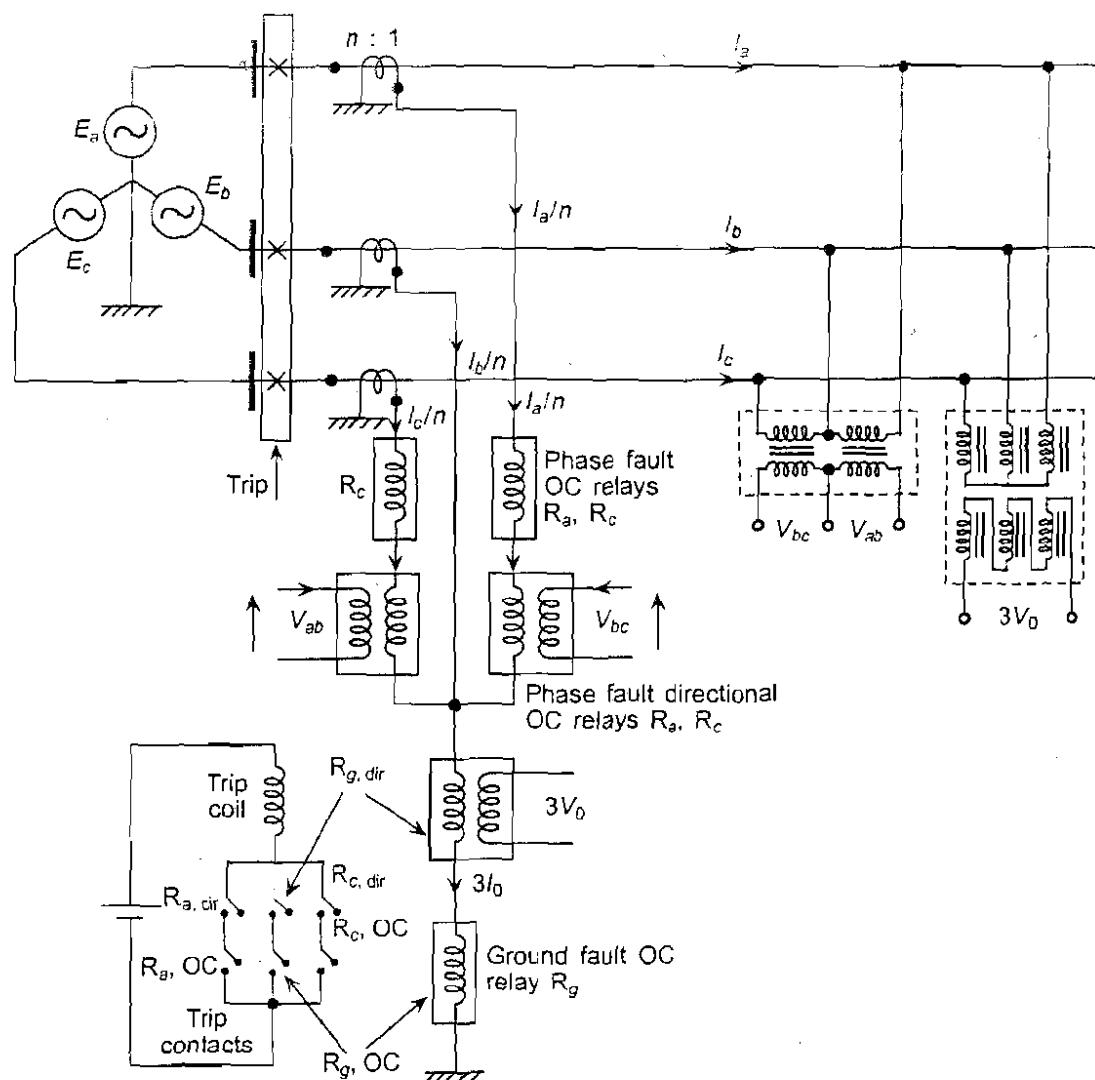


Figure 2.28 Complete scheme for directional OC protection of a three-phase feeder.

2.9.5 Directional Protection Under Non-fault Conditions (Reverse Power Relay)

There are situations where directional relays have to be used under non-fault conditions. Such an application of directional relay exists in reverse power protection of a turbo-alternator. To distinguish between the two, let us call these directional relays as *power directional relay*.

These situations are different from those where directional relays are applied during fault conditions in the manner that, in case of the power relays, there is no collapse of system voltage. Directional relays for short circuit protection are so connected that they develop maximum operating torque under fault conditions. However, directional power relays are so connected that they develop maximum torque when direction of power flow reverses.

Consider a power relay with an MTA of 30° Figure (2.29). In order to be used as a power relay it can be fed with I_a and V_{ca} .

It can be seen that I_a leads V_{ca} by 30° during reverse power flow, thus developing maximum tripping torque.

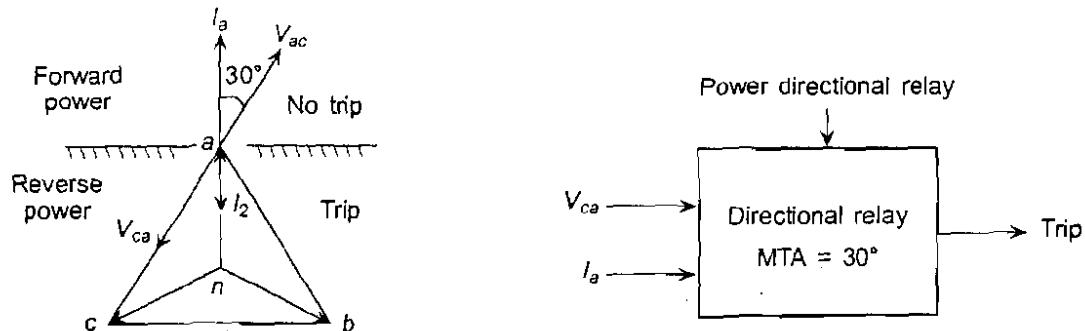


Figure 2.29 Connections of a power directional relay with MTA of 30° .

2.10 Drawbacks of Over-current Relays

The reach and operating time of the over-current relay depend upon the magnitude of fault current. The fault current that would result in case of a fault at a particular location depends upon:

1. The type of fault, i.e. whether it is a ground fault or a phase fault.
2. The source impedance as shown in Figure 2.30.

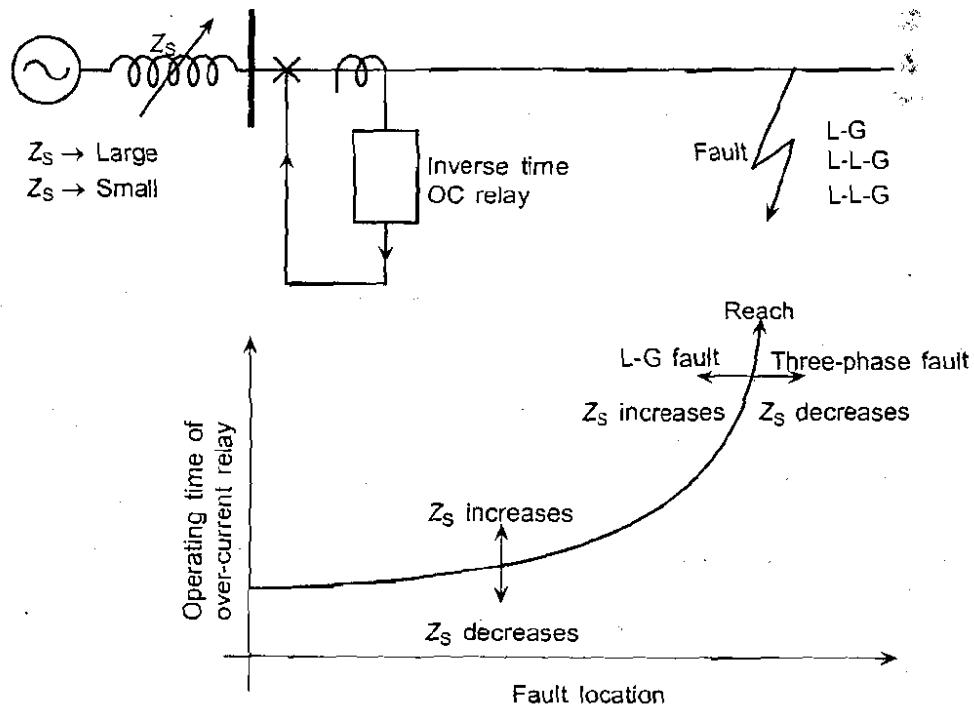


Figure 2.30 Fault current and reach is a function of fault type and source impedance.

Since neither the type of fault nor the source impedance is predictable, the reach of the over-current relay keeps on changing depending upon the source conditions and the type of fault. Thus, even though the relays are set with great care, since their reach is subject to variations, they are likely to suffer from loss of selectivity. Such a loss of selectivity can be tolerated to some extent in the low-voltage distribution systems, where the only objective to be met is the continuity of supply to the consumer. However in EHV interconnected system (grid), loss of selectivity can lead to danger to the stability of the power system, in addition to large disruptions to loads. Therefore, over-current relays cannot be relied upon as a primary means of protection in EHV systems.

Another principle of relaying, known as *distance measurement*, offers a much more accurate reach, which is independent of source conditions and type of fault. This is discussed in Chapter 6.

Review Questions

1. What are the necessary conditions for two alternating fluxes acting on a common rotor (a) to produce some torque and (b) to produce maximum torque?
2. What are the situations where DTOC relays are preferred over IDMT relays?
3. What is the difference between plug setting and pick-up value of an OC relay?
4. What are the drawbacks of using DTOC relays for the protection of long feeders?
5. Why does the fault current vary between a minimum and a maximum at any location?
6. The generator impedance does not affect the fault current to a great extent in the low-voltage distribution system. Explain.
7. Explain the overshoot time of a relay and its significance.
8. What do you mean by loss of selectivity between two OC relays in adjoining line sections? What are its causes?
9. While setting the pick-up value, the minimum fault current at the end of the adjoining feeder needs to be considered; but while setting the TMS the maximum fault current at the beginning of the next section needs to be considered. Explain.
10. What do you mean by an OC relay, supervised by a directional element?
11. What is the meaning of the term 'directional' vis a vis directional relaying?
12. What is meant by maximum torque angle vis a vis a directional relay?
13. How will you adjust the MTA of a directional relay?
14. What is the difference between the reverse power relay and the directional relay?
15. Why polarizing voltage from a healthy phase is used in three-phase directional relays?
16. While different connections like 90° , 30° , and 60° exist in case of directional phase fault relays, why is it that no such connections exist for directional ground fault relays?
17. What are the situations where there is no need to use directional OC relays and the situations where directional relays must be used?
18. Give the procedure for time setting of relays on a ring main feeder system.

Problems

1. The pressure coil of a directional relay has an impedance of $(100 + j274.74)$ ohms. What is the MTA for this relay? What change will have to be made to the pressure circuit so as to change this angle to (a) 30° and (b) 15° ?
2. For the system shown below, design the complete OC protection using the IDMT relays. Thus, decide the CT ratios, the plug settings and the TMS at all locations.

A B C D E

Load	115 A	80 A	100 A	77 A	70 A
Minimum fault current	1500 A	1000 A	780 A	585 A	390 A
Maximum fault current	6000 A	5000 A	3000 A	2000 A	1000 A

3

Differential Protection

3.1 Introduction

Differential protection is based on the fact that any fault within an electrical equipment would cause the current entering it, to be different, from that leaving it. Thus, we can compare the two currents either in magnitude or in phase or both and issue a trip output if the difference exceeds a predetermined set value. This method of detecting faults is very attractive when both ends of the apparatus are physically located near each other. A typical situation, where this is true, is in the case of a transformer, a generator or a busbar. In the case of transmission lines, the ends are too far apart for conventional differential relaying to be directly applied.

3.2 Dot Markings

Differential protection utilizes CTs at each terminal of the equipment under protection. Careful attention needs to be paid to the 'dot markings' (also known as 'polarity marks') on these CTs. We, therefore, briefly review the concept of dot markings.

Consider a set of three mutually coupled coils A , B , and C with terminals A_1-A_2 , B_1-B_2 and C_1-C_2 as shown in Figure 3.1. The question is: how shall we put dot marks on the terminals of these coils?

To answer this question, let us energize coil A as shown in Figure 3.2 so that the terminal A_1 becomes positive with respect to terminal A_2 . Now, this will cause an alternating current to flow through coil A , and thus set up an alternating flux ϕ_A in the direction shown, at the instant of time under consideration. This flux also links both coils B and C . Voltages will be induced in these coils. Now if a load were to be connected between terminals B_1 and B_2 , a current will be established. According to Lenz's law, this current would flow in such a direction so as to oppose the very cause (flux ϕ_A) that was responsible for its (current in coil B) production. Therefore, the direction of current through coil B will be such that the flux (ϕ_B) due to it opposes the flux ϕ_A . Thus, current will flow out of terminal B_2 , making B_2 instantaneously positive with respect to B_1 .

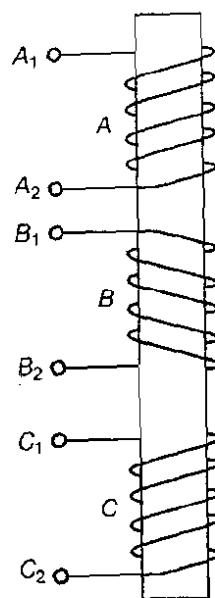


Figure 3.1 Dot markings.

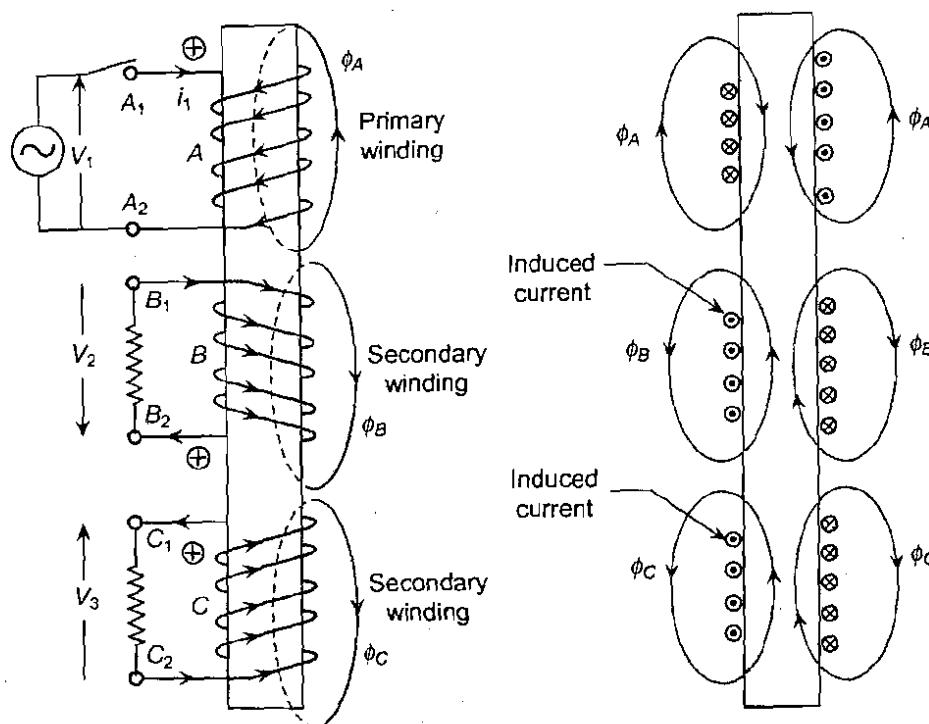


Figure 3.2 Dot marks: induced currents and flux.

Therefore, B_2 will have the same polarity as that of A_1 . Thus, dot marks can be put on A_1 and B_2 as shown in Figure. 3.3 to signify that these two terminals will be similarly phased.

Similar arguments show that current must leave terminal C_1 at the instant under consideration. Thus, C_1 will be similarly phased as A_1 . We, therefore, put dot marks on terminals A_1 , B_2 , and C_1 .

A little thought will convince the reader that we can instead put dot marks on terminals A_2 , B_1 , and C_2 , as shown in Figure 3.3.

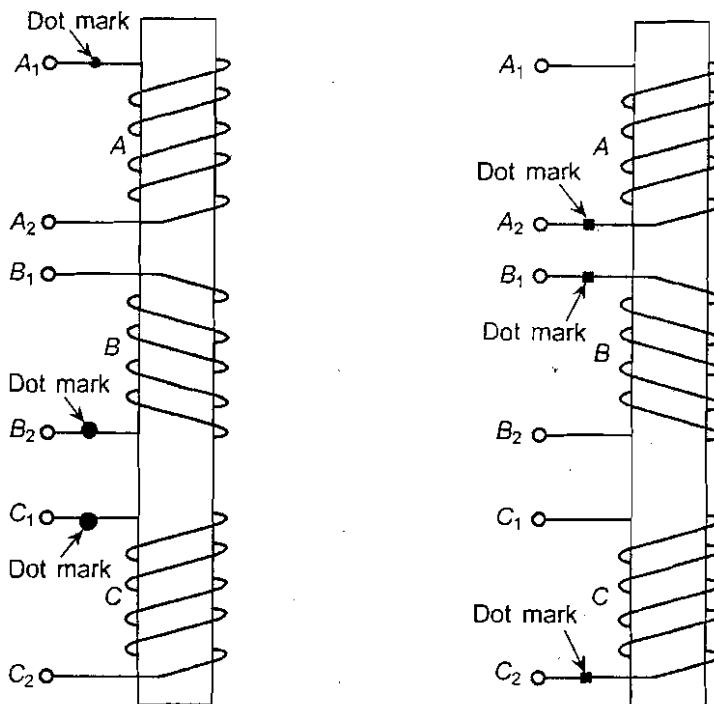


Figure 3.3 Dot marks: symbolic method of representation.

From the above discussion, we can generalize the following properties of dot markings:

When current enters the dot mark on the primary side of a CT, the current must leave the similarly marked dot mark on the secondary side.

If currents are made to enter dot marked terminals on two or more coupled coils then the fluxes produced by these currents are such that they add up.

3.3 Simple Differential Protection

3.3.1 Simple Differential Protection: Behaviour During Load

Figure 3.4 shows a simple differential relaying scheme (also known as Merz-Price scheme). The currents entering and leaving the equipment to be protected are stepped down with the help of CTs on either side. Careful attention must be paid to the dot marks placed on the CTs.

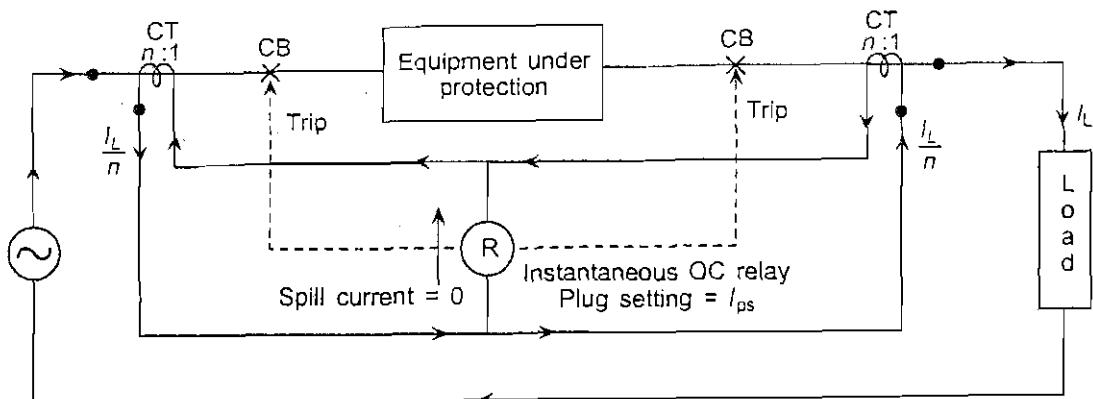


Figure 3.4 Simple differential protection.

The following rule can be applied in order to trace the currents in the circuit:

When current enters the dot mark on the primary side of the CT, the current must leave the similarly marked dot mark on the secondary side.

For the operating condition of normal load flow shown in Figure 3.4, the currents transformed by the two CTs, being equal in magnitude as well as in phase, just circulate on the secondary side. There is no tendency for the current to spill into the over-current relay. The over-current relay connected in the spill path is wired to trip the two circuit breakers on either side of the equipment being protected.

Assuming that the protected equipment is either a 1:1 ratio transformer or say a generator winding or a busbar, the two currents on the primary side will be equal. Hence the ratios of the two protective CTs will also be identical. The CT secondary circuits are so connected that in case the conditions are normal, the secondary currents simply circulate through the 'pilot' leads connecting the two secondary windings. For the operating condition of normal load flow, there is no current through the 'spill path' where an over-current relay is located. Hence, the OC relay will not trip the two CBs. Thus, the simple differential relay meets the first and foremost requirement that it remains stable during normal operating conditions.

3.3.2 Simple Differential Protection: Behaviour During External Fault

Next, the differential relaying scheme should also remain stable for any fault which is outside its protective zone. Such faults are called *external faults* or *through faults*. Figure 3.5 shows that during external faults too, the current leaving the protected zone is the same as that entering it. Assuming that the CTs transform the two currents with the same fidelity, there will be no current in the spill path and the scheme remains stable.

3.3.3 Simple Differential Protection: Behaviour During Internal Fault

Figure 3.6 shows an internal fault of magnitude $I_{f, int}$. The current leaving the protected zone is now I_2 whereas that entering it is I_1 , such that, $I_1 = I_2 + I_{f, int}$. As can be seen

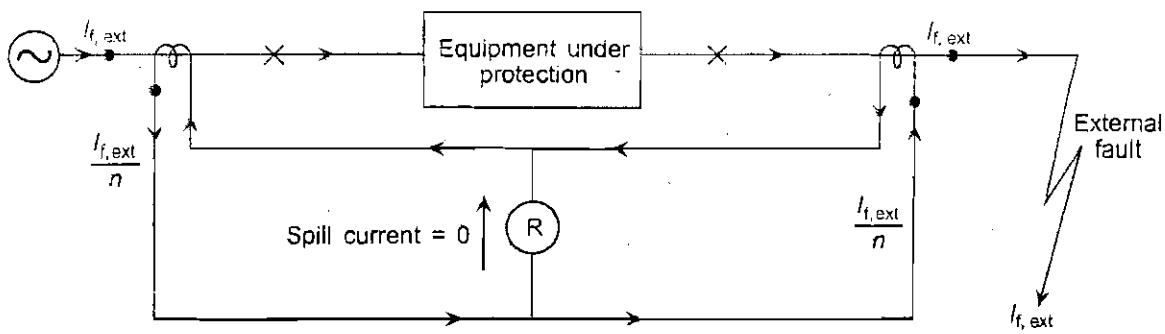


Figure 3.5 Simple differential scheme remains stable on external faults.

from the figure, current in the spill path is now ($I_{f, int}/n$), where n is the CT ratio. Assuming that the spill current is more than the pick-up value of the over-current relay, both the circuit breakers will be tripped out. Thus, the scheme meets the basic requirement of clearing internal faults.

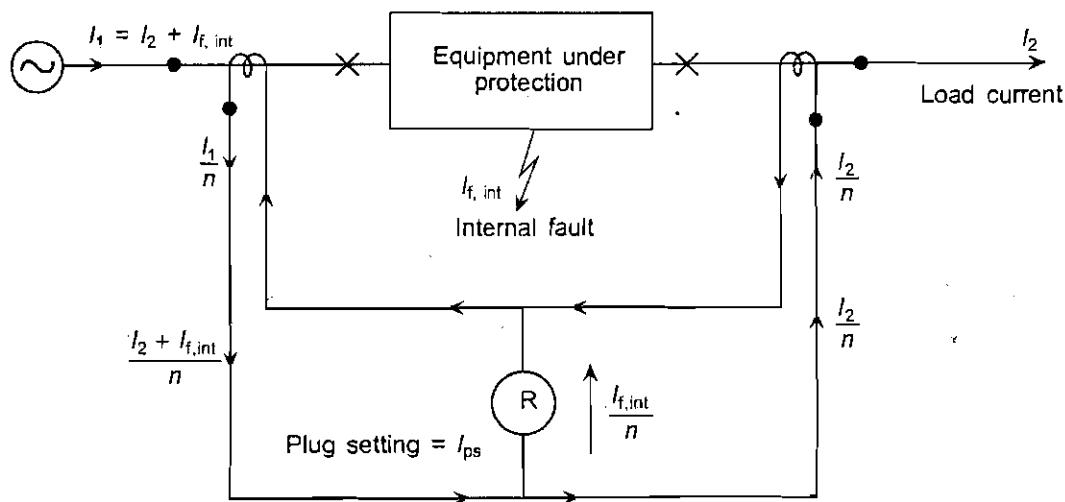


Figure 3.6 Simple differential scheme trips on internal faults.

The minimum internal fault current that will cause the tripping, is given by

$$I_{f, \min} = (\text{CT ratio}) (\text{Plug setting of the OC relay}) = nI_{ps}$$

3.3.4 Simple Differential Protection, Double-end-fed: Behaviour During Internal Fault

In the preceding analysis, we have assumed a single-end-fed system. How does the differential scheme behave in case of a double-end-fed system?

A double-end-fed system is shown in Figure 3.7, the internal fault is now fed from both sides. The internal fault current, $I_{f, int}$, is now equal to $(I_1 + I_2)$. Again, we see that the spill current is equal to $(I_{f, int}/n)$.

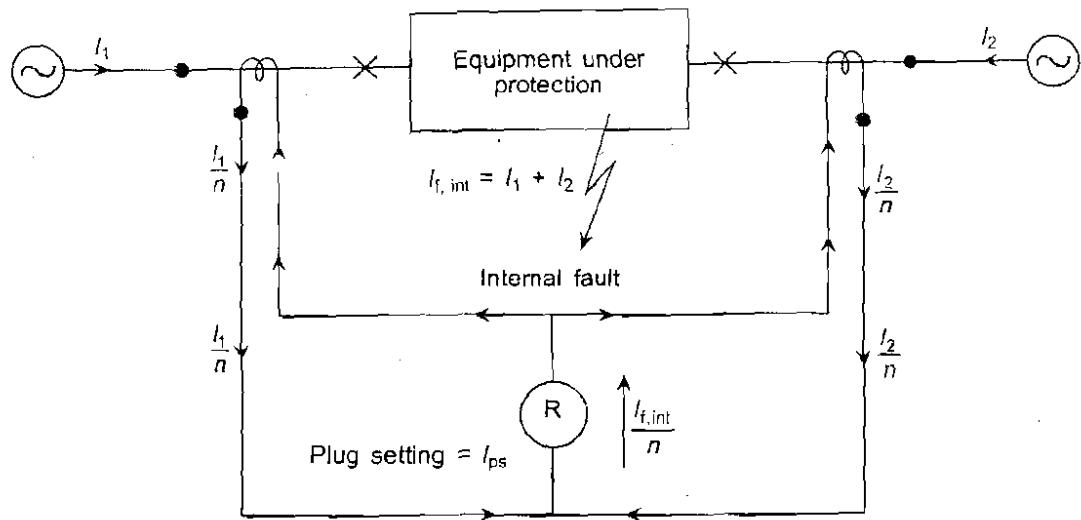


Figure 3.7 Simple differential scheme in a double-end-fed system operates for internal fault.

Assuming that the spill current is greater than I_{ps} , the plug setting of the OC relay, the relay will operate and trip out the circuit breakers on either side of the protected equipment.

3.4 Zone of Protection of the Differential Relay

The differential scheme generates a well-defined and closed zone of protection. This zone encompasses everything between the two CTs as shown in Figure 3.8. Thus, we talk of any fault between the two CTs as an 'internal fault'. To the differential scheme, all other faults are 'external faults' or 'through faults'. Ideally, therefore, a differential scheme is supposed to respond only to internal faults, and restrain from tripping on external or through faults.

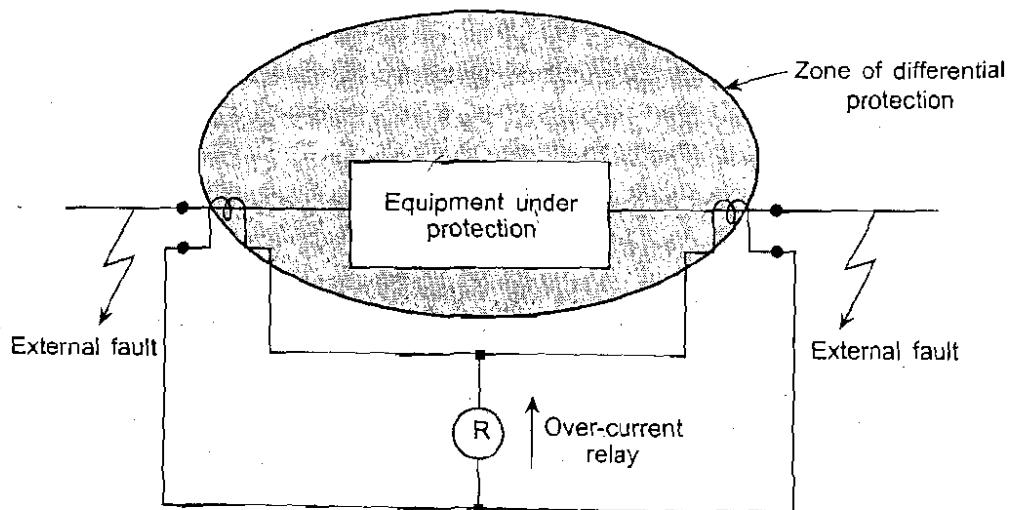


Figure 3.8 The zone of differential protection.

Thus, an ideal differential scheme should be able to respond to the smallest internal fault but restrain from tripping on the largest external fault. This ideal is difficult to achieve, especially for very heavy 'through faults' because of the non-ideal nature of the various components of the protective system. This is discussed in the following sections.

3.5 Actual Behaviour of a Simple Differential Scheme

In our discussion so far we have tacitly assumed that the CTs are ideal. However, in practice, CTs are subject to ratio and phase angle errors. Both these errors depend upon the burden on the CTs, which in turn depends on the lead lengths and the impedance of the relay coil. The errors, in general, increase as the primary current increases, as in the case of external faults. Figure 3.9 shows the primary and the secondary current phasors during an external fault.

Ideally, for 'through faults', secondary currents of both the CTs would be equal in magnitude and in phase with each other, and thus the spill current would be zero. However, as shown in Figure 3.9, CT₁ has an actual ratio of n_1 and phase-angle error of θ_1 while CT₂ has an actual ratio of n_2 and phase-angle error of θ_2 . The difference between these two currents, therefore, ends up as spill current, as shown in Figure 3.9. Since both the ratio and phase angle errors aggravate as primary current increases, the spill current builds up as the 'through fault' current goes on increasing.

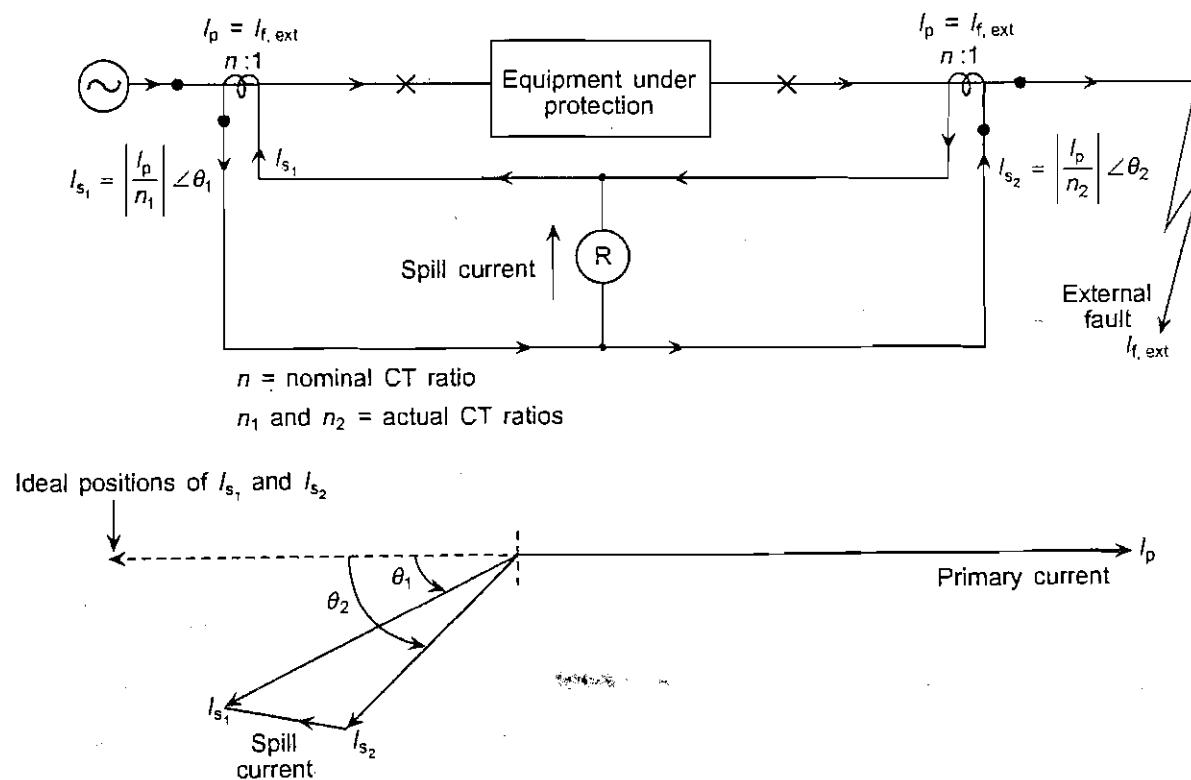


Figure 3.9 Spill current because of CT errors.

3.5.1 Through Fault Stability and Stability Ratio

As the 'through fault' current goes on increasing, various imperfections of the CTs get magnified. This causes the spill current to build up. Therefore, as the 'through fault' current goes on increasing, as shown in Figure 3.10, there comes a stage when the spill current, due to the difference between the secondary currents of the two CTs, exceeds the pick-up value of the over-current relay in the spill path. This causes the relay to operate, disconnecting the equipment under protection from rest of the system. This is clearly a case of maloperation, since the relay has tripped on external fault. In such instances, the differential scheme is said to have *lost stability*. To signify the ability of the differential scheme to restrain from tripping on external faults, we define 'through fault stability limit' as the maximum 'through fault' current beyond which the scheme loses stability. In Figure 3.10, 'through fault stability limit' is shown as I_{stab} .

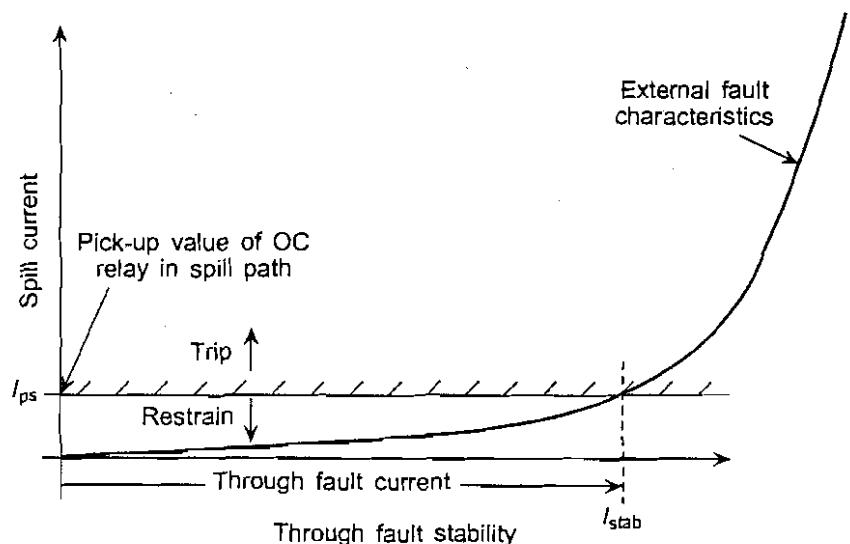


Figure 3.10 Characteristics of simple differential relay.

Compare this with the situation of an internal fault. The minimum internal fault current required for the scheme to operate, correctly in this case, is decided by pick-up value of the over-current relay in the spill path. To signify the spread between the minimum internal fault current at which the scheme operates and the maximum 'through fault' current beyond which the scheme (mal)operates, we define a term called stability ratio as:

$$\text{Stability ratio} = \frac{\text{maximum 'through fault' current beyond which scheme (mal)operates}}{\text{minimum internal fault current required for tripping}}$$

The higher the stability ratio, the better is the ability of the system to discriminate between external and internal faults. The stability ratio can be improved by improving the match between the two CTs.

3.5.2 Equivalent Circuit of CT

Figure 3.11 shows the equivalent circuit of the CT as referred to the secondary side.

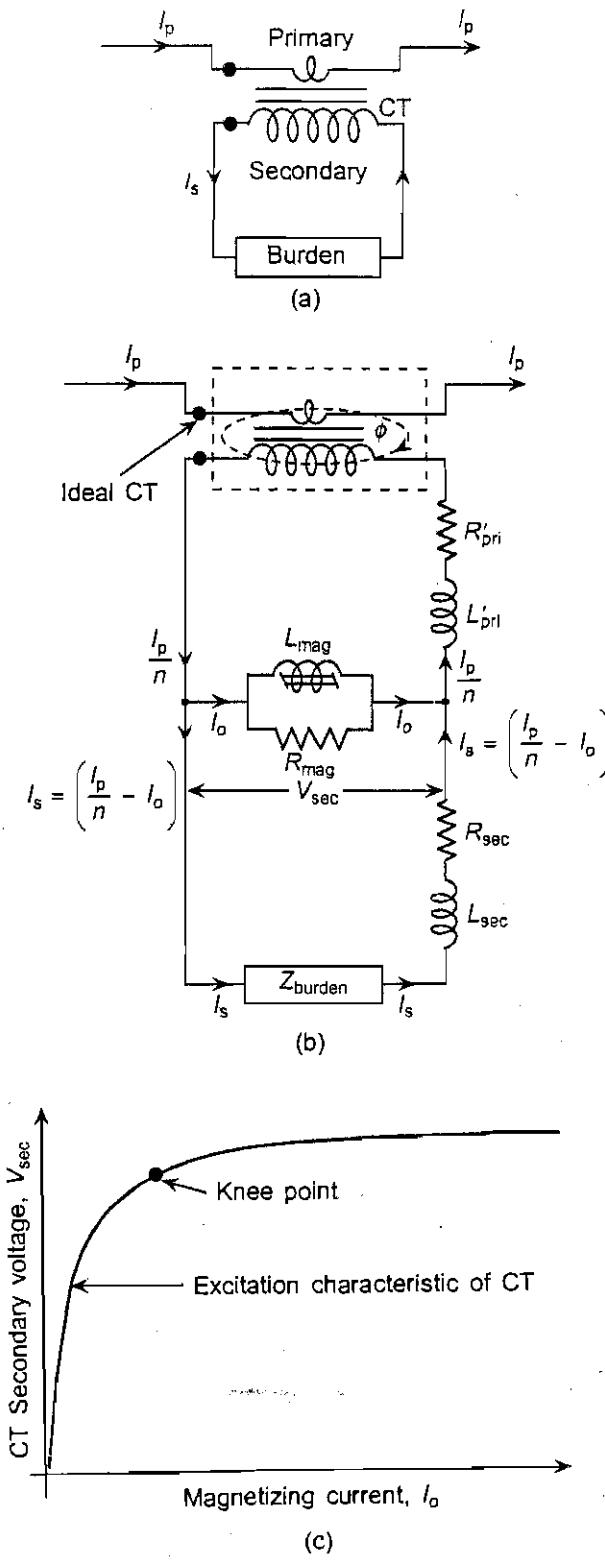


Figure 3.11 Equivalent circuit of CT.

R'_{pri} and L'_{pri} are the resistance and the leakage inductance of the primary winding as referred to the secondary side. R_{mag} and L_{mag} form the shunt magnetizing branch. The magnetizing inductance is highly nonlinear. R_{sec} and L_{sec} are the resistance and leakage inductance of the secondary winding. The impedance Z_{burden} includes the resistance and the inductance of the relay coils and resistance of the pilot wire (leads). Also shown in Figure 3.11(c) is a sketch of the magnetization characteristic of the CT (also known as open-circuit characteristic).

Out of the current I_p/n transformed by the ideal CT, the magnetizing branch draws the magnetization current I_o . It is to be noted that the magnetizing current is a nonlinear function of the excitation voltage V_{sec} . During normal operating conditions, when V_{sec} is small, the current I_o can be safely neglected. However, at higher values of primary current, (and therefore secondary current), as in case of 'through faults', the secondary voltage, V_{sec} , which is equal to $I_s(Z_{\text{sec}} + Z_{\text{burden}})$ increases and causes I_o to become an appreciable fraction of the current transformed by the ideal CT. Thus, we can no longer ignore I_o .

Differential scheme considering CT equivalent circuit

Figure 3.12 shows the simple differential scheme in which CT equivalent circuit has been explicitly included. The various currents shown in Figure 3.12 are those that result

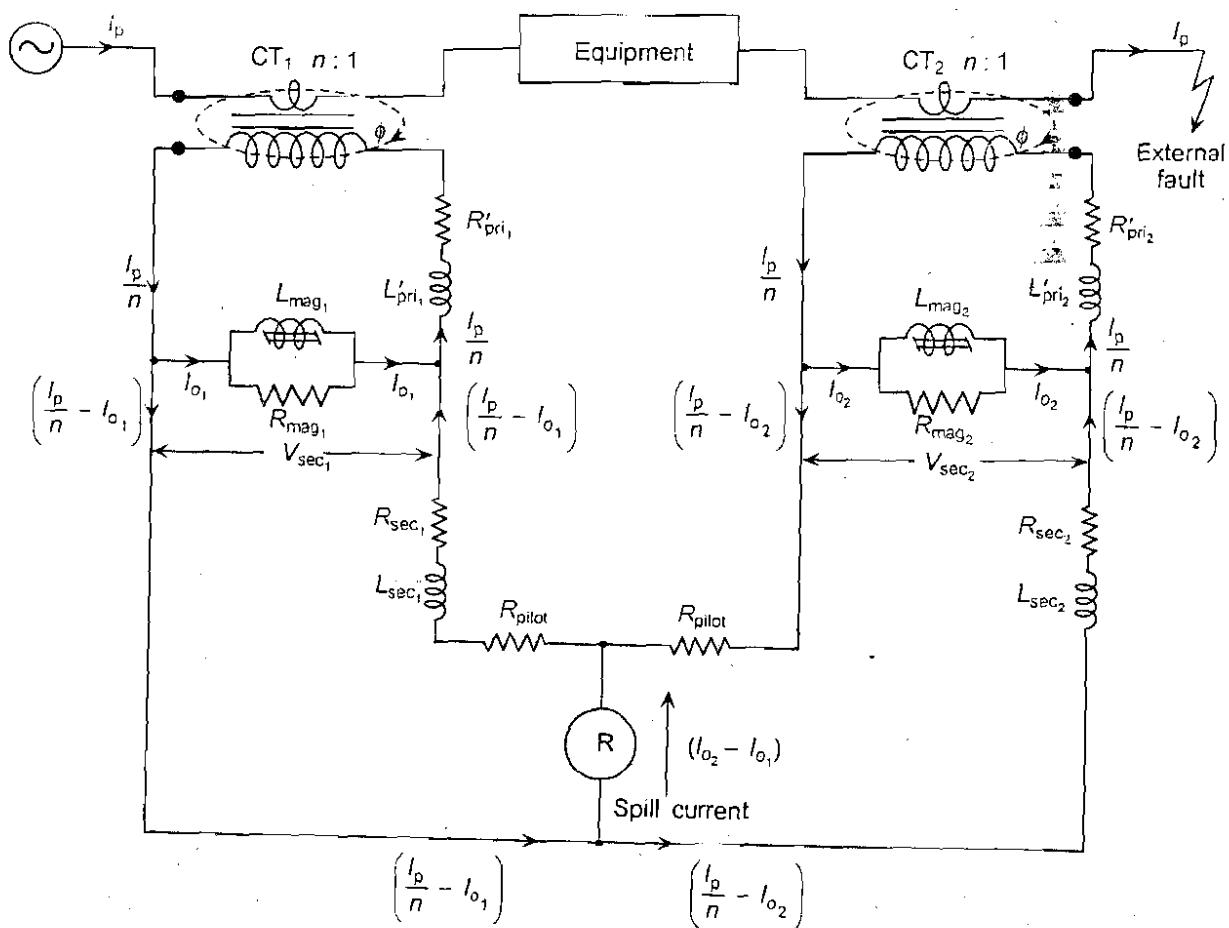


Figure 3.12 Simple differential scheme with CT equivalent circuits included.

during an external fault condition. Assuming that both CTs have the same nominal ratio of transformation n , we see that a spill current equal to the difference of the two magnetizing currents results. Since the magnetizing currents of the two CTs will generally vary widely, there is a substantial spill current during 'through fault' conditions. This results into loss of stability and maloperation of the simple differential scheme. Thus, the simple differential scheme, which looks attractively simple, cannot be used in practice without further modifications.

This is especially true in case of transformer protection. The CTs on the two sides of the transformer have to work at different primary system voltage. Because the currents on the two sides of the transformer are, in general, different, the ratios of transformation of the CTs are also different. Their designs are therefore different, making it impossible to get a close match between their characteristics. This explains why the spill current goes on increasing as the 'through fault' current increases.

In case of busbar protection, the primary voltages of the two CTs are the same, and the CT ratios are also the same. However, busbars are subjected to very heavy 'through fault' currents, which tend to magnify the differences between the characteristics of the two CTs. Thus, for busbar protection too, the simple differential scheme needs to be further modified.

Both these aspects have been dealt with in detail in subsequent chapters.

3.6 Percentage Differential Relay

The simple differential relay can be made more stable, if somehow, a restraining torque proportional to the 'through fault' current could be developed—the operating torque still being proportional to the spill current.

This idea has been implemented in the percentage differential relay shown in Figure 3.13. This relay has a restraining coil which is tapped at the centre, thus forming two sections with equal number of turns, $N_r/2$. The restraining coil is connected in the circulating current path, thus receiving the 'through fault' current. The operating coil, having N_o number of turns, is connected in the spill path. Let us work out the torque equation for this relay.

$$\text{Ampere-turns acting on the left-hand section of the restraining coil} = \frac{N_r}{2} I_1$$

$$\text{Ampere-turns acting on the right-hand section of the restraining coil} = \frac{N_r}{2} I_2$$

$$\text{Total ampere-turns acting on the restraining coil} = \frac{N_r}{2} (I_1 + I_2)$$

Noting that torque in an electromagnetic relay is proportional to the square of the flux,

$$\text{Torque produced by the restraining coil} = M \left[N_r \frac{(I_1 + I_2)}{2} \right]^2$$

where M is a constant of proportionality.

$$\text{Restraining torque produced by control spring} = T_{\text{spring}}$$

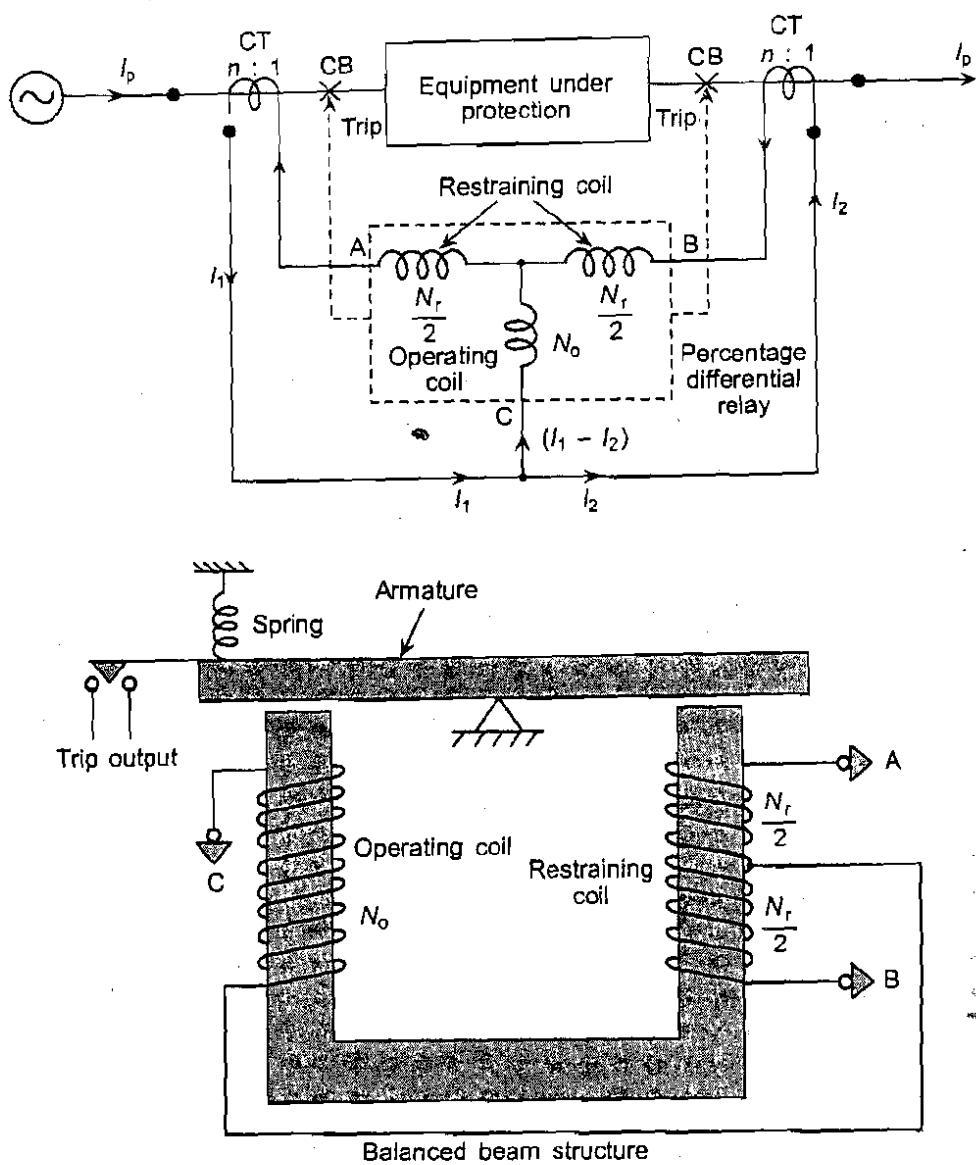


Figure 3.13 Percentage differential relay.

$$\text{Total restraining torque} = M \left[N_r \frac{(I_1 + I_2)}{2} \right]^2 + T_{\text{spring}}$$

Similarly,

$$\text{Operating torque} = M [N_o(I_1 - I_2)]^2$$

The relay trips if the operating torque is greater than the restraining torque. The relay will be on the verge of operation when the operating torque just balances out the restraining torque, i.e. when:

$$M [N_o(I_1 - I_2)]^2 = M \left[N_r \frac{(I_1 + I_2)}{2} \right]^2 \quad (\text{neglecting the restraining torque due to spring})$$

which can be written as

$$I_1 - I_2 = K \frac{(I_1 + I_2)}{2}$$

where $K = N_r/N_o$.

However, if we take into account the effect of control spring, the above equation can be written as

$$I_1 - I_2 = K \frac{(I_1 + I_2)}{2} + K_0$$

where K_0 accounts for the effect of spring.

Thus, the operating characteristics of this relay will be a straight line with a slope of (N_r/N_o) and an intercept K_0 on the y-axis. All points above the straight line will represent the condition where the operating torque is greater than the restraining torque and hence will fall in the *trip region* of the relay. All points below the straight line belong to the *restraining region*. The operating characteristics of the percentage differential relay are shown in Figure 3.14.

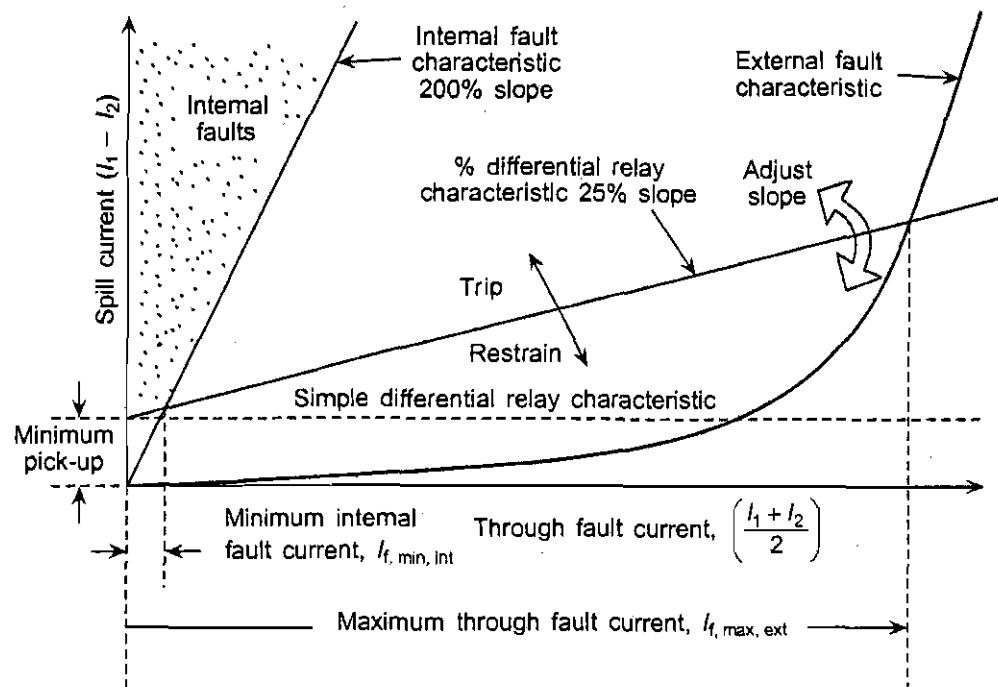


Figure 3.14 Operating characteristics of percentage differential relay.

Thus, the spill current must be greater than a definite percentage of the 'through fault' current for the relay to operate. Hence, the name *percentage differential* relay. The slope of the relay is customarily expressed as a percentage. Thus, a slope of 0.4 is expressed as 40% slope.

The percentage differential relay does not have a fixed pick-up value. The relay automatically adapts its pick-up value to the 'through fault' current. As the 'through fault' current goes on increasing, we are in effect asking the relay to take it easy, by introducing a restraining torque proportional to the circulating current. It can be seen from Figure 3.14, that the 'through fault' stability and the stability ratio of the percentage

differential relay is substantially better than that of the simple differential relay. The restraining winding is also known as the **biasing winding** because we bias the relay towards restraint. The slope of the characteristic is also known as *percentage bias*.

The characteristic of the percentage differential relay, superimposed on the 'through fault' characteristic, and the internal fault characteristic are shown in Figure 3.14. The slope of the internal fault characteristic can be found as follows:

Consider an internal fault in the case of a single-end-fed system. Since CT_2 will not contribute any current, i.e., $I_2 = 0$, the spill current, $(I_1 - I_2)$, will be equal to I_1 . The circulating current which is $[(I_1 + I_2)/2]$ will be equal to $(I_1/2)$. Thus, the following currents will exist during an internal fault:

$$\text{Spill current } I_1 - I_2 = I_1$$

$$\text{Circulating current } \frac{I_1 + I_2}{2} = \frac{I_1}{2}$$

Thus, during internal faults the spill current will be two times the circulating current, giving a slope of 2, which is expressed as 200%.

The minimum internal fault current below which the scheme will not respond is seen to be $I_{f,\min,int}$ and the maximum 'through fault' current above which the scheme will maloperate is seen to be $I_{f,\max,ext}$, as shown in Figure 3.14. Thus, the stability ratio is given by

$$\boxed{\text{Stability ratio} = \frac{I_{f,\max,ext}}{I_{f,\min,int}}}$$

The percentage differential relay can be made more immune to maloperation on 'through fault' by increasing the slope of the characteristic.

3.6.1 Block Diagram of Percentage Differential Relay

Figure 3.15 shows the block diagram of the percentage differential relay. The relay has two settings: the slope setting and the minimum pick-up setting. The slope is adjusted by changing the tapping on the restraining coil. It may be noted that both halves of the restraining coil need to be symmetrically tapped. The minimum pick-up is adjusted by changing the tension of the restraining spring.

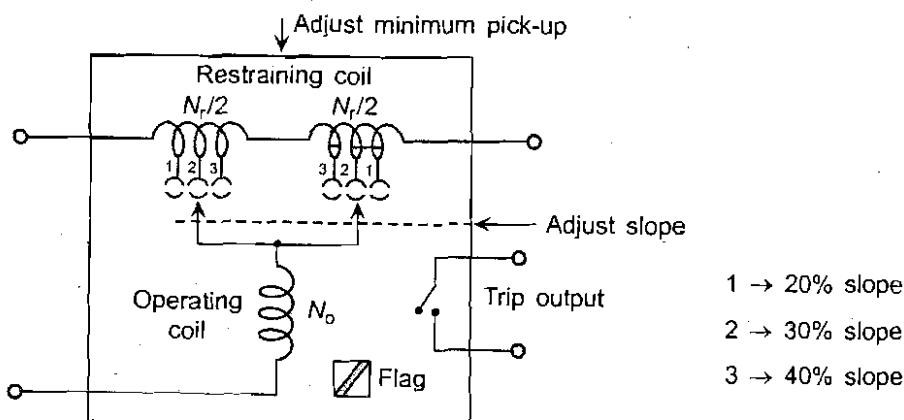


Figure 3.15 Block diagram of percentage differential relay showing its settings.

3.7 Earth Leakage Protection

Many times because of insulation failure the chassis of the equipment becomes live. This causes a leakage of current to earth from the chassis as the chassis is always connected to earth. However, the leakage current may be too small for an over-current relay to operate. This poses danger to the personnel who come in contact with the chassis. A special type of differential relay known as the *earth leakage relay* or *current balance relay* can easily detect such faults.

In case the chassis of the equipment is not earthed, the relay will not trip because of leakage. However, as soon as a person whose body is in contact with earth, touches the chassis, a path to earth becomes available, and assuming that the leakage current is of sufficient magnitude, the OC relay trips. The person will, of course, receive an electric shock before the circuit is tripped out.

3.7.1 Earth Leakage Protection for Single-phase Load

Figure 3.16 shows the earth leakage relay for a single-phase load.

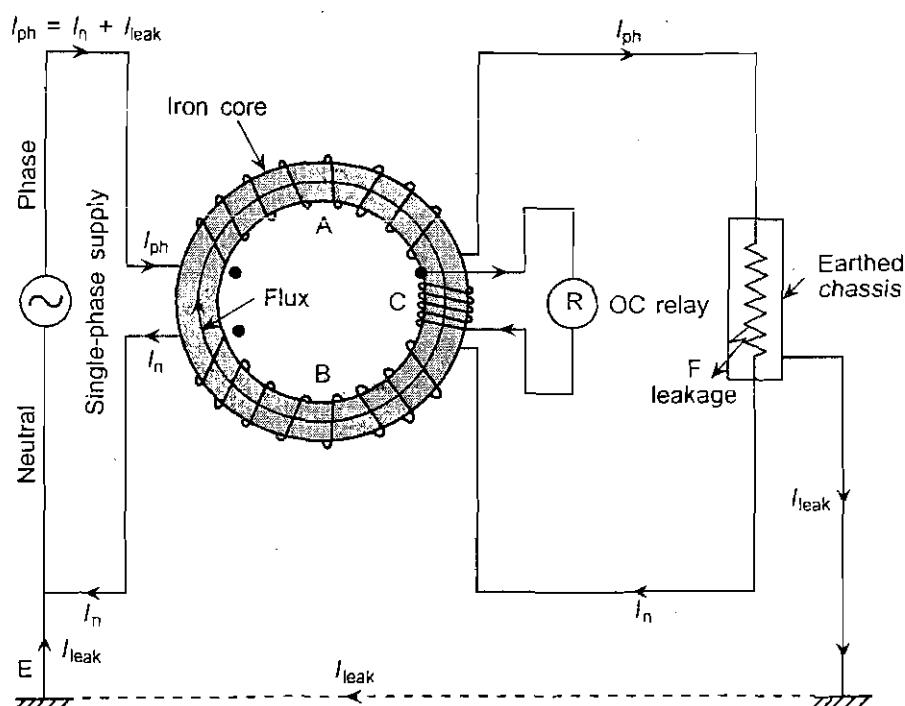


Figure 3.16 Earth leakage protection for single-phase load.

The relay consists of a toroidal core on which two identical windings A and B, each having N number of turns are wound in close proximity. A third coil C, known as the *pick-up coil*, is also wound and connected across an OC relay as shown in Figure 3.16. The phase and neutral leads are connected to these windings as shown in the figure so that windings A and B carry the currents in the phase wire and the neutral wire, respectively.

Under normal operating conditions, the current through the phase wire (and coil A) is exactly the same as that through the neutral wire (and coil B). Thus, there is no net

magnetomotive force (mmf) acting on the toroidal core. The flux linked with the pick-up coil is therefore zero, and thus no voltage is induced in the pick-up coil and the OC relay remains unenergized.

Now consider the situation of earth leakage as shown in Figure 3.16. The current in the phase wire is now greater than that in the neutral wire, as part of the current returns to the supply via the earth. The mmf acting on the toroid is now equal to $[N(I_{ph} - I_n)]$ or equal to $[N(I_{leak})]$. This mmf sets up flux in the core causing a voltage to be induced by the pick-up coil. The OC relay connected to the pick-up coil, therefore, gets energized, and trips the circuit.

3.7.2 Earth Leakage Protection for Three-phase Loads

Figure 3.17 shows earth leakage protection for a three-phase load. The three-phase leads are threaded through a CT core on which a pick-up winding is provided as in the case of single-phase earth leakage protection.

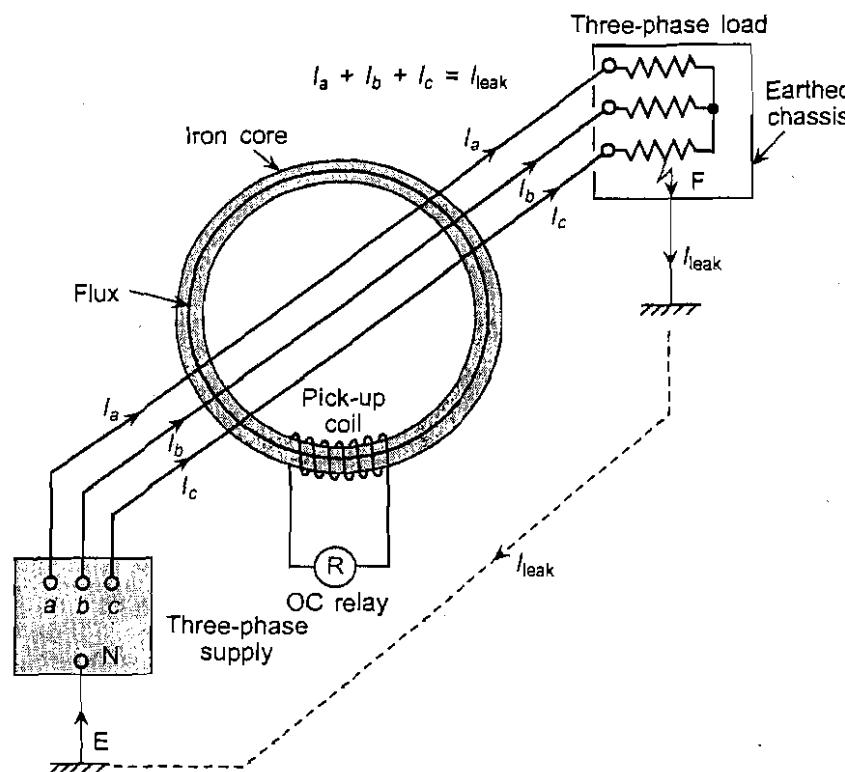


Figure 3.17 Earth leakage protection for three-phase loads.

During the normal balanced operating condition, the phasor sum of the three-phase currents is zero. Therefore, there is no net mmf acting on the core and the OC relay remains unenergized.

However, during the earth leakage situation shown in Figure 3.17, the net mmf acting on the core is (I_{leak}) ampere-turns. This causes a flux to be produced. A voltage is induced in the pick-up winding causing the OC relay connected across it to operate.

Review Questions

1. How will you check the polarity marks on a protection CT with the help of a 1.5 volt battery and a centre-zero voltmeter?
2. What do you mean by CT saturation?
3. Explain the following terms with respect to the simple differential scheme: Circulating current, spill current, internal fault, external fault, through fault, 'through fault' stability limit and stability ratio.
4. What are the drawbacks of the simple differential scheme?
5. What is the effect of the resistance of the pilot (lead) wires on the CT errors?
6. As the burden on a CT secondary goes on increasing, what happens to the magnitude and waveform of current delivered to the burden?
7. Explain how the percentage differential relay overcomes the drawbacks of the simple differential relay.
8. Prove that the slope of the internal fault characteristics for a single-end-fed system is 200%.
9. How do you adjust the slope of the percentage differential relay?
10. Show that the slope of the simple differential relay characteristics is zero.
11. Prove that the slope of the internal fault characteristics for a double-end-fed system is greater than 200%.
12. Higher slopes are required in cases where there is a lot of mismatch between the CTs at various terminals. Explain.
13. Which elements of the power system are ideal candidates for applying differential protection?
14. What problems, if any, do you anticipate in applying conventional differential protection to a transmission line?

Problems

1. For a 5 A CT, the total impedance of the secondary winding and leads is 0.01 ohm. Determine the VA capacity of the CT secondary at (a) the rated secondary current and (b) the maximum fault current of 20 times the rated CT secondary current.
2. In a simple differential scheme, the two CTs have a nominal ratio of 100 : 1. The CT errors for a 'through fault' current of 1000 A are as follows:

	CT ₁	CT ₂
<i>Ratio error</i>	5%	+6%
<i>Phase angle error</i>	2%	-4%

Determine the pick up of the OC relay in the spill path so that the scheme remains stable.

4

Transformer Protection

4.1 Types of Transformers

Transformers come in all shapes and sizes from the tiny balun transformers that you can place on the palm of your hand to the mammoth EHV power transformers that weigh several metric tonnes and occupy large areas. Various types of transformers used in the industry are listed below:

- Generator transformer
- Power transformer
- Distribution transformer
- Pole-mounted lighting transformer
- Grounding transformer
- Regulating transformer
- Welding transformer
- Converter transformer
- Instrument transformers (CT and PT)

Some of the above transformers could be autotransformers.

However, in this textbook, we restrict ourselves to protection of power and distribution transformers. A transformer will be provided with as much protection as is commensurate with its voltage and power rating and the importance of its application.

For example, over-current protection in the form of fuses may be the only protection provided to a small 100 kVA, 11 kV/440 V distribution transformer.

A 250 MVA, 15 kV/400 kV, generator-transformer in a large thermal power station, on the other hand, may be provided with very elaborate protection. This may consist of percentage differential protection (with harmonic restraint), a protection against incipient faults and a protection against over-fluxing as primary protection. These will be backed up by the over-current protection.

Since the terminals of a transformer are physically close together, it is an ideal candidate for application of the principle of differential protection.

4.2 Phasor Diagram for a Three-phase Transformer

There are four basic types of connections of a three-phase transformer, namely Y-Y, Y-Δ, Δ-Y and Δ-Δ.

The Y-Δ and the Δ-Y transformers introduce certain phase shifts between the voltages and currents on the primary and the secondary side. These phase shifts have to be carefully considered while applying differential protection. While connecting the CT secondary windings, we can choose such connections that nullify the phase shift.

Further, because of transformation ratio between the primary and the secondary sides of the power transformer, the primary currents for the CTs on the two sides will be different. The CTs must, therefore, have such ratio of transformation that currents in the relay pilot wires, coming from the CTs on the two sides are equal. Thus, ratios of transformation of the CTs on the primary and secondary side of the transformer, will in general, be different. This will ensure that during normal load flow as well as during external fault conditions, the differential scheme remains stable.

Figure 4.1 shows a three-phase transformer. It can be seen that the windings on the star-connected side carry the line currents I_A , I_B , I_C , while the windings on the delta side carry the phase currents whose magnitudes are

$$|I_a| = \frac{|I_a - I_c|}{\sqrt{3}}$$

$$|I_b| = \frac{|I_b - I_a|}{\sqrt{3}}$$

$$|I_c| = \frac{|I_c - I_b|}{\sqrt{3}}$$

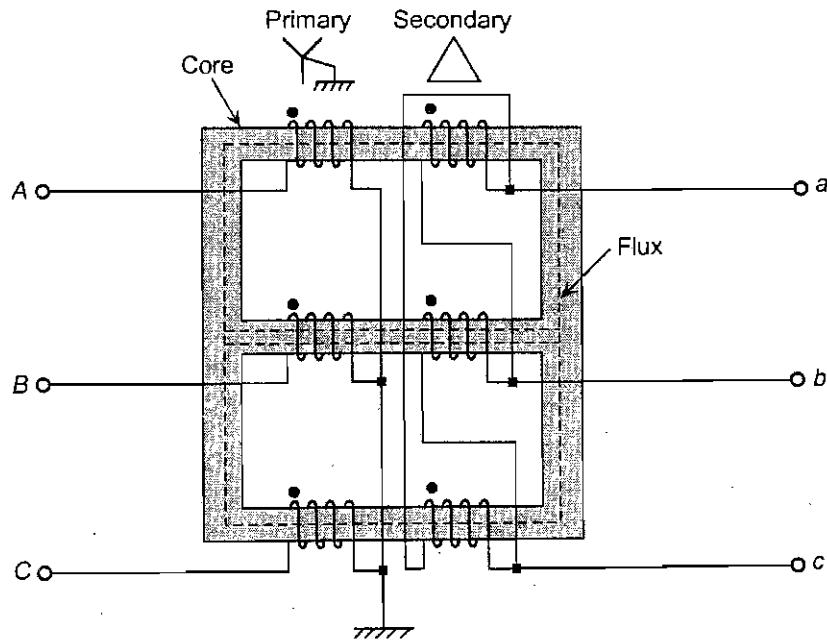


Figure 4.1 Construction of a three-phase transformer.

as shown in the phasor diagram in Figure 4.2. Each line current on the delta side is the phasor sum of two of the phase currents. Hence, there is a phase shift of 30° between the line currents on the two sides of the star-delta transformer. Figure 4.2 shows the schematic representation of the transformer connection with all voltages and currents.

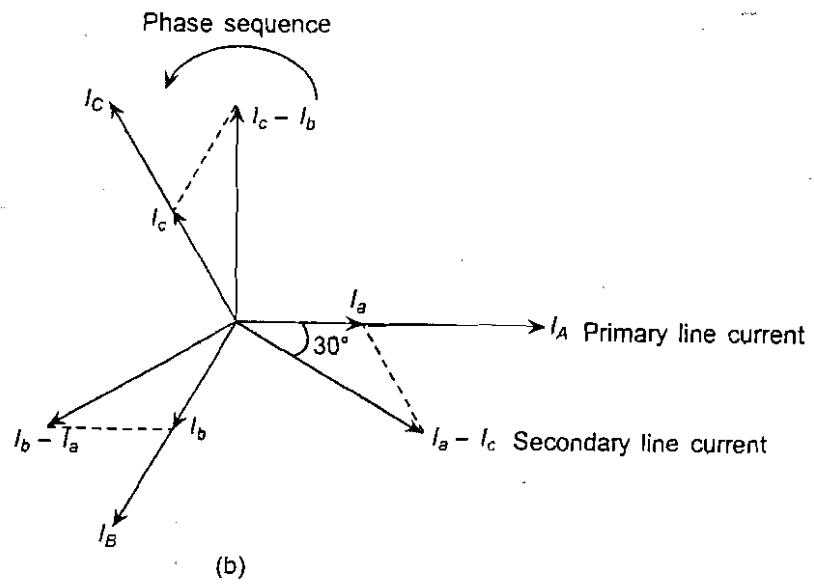
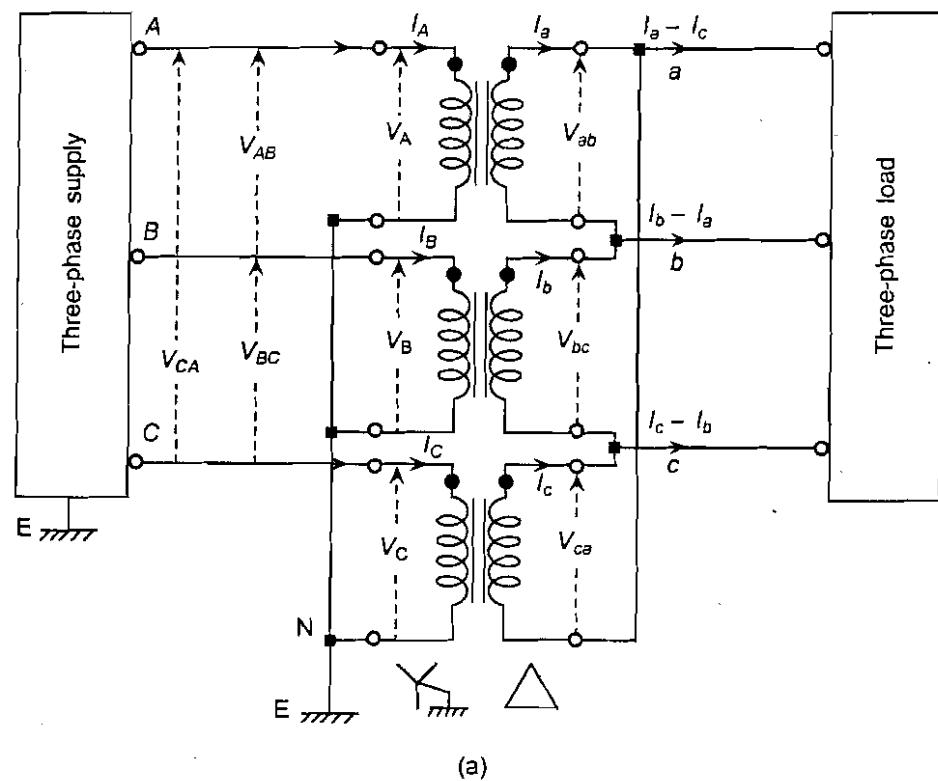


Figure 4.2 (a) Schematic representation of Y- Δ transformer; (b) phasor diagram showing the 30° phase shift between line currents on the two sides of a Y- Δ transformer.

Since we are interested in currents on the two sides, for the sake of differential protection, only the current phasors are shown. It can be seen that there is a phase shift of 30° between the line currents on the two sides of the star-delta transformer.

4.3 Equivalent Circuit of Transformer

Figure 4.3(a) shows the schematic representation of a single-phase transformer. The circuit can be reduced to the equivalent form shown in part (b) of the figure. It can be seen that the shunt branch, which represents the magnetization and accounts for the core loss, has a much larger impedance compared to the series branch which represents the winding resistance and the leakage reactance. Hence, in the event of short circuits, it is the series branch which essentially decides the short-circuit current. As shown in Figure 4.3(c), if the series impedance is 8% (i.e. 0.08 p.u.) then the short-circuit current for a fault on the secondary terminals will be $(1.0/0.08) = 12.5$ p.u.

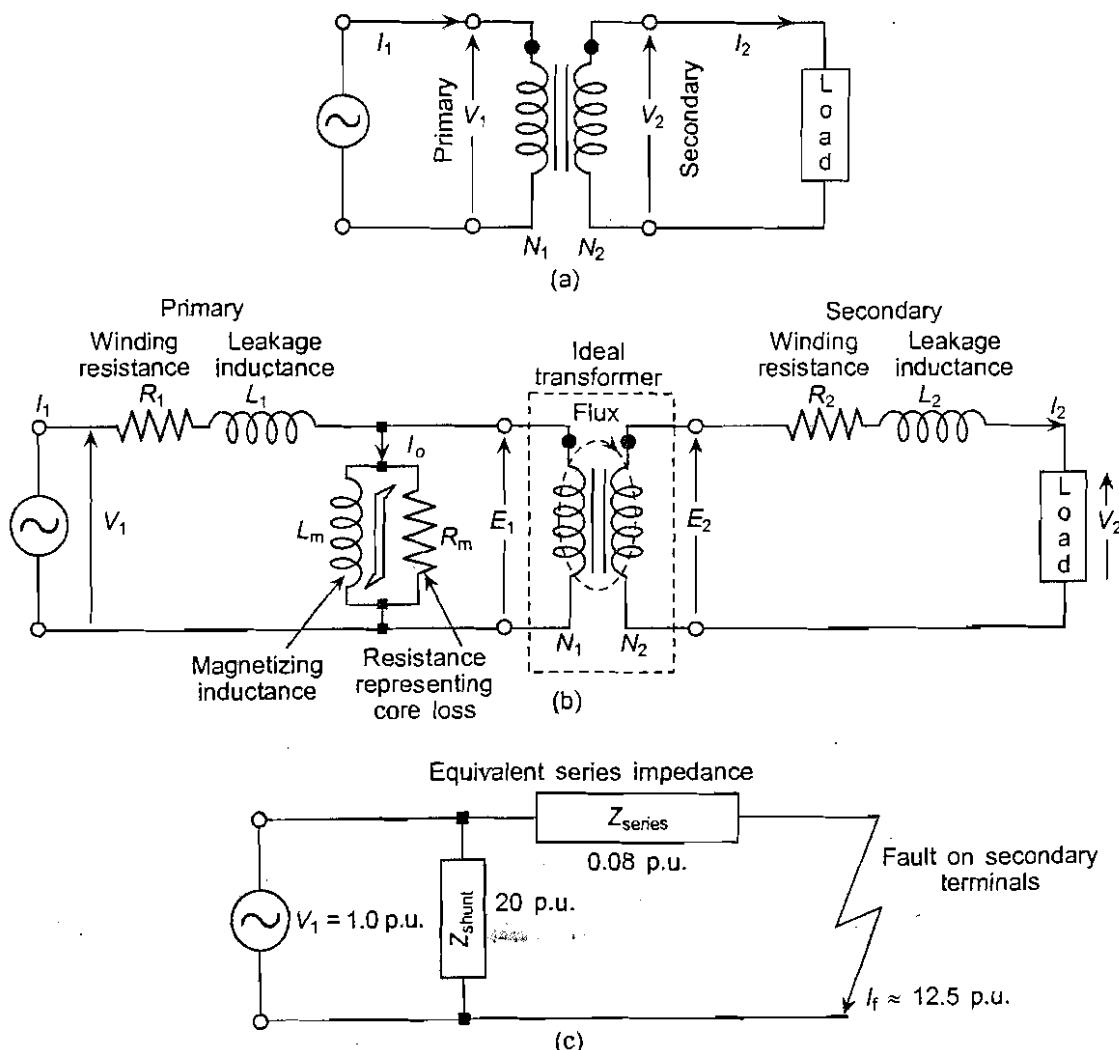


Figure 4.3 Single-phase transformer: (a) schematic diagram; (b) equivalent circuit; (c) model for finding short-circuit current.

4.4 Types of Faults in Transformers

Transformers are subject to a variety of faults. The most common being the winding to core faults because of weakening of insulation. Phase faults inside the transformer are rare. However, such faults may take place outside the transformer, on the transformer terminals, which fall within the transformer protection zone.

The variation of fault current with respect to fault location within the transformer depends upon the type of transformer connection, the method of grounding the transformer neutral and whether the current is being referred to the primary or the secondary side of the transformer. The interested reader may refer to *Power System Protection* (Vol. 3: Application) published by the Institution of Electrical Engineers, UK.

Figure 4.4 shows the variation of fault current with respect to fault location for a winding (phase) to ground fault for a resistance-grounded delta-star transformer, as seen from the primary and the secondary sides.

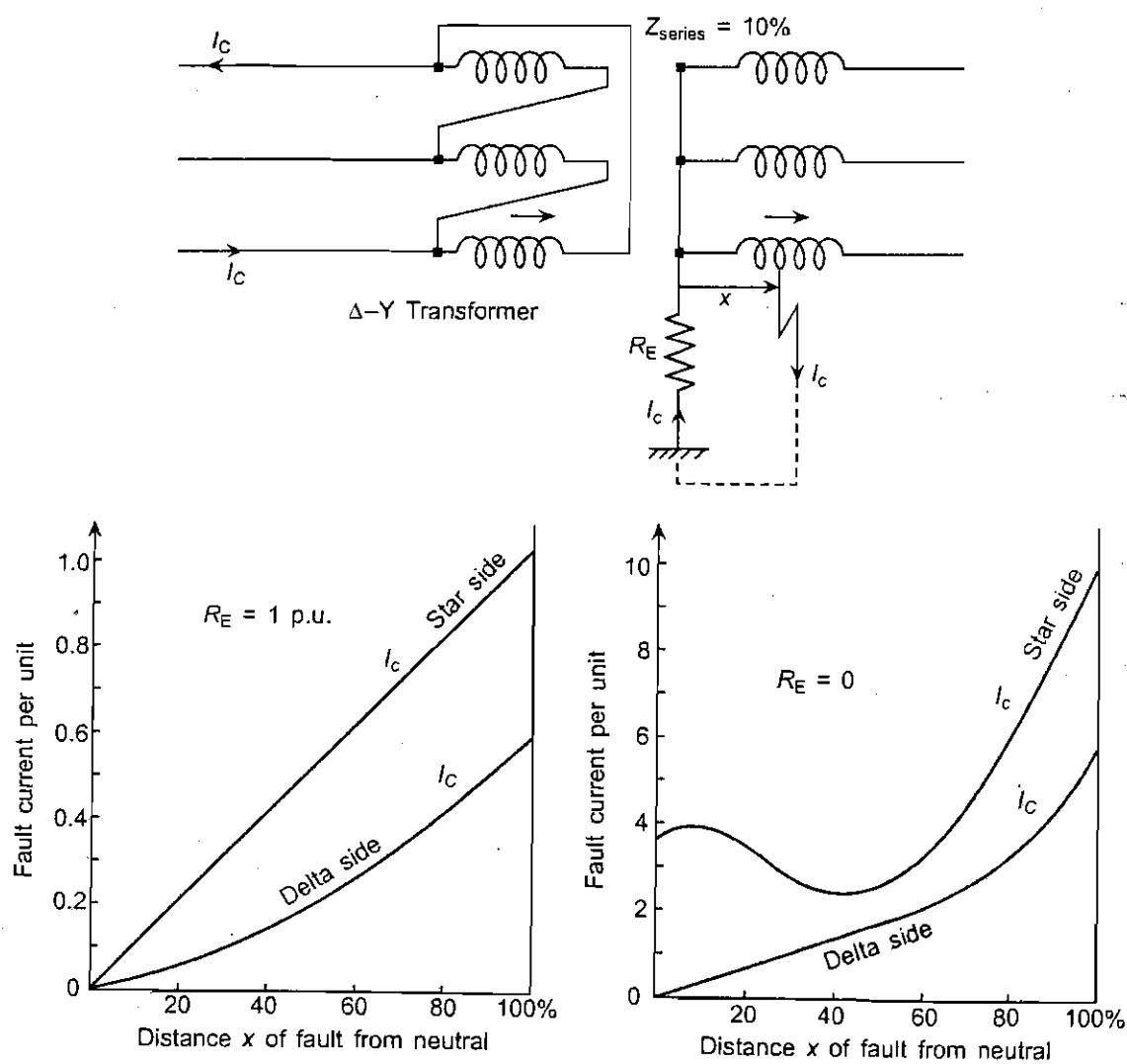


Figure 4.4 Variation of fault current with location for the Δ -Y transformer.

As shown in Figure 4.4 for a resistance-earthed star-connected winding, a winding-to-earth fault will give rise to a current dependent on the value of the earthing resistor and the distance of the fault from the neutral end of the winding. The effective ratio of transformation between the primary winding and the short-circuited portion of the secondary winding varies with the fault position. The current flowing through the transformer terminals is, therefore, for all practical purposes, proportional to the square of the percentage of the short-circuited winding.

For a solidly-earthed star winding, the fault current bears no simple relationship to the distance of the fault from the neutral end since the effective reactance of the fault path changes with the fault position. As shown in Figure 4.4, the minimum value of fault current occurs for a fault at 30% to 40% of the distance of end of winding from the neutral end.

For a delta-connected winding, the minimum voltage on the delta winding is at the centre of one phase and is 50% of the normal phase-to-earth voltage. The range of values of fault current is less than that of the star-connected winding. The value of the fault current depends upon the system earthing arrangements, and the curves of Figure 4.5 show that the minimum value of fault current occurs for a fault at the centre of one phase winding.

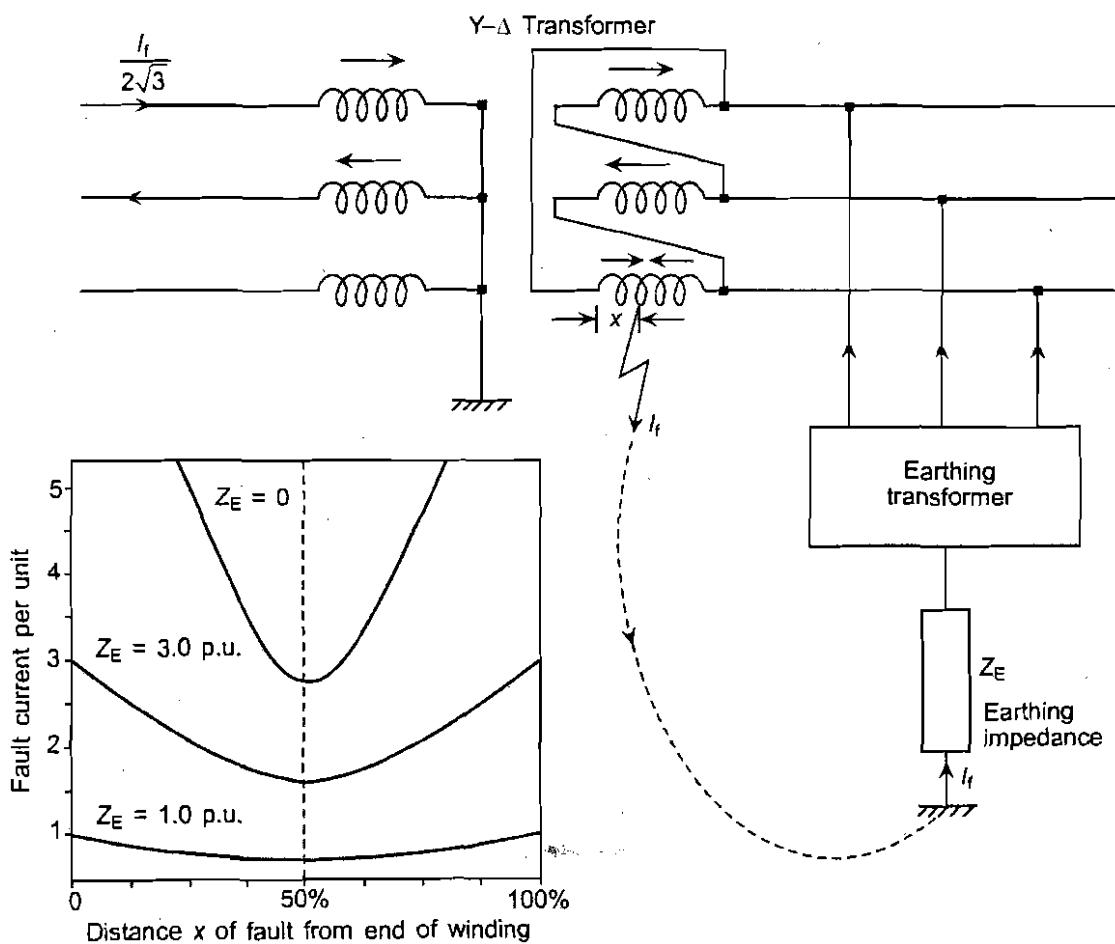


Figure 4.5 Variation of fault current with location for the Y-Δ transformer.

Power and distribution transformers are generally provided with on-line-tap-changing (OLTC) gear. This is another major source of faults.

All large transformers are of the oil-immersed type. There is a possibility of low level of oil due to leakage. In such cases, an alarm must be raised and the transformer may eventually have to be shut down.

Another peculiarity of transformers is that they experience large inrush currents at the time of switching if they happen to be unloaded. This is neither an abnormal condition nor a fault as far as the transformer is concerned. Inrush current needs special attention while designing the protection for a transformer.

A transformer may develop inter-turn faults giving rise to hot-spots within the winding. Seen from the terminals, such inter-turn faults may not cause appreciable currents. Hence, inter-turn faults are difficult to detect by electrical means. These are best detected by non-electrical methods.

Transformers may suffer from over-fluxing (also called over-excitation) due to under-frequency operation at rated voltage. Over-fluxing may also be caused when the transformer is subjected to over-voltage at the rated frequency. Since large transformers usually operate at their design limits, over-fluxing can be dangerous and needs immediate protection.

All these faults, abnormal operating conditions and peculiar operating conditions are dealt with in the following sections.

4.5 Over-current Protection

Figure 4.6 shows two numbers of phase-fault over-current relays and one ground-fault over-current relay for providing over-current protection to the star-delta transformer. Such a scheme may serve the purpose of providing either the primary protection for smaller transformers or the back-up protection for bigger transformers.

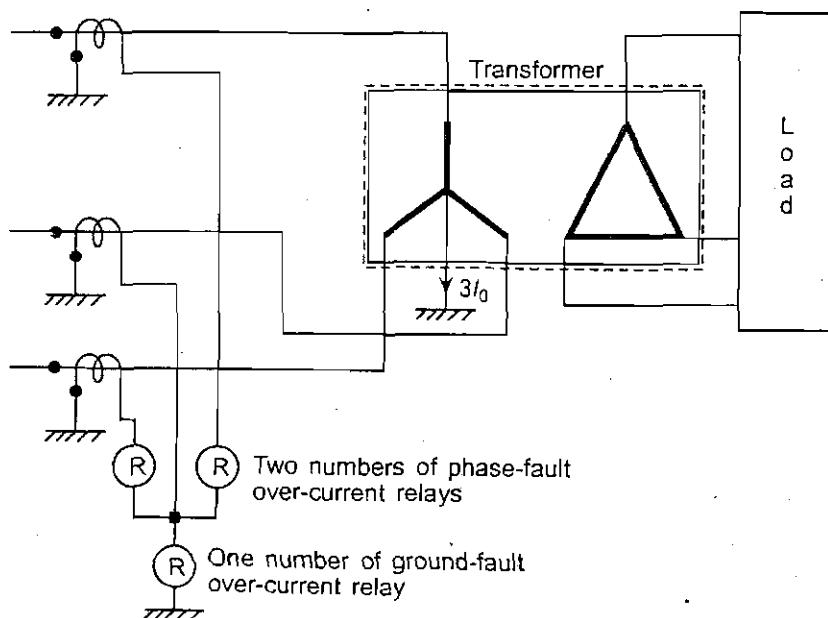


Figure 4.6 Over-current protection of a transformer.

The pick-up value of the phase-fault over-current units is set such that they do not pick up on maximum permissible overload, but are sensitive enough to pick up on the smallest phase fault. The pick-up of the earth fault relay, on the other hand, is independent of the loading of the transformer. The neutral current under load conditions is quite small. The neutral current is essentially because of load unbalance. It is interesting to note that the third harmonic currents, in particular and *triple-n harmonics* (harmonics of order 3, 6, 9, ...) in general, which arise due to distortions introduced by electronic loads, also end up as zero sequence currents and flow through the neutral.

4.6 Percentage Differential Protection of Transformers

4.6.1 Development of Connections

Figure 4.7 shows a delta-star transformer. Assume a turns ratio of 1 : 1. Note that the star point is grounded.

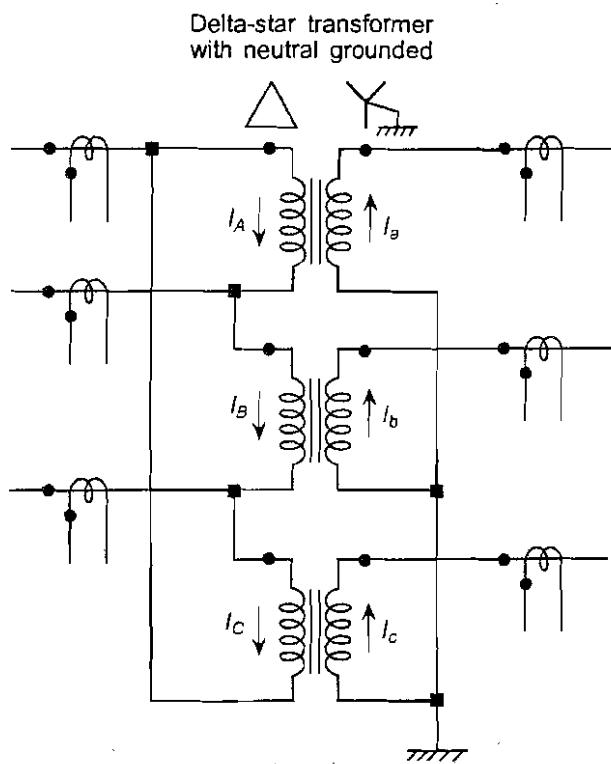


Figure 4.7 Development of CT connections for differential protection of three-phase transformer.

In order to devise the CT connections, we follow the following sequence of steps:

1. Determine the instantaneous directions of currents I_a , I_b and I_c through the secondary windings (see Figure 4.7).
2. The primary winding currents I_A , I_B and I_C are then determined. Note that because of the turns ratio of 1 : 1, $I_A = I_a$, $I_B = I_b$, $I_C = I_c$ (see Figure 4.8).

3. Line currents on the star side are determined. These are same as phase currents I_a , I_b and I_c .
 4. Line currents on the delta side are then determined. These are $(I_C - I_A)$, $(I_A - I_B)$ and $(I_B - I_C)$ as shown in Figure 4.8.
- Note: $(I_C - I_A)$, etc. are all phasor differences.

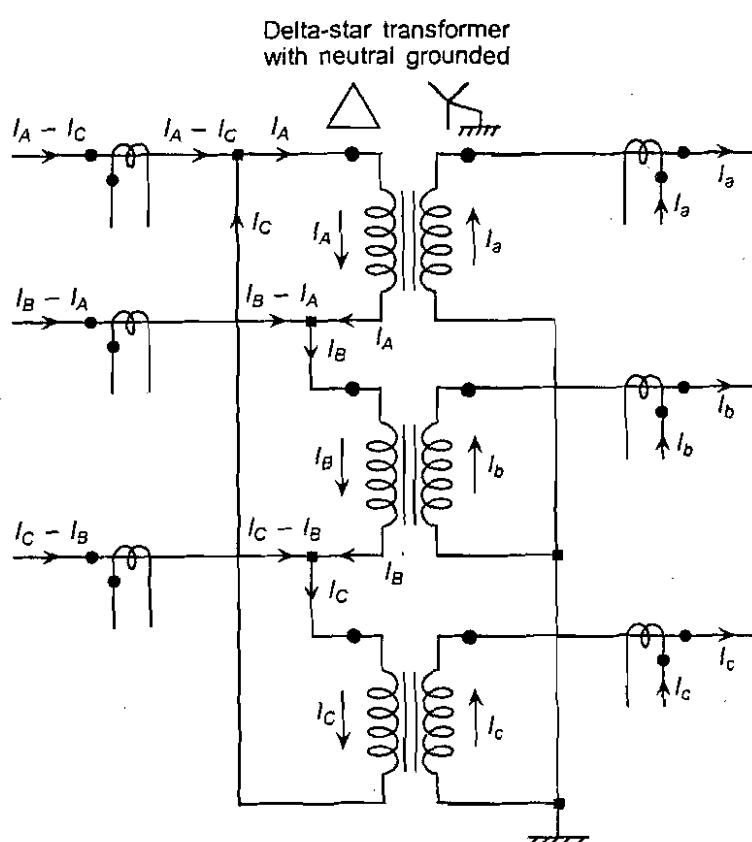


Figure 4.8 Determination of the line currents on the two sides of the transformer.

5. Therefore, if we connect the secondary windings of the CTs on both the sides in star, then the currents would not match up and a spill current would result. We observe, however, that if the secondary windings of CTs on the star side are connected in delta, then the line currents would exactly match with the secondary currents of CTs on the delta side, provided that these are connected in star. This is shown in Figure 4.9.

4.6.2 Phase c-to-Ground (c-g) External Fault

Consider phase c-to-ground (c-g) external fault as shown in Figure 4.10.

It can be seen that due to fault on phase c , there is an over-current in phase c . This current is supplied through two of the lines on the delta side. Similarly, due to the delta connections of CT secondary windings on the star side, two of the pilot wires carry the fault current, with the result that the current circulates in two of the percentage

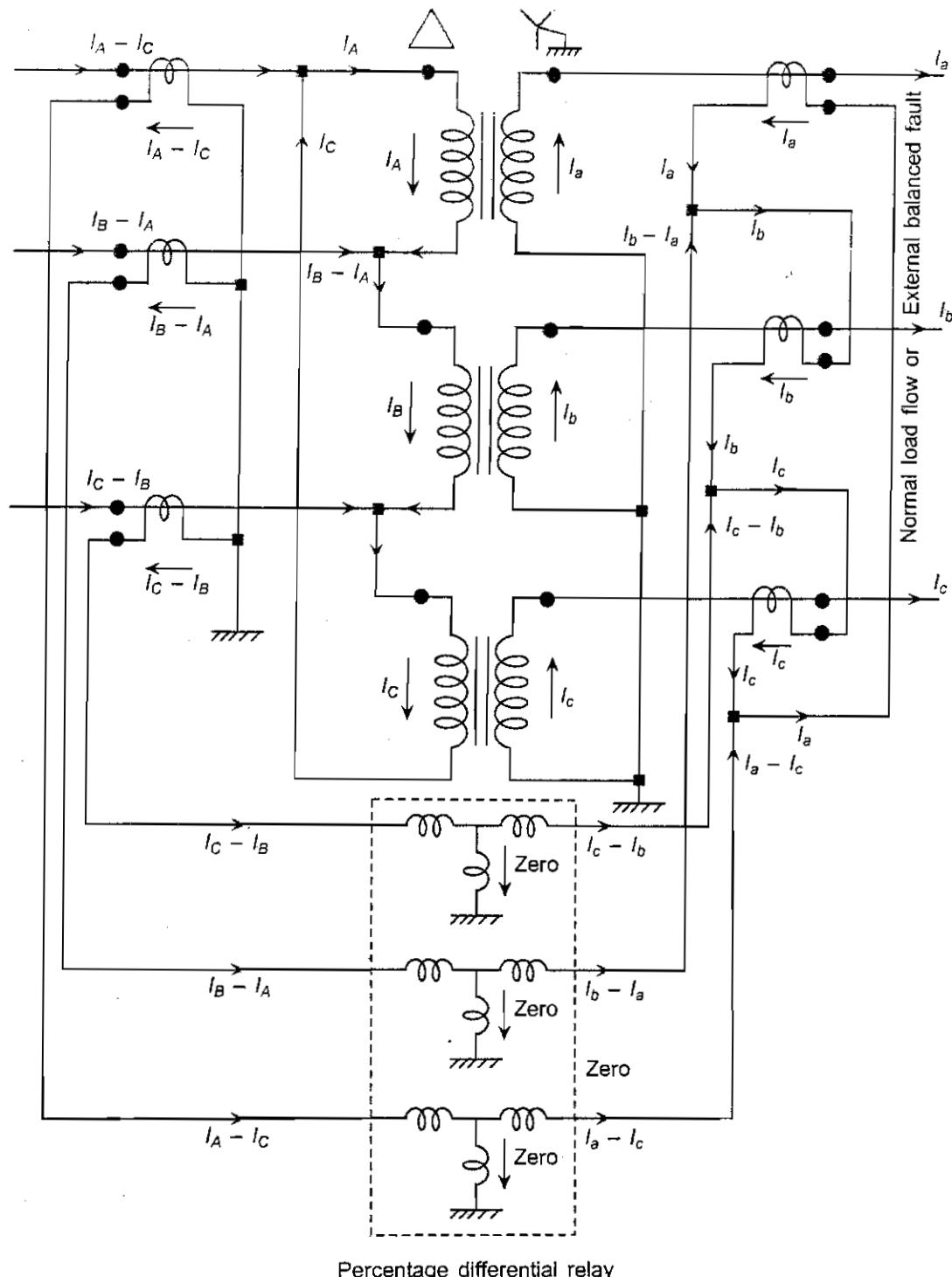


Figure 4.9 Final connections of percentage differential relay under normal load flow or external balanced fault.

differential units and there is no current in the spill path. Thus, the scheme remains stable on c-g external fault.

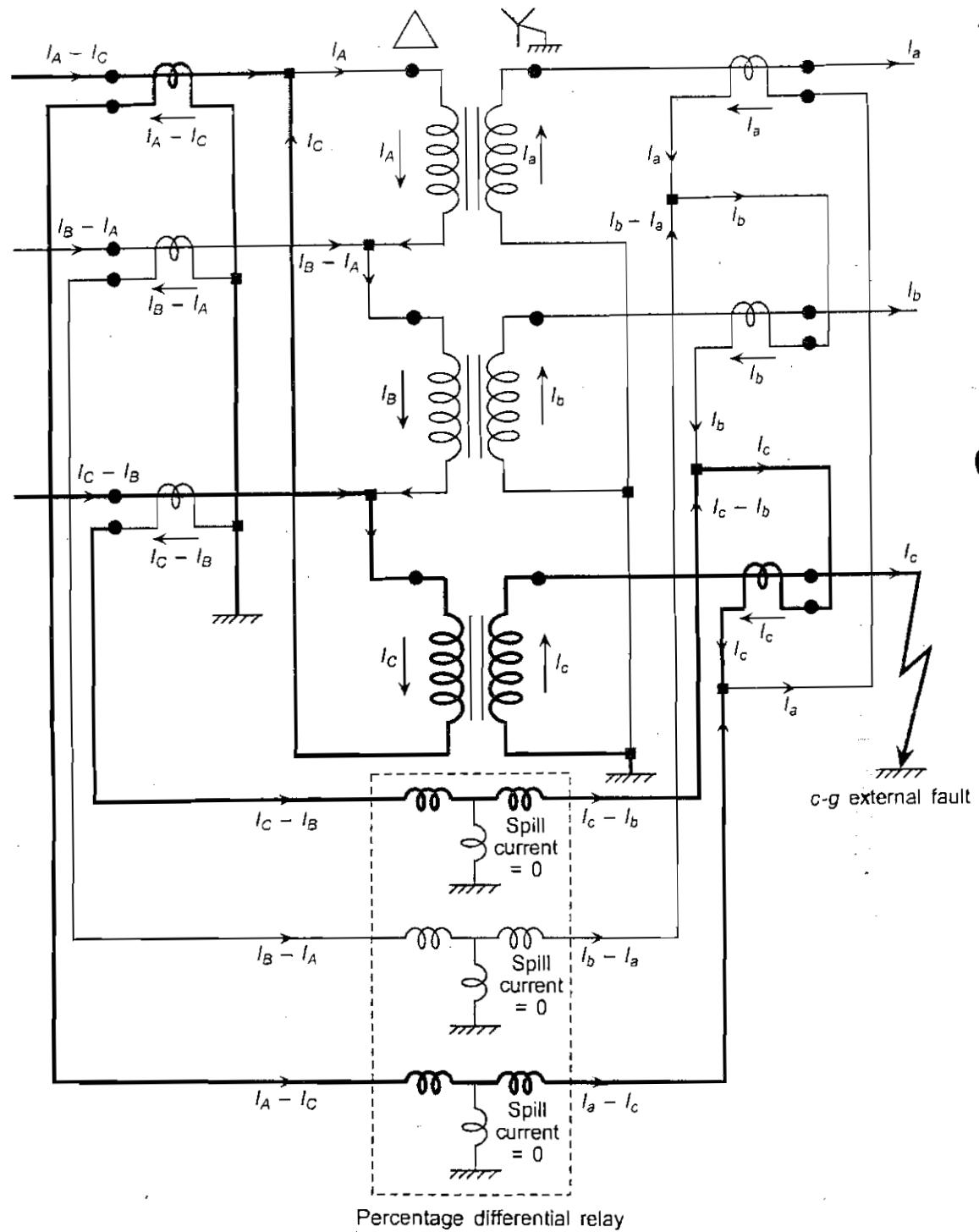


Figure 4.10 Phase c-to-ground (c-g) external fault.

4.6.3 Phase c-to-Ground (c-g) Internal Fault

A c-g internal fault is shown in Figure 4.11. The currents on the delta side are exactly the same as those in the case of c-g external fault. However, since the fault is internal,

there is no fault current through the primaries of the CTs on the star side. The path of the fault current is shown in bold lines. It can be seen from the figure that the fault current flows through the spill path in two of the percentage differential units causing them to operate, thus tripping out the transformer.

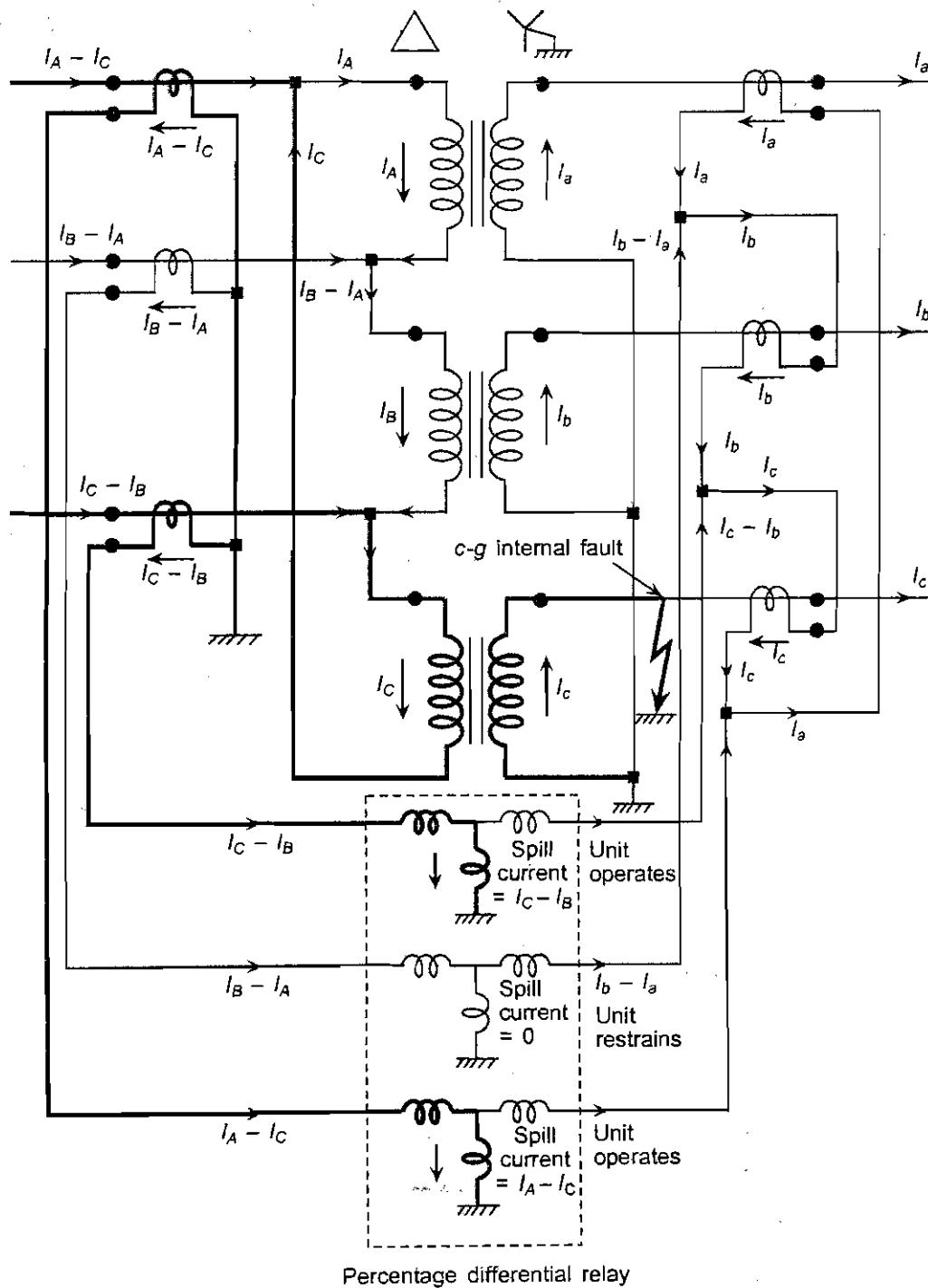


Figure 4.11 Phase c-to-ground (c-g) internal fault.

4.7 Inrush Phenomenon

Figure 4.12 shows an unloaded transformer being switched on to an ac supply.

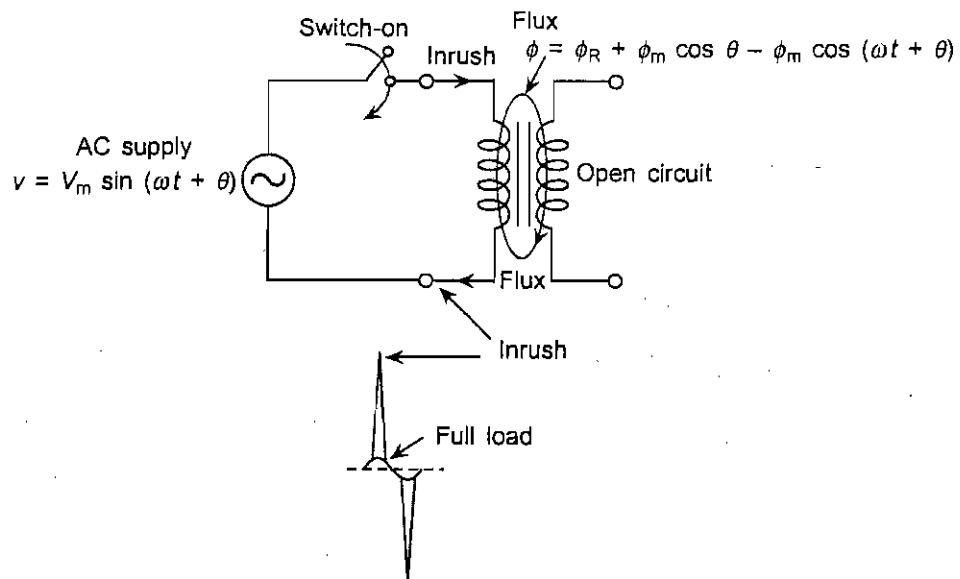


Figure 4.12 Inrush phenomenon: switching on an unloaded transformer.

Let the flux in the transformer be written as

$$\phi = \phi_m \sin \omega t \quad (4.1)$$

The induced voltage can then be written as

$$\begin{aligned} v &= N \frac{d\phi}{dt} \\ &= N \phi_m \omega \cos \omega t \\ &= N \phi_m \omega \sin (\omega t + 90^\circ) \end{aligned} \quad (4.2)$$

The applied voltage is exactly equal to the induced voltage. Thus, the flux in a transformer lags the applied voltage by 90° in the steady state as shown in Figure 4.13.

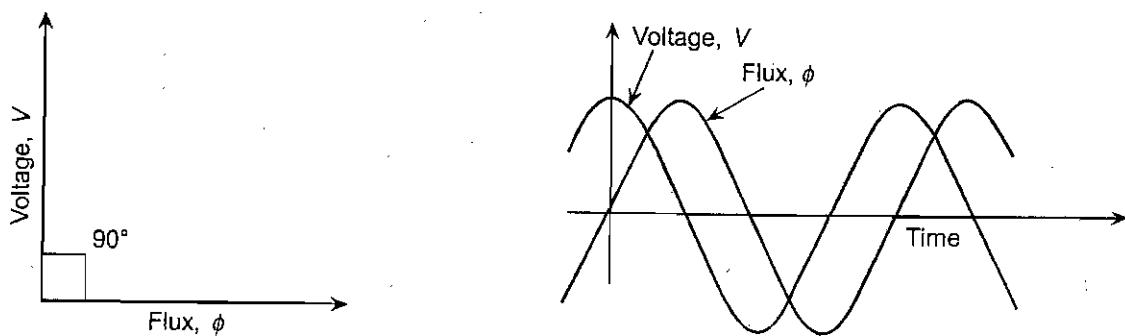


Figure 4.13 Flux lags the applied voltage by 90° .

Therefore, when voltage is passing through zero and becoming positive the flux should be at its negative maxima and increasing as shown in Figure 4.13. In a time equal to $T/2$ (half cycle), the flux changes from $-\phi_m$ to $+\phi_m$ as shown in Figure 4.14. The change in flux is therefore $2\phi_m$ in $T/2$ seconds. This is the steady-state picture.

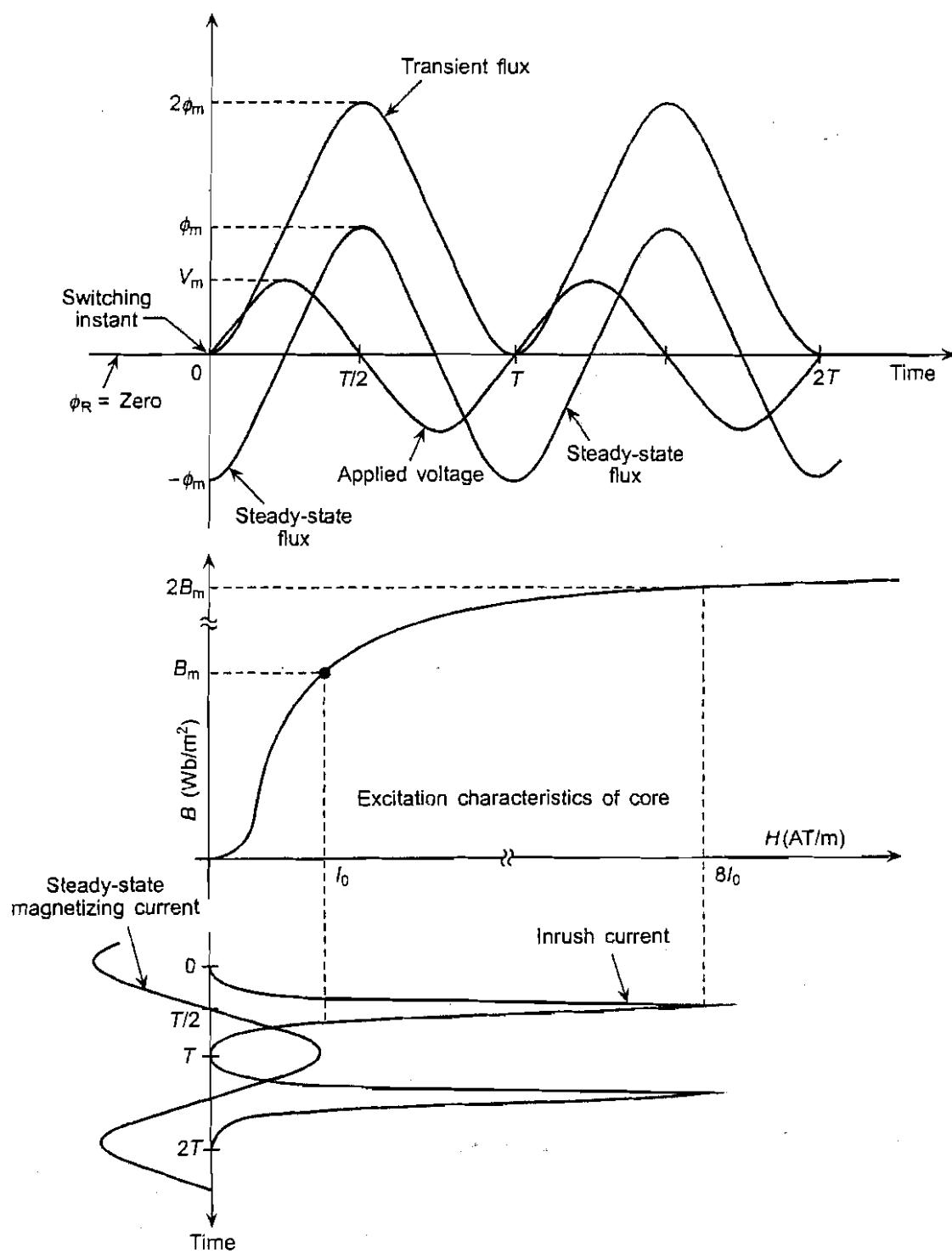


Figure 4.14 Inrush phenomenon.

Let us assume that the transformer is switched on at positive zero crossing of the voltage waveform as shown in Figure 4.14. Further, assume that the residual flux is zero. Thus, the initial value of flux is zero but subsequently the flux must have the same rate of change and same waveform as it has in the steady-state. Thus, the flux must reach a peak value of $+2\phi_m$ in half a cycle. Since power transformers operate near the knee of the saturation curve, a flux demand of $2\phi_m$ drives the transformer core deep into saturation, causing it to draw a very large magnetizing current with a peaky non-sinusoidal waveform. The magnetizing current is, therefore, very high, of the order of 8 to 30 times the full-load current. This current is known as *inrush current*. The time constant of this transient component of current could be of the order of a few seconds at worst.

The inrush phenomenon can be explained mathematically as follows:

Let the voltage be represented as

$$v = V_m \sin (\omega t + \theta) \quad (4.3)$$

The variable θ in the above expression controls the switching instant.

Let ϕ be the instantaneous value of the flux. Then we can write:

$$N \frac{d\phi}{dt} = v$$

or

$$N \frac{d\phi}{dt} = V_m \sin (\omega t + \theta)$$

or

$$d\phi = \left(\frac{V_m}{N} \right) \sin (\omega t + \theta) dt$$

or

$$\begin{aligned} \phi &= \left(\frac{V_m}{N} \right) \int \sin (\omega t + \theta) dt \\ &= -\left(\frac{V_m}{N\omega} \right) \cos (\omega t + \theta) + K \end{aligned} \quad (4.4)$$

where K is the constant of integration.

The value of K can be found out from the initial condition, i.e. when $t = 0$, $\phi = \phi_R$ = residual flux. Substituting this initial condition in Eq. (4.4), we get

$$\phi_R = -\left(\frac{V_m}{N\omega} \right) \cos \theta + K \quad (4.5)$$

which gives K as

$$K = \phi_R + \left(\frac{V_m}{N\omega} \right) \cos \theta$$

Thus the expression for flux in the transformer in the initial moments just after switching can be written as

$$\phi = \phi_R + \left(\frac{V_m}{N\omega} \right) \cos \theta - \left(\frac{V_m}{N\omega} \right) \cos(\omega t + \theta) \quad (4.6)$$

We can write $(V_m/N\omega)$ as ϕ_m , the peak value of the flux, giving

$$\phi = \phi_R + \phi_m \cos \theta - \phi_m \cos(\omega t + \theta) \quad (4.7)$$

Thus, the flux in the transformer is a function of the following three factors:

1. Residual flux ϕ_R
2. Instant of switching θ
3. Magnetic properties of core, i.e. the amount of magnetizing current required to produce a given amount of flux.

Thus, we see that for $\theta = 0$ and $\phi_R = +\phi_m$, the flux attains an amplitude of $3\phi_m$ at $\omega t = \pi$ radians. To satisfy a flux demand of $3\phi_m$, the transformer primary draws a very large magnetizing current with a peaky non-sinusoidal waveform.

Inrush is also experienced whenever there are sudden changes in the system voltage such as sudden recovery of system voltage on clearing of a fault, somewhere in the system.

While an unloaded transformer, which is being switched on, experiences an inrush, an adjacent transformer, which is in service, may also experience a smaller degree of inrush. This is known as *sympathetic inrush*.

Further, as such a high current flows only on one side of the transformer (on the side which is being connected to the supply), it looks like an internal fault to the differential scheme and ends up as spill current.

As seen in Section 4.3, a short circuit at the terminals of a transformer causes similar magnitudes of currents to flow. Hence, the percentage differential relay is likely to maloperate on magnetizing inrush.

4.7.1 Percentage Differential Relay with Harmonic Restraint

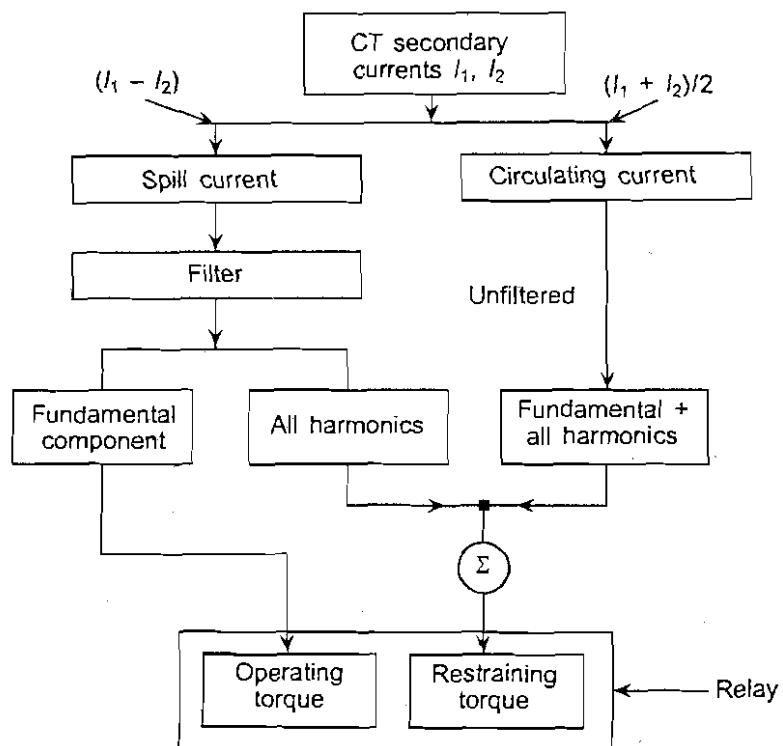
We have seen that the percentage differential scheme tends to maloperate due to magnetizing inrush. One way to combat this problem is to desensitize the relay for a brief period of time, just after switching on. However, this is not desirable, since the probability of insulation failure just after switching on is quite high, and a desensitized relay would be blind to faults taking place at that crucial time.

A solution to this problem suggests itself, when we compare the waveforms of internal fault current with that of the inrush current. The inrush waveform is rich in harmonics whereas the internal fault current consists of only of the fundamental. Thus, we can develop additional restraint based on harmonic content of the inrush current. This additional restraint comes into picture only during the inrush condition and is ineffective during faults. Table 4.1 gives the harmonic content of a typical inrush waveform.

Table 4.1 Harmonic content of inrush waveform

Frequency	Magnitude
Fundamental	100%
DC	40–60%
Second harmonic	30–70%
Third harmonic	10–30%
Fourth harmonic	Less than 5%
Fifth harmonic	Less than 5%
Sixth harmonic	Less than 5%
Seventh harmonic	Less than 5%

Figure 4.15 shows the conceptual scheme of a harmonic restraint differential relay. The fundamental component of spill current is segregated with the help of a filter and is used to develop the tripping torque. The non-fundamental component of the spill current aids the unfiltered circulating current in developing the restraining torque. This makes the relay stable on inrush while at the same time not affecting its operation in case of genuine internal faults.

**Figure 4.15** Conceptual representation of harmonic restraint percentage differential relay.

A harmonic restraint percentage differential relay which implements the conceptual scheme shown in Figure 4.15 is illustrated in Figure 4.16.

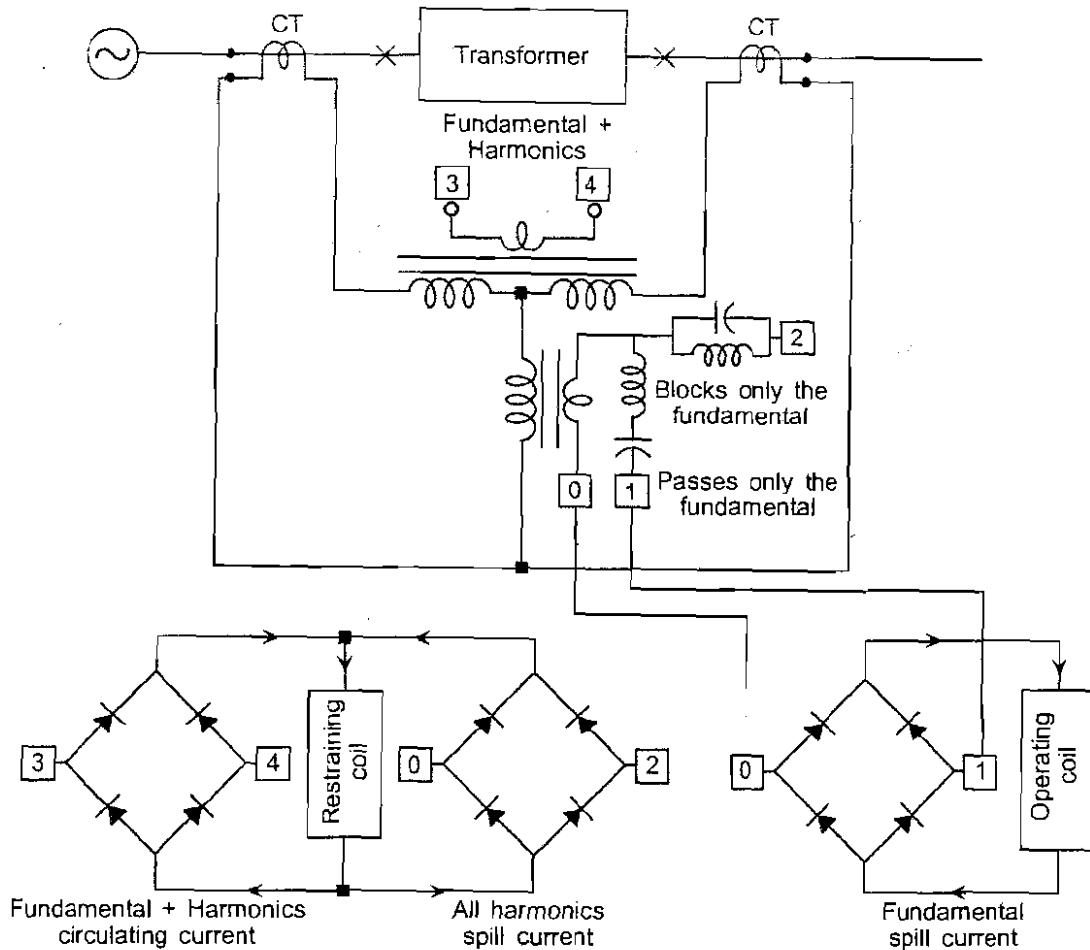


Figure 4.16 Percentage biased differential relay with harmonic restraint.

4.8 High Resistance Ground Faults in Transformers

A percentage differential relay has a certain minimum value of pick-up for internal faults. Faults with fault current below this value are not detected by the percentage differential relay. Winding-to-core faults, which are of the single phase-to-ground type, involving high resistance, fall in this category. Therefore, we must have a more sensitive relaying scheme to cater for high resistance ground faults. Further, the reach of such a protection must be restricted to the winding of the transformer; otherwise it may operate for any ground fault, anywhere in the system, beyond the transformer. Hence, such protection is known as *restricted earth fault protection*.

4.8.1 High Resistance Ground Faults on the Delta Side

Figure 4.17 shows the earth fault protection for the delta side of a delta-star transformer. If there is a fault on the star side then the currents flow in the lines connected to the delta side in such a way that there is no spill current through the relay on the CT secondary side, thus the reach is automatically restricted to the delta side.

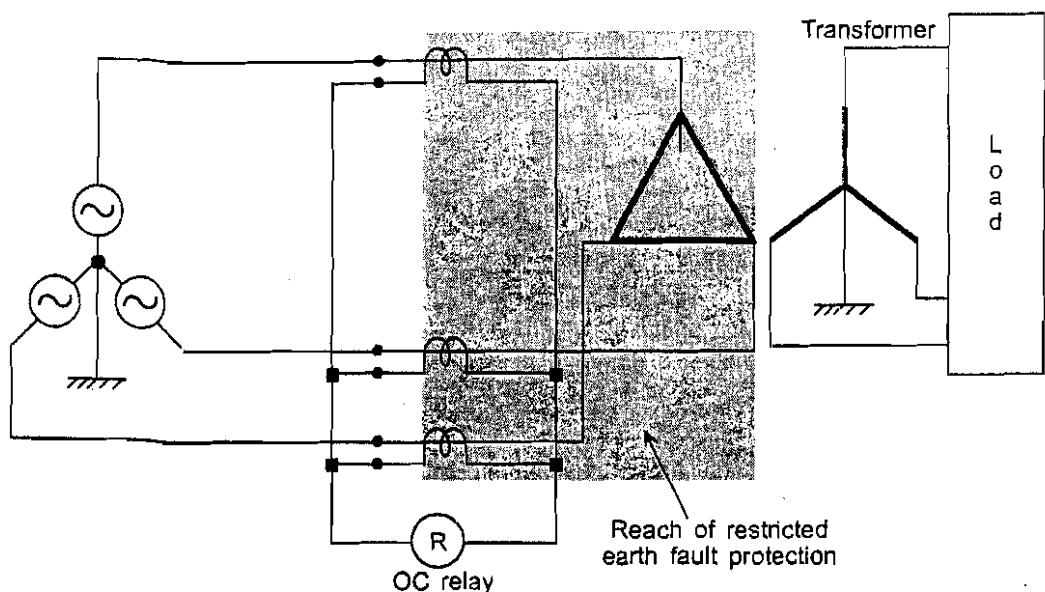


Figure 4.17 Earth fault protection for the delta side of delta-star transformer.

Since this is a current balance scheme, it is independent of the load current and hence can be made as sensitive as desired.

4.8.2 High Resistance Ground Faults on the Star Side

Figure 4.18 shows the restricted earth fault protection whose reach is limited to the star side of the transformer. Ground faults beyond the star side CTs, anywhere in the system, do cause current to flow on the secondary of the CTs. However, the currents circulate through the CT in the neutral path and the CT in faulted phase. Thus, no spill current flows and the scheme remains stable on external faults.

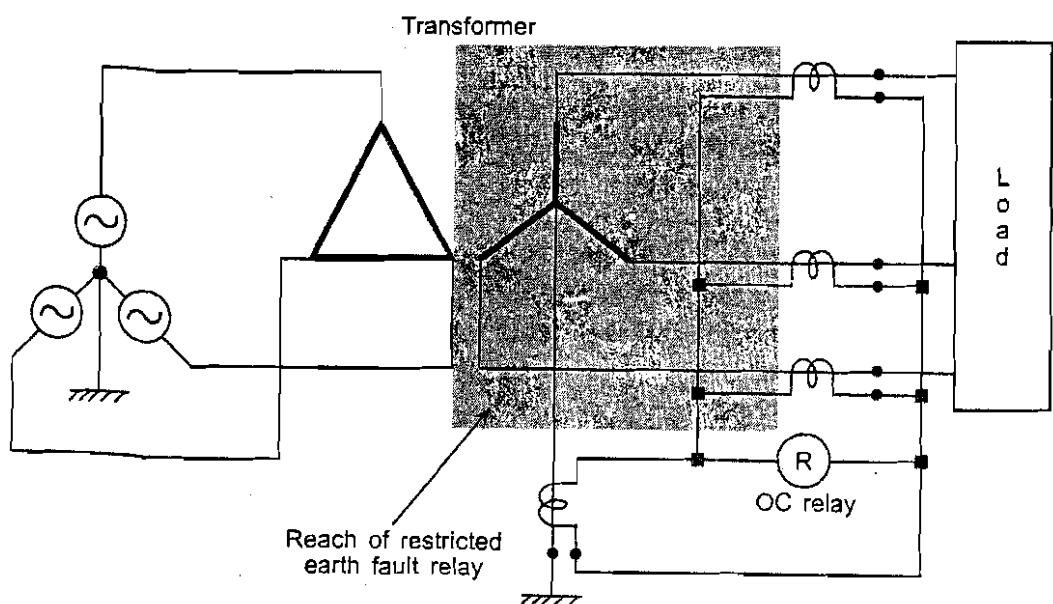


Figure 4.18 Restricted earth fault protection for star side of delta-star transformer.

The operation of the scheme for internal faults, restricted to the star side, can be easily verified and is left as an exercise to the reader.

4.9 Inter-turn Faults in Transformers

Inter-turn faults cause heavy current to flow within the shorted turns. However, seen from the transformer terminals, the reflected current can be quite small. This can be seen from the simplified analysis of Figure 4.19.

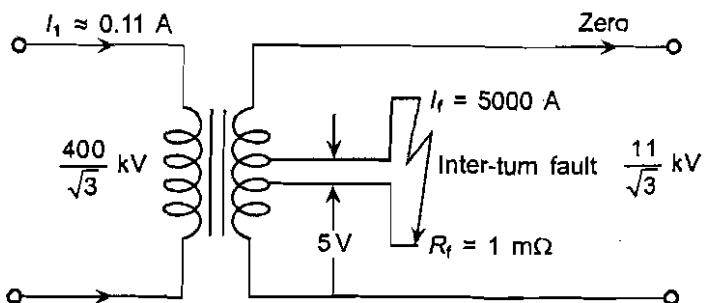


Figure 4.19 Calculation of terminal current for an inter-turn fault.

$$\text{Power dissipated} = I_f^2 R_f = (5 \times 10^3)^2 (1 \times 10^{-3}) = 25 \text{ kW}$$

Equating primary and secondary VA

$$\left(\frac{400}{\sqrt{3}} \text{ kV} \right) (I_1) = (5 \text{ V})(5000 \text{ A})$$

or

$$I_1 \approx 0.11 \text{ A}$$

The current that circulates within the short-circuited turns is 5000 A whereas at the 400 kV terminals the current is only of the order of 0.11 A. Thus, inter-turn faults are difficult to detect using over-current or differential principles of relaying. However, they can cause severe hot spots resulting in deterioration of insulation.

This has led to the development of Buchholz relay which makes use of the heat generated and the consequent decomposition of oil to sense the fault by purely non-electrical means.

4.10 Incipient Faults in Transformers

Faults which are not significant in the beginning but which slowly develop into serious faults are known as *incipient faults*. Buchholz relay provides protection against such incipient faults.

4.10.1 Buchholz Relay

Figure 4.20 shows the position of the Buchholz relay with respect to the transformer tank and the conservator.

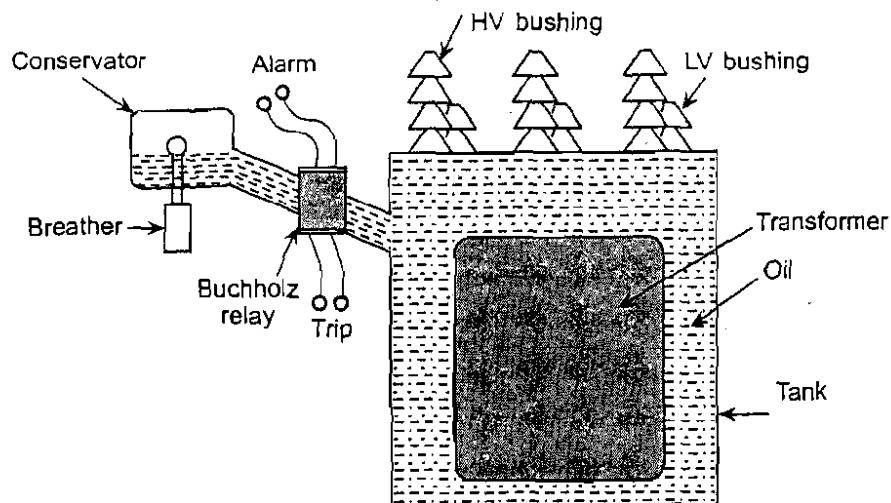


Figure 4.20 Placement of the Buchholz relay.

The conceptual diagram of the inner working of the Buchholz relay is shown in Figure 4.21. When an incipient fault such as a winding-to-core fault or an inter-turn fault occurs on the transformer winding, there is severe heating of the oil. This causes gases to be liberated from the oil around 350°C . There is a build-up of oil pressure causing oil to rush into the conservator. A vane is placed in the path of surge of oil between the transformer and the conservator. A set of contacts, operated by this vane, is used as trip contacts of the Buchholz relay. This output of Buchholz relay may be used to trip the transformer.

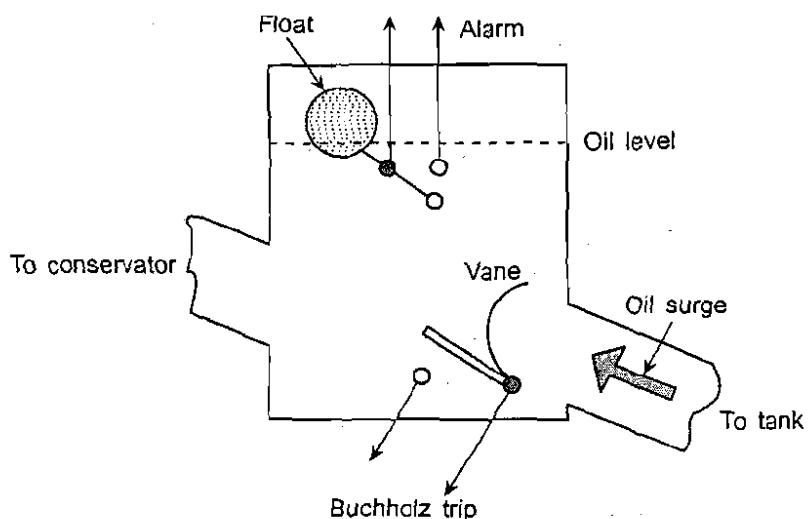


Figure 4.21 Construction of the Buchholz relay.

The Buchholz relay also has another set of contacts operated by a float. These contacts stay open when the transformer tank is filled with oil. However, in case of leakage of oil or decomposition of oil, the float sinks causing the contacts to close. Loss of oil will no doubt cause the transformer temperature to rise but does not warrant immediate tripping. Hence, normally these contacts are wired to an alarm which alerts the operator.

4.10.2 Analysis of Trapped Gases

The trapped gases in the conservator can give valuable clue to the type of damage that takes place inside the transformer. This is because the insulation between the winding turns, the insulation between the stampings of the core and the oil, all liberate specific gases when they get heated up due to a fault. The presence of these gases can be used as a *signature* of a particular type of damage that may have taken place inside the transformer. Table 4.2 lists this information.

Table 4.2 Analysis of trapped gases

Type of gas	Diagnosis
H ₂ and C ₂ H ₂	Arcing in oil between constructional parts
H ₂ , C ₂ H ₂ and CH ₄	Arcing with some deterioration of phenolic insulation, e.g. fault in tap changer
H ₂ , CH ₄ , C ₂ H ₄	Hot spot in core joints
H ₂ , CH ₄ , CO ₂ and C ₃ H ₆	Hot spot in a winding

4.11 Phenomenon of Over-fluxing in Transformers

4.11.1 Protection Against Over-fluxing

The flux and the applied voltage in a transformer are related through the following expression

$$V = 4.44 \phi_m f N$$

where

V is the rms value of the voltage

f is the frequency

N is the number of turns in the winding.

Thus, we can write the flux as

$$\phi_m = \frac{V}{4.44 f N}$$

Whenever there is an over-voltage (frequency remaining constant), the transformer core is subjected to a higher value of flux in order to be able to support the higher applied voltage. By design, power transformers operate at the knee of the saturation curve at normal voltage. Hence, any increase in applied voltage, and the consequent increase in flux density, drives the transformer deeper into saturation. The transformer, therefore, draws an excessive magnetization current. Hence, this condition is described as *over-excitation*. This, considerably, increases the core losses giving rise to overheating of the transformer. Further, saturation of the core causes the flux to flow into adjacent structures, causing high eddy current losses in the core and adjacent conducting materials. Such an operating condition cannot be allowed to continue for long and the transformer should be tripped if there is a prolonged over-excitation. Figure 4.22 shows a typical allowable over-excitation limit curve.

It can be easily seen that over-excitation can also occur in case of low-frequency operation of the transformer at rated voltage.

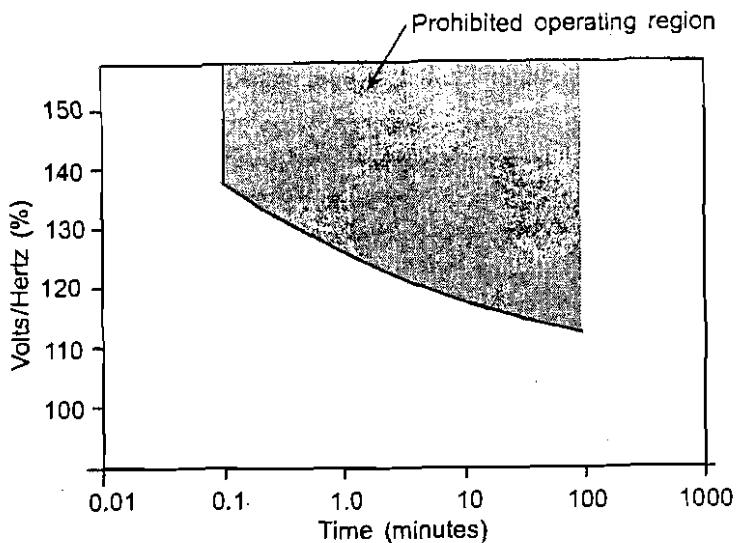


Figure 4.22 A typical transformer over-fluxing limit curve.

Therefore, to keep the working flux within the permissible design limits, the V/f ratio must not exceed the permissible limit. For example, a transformer designed for a per unit voltage limit of 1.25 per unit (125%) at rated frequency will experience over-fluxing whenever the per unit volts/hertz exceeds 1.25 (125%), i.e. whenever the voltage exceeds 125% at rated frequency or the frequency falls below approximately 80% (below approximately 40 Hz on 50 Hz basis) at rated voltage. Thus over-excitation can be detected by measuring the V/f ratio by a so-called **volts/hertz relay**.

Microprocessor-based volt/hertz relays have been developed and are in use. We refrain from further discussion of these relays in this textbook. The interested reader may consult manufacturers' literature for details.

4.12 Transformer Protection Application Chart

Transformers are used for a very wide variety of applications. The type of protection that will be provided for a transformer depends upon its kVA rating and its importance. The only protection that will possibly be provided to a small lighting transformer may be in the form of fuses while a transformer connected to a generator in a thermal power station may have very elaborate protection. Tables 4.3 and 4.4 summarize the transformer protection scenario and application of various protection schemes.

Table 4.3 Internal and external faults affecting transformers

<i>Internal faults</i>	<i>External faults</i>
Phase faults	System phase faults
Ground faults	System ground faults
Inter-turn faults	Overloads
Tap-changer failure	Over-fluxing
Leakage of oil from tank	

Table 4.4 Application of protective schemes

Fault	Protection scheme	
	Primary	Back-up
Phase faults	Percentage differential relay	Over-current/distance
Ground faults	Percentage differential relay	Over-current/distance
Inter-turn faults		Buchholz relay
Oil leaks		Buchholz relay
Overloads	OC relay with thermal image of protected unit	
Over-fluxing		Over-fluxing relay which measures (V/f) ratio

4.13 An Illustrative Numerical Problem

Problem For a 45 MVA, 11 kV/66 kV, star-delta transformer, design the percentage differential scheme. What is the minimum recommended percentage bias?

Solution As shown in the worksheet of Table 4.5, we find that the pilot wire currents are 6.817 A from the star side CTs while they are 3.936 A from the delta side CTs. Thus, we need intermediate CTs to correct this mismatch as shown in Figure 4.23. Such CTs are known as *interposing CTs* and are usually autotransformer types. The turns ratio of the interposing CTs is, therefore, found out to be $6.817/3.936 = 1.731 : 1$.

Table 4.5 Worksheet for % differential relay calculations

Step	11 kV star side	66 kV delta side
1 Full-load line current, I_{FL}	$\frac{45 \times 10^6}{\sqrt{3} \times 11 \times 10^3} = 2361.88 \text{ A}$	$\frac{45 \times 10^6}{\sqrt{3} \times 66 \times 10^3} = 393.64 \text{ A}$
2 To allow for 25% overload, choosing $(I_{FL} \times 1.25)$ as primary current	$2361.88 \times 1.25 \text{ A} = 2952.35 \text{ A}$	$393.64 \times 1.25 \text{ A} = 492.05 \text{ A}$
3 CT ratios (5 A relay)	Choosing a CT of 3000 : 5 i.e. CT ratio = 600	Choosing a CT of 500 : 5 i.e. CT ratio = 100
4 CT secondary currents	CT secondary current $= \frac{2361.88}{600} = 3.936 \text{ A}$	CT secondary current $= \frac{393.64}{100} = 3.936 \text{ A}$
5 Pilot wire currents	(CT secondaries are in Δ) Current in the pilot wires $= \sqrt{3} \times 3.936 \text{ A} = 6.817 \text{ A}$	(CT secondaries are in Y) Current in the pilot wires $= 3.936 \text{ A}$
6 Turns ratio of the interposing CT $(6.817/3.936) : 1$ $= 1.731 : 1$	Current after the interposing CT $= \frac{6.817}{1.731} = 3.938 \text{ A}$	Current in the pilot wires $= 3.936 \text{ A}$

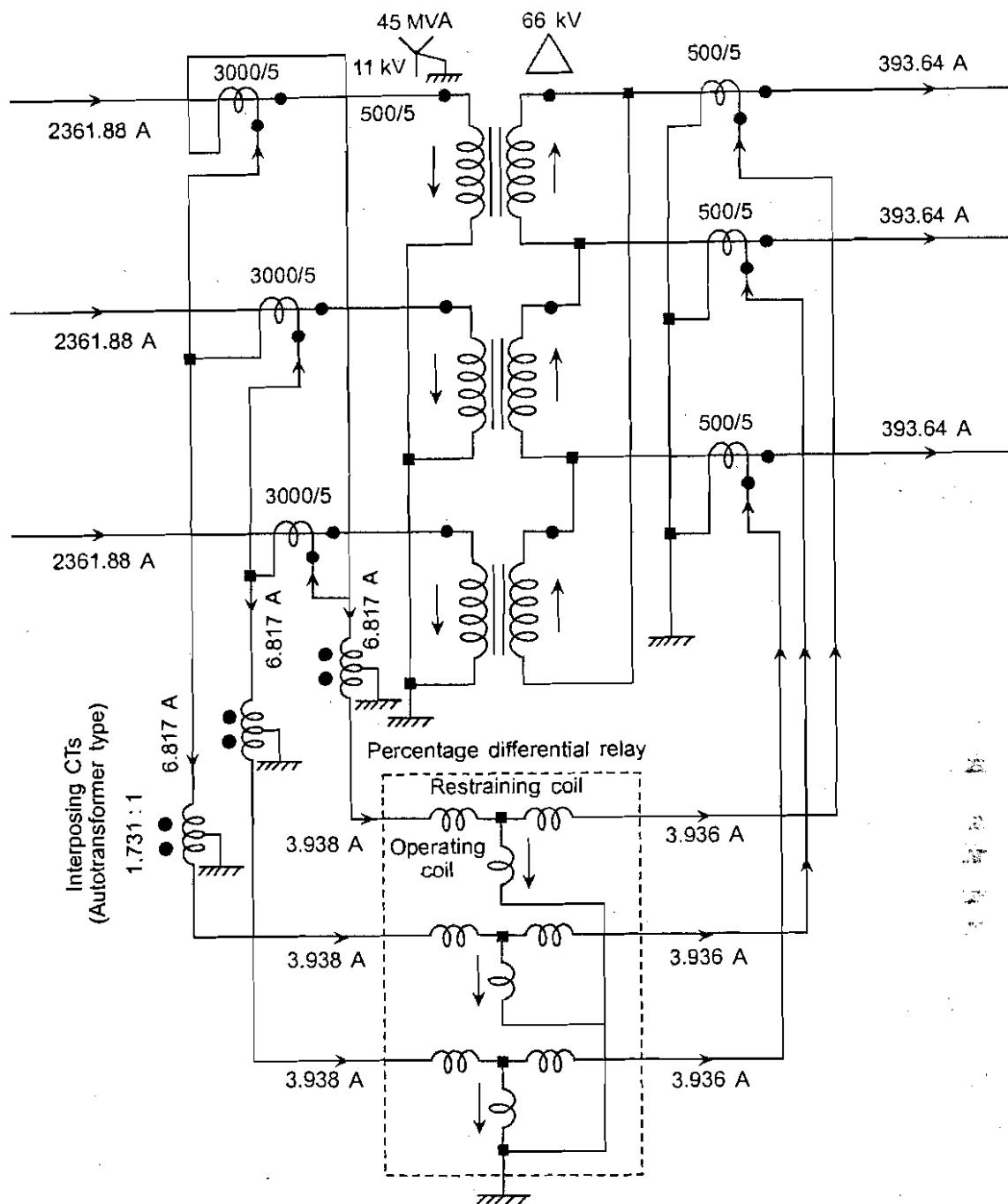


Figure 4.23 Numerical problem on percentage differential protection of transformer.

Assuming a slope of 40%, spill current required for tripping is

$$0.4 \left(\frac{3.936 + 3.938}{2} \right) = 1.57 \text{ A}$$

Actual spill current = $3.938 - 3.936 = 0.002 \text{ A}$. Therefore, the scheme remains stable on full load or external fault.

Review Questions

1. What factors cause spill current on external fault in case of transformer differential protection?
2. While connecting CT secondaries for differential protection of three-phase transformers, the CTs on the star side have to be connected in delta and vice versa. Explain.
3. The CT ratios of CTs on the two sides of a transformer will, in general, be different. Explain.
4. What is the effect of tap changing on the percentage bias setting of differential relay?
5. For a three-phase delta-star transformer, show that a line-to-ground fault (external as well as internal) on the star side appears like a line-to-line fault from the delta side.
6. Investigate the differential units which operate on $\alpha-g$ external and internal faults.
7. Repeat the above for line-to-line external and internal faults.
8. Explain the phenomenon of inrush. What are the factors on which the magnitude of inrush current depends?
9. Consider the following switching instants for a transformer:
 - (a) Voltage wave passing through zero from negative side, residual flux equal to positive peak value of steady-state flux.
 - (b) Voltage wave at its peak and decreasing, residual flux equal to negative peak value of steady-state flux.
 - (c) Voltage wave passing through zero from positive side, residual flux equal to zero.

Sketch the waveforms of voltage, flux and magnetization current for the above cases.

10. Which harmonic is the most dominant in the inrush waveform?
11. Explain the principle of percentage biased differential relay with harmonic restraint.
12. Why does the percentage differential relay fail to detect 'high resistance winding'-to-'core' faults?
13. What type of protection is used for the fault condition in Question 12?
14. Prove that the restricted earth fault relay does not operate for faults beyond the star connected winding of a three-phase delta-star transformer.

15. Prove that the restricted earth fault relay does operate for faults within the star connected winding of a three-phase delta-star transformer.
16. What do you mean by over-fluxing or over-excitation? What is the significance of the (V/f) ratio?
17. Why is over-fluxing harmful for the transformer?
18. What is the principle of over-fluxing protection?

Problems

1. Consider a single-phase 11 kV/11 kV, 1.1 MVA transformer protected by percentage differential protection. CTs with 5 A secondaries are used. It is known that the magnetizing currents of the two CTs, for maximum external fault current, differ by 0.5 A. Assuming no other source of error and a minimum pick-up of 0.01 A, find the minimum percentage bias setting so that the scheme remains stable on maximum external fault current.
(Ans. 9.8%)
2. Design the differential protection for a three-phase, 50 Hz transformer with the following nameplate ratings: MVA 250, 15.75 kV/400 kV, 50 Hz, delta-star.

5

Busbar Protection

5.1 Introduction

The word *bus* is derived from the Latin word *omnibus* which means common for all. Busbars are the *nerve-centres* of the power system where various circuits are connected together. These are the nodes of the electrical circuit. Figure 5.1 shows a busbar having an N_1 number of incoming lines and an N_2 number of outgoing lines. The protective zone, to be generated by the protective relays, is also shown. It may be noted that under the normal power flow condition the sum of incoming currents is equal to the sum of outgoing currents, i.e.

$$\sum_{k=1}^{N_1} I_{\text{in}_k} = \sum_{m=1}^{N_2} I_{\text{out}_m}$$

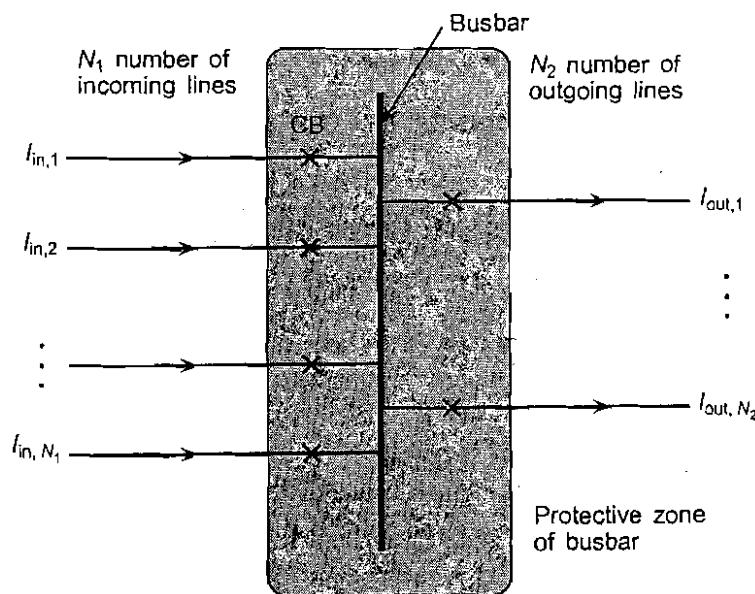


Figure 5.1 Introduction to busbars.

Thus, there is a large concentration of short-circuit capacity at the busbars. A fault on the busbar, though rare, causes enormous damage. When protective relays operate to isolate the busbar from the system, there is a large disruption to the loads. Busbars are located in switchyards, substations, and supply kiosks. The switchyards are well shielded from direct lightning strokes but because of their outdoor nature, are subject to the vagaries of weather. The substations are well protected in all respects and fault probability is indeed very low. Similarly, supply kiosks are totally enclosed and sealed.

The causes of faults experienced on busbars are: weakening of insulation because of ageing, corrosion because of salty water, breakdown of insulation because of overvoltages, foreign objects, and so on. For example, rodents, lizards and snakes are known to have caused busbar faults in remote unmanned substations.

Because of the low probability of busbar faults, for many years, it was considered unnecessary to provide explicit protection to busbars. It was felt at that time that maloperations of the busbar protection systems will be problematic by themselves and of little help in sensing genuine faults. It should be noted that busbars fall in the overlap between protective zones on either side, so they do get back-up protection. Hence, protection engineers hesitated from providing exclusive busbar protection.

However, as the system voltage went on increasing and short-circuit capacities went on building up, it was no longer advisable to leave busbars unprotected on a primary basis.

What form of protection is best suited for busbars? A little reflection will convince the reader that differential protection will suit this situation best because the ends (terminals) of the system are physically near to each other. Thus, by installing CTs on the two sides, we can simply compare the current entering the busbar with that leaving it. Any discrepancy between the two will immediately signal an internal fault.

In Section 5.2, we have explained the protection of busbars by the differential protection scheme.

5.2 Differential Protection of Busbars

5.2.1 Selection of CT Ratios in Case of Busbar Protection: Wrong Method

Figure 5.2 shows a busbar, having two incoming feeders and one outgoing feeder, being protected by a simple differential protection scheme. The currents shown are for normal load flow. Let us decide the CT ratios on the basis of maximum primary load current seen by each CT. Thus, the CTs on the incoming feeder will have CT ratios of 1000/1 A and 2000/1 A, respectively. The CT on the outgoing feeder will have a CT ratio of 3000/1 A. However, with this choice of CT ratios, it can be seen from the diagram that there is a spill current even during the healthy condition. Thus, the method of selecting CT ratio on the basis of maximum primary current seen by the feeder is not correct.

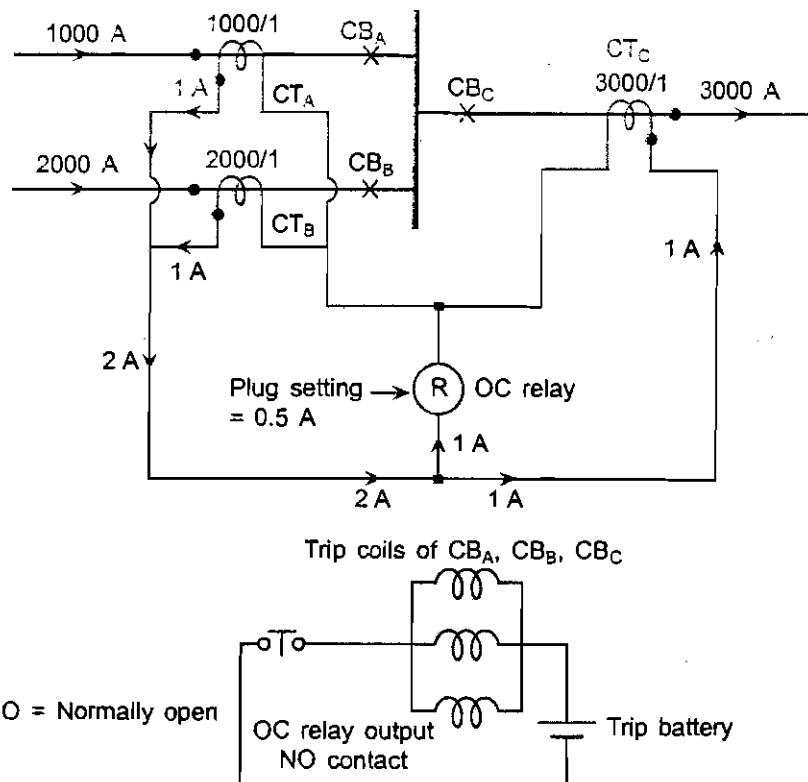


Figure 5.2 Wrong method of selection of CT ratios for differential protection of busbars.

5.2.2 Selection of CT Ratios in Case of Busbar Protection: Correct Method

Figure 5.3 shows the correct method of setting the CT ratios for the busbar differential protection. It can be seen that the CT ratios of all the CTs are equal and are based on the primary current of that feeder which carries the maximum current. Thus, all the CT

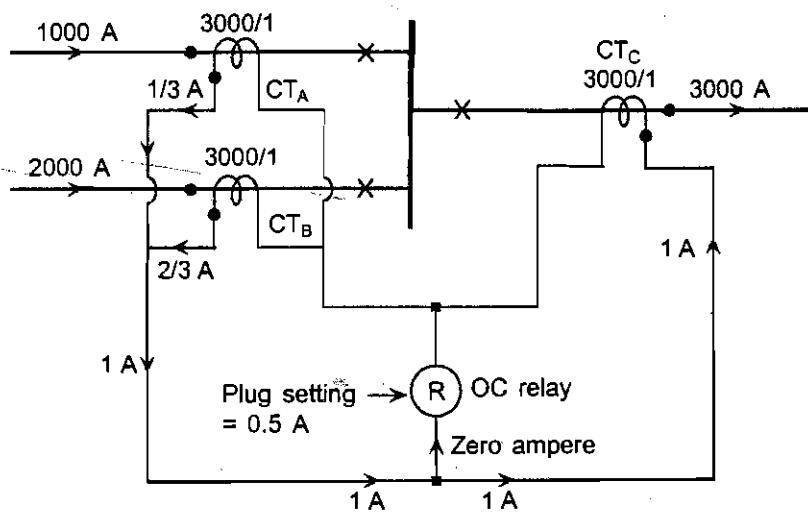


Figure 5.3 Correct method of selection of CT ratios for differential protection of busbars.

ratios are 3000/1 A. Therefore, as can be seen from the figure, there is no spill current through the OC relay connected in the spill path and the scheme remains stable.

We draw an important rule for the selection of CT ratios for all the CTs in a busbar differential protection, namely:

$$\text{CT ratio for all CTs in bus differential scheme} = \frac{\text{Maximum out of all the feeder currents}}{1 \text{ A or } 5 \text{ A}}$$

5.3 External and Internal Fault

In the preceding discussion, we have assumed that the CTs are ideal. When the CT primary current, or the burden on it, is within its design limits, the CT can indeed be assumed to be more or less ideal. However, as the primary current exceeds the design value or the CT burden (output of CT in VA) becomes excessive, the CT no longer behaves in an ideal fashion. The non-ideal behaviour of the CT has very serious implications for the protective schemes.

Figure 5.4 shows currents during an external fault beyond CT_C . It can be seen that CT_C , the CT on the faulted feeder, has to carry the sum of all currents fed into the fault by various feeders. Therefore, CT_C sees a substantially larger primary current than either CT_A or CT_B . In all likelihood, CT_C will therefore become saturated. We can, therefore, no longer assume that CT_C will faithfully transform the fault current. For the sake of illustration, we have assumed that the secondary current of CT_C is only 4 A instead of 10 A. It can be seen from Figure 5.4 that this results into a spill current of 6 A, causing the scheme to maloperate, i.e. lose stability on external fault.

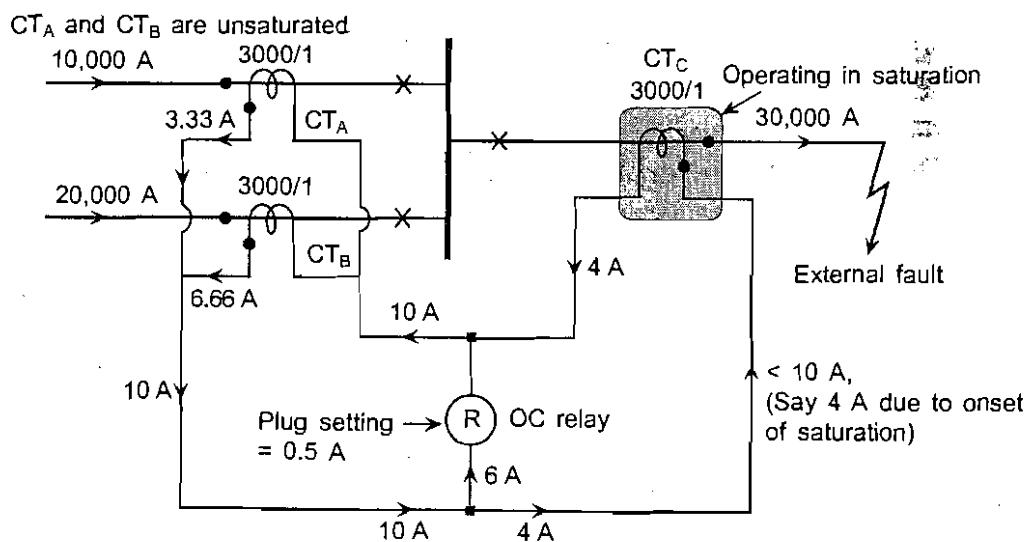


Figure 5.4 Behaviour of busbar differential scheme on external fault.

In the worst case scenario, CT_A and CT_B continue to transform faithfully as per their nameplate CT ratio but CT_C , which carries the total fault current, gets completely saturated. This clearly indicates the occurrence of an imbalance in transformed secondary currents, resulting in substantial spill current. This situation most likely will cause the scheme to operate. Operation of a differential scheme under external faults is, therefore, clearly a case of maloperation.

Interestingly, as the fault shifts by a small distance to the left and becomes an internal fault, still drawing the same current, the situation dramatically changes as far as CT_C is concerned. This is depicted in Figure 5.5, wherein it can be seen that CT_C now does not carry any fault current (assuming a single-end-fed system with source on left-hand side). Since CT_A and CT_B are not carrying excessive primary currents, they transform the current without too much error. There is thus a spill current in the spill path and the scheme operates as expected.

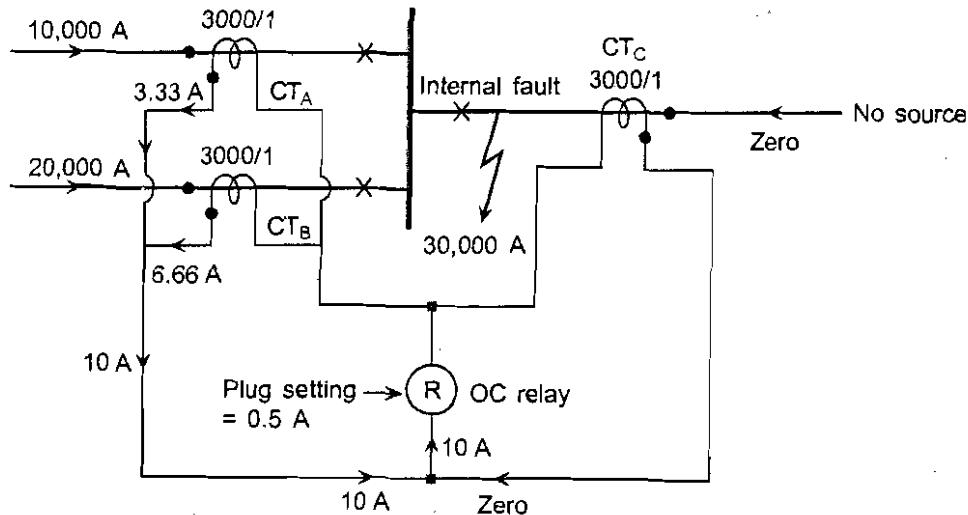


Figure 5.5 Behaviour of busbar differential scheme on internal fault.

The maloperation of the busbar differential scheme on external faults is caused due to non-ideal behaviour of a CT carrying excessive primary current. It will, therefore, be pertinent, at this point to take a closer look at the actual behaviour of protective current transformers.

5.4 Actual Behaviour of a Protective CT

Figure 5.6 shows the equivalent circuit of a current transformer referred to the secondary side. R'_p and X'_p are the primary winding resistance and leakage reactance, respectively, referred to the secondary side. R_s and X_s are the resistance and leakage reactance of the secondary winding, respectively. The excitation is modelled by X_o and core loss by R'_o in the equivalent circuit (referred to secondary).

At low values of primary current I_p , and therefore I_s , voltage E_s to be induced by the secondary winding, which is approximately equal to $(Z_{\text{burden}} I_s)$, is quite low. The working flux in the CT, which is equal to $(E_s / 4.44 fN)$ is also very low. The magnetizing current requirement is, therefore, correspondingly low. Thus, the secondary current I_s is substantially equal to I_p/N .

If the primary current increases, initially, the secondary current also increases proportionately. This causes the secondary induced voltage to increase as well. Increased secondary voltage can only be met with an increase in the working flux of the CT. As the flux increases, the transformer needs to draw a higher magnetizing current. However, because of the nonlinear nature of the B - H curve for the CT, as the knee of the excitation

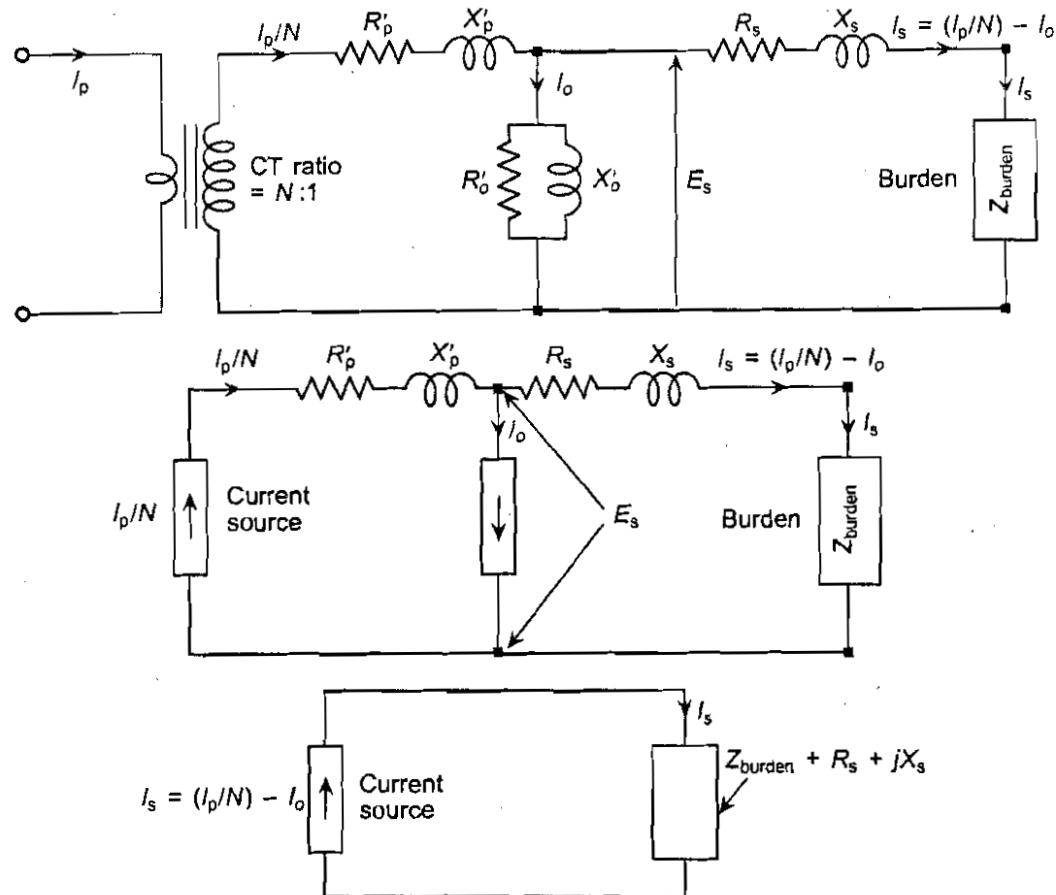


Figure 5.6 Equivalent circuit of CT.

characteristics is passed, any further increase in flux demand causes a disproportionately large increase in the magnetizing current requirement of the CT. This is illustrated in Figure 5.7. It may also be noted that \$I_o\$ is no longer sinusoidal and its waveform has a prominent peak.

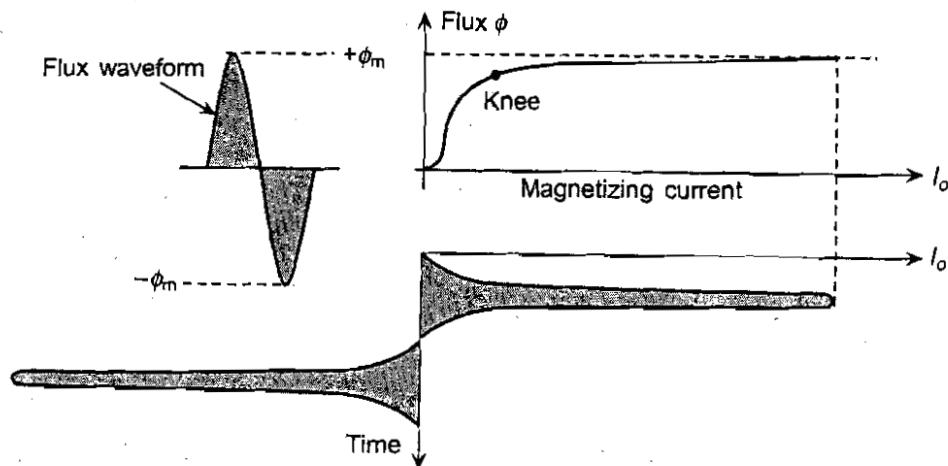


Figure 5.7 Operation of the CT beyond the knee point of the \$B\$-\$H\$ curve.

As the primary current goes on increasing, a stage comes when the magnetizing current requirement is so large that almost all the transformed current is taken up by the CT for the sole purpose of magnetization, with the result that there is hardly any current available for the burden. When this occurs, we say that the CT is completely saturated. The secondary induced voltage and burden current waveforms of a CT, operating in saturation, are highly distorted. They, in fact, consist only of sharp pulses near the zero-crossings of the primary current. This is shown in Figure 5.8, where it can be seen that in order to reach the peak of the sinusoidal flux waveform, the CT is driven deep into saturation. Due to flatness of the excitation curve in this region, a very large amount of exciting current is demanded by the CT. The waveform of the exciting current becomes distorted and is, in fact, very peaky in nature.

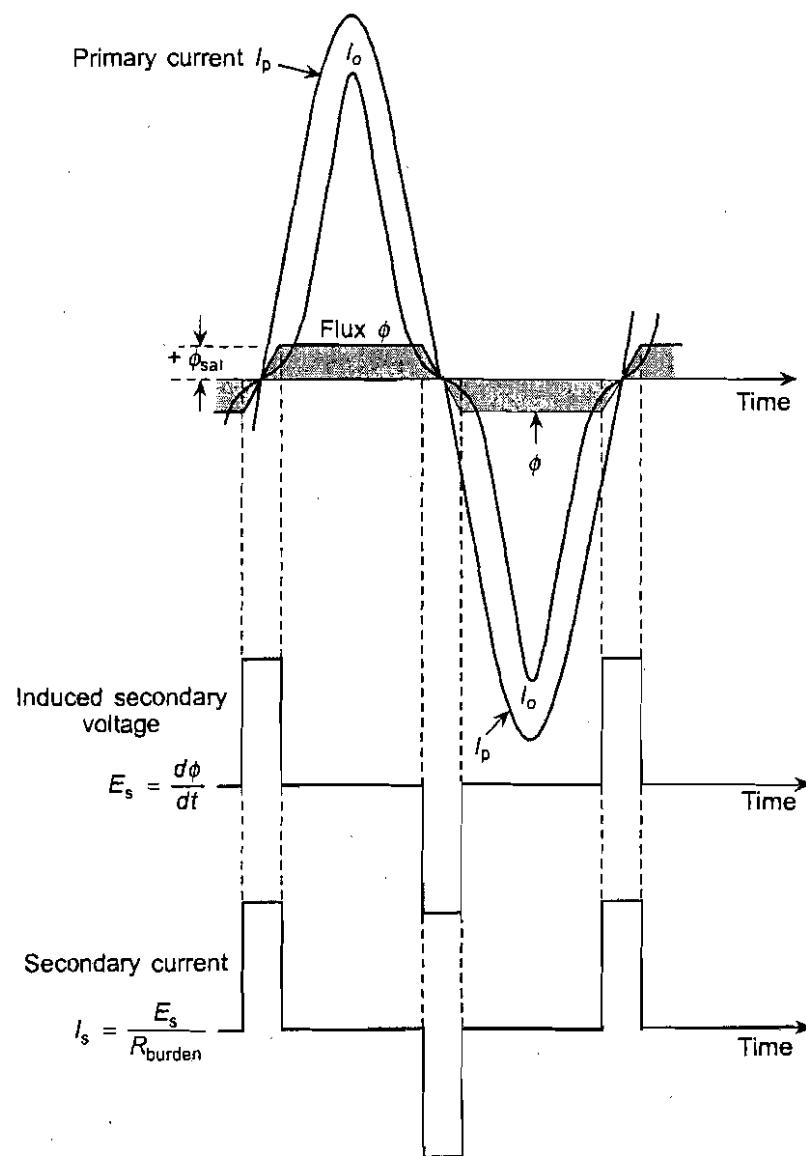


Figure 5.8 CT saturation due to excessive primary current.

5.5 Circuit Model of Saturated CT

In the light of the preceding discussion, the saturated CT is modelled as shown in Figure 5.9, where it can be seen that the magnetizing branch is replaced with a short circuit to signify the fact that the magnetizing branch is taking up all the secondary current and none is available to the burden.

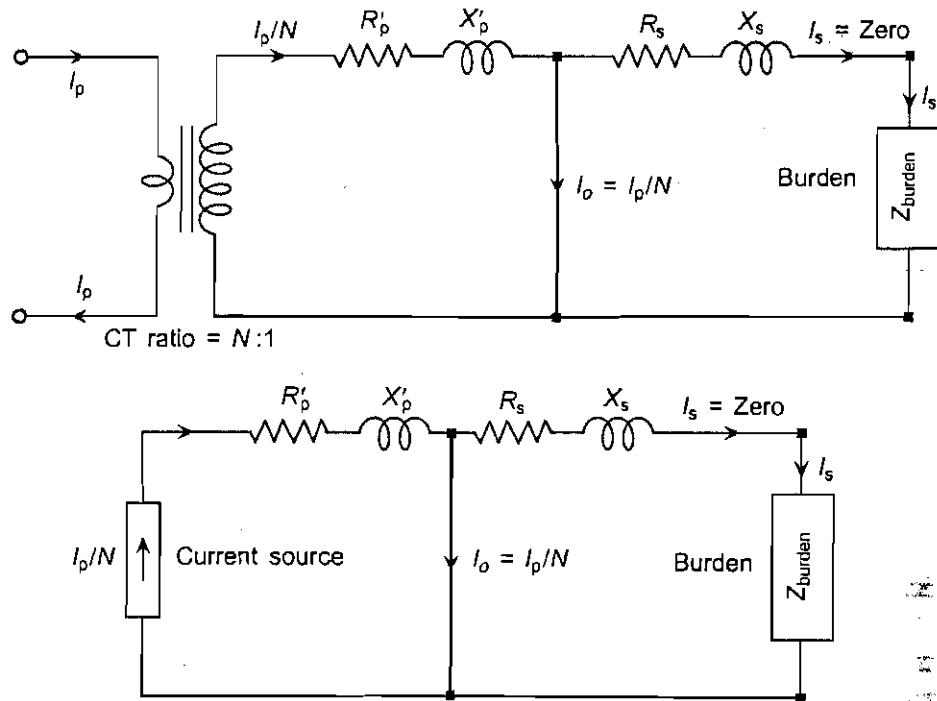


Figure 5.9 Circuit model of a saturated CT.

Thus, the circuit model consists of a current source of value (I_p/N) feeding into a short circuit through R'_p and X'_p . The connections to the outside world are available through R_s and X_s .

5.6 External Fault with One CT Saturated: Need for High Impedance Busbar Protection

Now, consider the external fault of 30,000 A, on the busbar shown in Figure 5.4. Assuming that CT_C gets completely saturated while CT_A and CT_B continue to operate normally, Figure 5.10 shows the equivalent circuit as seen from the CT secondaries. Note that for simplicity, all leakage reactances have been neglected.

It can be seen from Figure 5.10 that currents $[(I_A/N) - I_{oA}]$ and $[(I_B/N) - I_{oB}]$ sum up and the resultant current has two parallel paths available. One path is through the over-current relay and the other is through $(R_s + R_L)$ via the short representing the saturated CT magnetizing branch. Thus, the part of fault current will flow through the over-current relay, causing it to trip, even though the fault is external. Hence, the OC

relay needs to be restrained from tripping on external faults (with one CT completely saturated). We can easily accomplish this by connecting a high resistance (known as the *stabilizing resistance*) in series with the OC relay. The stabilizing resistance should be of such a value that under the worst case of maximum external fault and full saturation of one CT, the current through the OC relay is less than its pick-up value. Such schemes are known as high impedance busbar differential schemes.

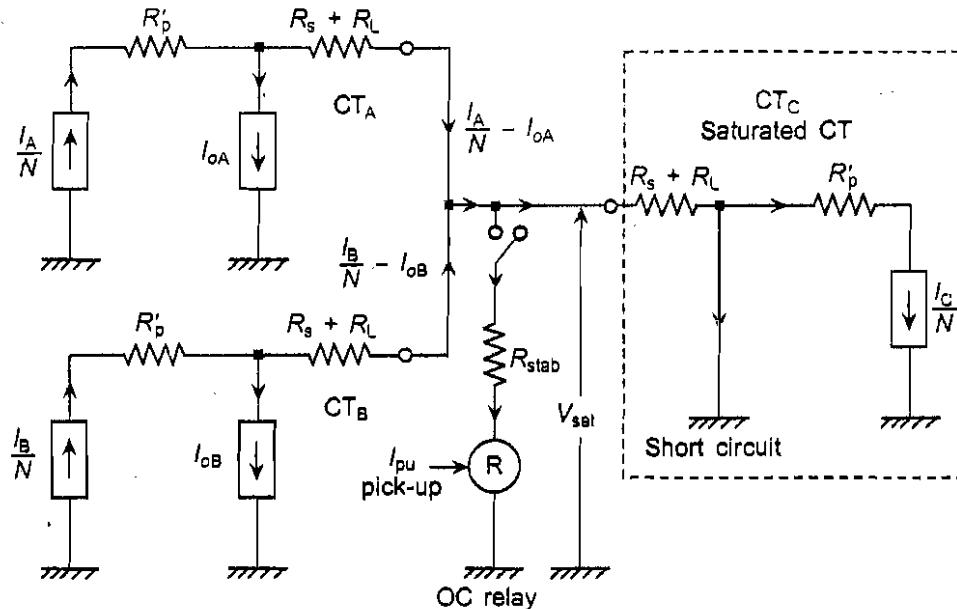


Figure 5.10 Secondary equivalent circuit with one CT fully saturated during external fault.

To find the value of the stabilizing resistance, let the pick-up value of the OC relay be I_{pu} and the value of the resistance associated with the saturated CT be $(R_s + R_L)$. The impedance of the secondary circuit of the saturated CT be represented by Z_s , where $Z_s = (R_s + R_L)$.

The procedure is as follows: First consider that the OC relay is not connected and find out the voltage that will be developed across it, let it be V_{set} . Now, the stabilizing resistance should be of such a value that with the relay connected, the current through the relay should be less than the pick-up value of the relay.

Therefore, we have the following relationship:

Voltage across the over current relay in series with the stabilizing resistor

$$\begin{aligned} V_{set} &= \left[\left(\frac{I_A}{N} - I_{oA} \right) + \left(\frac{I_B}{N} - I_{oB} \right) \right] Z_s \\ &= \left[\left(\frac{I_A}{N} + \frac{I_B}{N} \right) - (I_{oA} + I_{oB}) \right] Z_s \end{aligned}$$

In order that under this condition, the current through the relay be less than or equal to its pick-up value I_{pu} , we have

$$R_{stab} \geq \frac{V_{set}}{I_{pu}}$$

Assuming n feeders and further assuming that the magnetizing current of each unsaturated CT is same and equal to I_o , and noting that the transformation ratio of all the CTs is same and equal to N , we get the general expression:

$$V_{\text{set}} = \left[\left(\sum_{k=1}^{n-1} \frac{I_k}{N} \right) - (n-1)I_o \right] Z_s$$

where the subscript k varies from 1 to $n-1$, n being the total number of feeders terminating on the bus. Note that $\left(\sum_{k=1}^{n-1} I_k \right)$ is the maximum external fault current,

$I_{f,\text{ext,max}}$, up to which the differential scheme remains stable. Therefore, neglecting magnetizing currents, we can write

$$V_{\text{set}} = \left[\frac{I_{f,\text{ext,max}}}{N} \right] Z_s$$

The preceding equation gives the value of maximum external fault current up to which the differential relaying scheme remains stable as:

$$I_{f,\text{ext,max}} = \frac{NV_{\text{set}}}{Z_s}$$

5.7 Minimum Internal Fault That Can Be Detected by the High Impedance Busbar Differential Scheme

It will be worthwhile to investigate the minimum internal fault current $I_{f,\text{internal, primary}}$ that can be detected by the high impedance busbar differential scheme. The equivalent CT secondary circuit during internal fault is shown in Figure 5.11. It is assumed that none of the CTs is saturated. The high impedance scheme has a pick-up of I_{pu} , a stabilizing resistance of R_{stab} and, therefore, needs a minimum voltage of V_{set} to be developed across the series combination of the stabilizing resistance and the OC relay. Thus, the minimum fault current on the CT secondary side, that can develop the required voltage V_{set} , will be given by

$$V_{\text{set}} = I_{f,\text{min, sec}} R_{\text{stab}}$$

$$I_{f,\text{min, sec}} = \frac{V_{\text{set}}}{R_{\text{stab}}}$$

But

$$\frac{V_{\text{set}}}{R_{\text{stab}}} = I_{pu}$$

Therefore,

$$I_{f,\text{min, sec}} = I_{pu}$$

Figure 5.11 shows that during internal fault, all the CT secondaries feed into the spill path. Therefore, the current for a minimum internal fault in the high impedance spill path will be

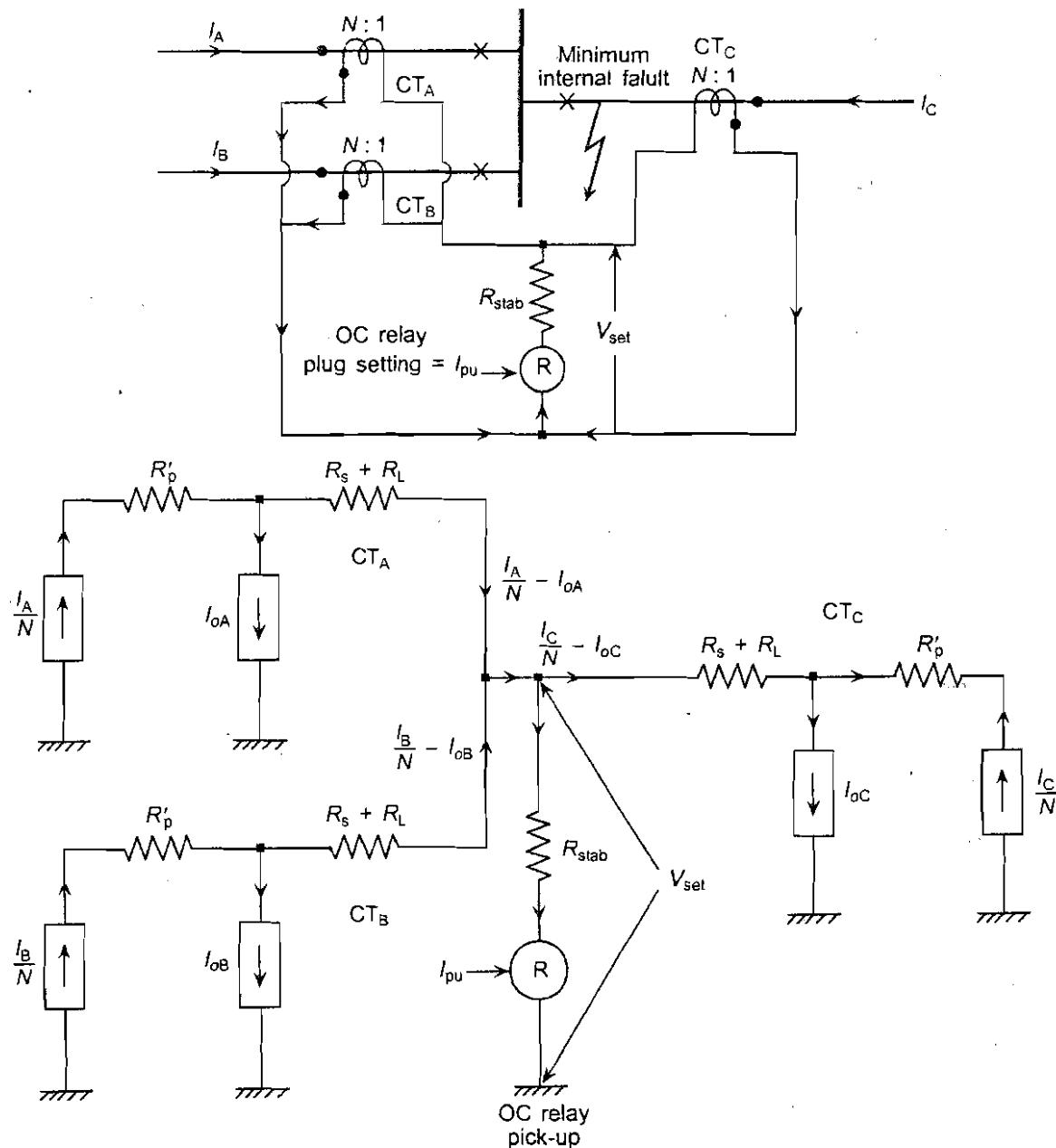


Figure 5.11 Minimum internal fault current that can be detected by high impedance busbar differential scheme.

$$\begin{aligned}
 I_{f, \text{min, sec}} = I_{pu} &= \left(\frac{I_A}{N} - I_{oA} \right) + \left(\frac{I_B}{N} - I_{oB} \right) + \left(\frac{I_C}{N} - I_{oC} \right) \\
 &= \left(\frac{I_A}{N} \right) + \left(\frac{I_B}{N} \right) + \left(\frac{I_C}{N} \right) - (I_{oA} + I_{oB} + I_{oC})
 \end{aligned}$$

$$\begin{aligned}
 &= \frac{I_A + I_B + I_C}{N} - (I_{oA} + I_{oB} + I_{oC}) \\
 &= \frac{I_{f,int,min,pri}}{N} - 3I_o
 \end{aligned}$$

Assuming $I_{oA} = I_{oB} = I_{oC} = I_o$ (i.e. all the CT magnetizing currents to be equal) and multiplying both sides by N , we get

$$NI_{pu} = I_{f,int,min,pri} - 3NI_o$$

or

$$I_{f,int,min,pri} = N(I_{pu} + 3I_o) \quad (\text{with 3 feeders terminating on the bus})$$

For the general case of n feeders terminating on the busbar, the minimum internal fault current that can be detected by the high impedance busbar differential scheme will be given by

$$I_{f,internal,minimum,primary} = N(I_{pu} + nI_o)$$

5.8 Stability Ratio of High Impedance Busbar Differential Scheme

The stability ratio S of the high impedance busbar differential scheme is defined as the *ratio of maximum external fault current for which the scheme remains stable to the minimum internal fault current for which it operates.*

$$S = \frac{I_{f,external,maximum}}{I_{f,internal,minum}}$$

The stability ratio is a dimensionless quantity. The higher the value of stability ratio S , the better is the quality of differential protection. Stability ratios of a few tens are common in EHV busbar differential schemes.

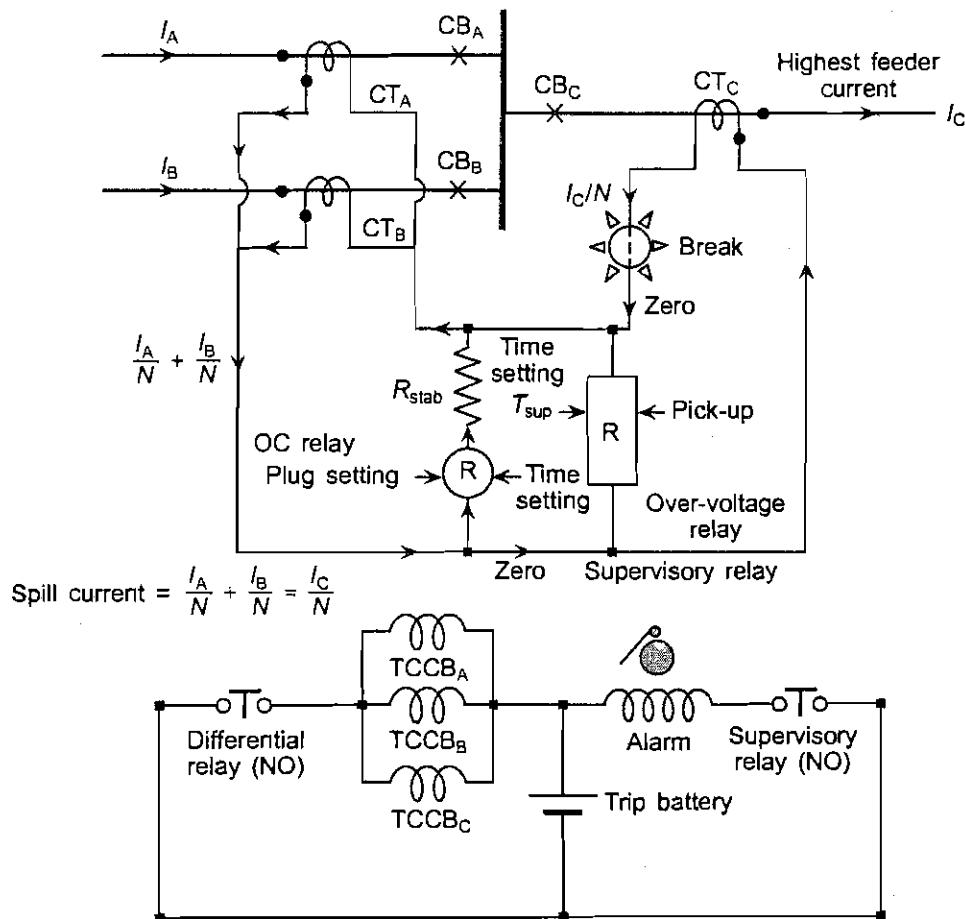
5.9 Supervisory Relay

In the busbar differential scheme, it may, at times, happen that a particular CT secondary gets open circuited. At other times there may be a break in the pilot wire coming from a particular CT secondary winding. Thus, even though there may be no internal fault on the busbar, an imbalance is created on the secondary side, causing a spill current which is equal to the current that was being contributed by the particular CT before its secondary got open circuited.

Such types of events are, no doubt, dangerous. The current contribution of an individual CT would be much less than the pick-up value of the OC relay and the scheme will remain insensitive to such CT open-circuit faults. All the same, we need to develop a mechanism to detect such faults so as to raise an alarm to alert the operating personnel.

The highest spill current, in case of loss of one CT secondary current, will be caused in case of the CT which carries the maximum load current, $I_{\text{load, max}}$.

Figure 5.12 shows the normal load being supplied by the feeders. There is a break in the pilot wire coming from secondary of CT_C . This will cause a spill current equal to the current that was being contributed by CT_C before the break occurred, as shown in Figure 5.12. Thus, the spill current = I_C/N . This spill current will develop a voltage across the series combination of the stabilizing resistance and OC relay, which can be sensed by a sensitive over-voltage relay known as *supervisory relay*.



NO = Normally open, NC = Normally closed, TCCB = Trip coil of CB

Figure 5.12 Supervisory relay to prevent against maloperation due to loss of a CT secondary current.

The supervisory relay is set to pick-up at:

$$V_{\text{supervisory}} = \frac{I_{\text{load,max}}}{N} (R_{\text{stabilizing}} + R_{\text{OC relay}})$$

The above discussion neglects the magnetizing currents of the CTs.

The setting of the supervisory relay $V_{\text{supervisory}}$ will be much less than the setting of the high impedance differential relay V_{set} .

5.10 Protection of Three-phase Busbars

All high voltage busbars are three-phase, however we showed single-phase busbars so as to keep the diagrams uncluttered. Figure 5.13 shows a three-phase busbar with two incoming and three outgoing lines.

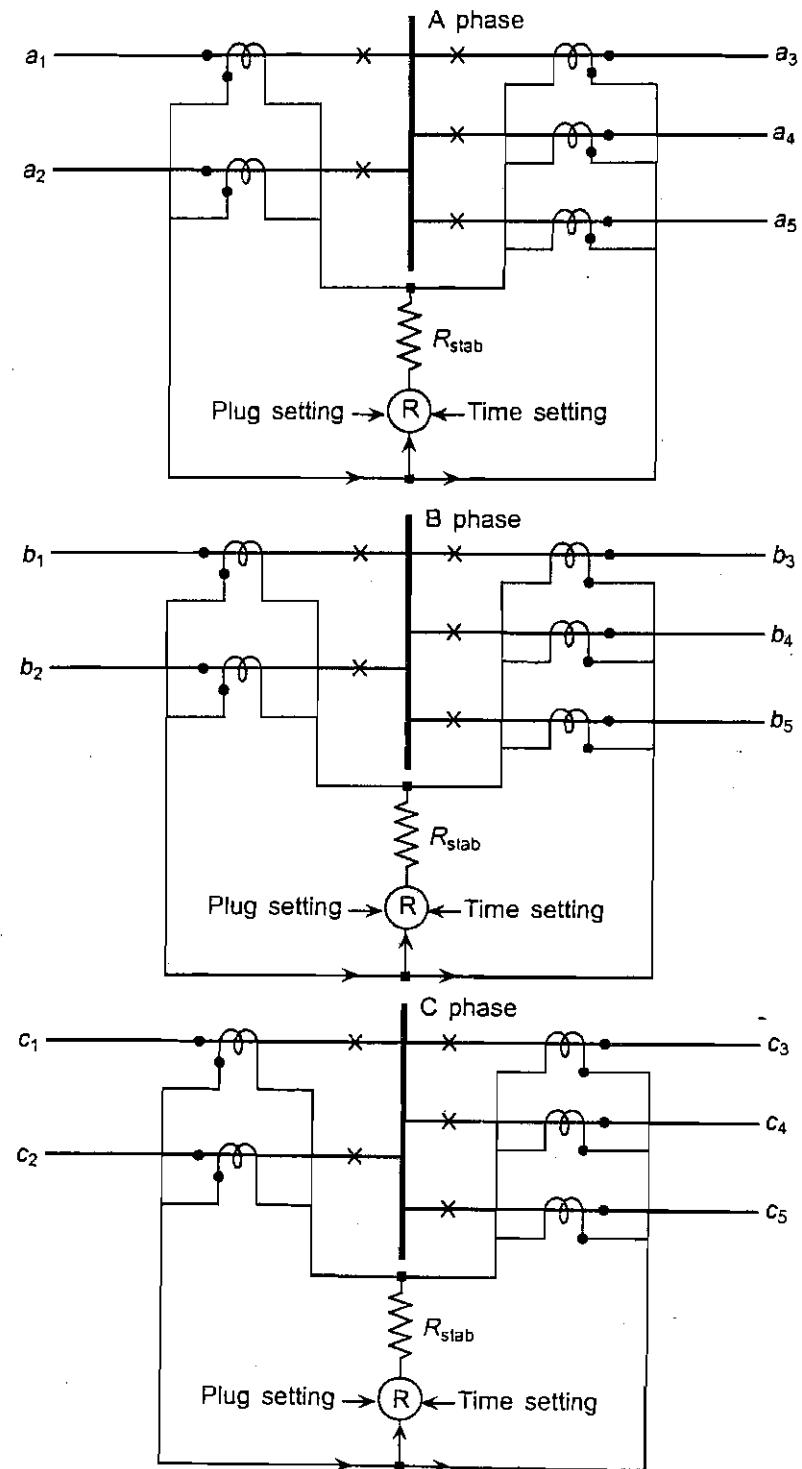


Figure 5.13 High impedance three-phase busbar differential protection.

5.11 Numerical Example on Design of High Impedance Busbar Differential Scheme

A 132 kV busbar consists of two incoming lines and four outgoing lines. The system is solidly earthed and the switchgear capacity is 3500 MVA at 132 kV. The parameters are:

Maximum full-load current in one line	= 500 A
R_s = CT secondary resistance	= 0.7 Ω
$R_{\text{lead wire}}$	= 2.0 Ω
Relay load (1 A relay is used)	= 1.0 Ω
CT magnetizing current up to 120 V	= 0.28 mA/V (assumed linear)
CT saturation voltage V_{knee}	> 120 V

1. If the over-current relay in the spill path is set at 1.0 A and the voltage setting V_{set} is 100 V, find
 - (a) the maximum 'through fault' current up to which the scheme will remain stable.
 - (b) whether the answer in part (a) is commensurate with the switchgear capacity.
 - (c) the minimum internal fault current which will be detected by the scheme.
 - (d) the setting for detecting minimum internal fault current of 500 A?
 - (e) the value of the stabilizing resistance.
2. It is required that a break in the pilot wire from a CT carrying a current of 25 A and more should be detected by the supervisory relay. Calculate the setting of the supervisory relay?

Solution

- 1(a). Let us choose 1 A CTs. Therefore, as explained in the text:

$$\text{CT ratio for all CTs} = \text{Maximum of all the feeder currents : 1}$$

$$= 500 : 1$$

$$I_{f,\text{ext,max}} = \frac{NV_{\text{set}}}{Z_s}$$

$$\frac{500 \times 100}{2 + 0.7} = 18518.51 \text{ A}$$

- 1(b). From the given data, the maximum 'through fault' current that can be handled by the switchgear is:

$$\frac{3500 \times 10^6}{\sqrt{3} \times 132 \times 10^3} = 15,300 \text{ A}$$

The scheme remains stable up to 'through fault' current of 18518.51 A. However, the switchgear is designed to handle only 15,300 A. Therefore, we need to fine tune the setting to:

$$V_{\text{set}} = \frac{15,300 \times 2.7}{500} = 82.62 \text{ V}$$

- 1(c). Minimum internal fault current (for $V_{\text{set}} = 100 \text{ V}$ and $I_{\text{pu}} = 1.0 \text{ A}$) is given by

$$I_{f,\text{int,min,pri}} = N(I_{\text{pu}} + nI_o)$$

$$N = 500, I_{\text{pu}} = 1.0 \text{ A} \quad \text{and} \quad n = 6$$

I_o is given as 0.28 mA per volt, therefore, for a voltage of 82.62 V;

$$I_o = (0.28 \text{ mA/V})(82.62 \text{ V}) \text{ mA} = 0.02313 \text{ A}$$

Thus,

$$I_{f,\text{int,min,pri}} = 500 [1 + (6)(0.0231)] = 569.39 \text{ A}$$

- 1(d). For minimum internal fault current of 500 A, the pick-up value should be:

$$\begin{aligned} I_{\text{pu}} &= \left(\frac{I_{f,\text{int,min,pri}}}{N} \right) - nI_o \\ &= \frac{500}{500} - (6)(0.0231) = 0.861 \text{ A} \end{aligned}$$

$$1(e). R_{\text{stabilizing}} + R_{\text{OC relay}} = \frac{V_{\text{set}}}{I_{\text{pu}}} = \frac{82.62 \text{ V}}{0.861 \text{ A}} = 95.93 \Omega$$

$$R_{\text{OC relay}} = 1 \Omega$$

$$R_{\text{stabilizing}} = 94.93 \Omega$$

2. Setting of supervisory relay

Neglecting magnetizing currents of the CTs, we get

$$\begin{aligned} V_{\text{supervisory}} &= \frac{I_{\text{load, lost, CT}}}{N} (R_{\text{stabilizing}} + R_{\text{OC relay}}) \\ &= \left(\frac{25}{500} \right) (95.93) = 4.79 \text{ V} \end{aligned}$$

Review Questions

1. Describe the unique features of a busbar, from the point of view of application of its protection.
2. Maloperation of busbar protection causes large disturbances to the system. Explain.
3. The CT ratio for all the CTs in the busbar differential scheme has to be same and is decided by the feeder carrying maximum current. Explain.
4. Discuss the behaviour of a CT in deep saturation. What are its implications for the busbar differential protection?
5. Why does a busbar differential scheme have a tendency to operate for external faults.
6. How is the value of stabilizing resistance and its wattage decided?
7. In the case of high impedance busbar differential scheme, how will you find out the minimum internal fault current for which the scheme will operate?
8. Define stability ratio and discuss its significance. What is the typical range of values of stability ratio for a high impedance busbar differential scheme?
9. While normal load is being supplied, an open circuit takes place in one of the pilot wires. What will be the consequences as far as the busbar differential relay is concerned?
10. Suggest an add-on to the differential relay, to avert a possible maloperation in the above scenario.
11. Sketch the high impedance busbar differential protection for a three-phase busbar having three incoming and two outgoing feeders.

6

Distance Protection of Transmission Lines

6.1 Drawbacks of Over-current Protection

Over-current protection is very appealing and attractive because of its inherent simplicity. It is used as a primary protection for low voltage (LV) distribution lines. However, it has some major drawbacks which causes it to maloperate. In LV systems, however, maloperation of relays can be tolerated. The only consideration in LV systems is the continuity of supply to the consumers. However, in EHV systems maloperations cannot be tolerated. This is because EHV lines are part of an interconnected grid. Any maloperation on these systems jeopardizes the stability of the electric grid.

The reach of over-current relay depends on the type of fault as well as on the source impedance as shown in Figures 6.1 and 6.2.

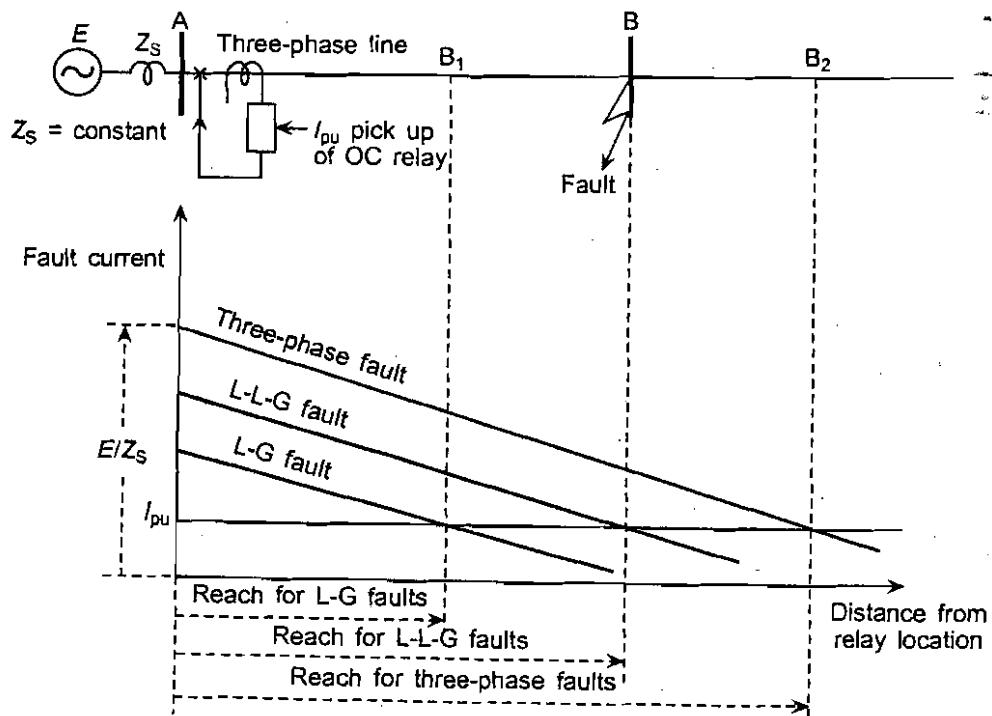


Figure 6.1 Effect of type of fault on reach of over-current relay.

It can be seen from Figure 6.1 that if the OC relay pick-up setting equal to I_{pu} gives a reach up to bus B for L-L-G faults, then the reach for L-G faults is only up to point B_1 whereas the reach for three-phase faults is up to point B_2 . Thus, the relay may under-reach or over-reach depending upon the type of fault. This is clearly not a desirable trait.

Figure 6.2 shows that if the OC relay pick-up setting equal to I_{pu} gives a reach up to bus B, assuming a source impedance of Z_{S2} then it under-reaches to point B_1 if the source impedance increases to Z_{S1} , and over-reaches to point B_2 if the source impedance decreases to Z_{S3} (assuming that the fault type is the same in all the three cases). This, again, is not a desirable feature.

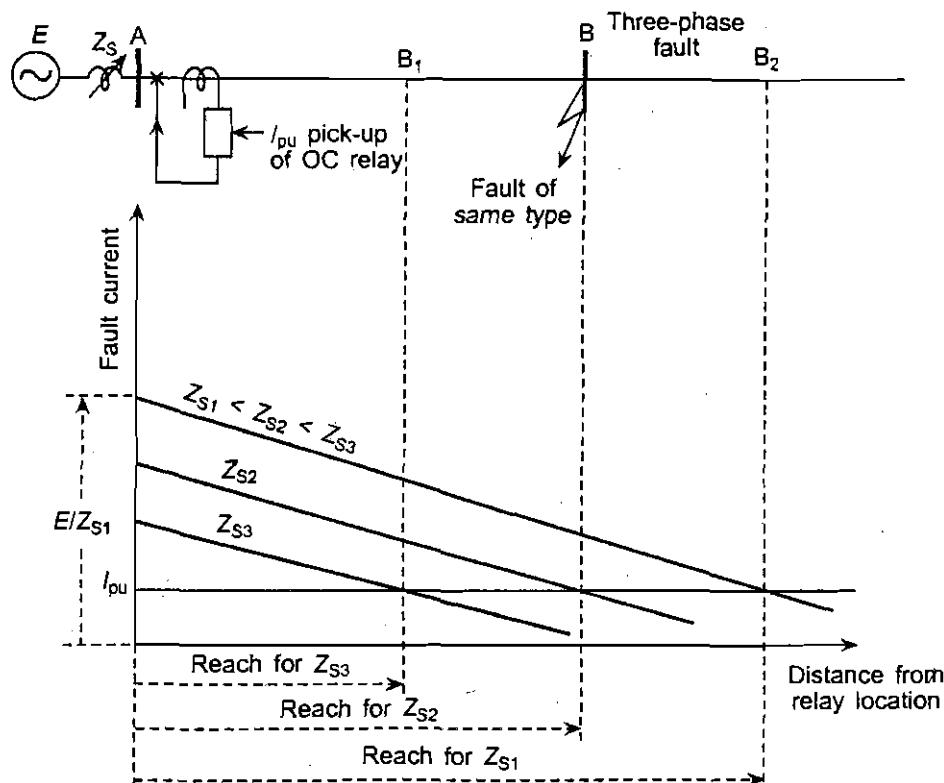


Figure 6.2 Effect of source impedance on reach of over-current relay.

Thus, we see that the fault current is a function of fault type as well as the source impedance, both of which are variable. We must, therefore, look for a relay whose reach does not depend upon the actual magnitude of the fault current. Search for such a relaying principle has led to distance relays, whose reach is not dependent on the actual magnitude of the fault current but on the ratio of voltage at relay location and the fault current. This is discussed in Section 6.2.

6.2 Introduction to Distance Protection

Consider a transmission line AB as shown in Figure 6.3(a). Let us assume that there is source only at end A. We wish to generate a zone of protection which extends from A to

B. Assume that the proposed relay is located at end A, where the local current and voltage are available through a CT and a PT, whose ratios have been assumed as 1 : 1 for the sake of simplicity. The reach of the distance relay is thus made equal to Z_{set} . The line is modelled as a series $R-L$ circuit for the purpose of relaying without much loss of accuracy, as shown in Figure 6.3(b).

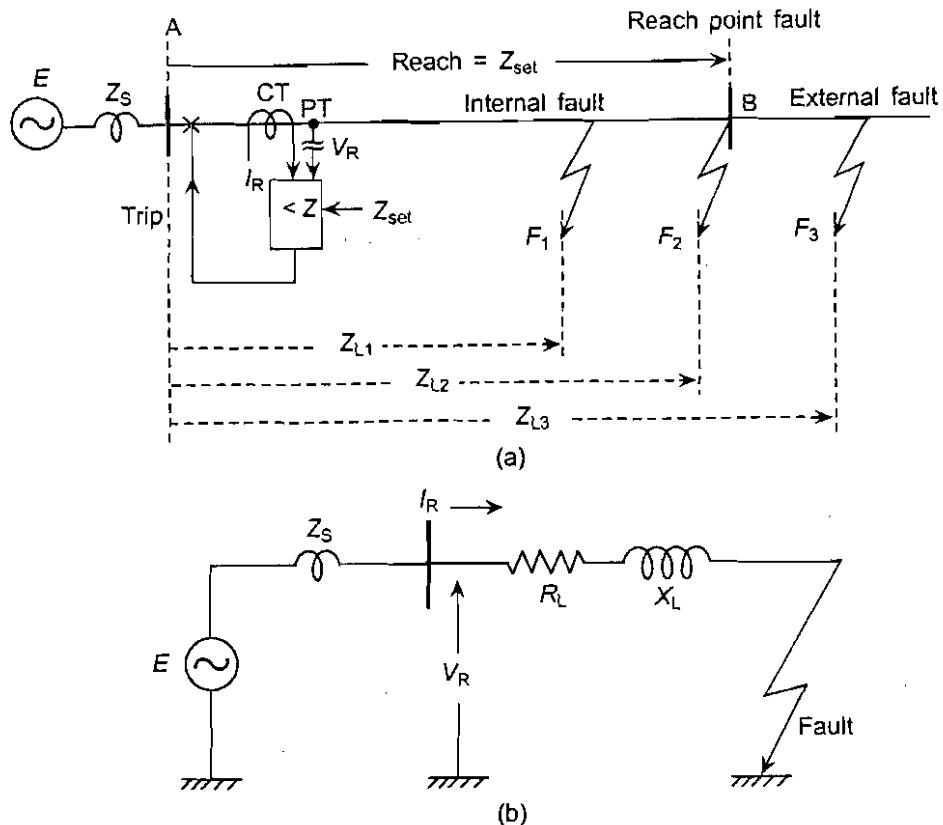


Figure 6.3 Introduction to distance relaying.

Consider three faults: an internal fault F_1 , an external fault F_3 , and a fault at reach point fault F_2 . Now, let us compare the relay voltage V_R with the product of relay current I_R and Z_{set} as shown in Table 6.1 for all the three faults.

Table 6.1 Introduction to distance relays

Fault	Current at relay location, I_R	Voltage at relay location, V_R	Compare $ V_R : I_R Z_{\text{set}} $	Desired response of relay
F_3 , External	I_{R3}	V_{R3}	$ V_{R3} > I_{R3} Z_{\text{set}} $	Restrain
F_2 , Reach point	I_{R2}	V_{R2}	$ V_{R2} = I_{R2} Z_{\text{set}} $	Verge of operation
F_1 , Internal	I_{R1}	V_{R1}	$ V_{R1} < I_{R1} Z_{\text{set}} $	Trip

Thus, we can see from Table 6.1 that the *trip law* that emerges is:

If $|V_R| < |I_R| |Z_{\text{set}}|$ then trip;
else restrain

This can be written as:

If $\frac{|V_R|}{|I_R|} < |Z_{\text{set}}|$ then trip;
else restrain

However, the ratio $|V_R|/|I_R|$ is the magnitude of the apparent impedance $|Z_R|$ as seen by the relay, therefore, the trip law can be written as:

If $|Z_R| < |Z_{\text{set}}|$ then trip;
else restrain

The relay, therefore, somehow, has to compute the impedance as seen from its location and compare it with set value to take the trip decision. Because of the simple series model of the faulted line, the line impedance is directly proportional to the distance to fault. Hence the name *distance relay*. Such a relay is called *under-impedance relay*. In practice, however, the word *under* is dropped and the relay is simply called *impedance relay*. It is possible to synthesize several more complicated distance relays. To distinguish this relay from the other distance relays, we will call it *simple impedance relay*.

It may be noted that we need not actually perform a division of $|V_R|$ by $|I_R|$ to compute $|Z_R|$. We can get around the computation by performing a comparison instead! The readers would appreciate that an arithmetic division is a much more complicated operation than a straight comparison. In fact, till microprocessors became available, it was not possible at all to do any arithmetic computation in a relay. This is indeed one of those engineering solutions, which is very ingenious.

The characteristic of a distance relay on the V - I plane is shown in Figure 6.4. However, it is more instructive to represent this characteristic on the R - X plane. The R (resistance) axis represents the real part of the (V/I) ratio whereas the X (reactance) axis

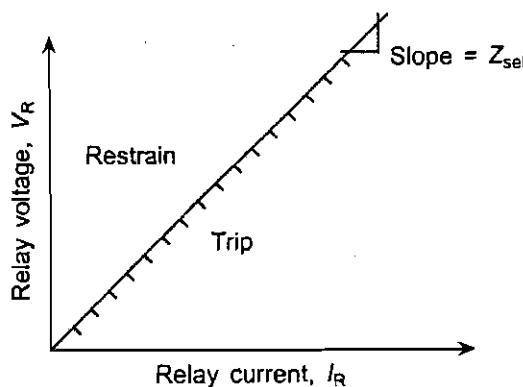
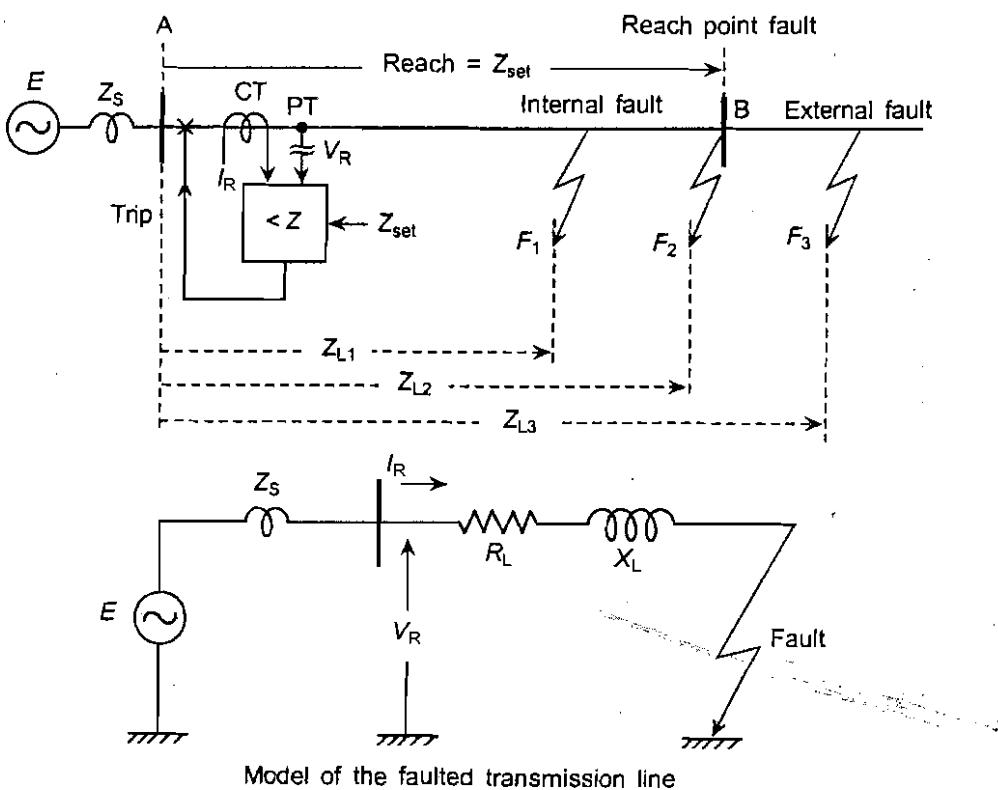


Figure 6.4 Characteristic of simple impedance relay on V - I plane.

represents the imaginary part of the (V/I), both V and I being phasors. This is shown in Figure 6.5 wherein the fault characteristic of the faulted line, for metallic faults, is also superimposed. (Metallic faults are those faults which do not involve appreciable fault resistance.) This is a straight line with a slope equal to the line characteristic angle $\tan^{-1}(\omega L/R)$, where L is the inductance per unit length of the line and R is the resistance per unit length of the line. Thus, a fault anywhere on the transmission line can be

mapped on to this straight line. It is obvious that the tripping characteristic of the distance relay to protect the entire length of the transmission line should actually be a small area on the R - X plane, which snugly encompasses the fault characteristics of the transmission line. Unfortunately, the tripping characteristic of the simple impedance relay encompasses too large an area on the R - X plane than that ideally required. This is an undesirable trait because it gives rise to maloperations of the relay. This is discussed in greater detail in subsequent sections.



Model of the faulted transmission line

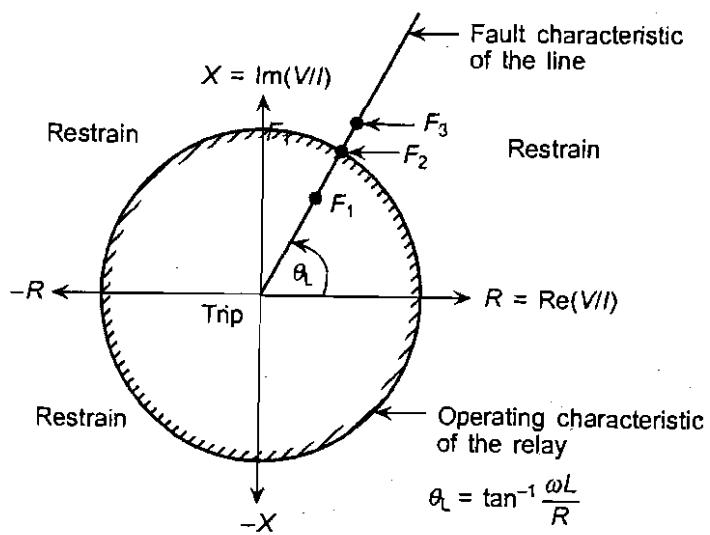


Figure 6.5 Characteristics of simple impedance relay on R - X plane with fault characteristic of the line superimposed.

Further, most of the faults involve an arc. The arc is resistive in nature. The arc resistance is a function of the spark-over distance S in feet, the wind velocity u in mph and time t in seconds and the current I in amperes, as already pointed out in Chapter 1. The arc resistance is given by the well-known Warrington formula:

$$R_{\text{arc}} = \frac{8750(S + 3ut)}{I^{1.4}}$$

When we consider the arc resistance, the fault characteristic of the transmission line gets modified from the straight line with a slope of $\tan^{-1}(\omega L/R)$ to an area as shown in Figure 6.6.

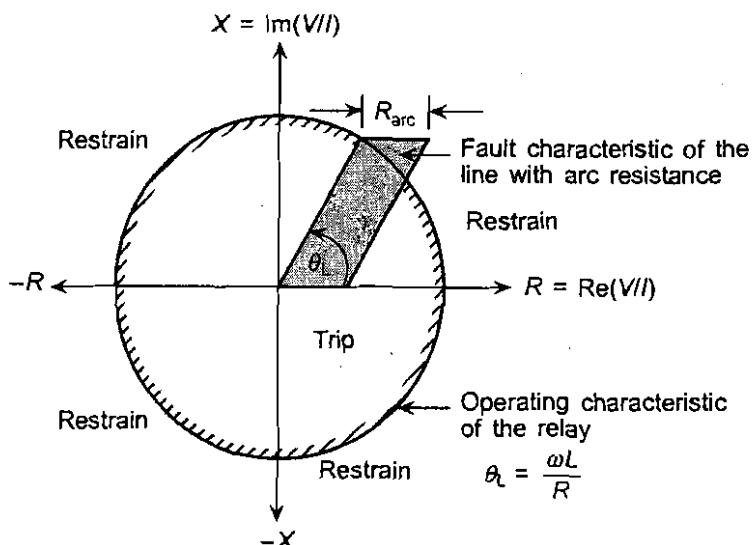


Figure 6.6 Fault characteristic of transmission line with fault resistance.

6.3 Simple Impedance Relay

6.3.1 Trip Law for Simple Impedance Relay Using Universal Torque Equation

It is possible to synthesize many types of relays using the electromechanical structures. We can write a generic torque equation for such a structure where there are torques produced within the relay structure by

- current at relay location
- voltage at relay location
- interaction between the above voltage and current (directional unit).

Individual torques may be made to act in such a way as to close the trip contact or to oppose the closing of the trip contact. The torque which tends to close the trip contact, is called the *operating torque*, and the torque which tends to oppose the closing of the trip contact, is called the *restraining torque*.

Consider the generic torque equation

$$T = k_1|I_R|^2 + k_2|V_R|^2 + k_3|V_R||I_R| \cos(\theta - \tau) + k_4$$

where

T is the net torque on the actuating structure of the relay

$k_1|I_R|^2$ is the torque due to current fed to the relay current coil

$k_2|V_R|^2$ is the torque due to voltage applied to the relay pressure coil

$k_3|V_R||I_R| \cos(\theta - \tau)$ is the torque due to the directional unit

θ is the angle between voltage and current fed to the relay

τ is the maximum torque angle for the directional unit

k_4 is the torque due to spring, which can be neglected compared to the operating torque when the relay is on the verge of operation

Let k_1 be positive, k_2 be negative and k_3 be equal to zero. Therefore, the relay will trip if

$$k_1|I_R|^2 > k_2|V_R|^2$$

which can be written as

$$k_2|V_R|^2 < k_1|I_R|^2$$

Further manipulation leads to

$$\frac{|V_R|^2}{|I_R|^2} < \frac{k_1}{k_2}$$

$$\frac{|V_R|}{|I_R|} < \sqrt{\frac{k_1}{k_2}}$$

Now,

$$\frac{|V_R|}{|I_R|} = |Z_{seen}|$$

where $|Z_{seen}|$ is the magnitude of the impedance seen by the relay.

Further, let $\sqrt{(k_1/k_2)} = |Z_{set}|$ be the impedance setting.

Thus, we can write

$$\text{If } |Z_{seen}| < |Z_{set}| \text{ then trip; else restrain}$$

This is the *trip law* for the so-called *simple impedance relay*. We can, therefore, describe the simple impedance relay as an *over-current relay with voltage restraint*.

6.3.2 Implementation of Simple Impedance Relay Using Balanced Beam Structure

The simple impedance relay can be easily implemented using a *balanced beam structure* as shown in Figure 6.7. It can be seen from the figure that the current coil exerts a torque

on the soft iron armature in such a way that it tends to close the trip contacts. The voltage coil, on the other hand, tends to keep the trip contacts open, thus providing the restraining torque. The control spring keeps the contacts open when the relay is in unenergized condition.

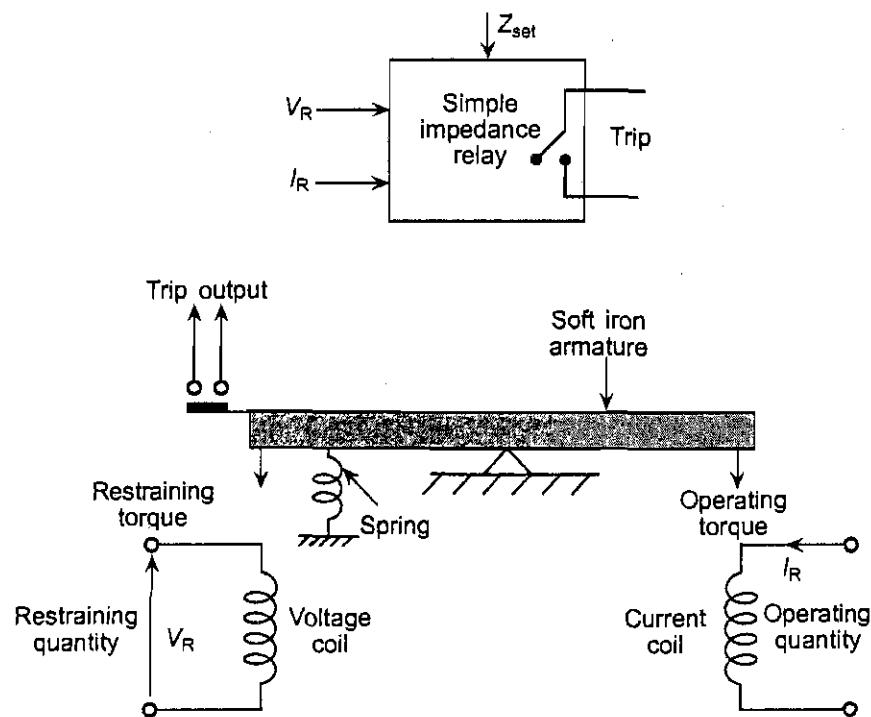


Figure 6.7 Balanced beam construction of simple impedance relay.

The operating torque is proportional to $|I_R|^2$ and the restraining torque is proportional to $|V_R|^2$. Thus, the relay operates if

$$k_1|I_R|^2 > k_2|V_R|^2, \text{ where } k_1 \text{ and } k_2 \text{ are proportionality constants.}$$

or

$$k_2|V_R|^2 < k_1|I_R|^2$$

or

$$\frac{|V_R|^2}{|I_R|^2} < \frac{k_1}{k_2}$$

or

$$\frac{|V_R|}{|I_R|} < \sqrt{\frac{k_1}{k_2}}$$

or

$$Z_{\text{seen}} < Z_{\text{set}}$$

Thus, the balanced beam structure implements the simple impedance relay.

6.3.3 Performance of Simple Impedance Relay During Normal Load Flow

A distance relay is fed with current and voltage at the relay location. Thus, it keeps on monitoring the transmission line all the time, which includes the normal operating conditions when load is being supplied. What is the impedance seen by the relay under such conditions? Does the relay tend to (mal)operate during such normal operating conditions? These are some of the questions which need to be addressed.

The impedance seen by the relay during normal load flow will be as shown in Figure 6.8 for the double-end-fed system. Fortunately, the impedance seen by the relay under such a condition is quite large and falls outside the trip area of the relay operating characteristics. Thus, the simple impedance relay is stable during normal operating conditions.

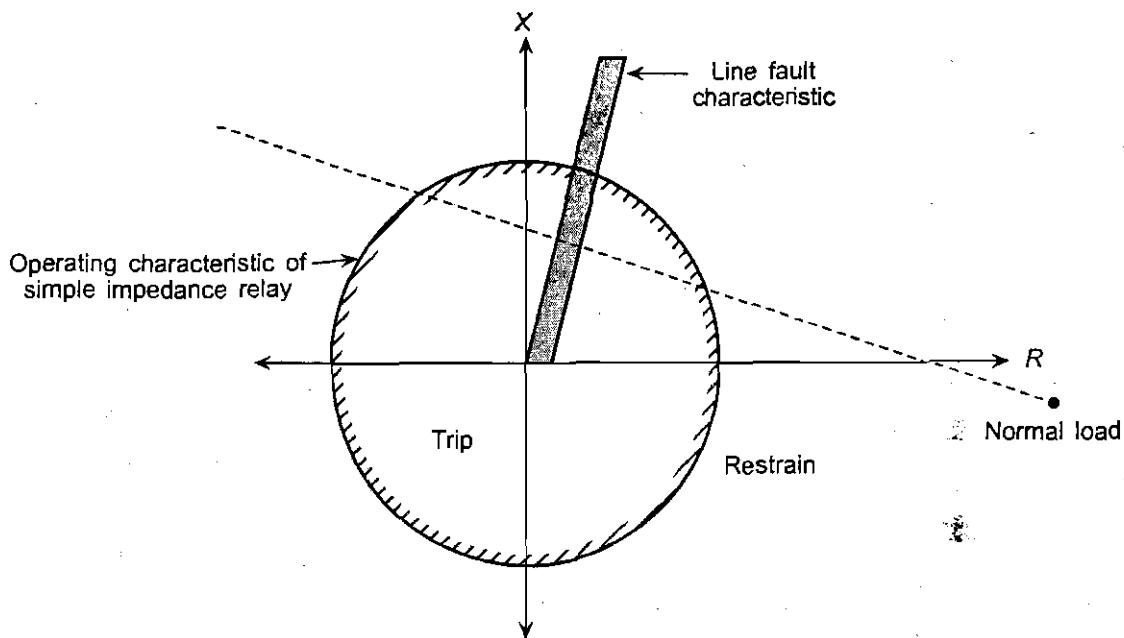


Figure 6.8 Performance of simple impedance relay during normal load flow.

6.3.4 Effect of Arc Resistance on Reach of Simple Impedance Relay

Consider an arcing fault, with a fault resistance of R_{arc} , at point C in the single line diagram of Figure 6.9. The impedance seen by the relay lies on the boundary between the trip and restraining regions, thus any arcing fault just beyond point C will not be detected.

Therefore, the simple impedance relay under-reaches because of an arcing fault. The percentage under-reach is defined as *the ratio of the distance by which the relay under-reaches, to the reach setting of the relay*. With reference to Figure 6.9, the percentage under-reach can be seen to be

$$\frac{BC}{AB} \times 100\%$$

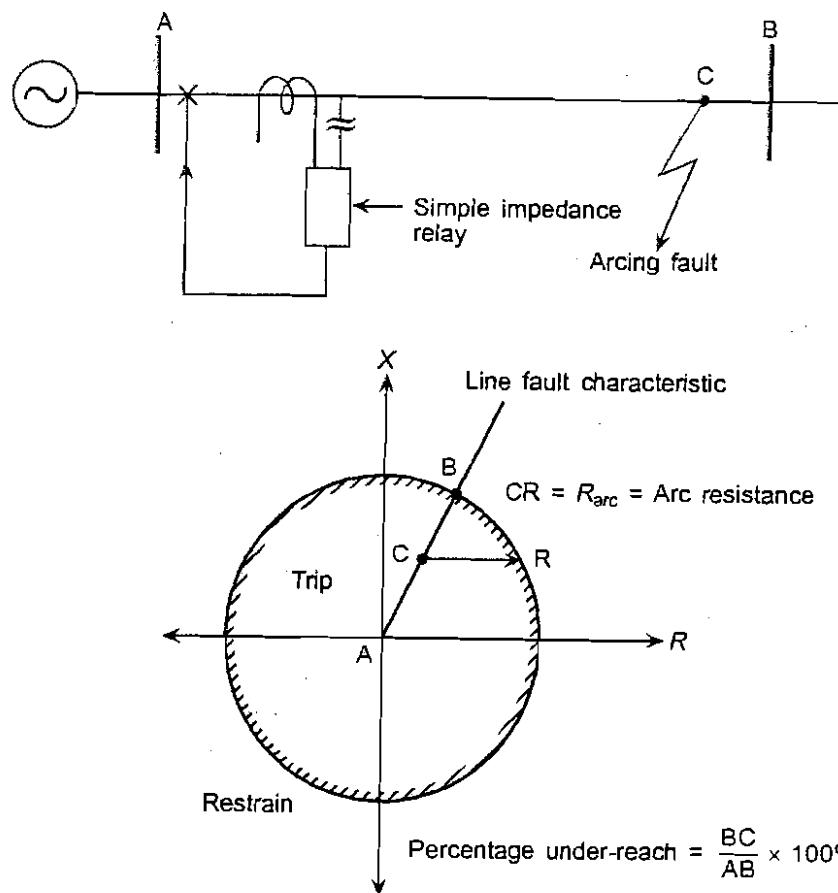


Figure 6.9 Effect of fault resistance on reach of simple impedance relay.

6.3.5 Directional Property Exhibited by Simple Impedance Relay

The reach of the simple impedance relay is independent of the phase angle between voltage and current at the relay location. Thus, the relay does not possess directional property. Its reach would extend equally in the forward as well as the reverse direction. As shown in Figure 6.10, the first quadrant of the R - X plane represents the forward faults whereas the third quadrant represents the reverse faults.

Therefore, the simple impedance relay, by itself, will not be useful in situations where selectivity between the forward and reverse faults has to be maintained. We can, however, supervise it with the help of a directional element and get the desired selectivity.

6.3.6 Performance of Simple Impedance Relay During Power Swing

When a power system is operating in steady state, all the rotor or machine angles are constant. Whenever there are sudden and large changes of power in the system, (say due to outage of a major tie-line), the rotor angles undergo oscillations till the system reaches a new stable state. This phenomenon is known as *power swing*. The frequency of oscillations of the rotor angle during power swing is quite low, of the order of a few hertz, due to large inertias of the rotating masses involved.

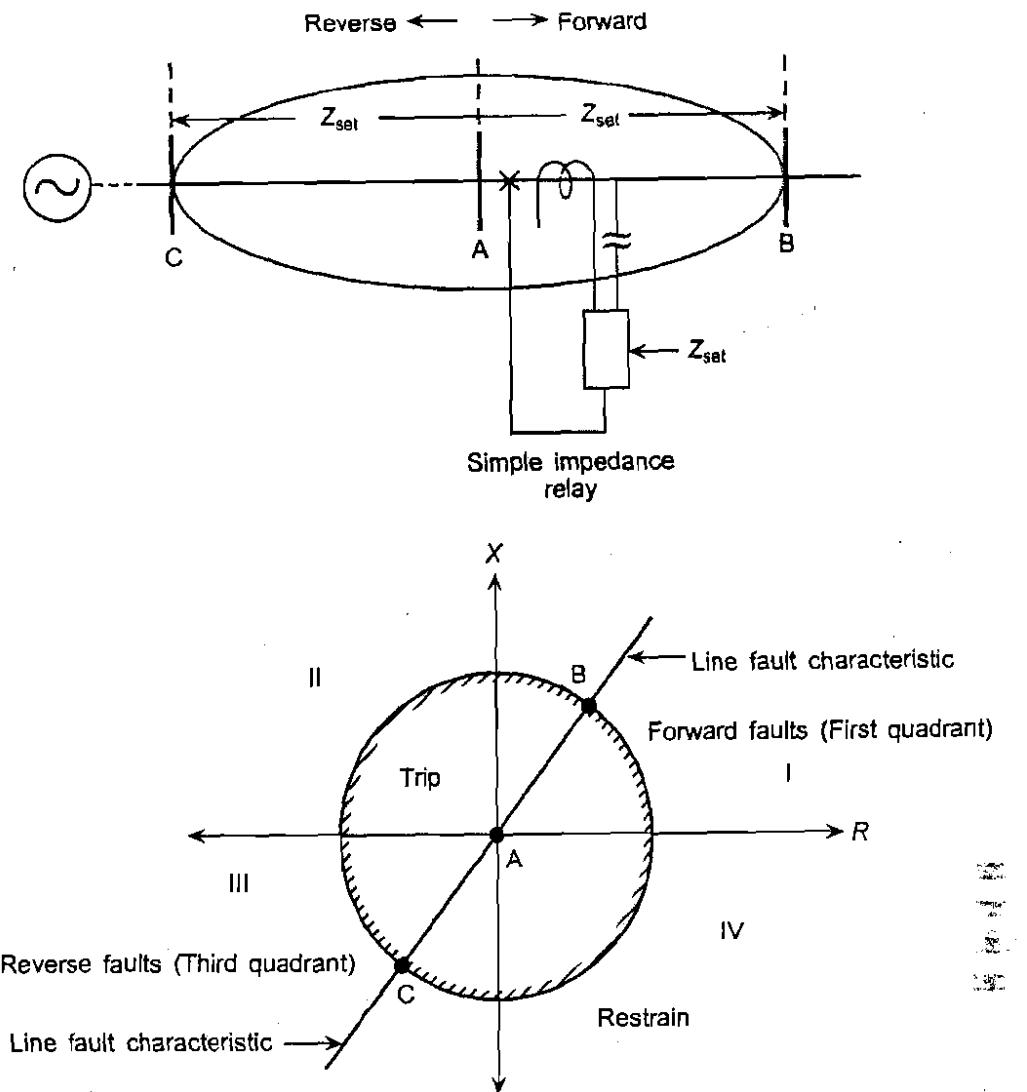


Figure 6.10 Directional property of simple impedance relay.

The impedance seen by the distance relay during power swing is of special interest to the relaying engineer. It can be shown that, during power swing, the locus of the tip of impedance seen by the relay passes, rather slowly, through the electrical centre of the transmission system consisting of the series combination of the source impedance behind the relay location, the transmission line impedance and the impedance of the source at the remote end. This is shown in Figure 6.11.

Thus, at some point during the power swing, the apparent impedance enters the trip region of the relay operating characteristic. Further, when it passes through the electrical centre, it looks as if there is a metallic fault at the electrical centre of the transmission system. This causes the relay to trip, putting the line out of service, adding to the disturbance already present in the system. Therefore, tripping because of power swing has to be more often blocked than unblocked.

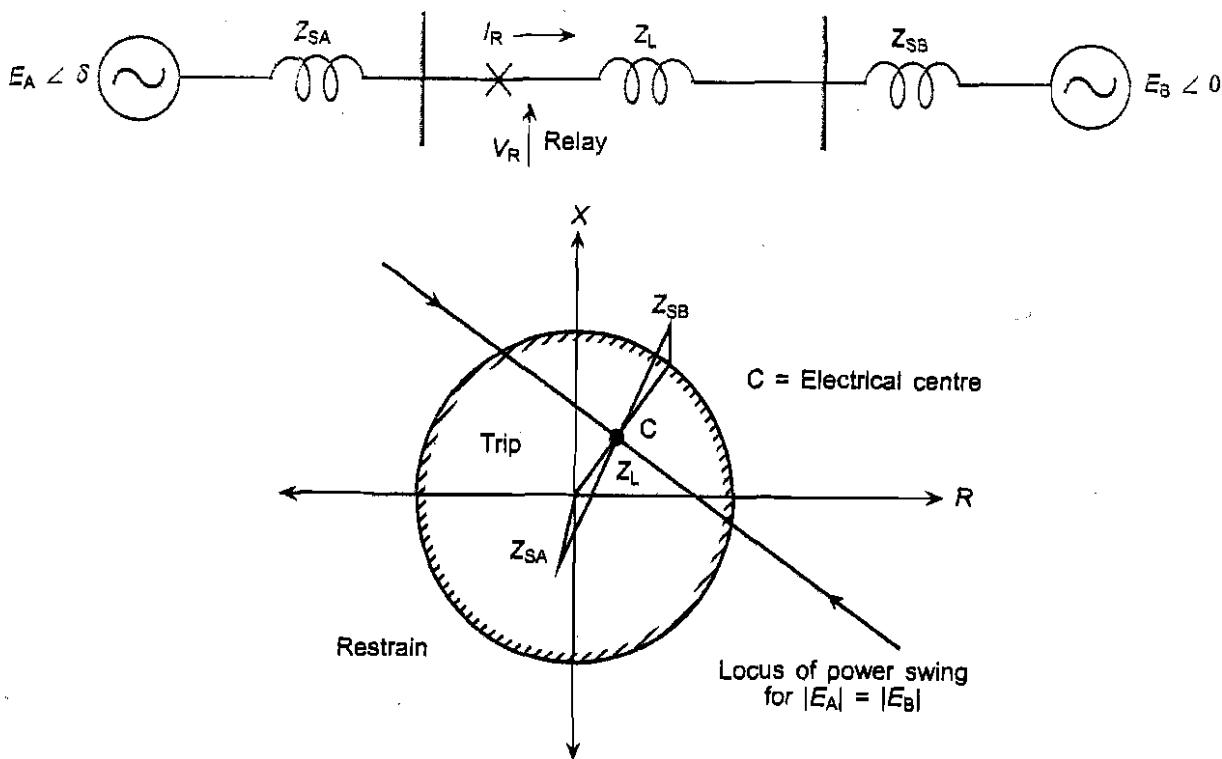


Figure 6.11 Effect of power swing on simple impedance relay.

It may be mentioned here that the larger the area occupied by the relay on the R - X diagram, the more prone it is to maloperation due to power swing. Since the simple impedance relay occupies substantial area in all the four quadrants of the R - X plane, it is very much vulnerable to maloperation on power swing.

6.4 Reactance Relay

6.4.1 Trip Law for Reactance Relay Using Universal Torque Equation

Again consider the universal torque equation:

$$T = k_1|I_R|^2 + k_2|V_R|^2 + k_3|V_R||I_R|\cos(\theta - \tau) + k_4$$

If we set k_2 equal to zero, make k_1 positive (i.e. cause the current to provide tripping torque) and make k_3 negative (i.e. cause the directional torque to oppose tripping), noting that k_4 can be neglected when the relay is on the verge of operation, we get the following trip law:

If $k_1|I_R|^2 > k_3|V_R||I_R|\cos(\theta - \tau)$ then trip; else restrain

which can be written as:

$$k_3|V_R||I_R|\cos(\theta - \tau) < k_1|I_R|^2$$

and can be simplified as:

$$\frac{|V_R||I_R|}{|I_R|^2} \cos(\theta - \tau) < \frac{k_1}{k_3}$$

or

$$\frac{|V_R|}{|I_R|} \cos(\theta - \tau) < \frac{k_1}{k_3}$$

However, $|V_R|/|I_R| = |Z_{\text{seen}}|$, the apparent impedance seen by the relay.

Therefore,

$$|Z_{\text{seen}}| \cos(\theta - \tau) < \frac{k_1}{k_3}$$

If we set the MTA of the directional element to be 90° , and let $(k_1/k_3) = X_n$, we get

$$|Z_{\text{seen}}| \cos(90^\circ) < X_n$$

Since $|Z_{\text{seen}}| \cos(90^\circ) = |Z_{\text{seen}}| \sin \theta = |X_{\text{seen}}|$, which is the reactive part of the impedance seen by the relay, we finally get the trip law as:

If $|X_{\text{seen}}| < |X_n|$ then trip; else restrain

The relay is thus sensitive only to the reactive part of the impedance seen, and trips if the reactive part is less than a particular set value X_n . Hence, such a relay is called a *reactance relay*. The operating characteristic of the relay on the $R-X$ plane is a straight line with intercept of X_n on the reactance axis. The entire area below this straight line represents the trip region. Thus, the area occupied is too large. This is shown in Figure 6.12.

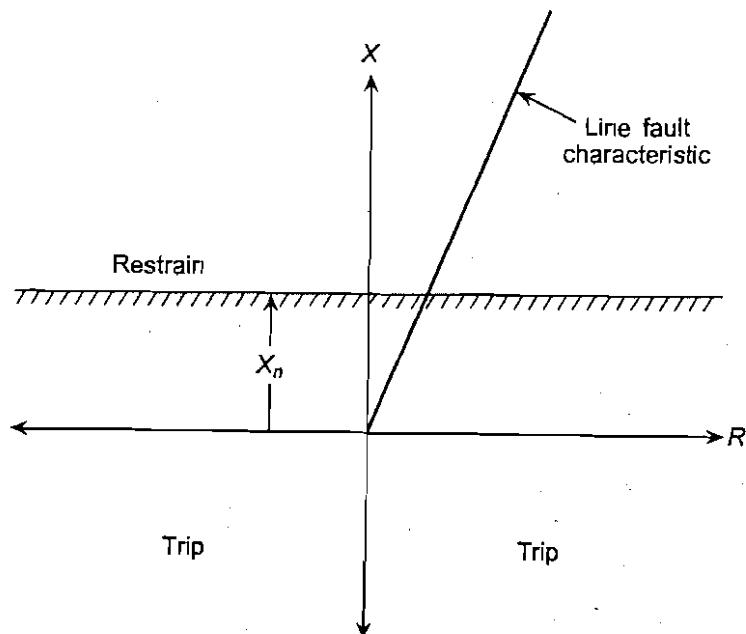


Figure 6.12 Characteristic of reactance relay.

6.4.2 Implementation of Reactance Relay Using the Induction Cup Structure

The implementation of the reactance relay using the four-pole induction cup structure is shown in Figure 6.13.

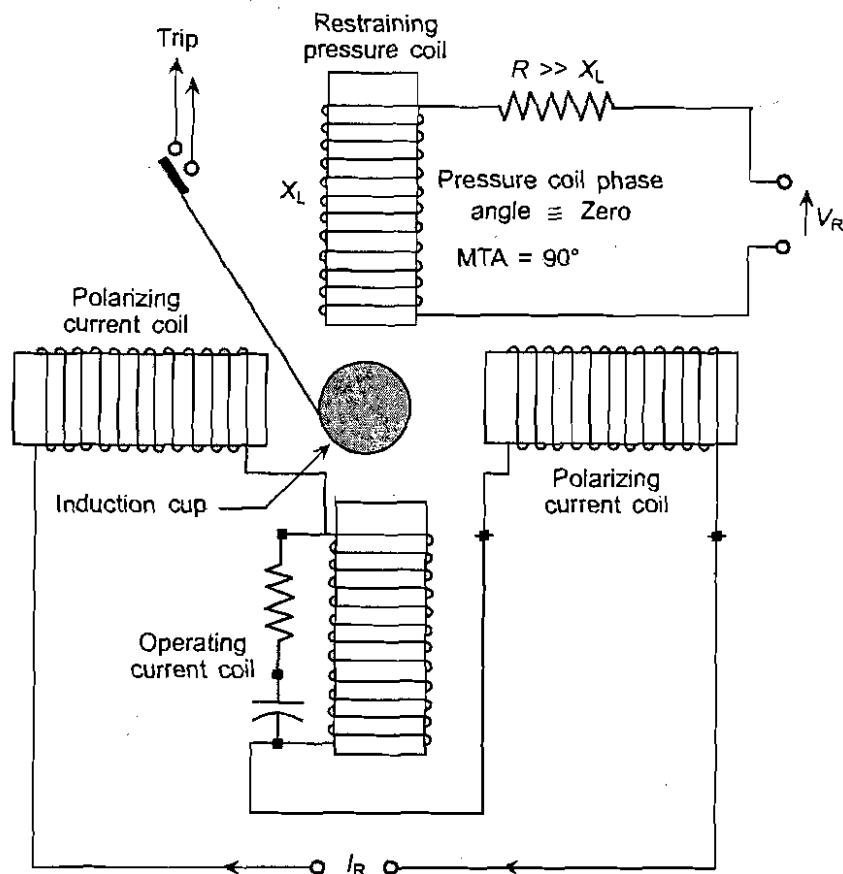


Figure 6.13 Implementation of reactance relay using the four-pole induction cup structure.

The current through one of the coils is shifted in phase so that the torque proportional to I^2 is produced by the interaction of the fluxes created by the two currents. The current through the pressure coil is made to flow nearly in phase with the pressure coil voltage by connecting a resistance whose value is much large compared to the pressure coil inductance. This makes the phase angle of pressure coil nearly equal to zero, making the maximum torque angle τ equal to 90° (since $MTA = 90^\circ - \text{phase angle of pressure coil}$).

The four-pole induction cup structure has a high torque to weight ratio and is, therefore, a very sensitive measuring unit.

6.4.3 Performance of Reactance Relay During Normal Load Flow

The reactance relay occupies all the area below the straight line $X = X_n$ on the R - X plane. The impedance seen by the relay during normal load flow conditions (double-end-fed system) unfortunately falls in the trip region of the reactance relay operating

characteristic as shown in Figure 6.14. Thus, a reactance relay will operate during normal load flow. This is clearly unacceptable. Therefore, the reactance relay cannot be used by itself for protection of the transmission line but needs to be supervised from another relay to prevent its operation on load. A question may arise in the readers' mind at this stage. Why to bother about a relay which cannot even restrain on load? The answer lies in the superior performance of the relay in the face of fault resistance. This is discussed in Section 6.4.4.

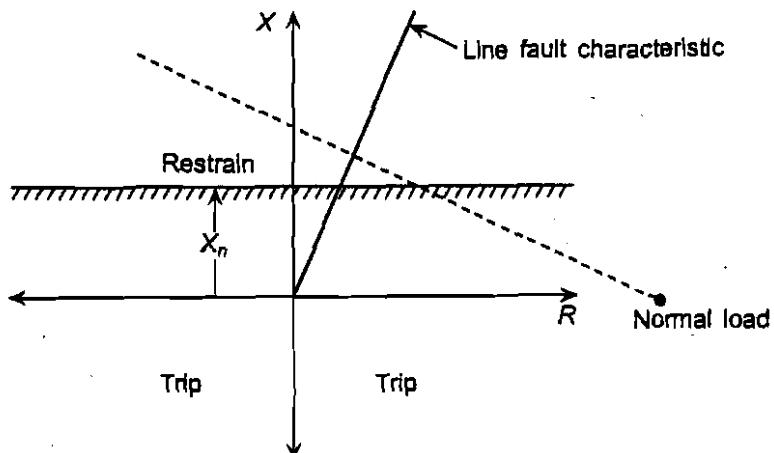


Figure 6.14 Reactance relay operates during normal load flow.

6.4.4 Effect of Arc Resistance on Reach of Reactance Relay

Figure 6.15 shows a line section A-B being protected using a reactance relay. Let there be a fault at the end of the protected line section, at point B, with a resistance equal to B-C. It can be seen that the tip of the impedance seen phasor AC, still remains within the trip region. Thus, the reach of the reactance relay remains unaffected in spite of the presence of arc resistance. This is only to be expected, as the relay measures only the reactive part of the ratio of phasors V and I .

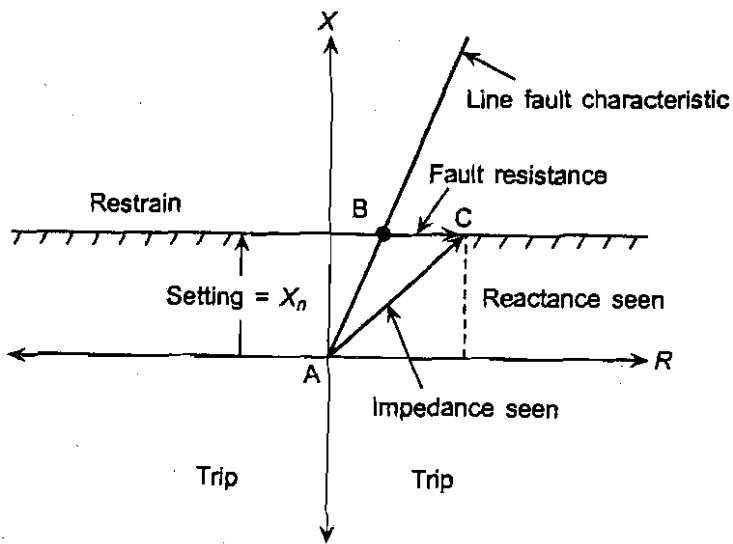


Figure 6.15 Effect of arc resistance on reach of reactance relay.

The ability of the reactance relay to respond correctly in the presence of fault resistance is a very useful trait and accounts for the popularity of the relay, in spite of the fact that it undesirably trips during normal load flow. The reactance relay finds wide applications in fault locators where the exact location of the fault can be found out in the presence of fault resistance.

6.4.5 Directional Property Exhibited by Reactance Relay

As mentioned previously, the first quadrant represents the forward faults whereas the third quadrant represents the reverse faults. Since the trip characteristic of the reactance relay occupies areas in both these quadrants, it does not exhibit any directional property.

Thus a reactance relay which is set to protect the line section AB, as shown in Figure 6.16, in the forward direction also responds in the reverse direction for an unlimited distance. This again, is not a desirable feature. Therefore, we should use the reactance relay in conjunction with a directional relay or another distance relay having the directional feature like the Mho relay.

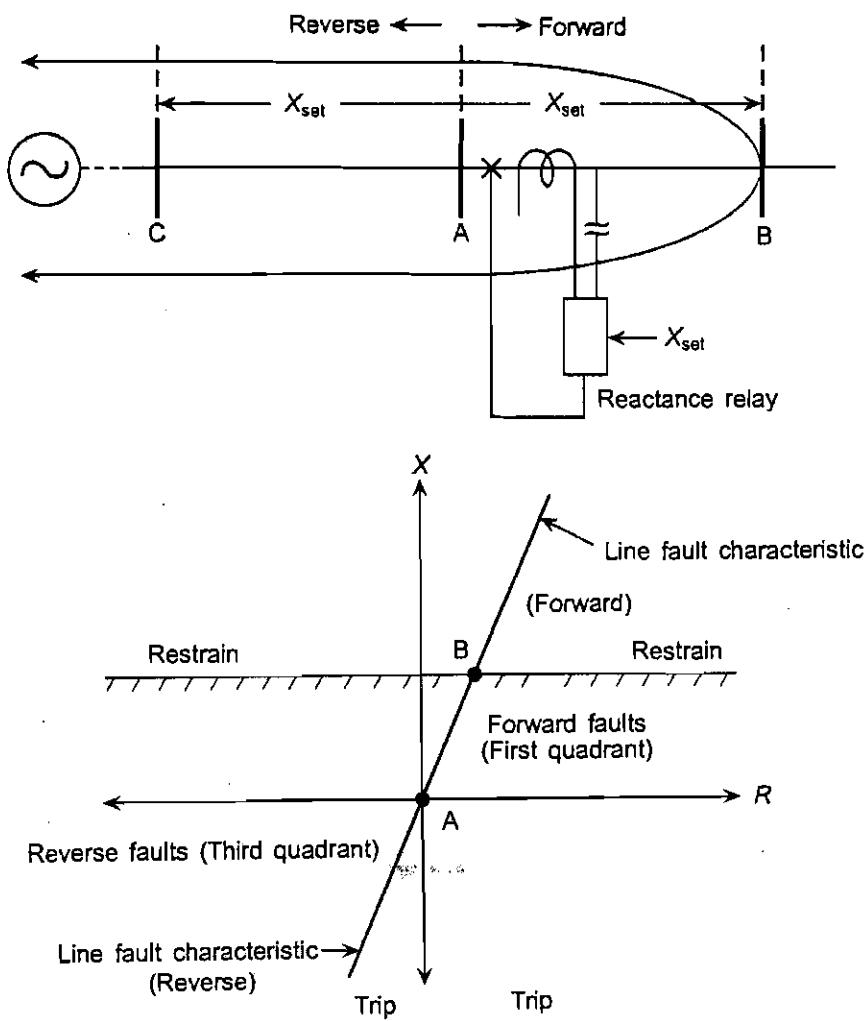


Figure 6.16 Directional property of reactance relay.

6.4.6 Performance of Reactance Relay During Power Swing

The reactance relay occupies such a large area on the R - X plane that it operates even during normal load flow. As shown in Figure 6.17, during power swing, the tip of the impedance-seen phasor approaches the electrical centre of the system. Even before this happens, it is already in the trip region of the reactance relay characteristic. Therefore, the reactance relay operates on power swing as well. Again, this is not a desirable trait.

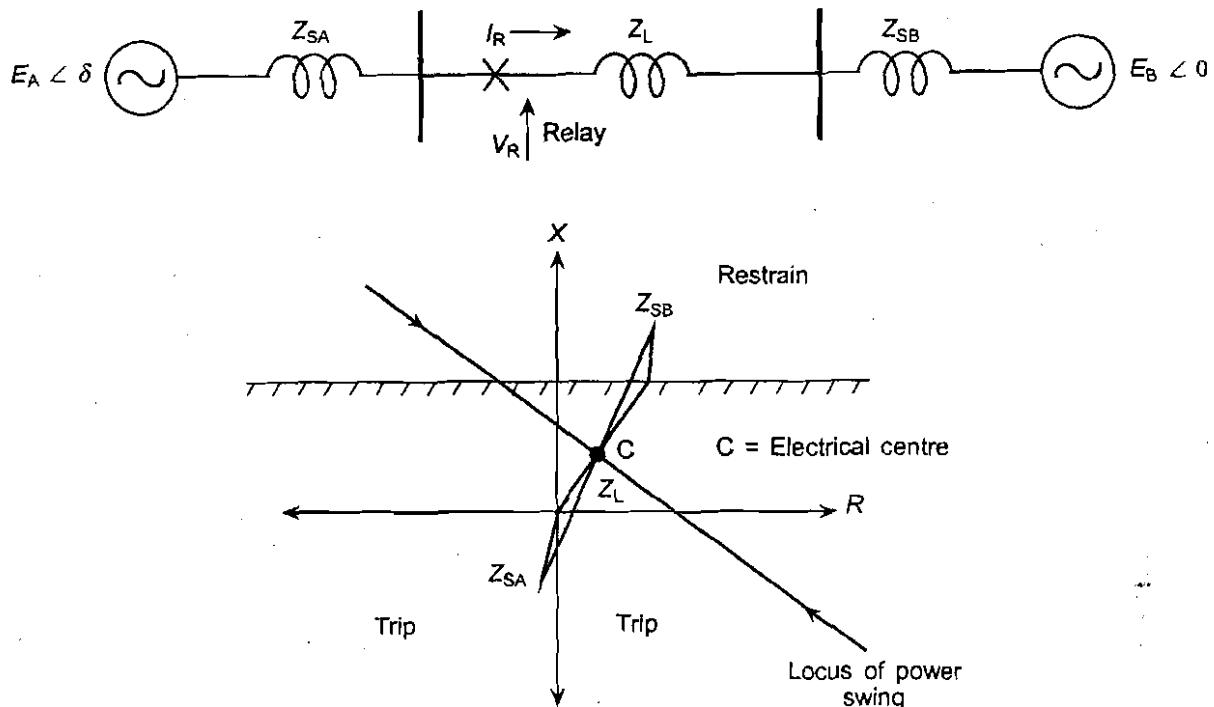


Figure 6.17 Performance of reactance relay during power swing.

6.5 Mho Relay

6.5.1 Trip Law for Mho Relay Using Universal Torque Equation

Once again, consider the universal torque equation:

$$T = k_1 |I_R|^2 + k_2 |V_R|^2 + k_3 |V_R| |I_R| \cos(\theta - \tau) + k_4$$

If we set $k_1 = 0$, make k_2 negative (i.e. make the voltage provide restraining torque) and make k_3 positive (i.e. make the directional element produce tripping torque), since k_4 is negligible compared to the operating and restraining torques, the relay will trip if

$$k_3 |V_R| |I_R| \cos(\theta - \tau) > k_2 |V_R|^2$$

The relay can thus be described as *directional relay with voltage restraint*. The torque equation can be manipulated as

$$k_2 |V_R|^2 < k_3 |V_R| |I_R| \cos(\theta - \tau)$$

or

$$\frac{|V_R|^2}{|V_R||I_R|} < \frac{k_3}{k_2} \cos(\theta - \tau)$$

or

$$\frac{|V_R|}{|I_R|} < \frac{k_3}{k_2} \cos(\theta - \tau)$$

Here $|V_R|/|I_R|$ is the impedance seen by the relay $|Z_{\text{seen}}|$ and we can set the ratio $k_1/k_2 = Z_n$, the setting impedance. Now, the trip law can be written as

If $|Z_{\text{seen}}| < |Z_n| \cos(\theta - \tau)$ then trip; else restrain

where θ is the phase angle between the voltage and current fed to the relay. The relay characteristic is as shown in Figure 6.18.

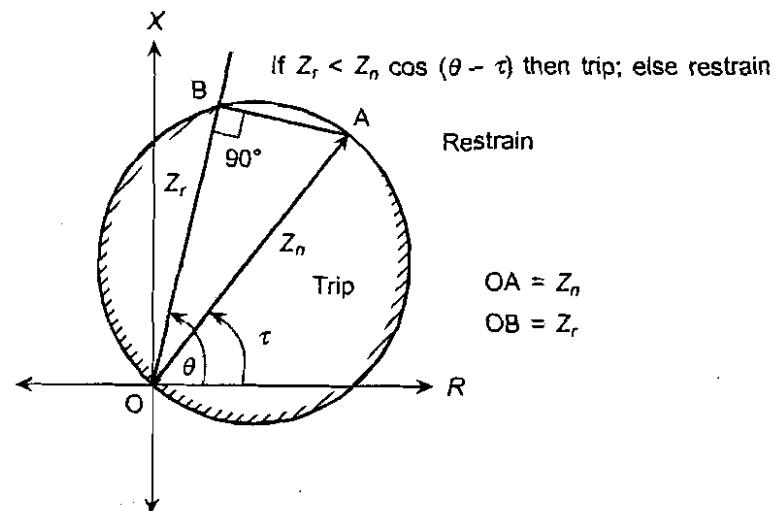


Figure 6.18 Mho relay characteristic.

6.5.2 Implementation of Mho Relay Using Induction Cup Structure

Figure 6.19 shows a four-pole induction cup structure. The flux due to operating voltage coil interacts with the induced current due to the current coil to produce the operating torque proportional to $VI \cos(\theta - \tau)$. The restraining torque is produced because of the fluxes created by the operating and polarizing voltage coils. The resistor R and capacitor C in the voltage coil circuit enable adjustment of MTA to any desired value.

The advantage of the four-pole induction cup structure is its increased sensitivity due to high torque to weight ratio, over the simple induction disc structure.

6.5.3 Performance of Mho Relay During Normal Load Flow

It can be seen from Figure 6.20 that the impedance seen by the relay during normal load (double-end-fed system) is well outside the trip region of the characteristic. Thus, the relay is stable during load conditions.

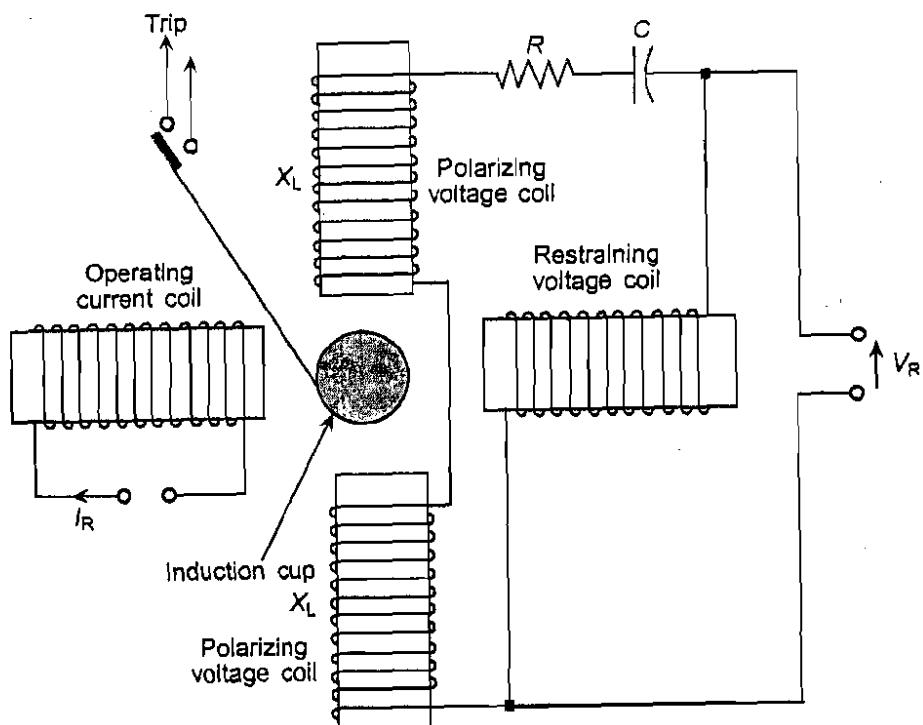


Figure 6.19 Implementation of mho relay using the four-pole induction cup structure.

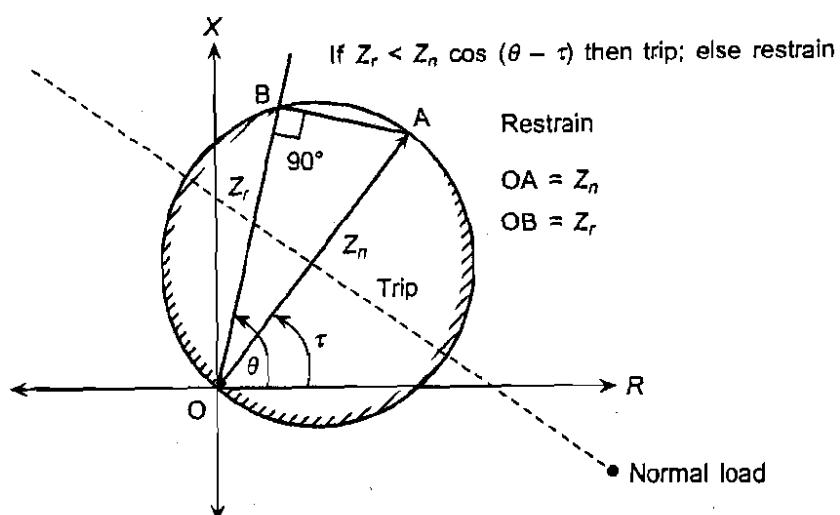


Figure 6.20 Performance of mho relay on load.

6.5.4 Effect of Arc Resistance on Mho Relay Reach

Consider an arcing fault at point B towards the end of the protected line section OA as shown in Figure 6.21. Let the fault resistance be BC. The impedance seen by the relay considering the fault resistance just lies on the verge of the trip region. Any fault beyond point B will cause the relay to restrain. Thus, effectively, the reach of the relay has come down from OA to OB. The absolute under-reach is AB. The percentage under-reach is $(AB/OA) \times 100\%$.

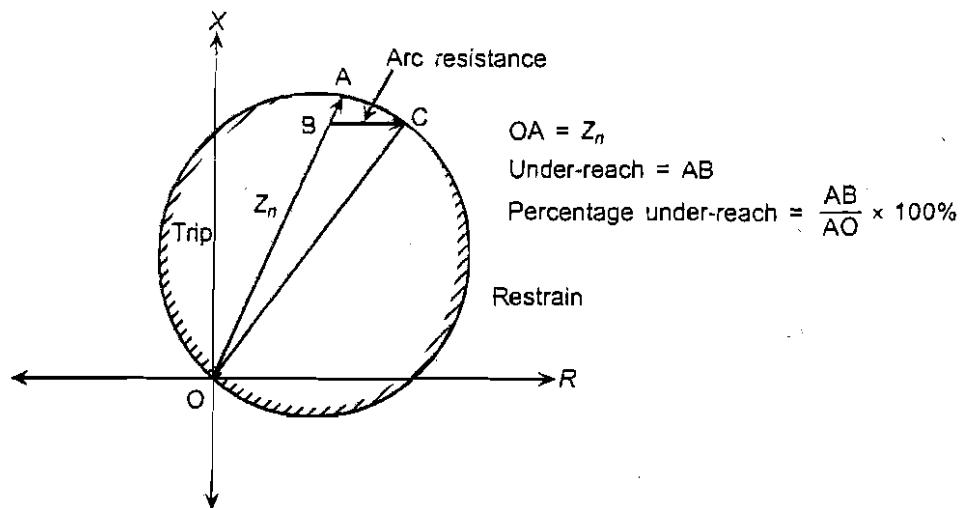


Figure 6.21 Effect of arc resistance on reach of mho relay.

Recall that the simple impedance relay also suffers from under-reach due to fault resistance. If we compare the under-reach of the two relays for the same fault resistance then we find that the percentage under-reach of the mho relay is slightly more than that of the simple impedance relay.

6.5.5 Directional Property Exhibited by Mho Relay

Figure 6.22 shows the characteristic of a directional relay on the R - X plane. It is seen to be a straight line at right angle to the MTA line. The straight line can be considered as a circle with infinite radius. A mho relay is a directional relay with voltage restraint. The addition of voltage restraint to directional relay causes the radius to take a finite value and collapse into the mho circle with diameter equal to Z_n as shown in Figure 6.23. Thus, the mho relay very much possesses the directional property which makes it so useful.

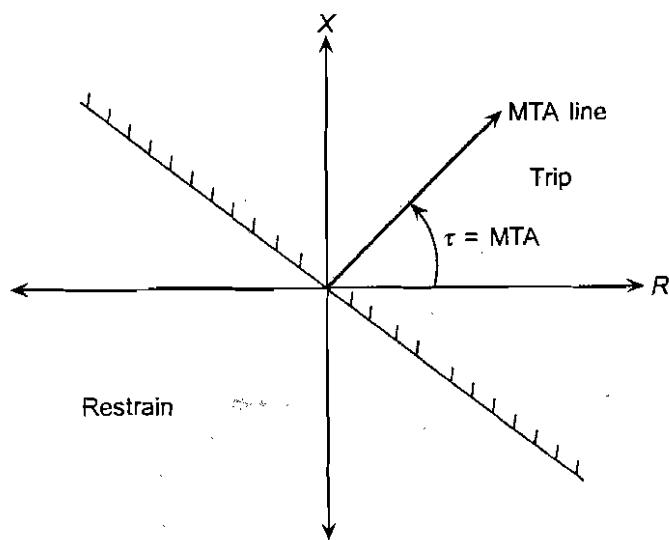


Figure 6.22 Characteristic of directional relay on the R - X plane.

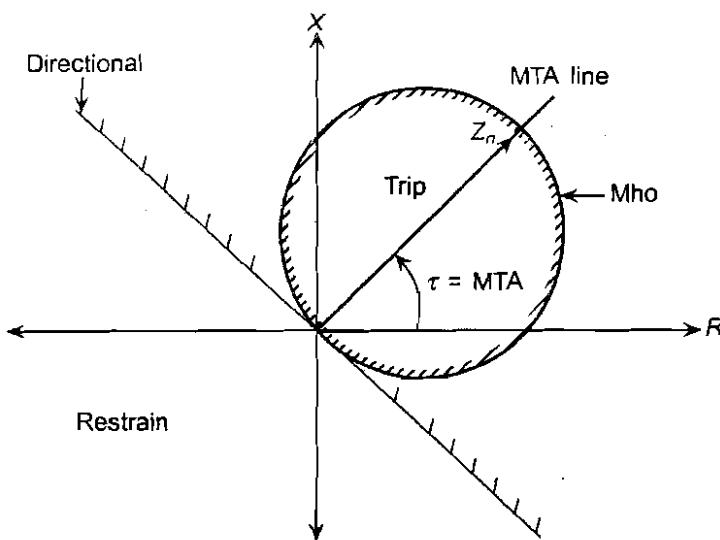


Figure 6.23 Directional property of mho relay.

6.5.6 Performance of Mho Relay During Power Swing

The mho relay occupies a much smaller area on the R - X plane. To that extent, it is less immune to power swing. However, when the swing is very large, the impedance seen enters the mho circle and the relay trips, as shown in Figure 6.24. Special relays known as *blinders* can be used to prevent operation on power swing.

Blocking and tripping schemes are discussed in Appendix B.

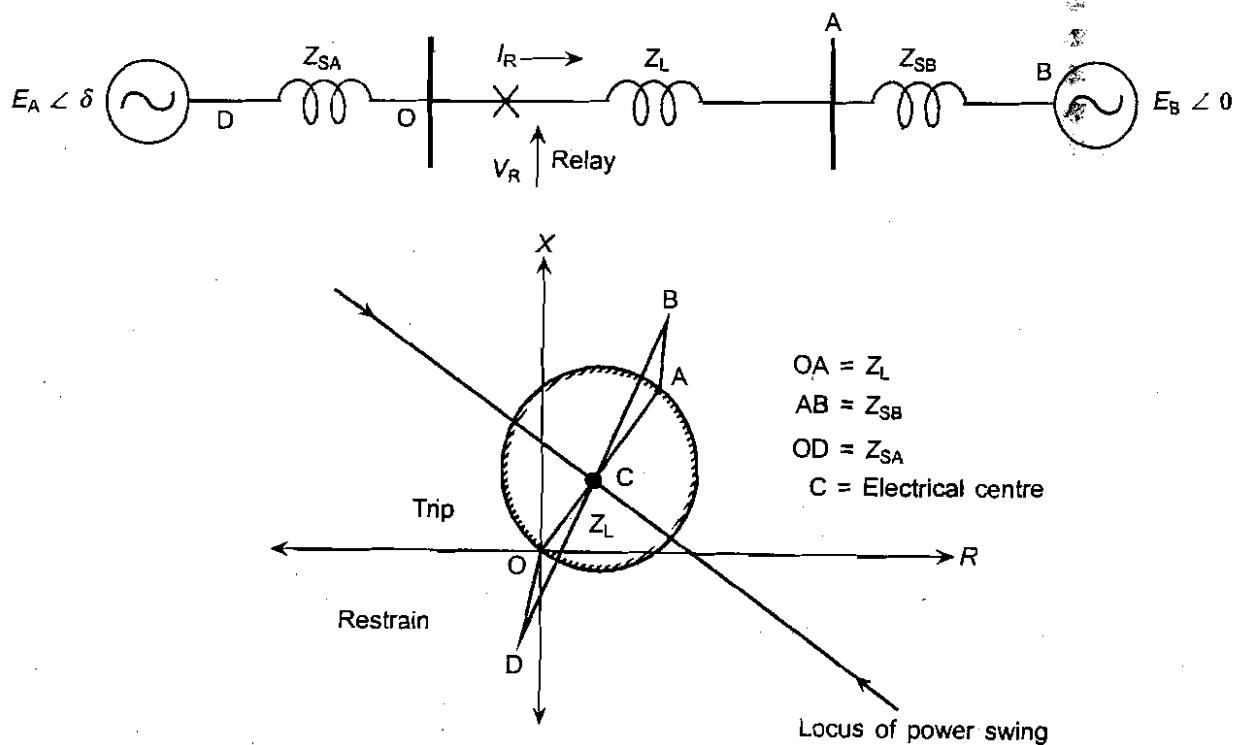


Figure 6.24 Performance of mho relay during power swing.

6.6 Comparison Between Distance Relays

It is instructive to compare the three distance relays as shown in Table 6.2.

Table 6.2 Comparison of distance relays

<i>Simple impedance relay (S.I.R.)</i>	<i>Reactance relay</i>	<i>Mho relay</i>
<i>Operating quantity</i>	Current	Current
<i>Restraining quantity</i>	Voltage	Directional element, MTA = 90°
<i>Directional property</i>	No	No
<i>Performance on load</i>	Restrains	Trips
<i>Effect of fault resistance</i>	Under-reaches	Reach unaffected
<i>Area occupied on the R-X plane</i>	Moderate	Very large
<i>Effect of power swing</i>	Maloperates	Maloperates, though effect is less than S.I.R.

We can see from Table 6.2 that it is not possible to use the reactance relay for transmission line protection on a standalone basis. It has to be used in conjunction with a directional or a mho element. The mho relay is much better on most of the counts. One remarkable property of reactance relay is its immunity to fault resistance. However, it lacks stability on load and does not have directional property. Considering pros and cons, the mho relay is found to be a much better fit for long lines which are likely to be subjected to frequent power swings, whereas the reactance relay (in conjunction with mho) is preferred for short lines.

6.7 Distance Protection of a Three-phase Line

Up till now we have been tacitly assuming the transmission line to be a single-phase line. However, in practice, transmission lines are always three-phase in nature. A three-phase line is subject to phase faults as well as ground faults. The questions that naturally arise are:

1. How are we going to provide protection against all the ten shunt faults?
2. In what way the CT currents and PT voltage will have to be processed?
3. Can a single distance measurement unit look after all the phase faults as well as ground faults? If no, how many distance measurement units will be required for catering to all the ten shunt faults?
4. What will be the setting of the distance measuring units?
5. Whether to measure positive sequence impedance or negative sequence impedance or zero sequence impedance? See Figure 6.25.

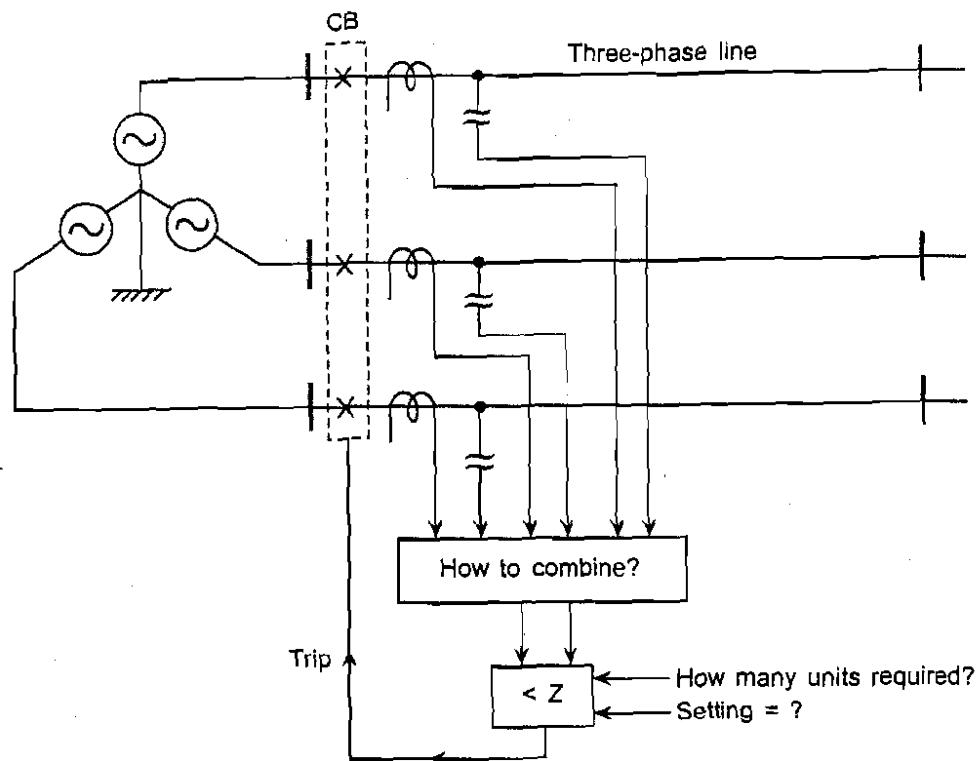


Figure 6.25 The problem of providing distance protection to a three-phase line.

It turns out that we have to provide separate protection for phase faults and ground faults. Phase faults associated with one pair of phases are catered to by a single distance-measuring unit. Thus, three numbers of phase fault-measuring units can cater for all the seven-phase faults, namely, $a-b$, $a-b-g$, $b-c$, $b-c-g$, $c-a$, $c-a-g$, $a-b-c$.

Each of the three ground faults are catered to by a separate ground fault-measuring distance unit. Thus, three numbers of ground fault-measuring units can cater for all the three ground faults.

Therefore, a total of six numbers of measuring units are required for protection against all the ten shunt faults.

Table 6.3 lists the presence of sequence components, in voltage and current, during various faults wherein it can be seen that positive sequence component is the only component which is present during all faults. Thus, it would be prudent to measure positive sequence impedance between the relay location and the fault so as to cater for every fault.

Table 6.3 Presence of sequence components in various faults

Fault	Positive sequence	Negative sequence	Zero sequence
L-G	Yes	Yes	Yes
L-L	Yes	Yes	No
L-L-G	Yes	Yes	Yes
L-L-L	Yes	No	No

6.7.1 Phase Faults

Let us consider a phase b to phase c fault as shown in Figure 6.26. What combination of voltage and current when fed to a distance-measuring unit will measure the positive sequence impedance between the relay location and the fault point?

This question can be answered if we analyze the problem with the help of symmetrical components. A phase-to-phase fault can be represented by a parallel combination of the positive and negative sequence networks at the fault point. The zero-sequence network remains open circuited as shown in Figure 6.26.

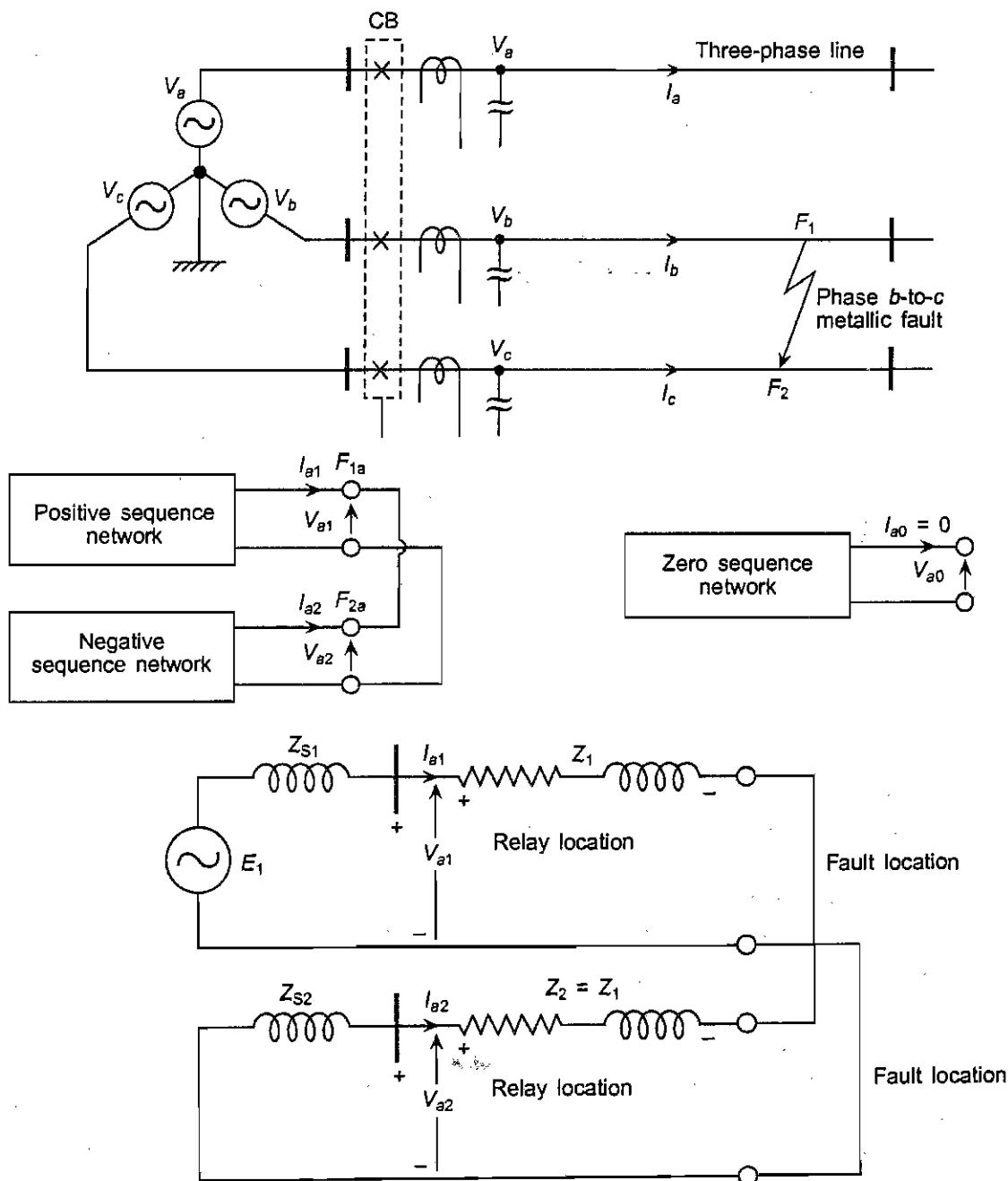


Figure 6.26 Phase a sequence network connection for b - c phase fault.

Writing KVL around the loop in Figure 6.26, we get

$$V_{a1} - I_{a1}Z_1 + I_{a2}Z_1 - V_{a2} = 0$$

or

$$V_{a1} - V_{a2} = (I_{a1} - I_{a2}) Z_1$$

or

$$\frac{V_{a1} - V_{a2}}{I_{a1} - I_{a2}} = Z_1$$

Thus, the ratio of difference of positive and negative sequence voltages and currents gives the desired value of positive sequence impedance between the relay location and the fault point. However, the sequence components of voltage and current are not readily available at the relay location. Instead, the line voltages and currents are readily available. Let us see if we can manipulate the line voltages and currents to get the desired sequence components.

We have

$$V_a = V_{a0} + V_{a1} + V_{a2}$$

$$V_b = V_{a0} + a^2 V_{a1} + a V_{a2}$$

$$V_c = V_{a0} + a V_{a1} + a^2 V_{a2}$$

from which we get

$$\begin{aligned} V_b - V_c &= (a^2 - a)V_{a1} + (a - a^2)V_{a2} \\ &= (a^2 - a)V_{a1} - (a^2 - a)V_{a2} \\ &= (a^2 - a)(V_{a1} - V_{a2}) \end{aligned}$$

Therefore,

$$V_{a1} - V_{a2} = \frac{V_b - V_c}{a^2 - a}$$

Similarly it can be proved that

$$I_{a1} - I_{a2} = \frac{I_b - I_c}{a^2 - a}$$

Therefore,

$$\frac{V_{a1} - V_{a2}}{I_{a1} - I_{a2}} = \frac{V_b - V_c}{I_b - I_c} = Z_1$$

Thus, a distance measuring unit with voltage of ($V_b - V_c = V_{bc}$) and current of ($I_b - I_c$) will measure positive sequence impedance up to fault point Z_1 , in case of phase b-to-c faults. Similarly, we shall need two more units with inputs of V_{ab} , ($I_a - I_b$) and V_{ca} , ($I_c - I_a$) to cater for phase a-to-b and phase c-to-a faults. The distance measuring units which cater for phase a-b, b-c and c-a faults are called *phase fault units*.

6.7.2 Ground Faults

A ground fault is represented by series connection of the positive, negative and the zero sequence equivalent circuit. See Figure 6.27.

Applying KVL around the loop formed by the series connection of the three sequence networks, we get

$$V_{a0} + V_{a1} + V_{a2} = I_{a1}Z_1 + I_{a2}Z_1 + I_{a0}Z_0$$

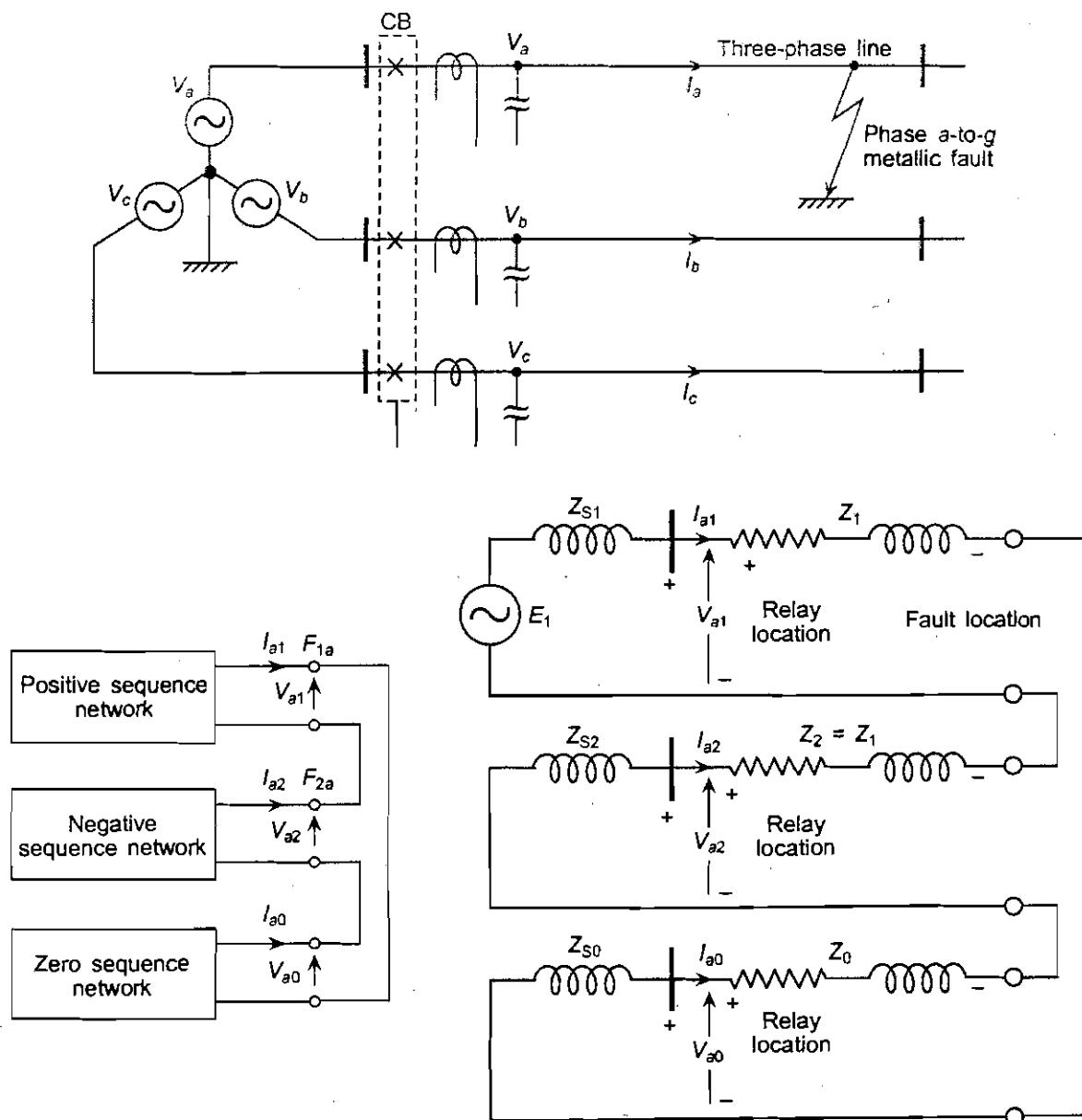


Figure 6.27 Phase a sequence network connections for a - g fault.

However, noting that $V_{a0} + V_{a1} + V_{a2} = V_a$ and adding and subtracting $(I_{a0}Z_1)$ on the right-hand side, we get

$$\begin{aligned} V_a &= I_{a1}Z_1 + I_{a2}Z_1 + I_{a0}Z_1 - I_{a0}Z_1 + I_{a0}Z_0 \\ &= (I_{a1} + I_{a2} + I_{a0})Z_1 + (Z_0 - Z_1)I_{a0} \\ &= I_aZ_1 + (Z_0 - Z_1)I_{a0} \end{aligned}$$

or

$$V_a = \left(I_a + \frac{Z_0 - Z_1}{Z_1} I_{a0} \right) Z_1$$

However,

$$I_{a0} = \frac{I_a + I_b + I_c}{3}. \text{ Let us also write: } I_a + I_b + I_c = I_{\text{res}}$$

Therefore, we have

$$I_{a0} = \frac{I_{\text{res}}}{3}, \text{ where } I_{\text{res}} \text{ is the residual current.}$$

Hence,

$$V_a = \left(I_a + \frac{Z_0 - Z_1}{3Z_1} I_{\text{res}} \right) Z_1$$

Finally, we get the desired impedance as the ratio of:

$$Z_1 = \frac{V_a}{I_a + \frac{Z_0 - Z_1}{3Z_1} I_{\text{res}}}$$

In the above equation Z_1 appears on both sides and the expression appears a bit mixed up. However, in actual practice, there is a definite relationship between Z_0 and Z_1 . For three-phase transmission lines Z_0 is 2.5 to 3 times Z_1 . The exact relationship depends upon the geometry of the phase conductors and the placement of earth conductors. Let us assume that $Z_0 = 3Z_1$. Then, the above equation simplifies to:

$$\begin{aligned} Z_1 &= \frac{V_a}{I_a + \frac{2}{3} I_{\text{res}}} \\ &= \frac{V_a}{I_a + K I_{\text{res}}}; \text{ where } K = \frac{Z_0 - Z_1}{3Z_1} \end{aligned}$$

Thus, the phase current has to be compensated with a fraction of the residual current I_{res} . The factor K is known as *the residual current compensation factor* or *zero-sequence current compensation factor*.

Therefore, three numbers of distance measuring units with inputs of

$$[V_a, (I_a + K I_{\text{res}})], [V_b, (I_b + K I_{\text{res}})], \text{ and } [V_c, (I_c + K I_{\text{res}})]$$

will be needed for catering to all the three single line to ground faults. These units will be called *ground fault units*.

6.7.3 Complete Protection of a Three-phase Line

Further it can be shown that the phase fault units also cater for corresponding double line-to-ground faults (L-L-G faults). In the case of a balanced three-phase fault, again, all the phase fault units respond. The proof of this is left to the reader.

Thus, in all, six distance measuring units each set at Z_1 , the positive-sequence impedance of the line section, are sufficient for complete protection against all the ten shunt faults, as shown in Figure 6.28.

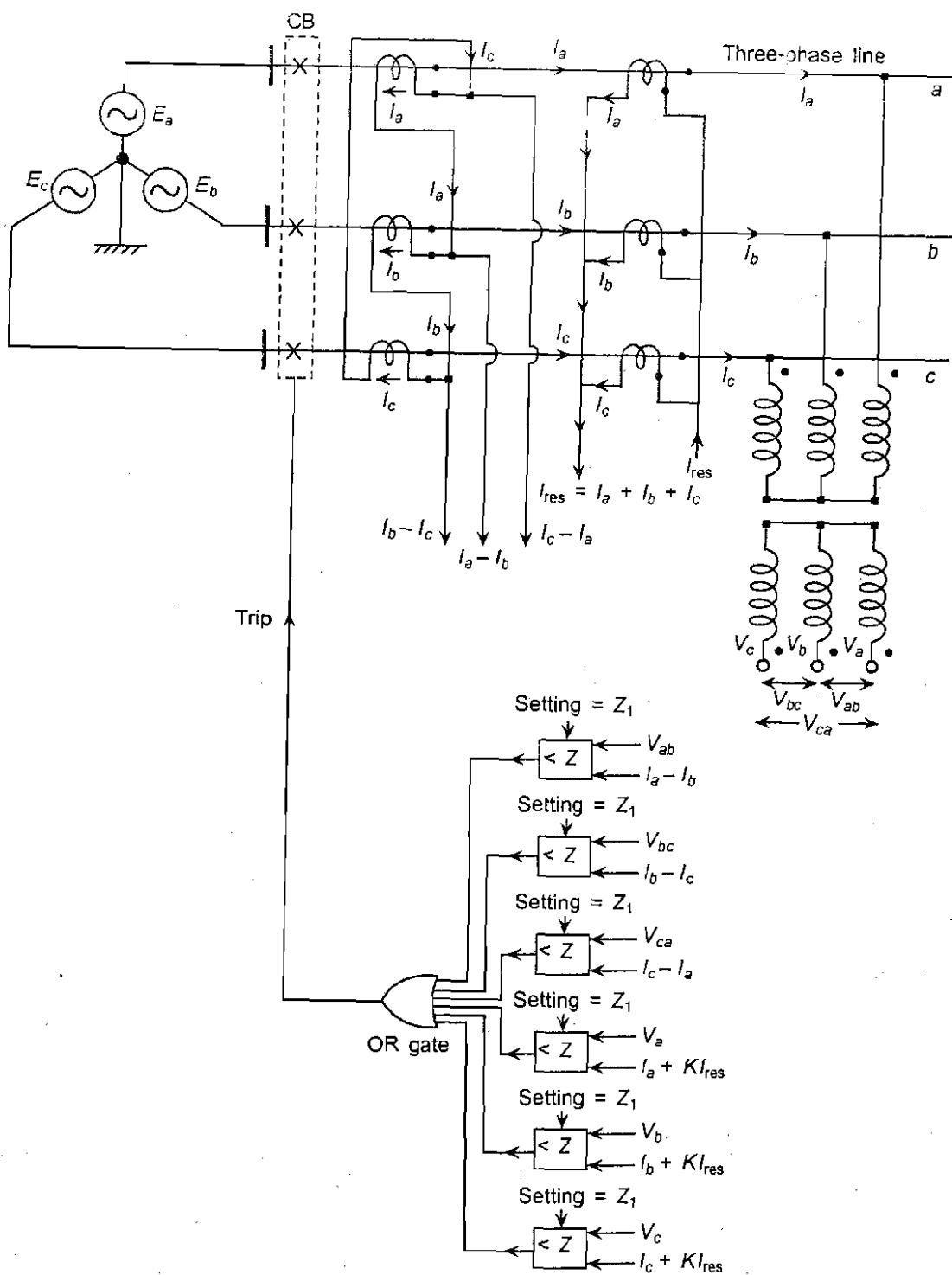


Figure 6.28 Complete protection of a three-phase line.

6.8 Reasons for Inaccuracy of Distance Relay Reach

Ideally we would have liked to set the reach of the distance relay to 100% of the line section. However, it is not possible to get the exact reach of 100% in practice. There is

always certain amount of uncertainty and ambiguity about the actual reach. Various contributing factors for this ambiguity in reach are:

- Inaccuracy in CT and PT ratios.
- Ambiguity about line parameters (line parameters are seldom measured, they are calculated from line data).
- Variation of line parameters with atmospheric conditions.
- DC offset in fault current.
- Transient response of capacitive voltage transformers (CVT).

Out of these factors DC offset and CVT transient response cause over-reach. Other factors may cause error on either side. Thus, there is always a possibility of over-reach. If the reach of distance relay is adjusted to 100% then over-reach will cause loss of selectivity with the distance protection of the next section. This cannot be tolerated in the case of EHV lines. Thus, it is a usual practice to set the reach of distance protection to about 80 to 90% of the line section. This leaves 20% to 10% of line without primary protection. Therefore, a comprehensive scheme of distance protection has evolved, providing primary protection to the line section under consideration as well as back-up to the next line section. This is discussed in Section 6.9.

6.9 Three-stepped Distance Protection

6.9.1 First Step

As discussed in Section 6.8, it is not advisable to set the reach of distance protection to 100%. The first step of distance protection is, therefore, set to reach up to 80 to 90% of the length of the line section. This is an instantaneous protection, i.e. there is no intentional time delay.

6.9.2 Second Step

The second step is required in order to provide primary protection to the remaining 10% of the line, which is left out of the first step. In addition, it is set to cover up to 50% of the next line section. The motivation behind this extended reach is: (i) it should provide some back-up to the next line section including the bus; (ii) in the event of maximum under-reach it should still be able to cover the bus faults at the bus between the two lines. The operating time of this step has to be delayed so as to be selective with step I. Thus:

Operating time of step II = Operating time of step I + Selective time interval
where

$$\text{Selective time interval} = \text{CB operating time} + \text{Relay over-travel time}$$

When there are more than one adjoining lines, the second step should extend up to 50% into the shortest adjoining line. If it is set to reach up to 50% of longest adjoining line, as shown in Figure 6.29(d), then there is a loss of selectivity with second step of

shortest adjoining line. In Figure 6.29(d) faults in the region between points D_1 and D_2 are in the second step of primary protection at bus B, provided by relay R_B , as well as in the second step of relay R_A at bus A. Therefore, there is loss of selectivity between second steps of distance relays R_A and R_B . Hence the second step of the distance relay is set to reach up to 50% into the shortest adjoining line.

6.9.3 Third Step

The third step is provided with an intention to give full back-up to the adjoining line section. It covers the line section under consideration, 100% of the next line section and reaches further into the system. The motivation behind the extended reach of this step is to give full back-up to the next line section in spite of the maximum under-reach of the third step.

The three-stepped distance protection is shown in Figures 6.29(a), (b), (c), and (d).

Note that in Figure 6.29(c), there is an additional distance measuring unit whose reach is beyond the third zone reach. The operating time of this unit is instantaneous. This unit is known as a *fault detector* or *starter unit*.

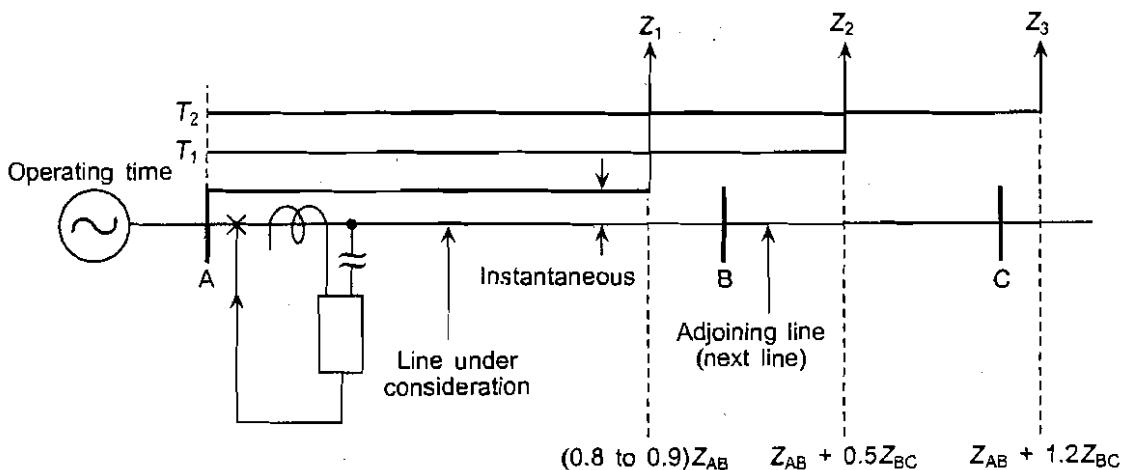


Figure 6.29(a) Three-stepped distance protection.

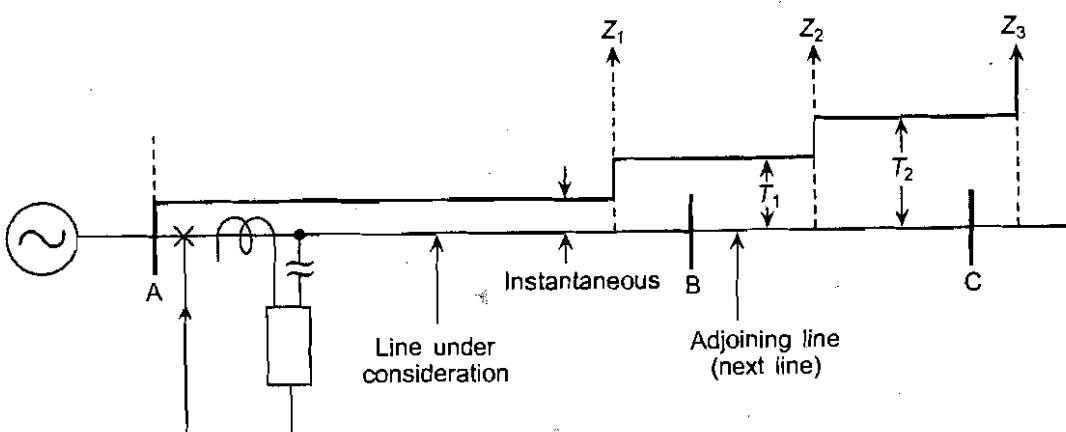


Figure 6.29(b) Three-stepped distance protection simplified representation.

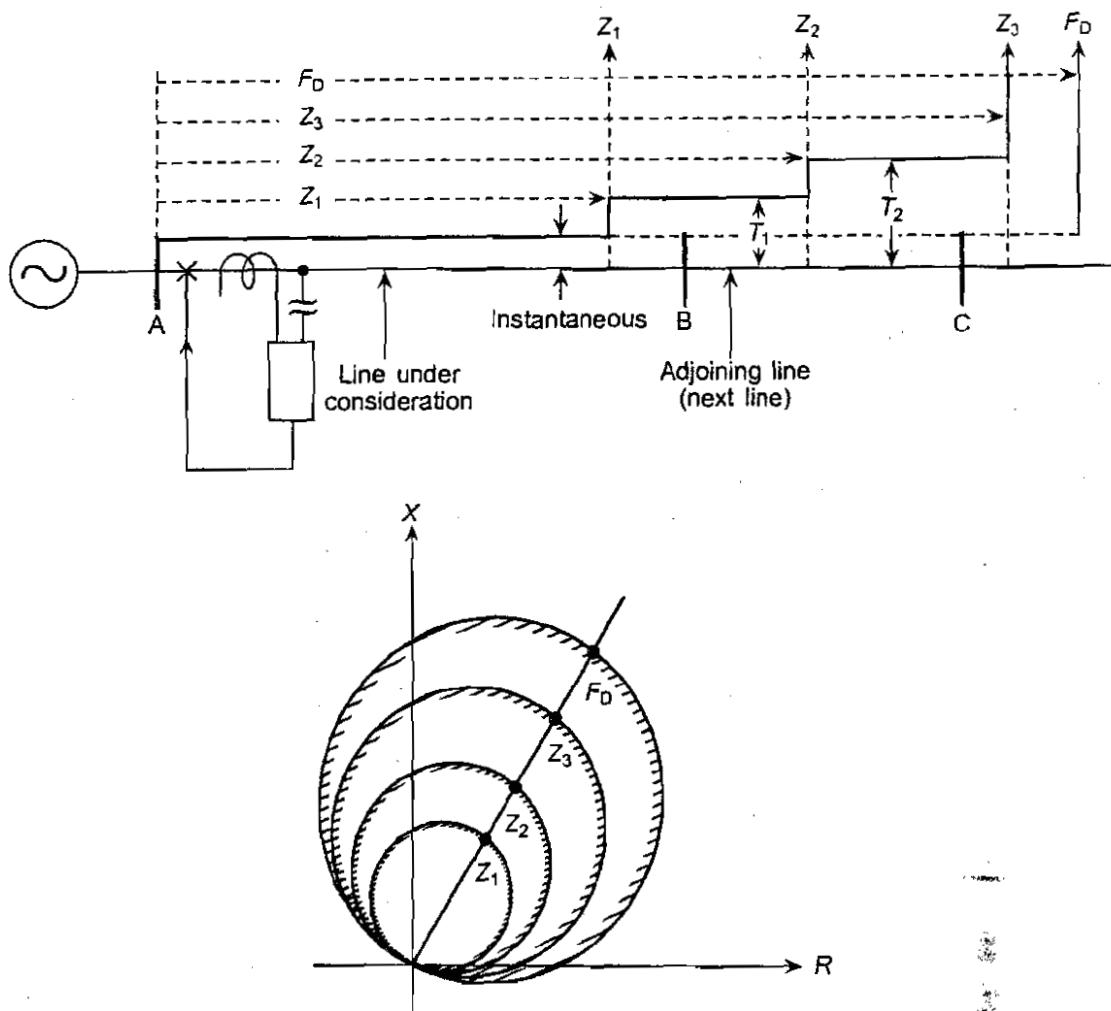


Figure 6.29(c) Three-stepped distance protection using mho relays.

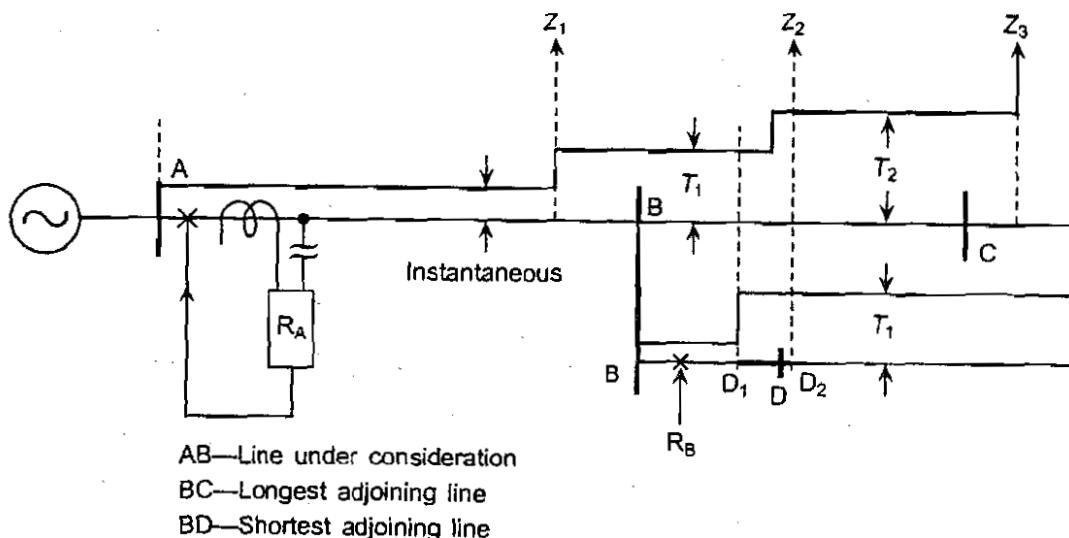


Figure 6.29(d) Loss of selectivity of second zone of R_A with second zone of R_B .

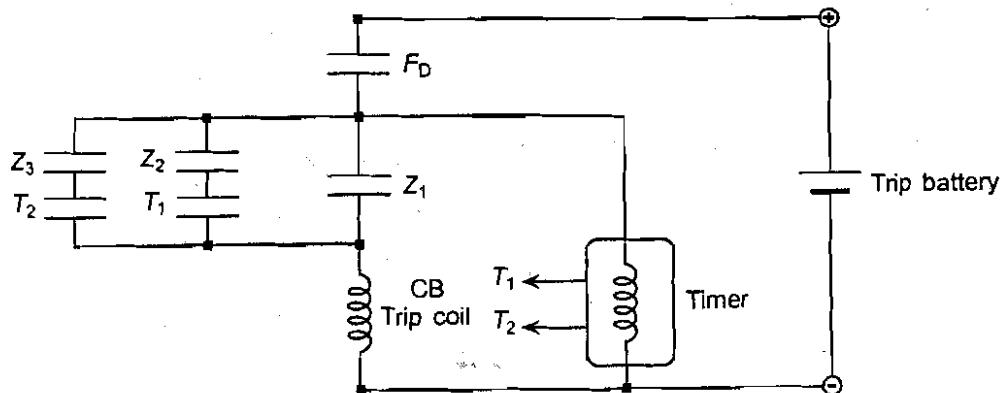
Table 6.3 summarizes the philosophy of three-stepped distance protection.

Table 6.3 Philosophy of the three-stepped distance protection

	Purpose	Reach	Operating time	Remarks
First step	Primary protection	80 to 90% of line section	Instantaneous, i.e. no intentional time delay $T_{\text{instantaneous}}$	<ul style="list-style-type: none"> Avoids loss of selectivity with protection of next zone in case of maximum over-reach
Second step	Primary protection of remaining 20 to 10%	100% of line under consideration + 50% of shortest adjoining line	$T_{\text{instantaneous}} + \text{Selective time interval} = T_1$	<ul style="list-style-type: none"> Provides primary protection to part of line left out of first step and provides some back-up to the bus and the next line. Shortest adjoining line is to be considered. If the longest adjoining line is considered, then it causes loss of selectivity.
Third step	Back-up protection	100% of line under consideration + 100% of longest adjoining line + 10 to 20% extra	$T_1 + \text{Selective time interval} = T_2$	<ul style="list-style-type: none"> Idea is to provide full back-up to the adjoining line, even in case of maximum under-reach. Longest adjoining line has to be considered. If shortest adjoining line is considered then the longer adjoining line will not get back-up protection.

6.10 Trip Contact Configuration for the Three-stepped Distance Protection

The trip contact circuit which implements the three-stepped distance protection scheme is shown in Figure 6.30. The fault detector initiates the timer in case it detects a fault



F_D = NO contact of fault detector, Z_1 = NO contact of step I measuring unit, Z_2 = NO contact of step II measuring unit, T_1 = NO contact closed by timer after time T_1 after closure of F_D , Z_3 = NO contact of step III, T_2 = NO contact closed by timer after time T_2 after closure of F_D

Figure 6.30 Trip contact circuit of the three-stepped distance scheme.

within its reach setting. The timer issues two outputs after it gets energized. The first output is after an elapse of time T_1 and the second after time T_2 . Both these outputs are in the form of closure of a normally open (NO) contact.

In case the fault is within the first step of distance protection, the trip coil gets energized through the Z_1 and F_D contacts. Depending upon whether the fault is within the second or the third step, the trip coil gets energized through the series combination of either Z_2, T_1 or Z_3, T_2 .

6.11 Three-stepped Protection of Three-phase Line Against All Ten Shunt Faults

We have already seen that three numbers of phase fault measuring units, which are fed with delta voltages and delta currents, and three numbers of ground fault measuring units, which are fed with phase voltages and phase currents compensated with residual current, are required for complete protection of a three-phase line against all the ten shunt faults. Thus in all six measuring units are required.

The setting of each measuring unit is based on the positive sequence impedance of the line.

Now, in order to generate three zones, $3 \times 6 = 18$, measuring units will be required. This is a rather costly affair! Therefore, schemes, which save upon the number of measuring units, have been devised.

One popular idea, known as the *switched distance scheme* uses only three measuring units, but switches the inputs to them with the help of a fault detector. This brings down the number of measuring units from 18 to 3×3 or 9. The interested reader should look up literature on protective relaying to learn more about these schemes.

6.12 Impedance Seen from Relay Side

Up till now we have assumed that the CT ratio as well as the PT ratio is 1 : 1. In practice, however, the CT ratio as well as the PT ratio are far from unity. In such a situation, what is the impedance seen from the relay side, i.e. from the CT and PT secondary sides? It can be seen from Figure 6.31 that:

$$V_R = \frac{V_L}{PTR} \quad \text{and} \quad I_R = \frac{I_L}{CTR}; \text{ where PTR} = \text{PT ratio, CTR} = \text{CT ratio}$$

$$Z_{\text{relay}} = \frac{V_R}{I_R} = \left(\frac{V_L}{I_L} \right) \left(\frac{CTR}{PTR} \right)$$

but $\frac{V_L}{I_L} = Z_f = \text{actual line side impedance}$

Therefore,

$$Z_{\text{relay}} = Z_f \left(\frac{CTR}{PTR} \right)$$

where Z_f is the fault impedance as seen from the line side.

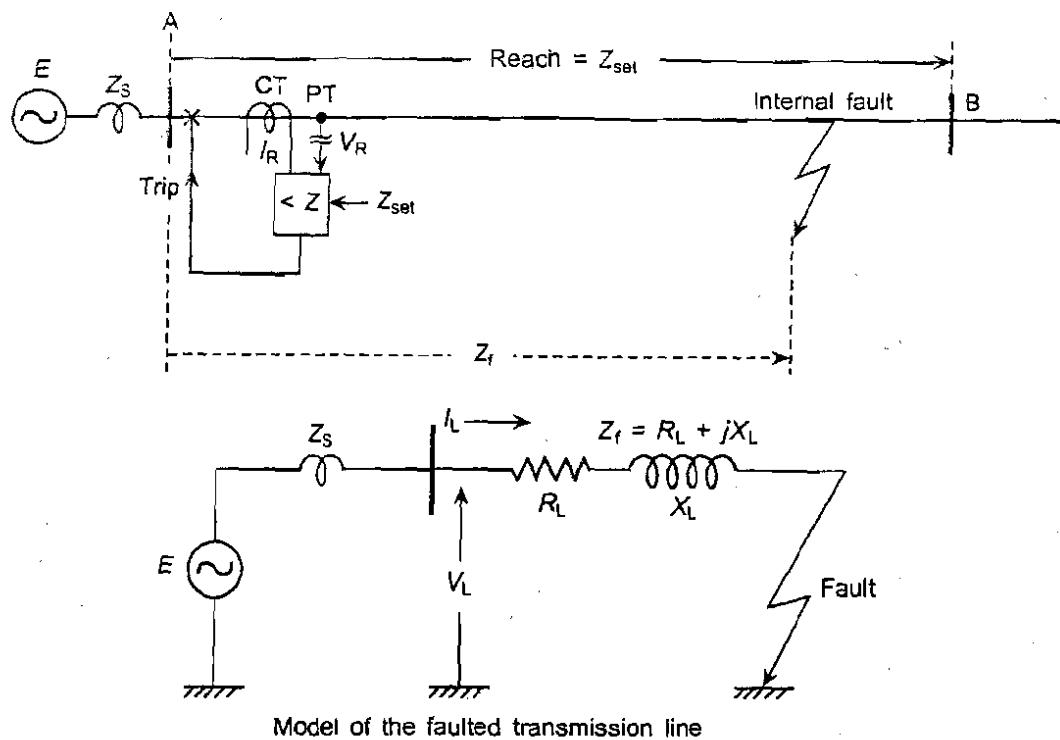


Figure 6.31 Impedance seen from the relay side.

6.13 Three-stepped Protection of Double-End-Fed Lines

Figure 6.32 shows a double-end-fed line AB. There are sources at both the ends. Therefore, there is an in-feed of fault power from both sides. Hence, circuit breakers and three-stepped distance schemes will have to be provided at both the ends.

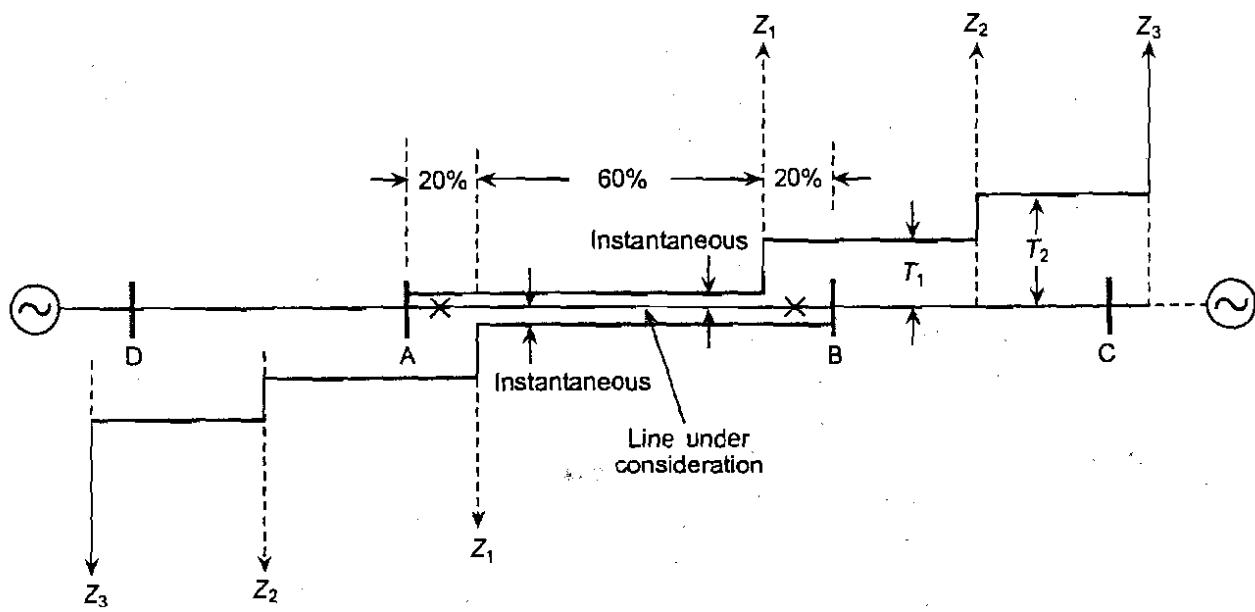


Figure 6.32 Only 60% of the line gets high speed distance protection.

The time versus reach characteristics for three-stepped distance schemes at both the ends are shown in Figure 6.32. It can be easily seen that only 60% of the line gets high speed distance protection. The remainder 40% of the line length falls in the step II which is a delayed one. This is clearly not a happy situation. We need to improve upon the operating time for rest of the 40% of the line.

A fault in the end 20% of the line falls within the first zone of the distance relays installed at the nearest end and there is no ambiguity about its location. The same fault when seen from the far end because of the uncertainties involved could well be beyond the bus. Thus, if we could, somehow convey the information that the fault is within the protected zone to the far end, and then the tripping from the remote end need not wait till time T_1 of the second step.

This principle is made use of in the carrier-aided distance schemes discussed in Chapter 7.

Review Questions

1. What are the drawbacks, if any, of over-current relays?
2. Why are over-current relays not used for primary protection of EHV lines in spite of the fact that instantaneous over-current relays exist?
3. How is the transmission line modelled for the sake of distance relaying?
4. Arc resistance is a function of spark-over distance, wind velocity and time. Explain.
5. What do you mean by a metallic fault?
6. How is it different from an arcing fault?
7. What is the effect of fault resistance on the reach of various distance relays? Which relay is the most affected and which the least affected?
8. What do you mean by power swing?
9. Will an over-current relay be affected by power swing?
10. How do different distance relays perform with respect to their behaviour on load, effect of arc resistance on the reach and response to power swing?
11. Prove that $a-b$ distance measuring unit fed with $(V_a - V_b)$ and $(I_a - I_b)$ responds correctly to $a-b-g$ faults as well as $a-b-c$ faults.
12. Why is residual current compensation required in case of ground fault distance measuring unit?
13. Explain the need for a three-stepped distance protection of a transmission line.
14. How many distance measuring units will be required for the complete three-stepped protection of a transmission line section in case of (i) a singly-fed systems and (ii) a double-end-fed system?
15. The impedance seen from the relay side in a distance relay is 10 ohms. Given that the CT ratio is 1000 : 1 and the PT ratio is 100,000 : 110, determine the actual impedance. Given that the line has a resistance of 1 milliohm per km and a reactance of 20 milliohm per km, find the distance to fault. Assume single-phase line.

7 Carrier-aided Protection of Transmission Lines

7.1 Need for Carrier-aided Protection

The main aim of the electrical power system is to maintain uninterrupted supply of electricity to consumers. Electrical faults, however, cause interruption to the supply. When a fault takes place it is detected by protective relays and the fault current is interrupted by the circuit breaker. The maintenance personnel must then rush to the fault location, rectify the fault, and restore the supply. This applies to permanent faults.

However, there is statistical evidence, as shown in Table 7.1, that about 80% of faults are not permanent but are transient. These faults are caused by breakdown of air surrounding the insulator. These faults can disappear by themselves, if the supply is briefly interrupted and the arc-path is allowed to de-ionize.

Table 7.1 Fault statistics

Type of fault	Probability
Transient	80%
Semi-permanent	10%
Permanent	10%

Thus, whenever a fault takes place, we can tentatively assume that a transient fault has interrupted the supply. We then wait for a short while before switching on the circuit breaker. This is known as *reclosure*. The reclosure can be carried out manually or automatically.

If the fault was indeed a transient one and the interruption was of a duration greater than the de-ionization time, then the reclosure would be successful, that is, there would be no recurrence of the fault. The typical de-ionization times for various system voltages are listed in Table 7.2.

Table 7.2 Typical de-ionization times

System voltage	Typical de-ionization time
66 kV	0.10 s
132 kV	0.17 s
220 kV	0.28 s
400 kV	0.50 s

If the fault is a permanent one, reclosure will be unsuccessful, i.e. the protective relay would immediately cause the circuit breaker to trip. Thus, in case of a transient fault, reclosure helps in keeping the downtime to a minimum and in increasing the availability of supply. Reclosure has different implications for low/medium voltage (LV/MV) and high or extra high voltage (HV/EHV) systems.

In low and medium voltage systems, a maximum of three consecutive reclosures are allowed. If the fault persists even after the third reclosure, i.e. even when the third reclosure fails, then the circuit breaker is locked out and no more reclosures are allowed. The multiple reclosures in LV and MV systems help in burning out the object responsible for the fault, say, a tree branch, and thus in clearing out the fault.

Only one reclosure is allowed in HV/EHV systems because reclosure imposes arduous duty on the circuit breakers and other elements of the power system as the fault MVA is very large.

In HV/EHV systems, reclosure, if done sufficiently fast, helps in improving the stability of the system. This is so because as soon as there is an interruption in the system, the rotor angles of various generators start drifting apart and if they drift apart beyond a critical angle, the system loses stability. If, however, the supply is restored before this critical time elapses, the system can pull together and remain stable.

Since HV/EHV lines are generally tie lines, there is presence of source at both the ends. Thus, in order for the transient fault arc to be quickly quenched, the line must be instantaneously and simultaneously tripped from both ends, before a reclosure can be attempted.

The three-stepped distance protection for the entire line length does not meet the requirement of instantaneous and simultaneous tripping from both ends. Only about 60% of the length in the middle of the line gets high speed protection from both ends. For about 20% of line length, near each end of the line, i.e. a total of 40% of line length, the protection is instantaneous from the local end but is delayed from the remote end. This is shown in Figure 7.1. Thus, in order to be able to implement auto-reclosure, we need to augment the distance protection so that instantaneous tripping from both ends for 100% of the line length becomes possible.

Carrier-based schemes help us in achieving this objective.

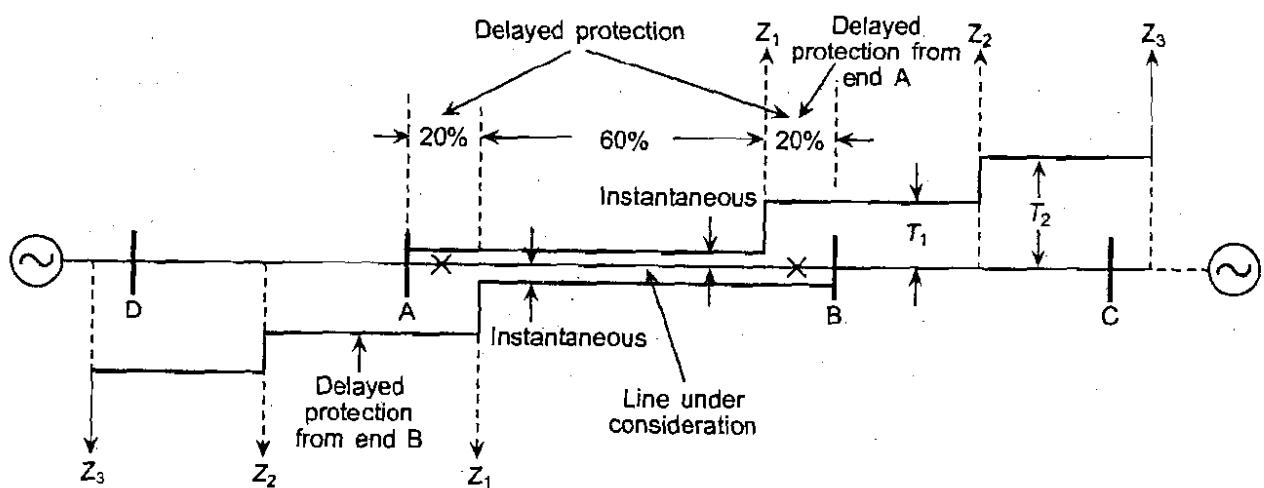


Figure 7.1 Only 60% of line length in the middle gets high speed protection from both ends.

7.2 Various Options for a Carrier

Protective relays process information contained in the voltage and current at the local end. The relay, only indirectly infers about the conditions at the remote end through these signals. As the fault distance increases, the picture becomes more and more fuzzy. Hence, there is always an ambiguity about the exact location of a remote fault. It becomes impossible to distinguish between a fault just beyond the remote bus and one just ahead of it. However, there is no ambiguity about the same fault from the end nearest to the fault because as the fault moves from just beyond the bus to just ahead of it, there is an almost 180 degrees change in the phase of current at the nearest end. Thus, the nearest end has the clear-cut information which is so difficult to extract using power, frequency, current and voltage at the remote end. If we could, somehow pass on this small amount of information from one end to the other, it would enhance the quality of decision making at both the ends. We, therefore, need some *carrier* to carry this information. Various attributes of an ideal carrier channel can be listed as follows:

- Delay involved in the communication should be small compared to the time period of the system frequency. At 50 Hz, the delay should be much less than 20 milliseconds.
- Since only a small amount of information is to be passed, the carrier channel need not have very high bandwidth for protection purposes.
- Faults on the power system should not adversely affect the functioning of the carrier channel.
- Carrier channel should be under full control of the utility company.
- The carrier equipment, such as carrier transmitter and receiver, should be protected from the high potential of the EHV line.
- The carrier channel should be economical.

Various available options for a carrier signal are listed, along with their salient features, in Table 7.3.

7.3 Coupling and Trapping the Carrier into the Desired Line Section

The power transmission line operates at very high voltage levels of the order of hundreds of kilovolts. The carrier signalling equipment, viz. the carrier current transmitter and the carrier current receiver, operate at a much lower voltage. Therefore, we need a method of coupling the two so that neither the high voltage line gets shorted through the carrier equipment nor does the signalling equipment get damaged due to the extra-high voltages of the power line. Figure 7.2 shows one such arrangement for coupling the carrier on a line-to-ground basis. *Line traps* which confine the carrier signal to the desired line section are also shown.

Table 7.3 Various possible carriers of information for relaying purposes

Leased telephone line from the telephone service provider	Running cost is very high. Maintenance is a problem and guarantee of quality of service may be difficult to obtain.
Terrestrial microwave communication channel (either owned by the utility or leased)	Frequency range is between 3 and 30 GHz. The range of communication is <i>line of sight</i> . A large number of antenna towers are required. Therefore, initial investment and maintenance cost are both very high. Provides very large bandwidth, which may be shared with other data communication services.
Satellite communication using VSAT terminals using geostationary satellite at 36,000 km	Frequency range is between 3 and 30 GHz. Propagation delays involved are of the order of $(2)(36000) \text{ km}/(3)(10)^5 \text{ km/s} = 240 \text{ ms}$ i.e. 12 cycles (50 Hz basis) and this is not permissible for real-time power system protection. Large bandwidth is available.
Power line carrier communication	Most economical, since power line conductor doubles as the physical medium for carrying the <i>carrier</i> signal. The carrier signal is a signal of much higher frequency, compared to power frequency, which is coupled to the EHV line. Frequency band allocated to this service is 50–200 kHz. Thus, the carrier signal frequency is just above the audible frequency range and just below the medium wave radio broadcast band. Due to moderately low frequency of the carrier, a small bandwidth is available. However, protective relaying does not need a large bandwidth. What is important is the delay involved, which is very small in case of power line carrier, for example, a 1000 km line will cause a delay of 0.33 milliseconds.

The impedance of the coupling capacitor is very large at 50 Hz compared to that of the parallel tuned circuit (which is tuned to carrier frequency) consisting of L_P and C_P . Therefore, the coupling capacitor drops most of the 50 Hz voltage so that a very small 50 Hz voltage appears across the signalling equipment. The series circuit consisting of C_S and L_S , as shown in Figure 7.2, is designed to resonate at the carrier frequency. Since the impedance of a series resonant L - C circuit is ideally zero, it provides very good coupling at the carrier frequency.

The parallel circuit consisting of L_P and C_P is tuned to resonance at the carrier frequency. Since the impedance of a parallel resonant circuit is ideally infinite at the resonant frequency, it develops maximum voltage at carrier frequency, thus helping to extract the maximum carrier signal.

The series and parallel L - C tuned circuits, therefore, help in efficiently coupling the carrier into the EHV line. The carrier signal, however, needs to be confined to the desired line section. The two line traps, which are parallel tuned L - C circuits, resonant at the carrier frequency, prevent the carrier signal from spreading into rest of the transmission system by virtue of their extremely high impedance at the carrier frequency. The line traps have to be so designed, however, that they do not offer any significant impedance at 50 Hz (power frequency). The line ends are thus clearly demarcated as far as the carrier signal is concerned. This clear-cut demarcation helps in establishing a well-defined zone whose boundaries are crisply defined.

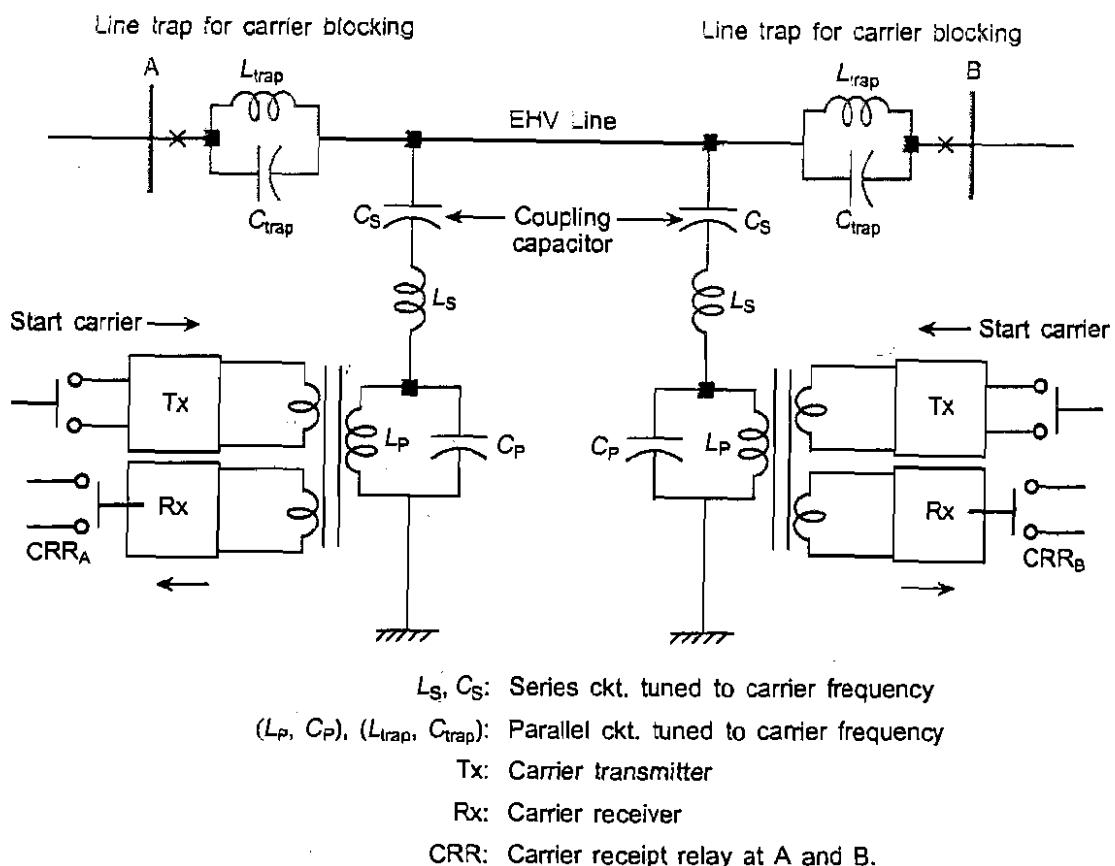


Figure 7.2 Coupling a carrier and trapping it into the desired line section (single line-to-ground coupling).

7.3.1 Single Line-to-ground Coupling

In Figure 7.2 we have shown carrier coupling on a single line-to-ground basis. Is this type of coupling, a wise choice?

Recall that, statistically, majority of faults are of the line-to-ground type. Further, in power line carrier communication, the information has to be passed over the power line itself. Therefore, during faults, when the carrier is needed the most, the carrier will have to be passed across the line-to-ground fault. This is bound to cause severe attenuation of the carrier signal, rendering it unusable at the remote end. Thus, line-to-ground coupling is not a very sound choice as far as carrier coupling is concerned.

7.3.2 Line-to-line Coupling

Figure 7.3 shows carrier coupling on the line-to-line basis. The carrier signals propagate through air between the line conductors, therefore, the attenuation is much less. This mode of transmission, known as the *aerial mode*, results in a much better performance during single line-to-ground faults.

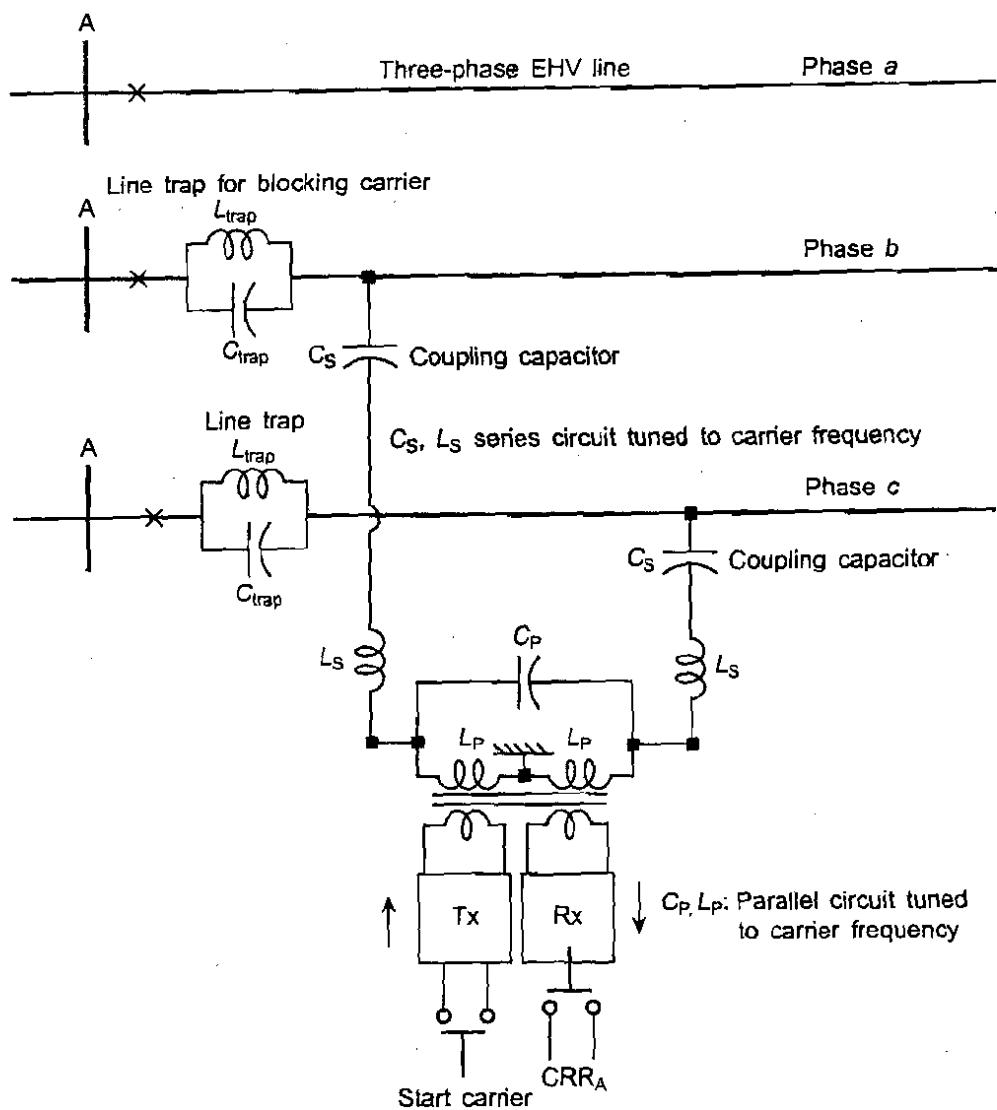


Figure 7.3 Line-to-line coupling.

7.4 Unit Type Carrier-aided Directional Comparison Relaying

This protection takes advantage of the fact that as the fault location changes from just ahead of the bus to just beyond the bus, the nearest directional relay sees a sharp change in the fault direction whereas the remote relay does not see any change in the direction of the fault. The remote relay cannot tell whether the fault is within the line zone or outside it whereas the nearest end relay has no difficulty at all in discriminating between the same. The information about the fault direction, as seen from each end, is conveyed over the power-line carrier to the other end. At each end, simply ANDing the contact of the local relay with the status of the contact of the remote relay gives rise to a unit type of directional protection.

Figure 7.4(a) shows an internal fault for which AND gates at both the ends become enabled and instantaneously trip the associated circuit breakers. This generates a well-defined zone of protection consisting of the line length between buses A and B.

Figure 7.4(b) shows an external fault. Since one input for each of the AND gates is low, both the AND gates are disabled, thus the unit scheme restrains on external faults.

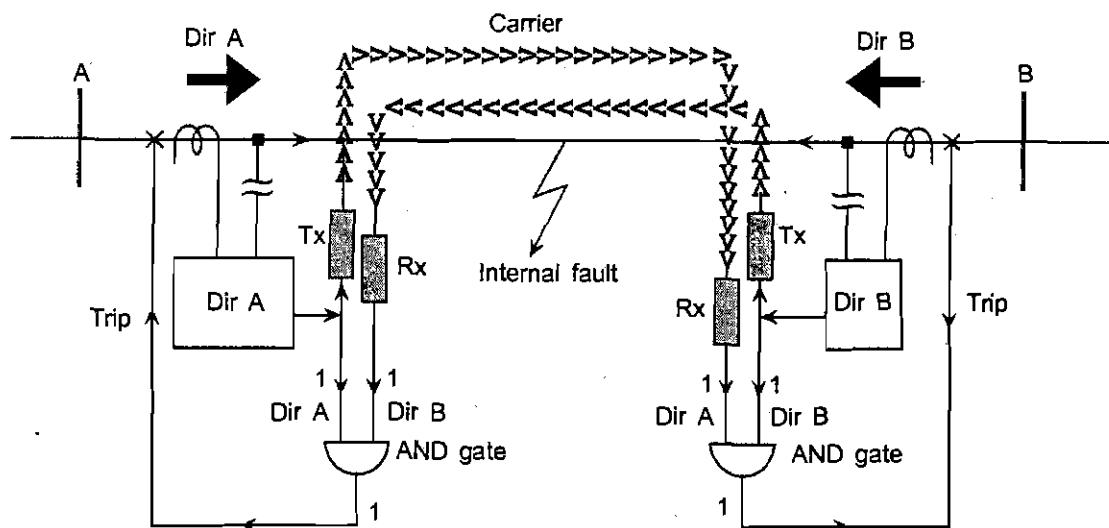


Figure 7.4(a) Unit type carrier-aided directional comparison relaying: internal fault.

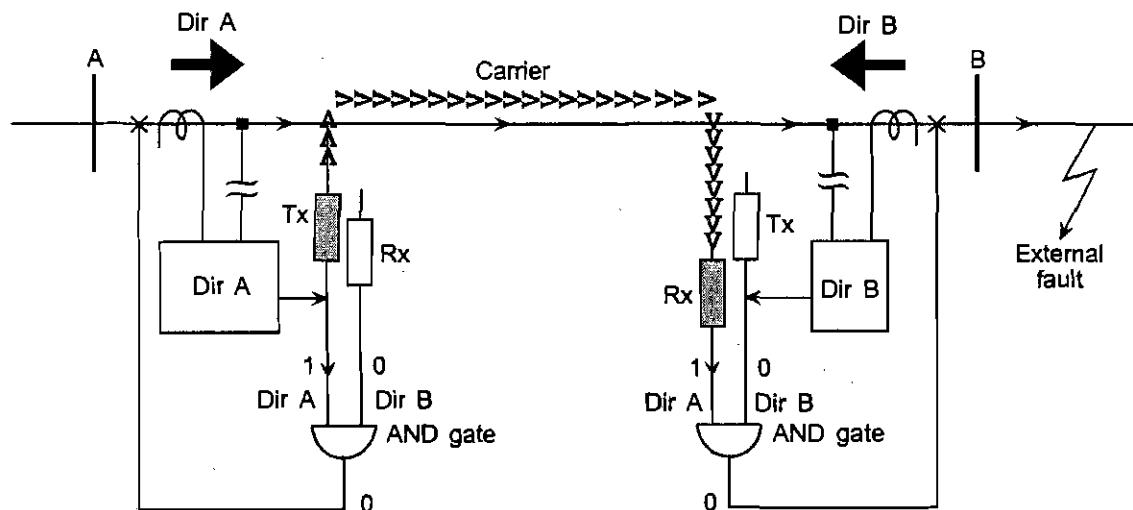


Figure 7.4(b) Unit type carrier-aided directional comparison relaying: external fault.

There is absolute selectivity as far as the ends of the zone are concerned, giving rise to a well-defined protective zone, hence this scheme is classified as a *unit type* of protection. Both the relays use the directional principle, hence it is called *unit type directional* protection.

7.5 Carrier-aided Distance Schemes for Acceleration of Zone II

7.5.1 Transfer Trip or Inter-trip

As mentioned earlier, the faults in the end 40% (20% on each side) of the transmission line fall in the second step of distance protection. It is, therefore, a delayed protection. Thus, only about 60% of the mid-length of the line, gets high-speed distance protection. For faults in the end 40%, the nearest distance protection trips instantaneously but the remote end protection is a delayed one. How to speed up the remote end distance protection?

Consider a fault in the second zone of distance protection, but not beyond end B, as seen from end A. We can make use of the first zone, Z_1 contact of the local relay at end B, to initiate a carrier and thus remotely operate a contact to close the trip circuit of the remote circuit breaker at end A. The logic of this scheme is shown in Figure 7.5. The logic can be understood by following the Roman numerals written in parentheses as follows:

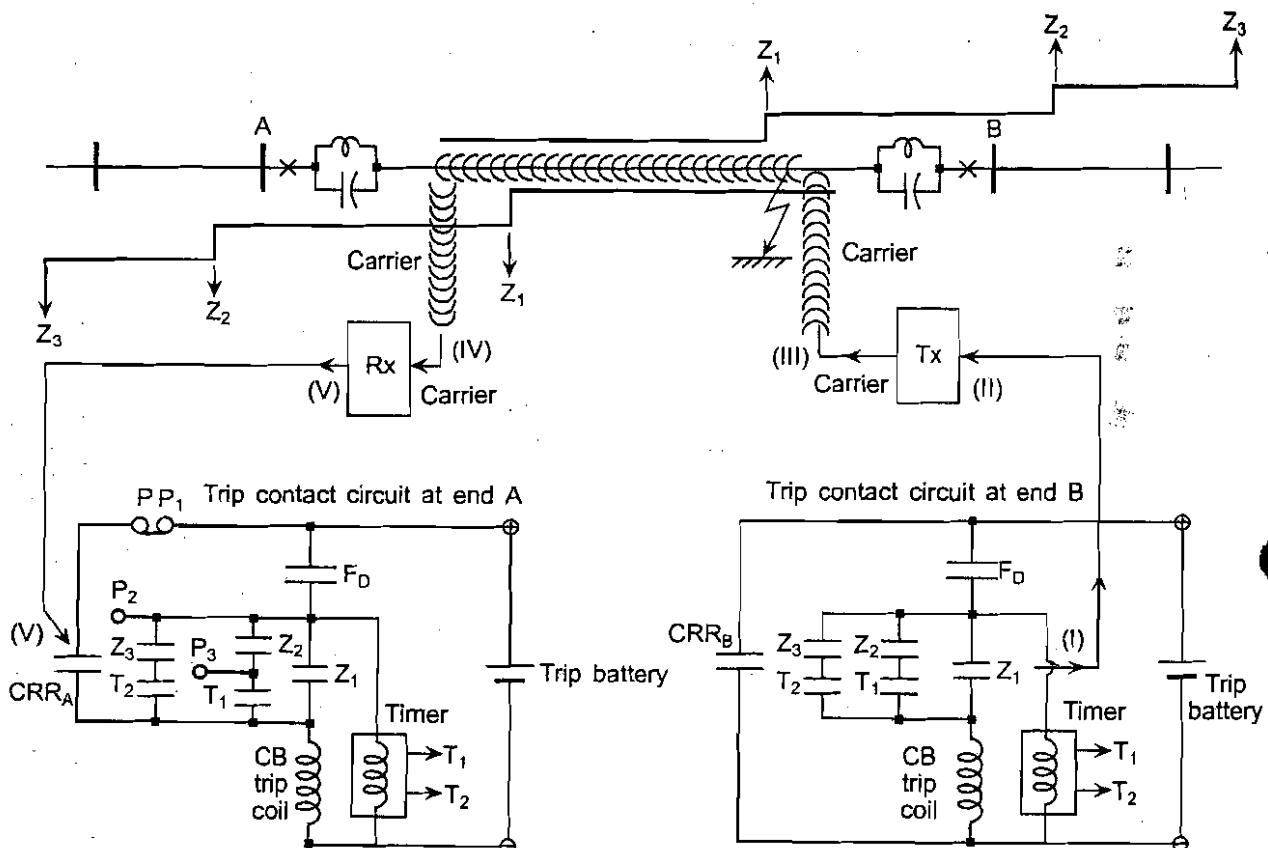


Figure 7.5 Acceleration of zone II of distance relay using carrier.

- (I) Z_1 contact of the local relay at end B operates (NO → CLOSES).
- (II) This contact closure is used to switch on the carrier transmitter at end B, marked as Tx in the figure.
- (III) The carrier transmitter injects the carrier into the line.

- (IV) The carrier signal arrives at the remote end A at approximately the speed of light, after a very short delay, and is received by the carrier current receiver, marked as Rx.
- (V) The output of the receiver (Carrier Receipt Relay, at end A, designated as CRR_A) is in the form of closure of the contact CRR_A.

Now, the CRR_A contact can be used to energize the trip coil of the circuit breaker at remote end A in several alternative ways.

If we bypass the fault detector F_D contact by connecting point P with P₁, then the scheme is known as *transfer trip* or *inter-trip*.

In this scheme, the carrier signal is required for tripping purposes. Therefore, in case of either the failure of carrier equipment or severe attenuation of the carrier signal due to fault, the operation of the scheme is jeopardized. Thus a tripping carrier scheme lacks robustness. Ideally, the carrier-based scheme should be such that in case of failure of carrier, it should automatically revert back to the three-stepped distance scheme. The logic can be built in such a way that the carrier signal is not required for tripping but is required for blocking the tripping. Such schemes are obviously more robust and are known as *blocking carrier* schemes.

7.5.2 Permissive Inter-trip

At times, noise may cause false tripping in the scheme described in Section 7.5.1. Therefore, we can take advantage of the fault detector output. Hence if point P, in Figure 7.5 is connected to point P₂ then the scheme is known as *permissive inter-trip*.

7.5.3 Acceleration of Zone II

Alternatively we can simply bypass the zone II timer contact T₂, in Figure 7.5, with CRR_A, in which case the scheme is known as *acceleration of zone II*.

7.5.4 Pre-acceleration of Zone II

In this scheme, the zone II timing is accelerated from T₁ to a much smaller value. This is done by shorting out the T₁ contact of the timer (which controls Z₂ timing), with the normally closed output of carrier receipt relay at end A, CRR_A, as shown in Figure 7.6. In case the fault is beyond the bus, the directional relay sees the fault and initiates a carrier. The carrier is now sent over a line section which is healthy (on which there is no fault). On receipt of the carrier at end A, the carrier receipt relay changes state from CLOSE to OPEN. Thus T₁ contact now comes into picture and decides the operating time of zone II. The sequence of events can be easily understood, if one follows the Roman numerals written in parentheses in Figure 7.6.

- (I) Fault takes place beyond the bus, in zone II, as seen from end A.
- (II) Directional relay at end B senses the fault and instantaneously issues the trip output.
- (III) The trip output of directional relay is used to start the carrier transmitter at end B.
- (IV) The carrier transmitter at end B sends the carrier over the healthy power line.

- (V) The carrier is received at end A, after a brief propagation delay, by the carrier receiver.
- (VI) Carrier receiver issues an output, CRR_A, in the form of a changeover of contact from CLOSE to OPEN.
- (VII) This output is used in parallel with the T₁ contact to de-accelerate the zone II time which was pre-accelerated with the help of NC contact of CRR_A.

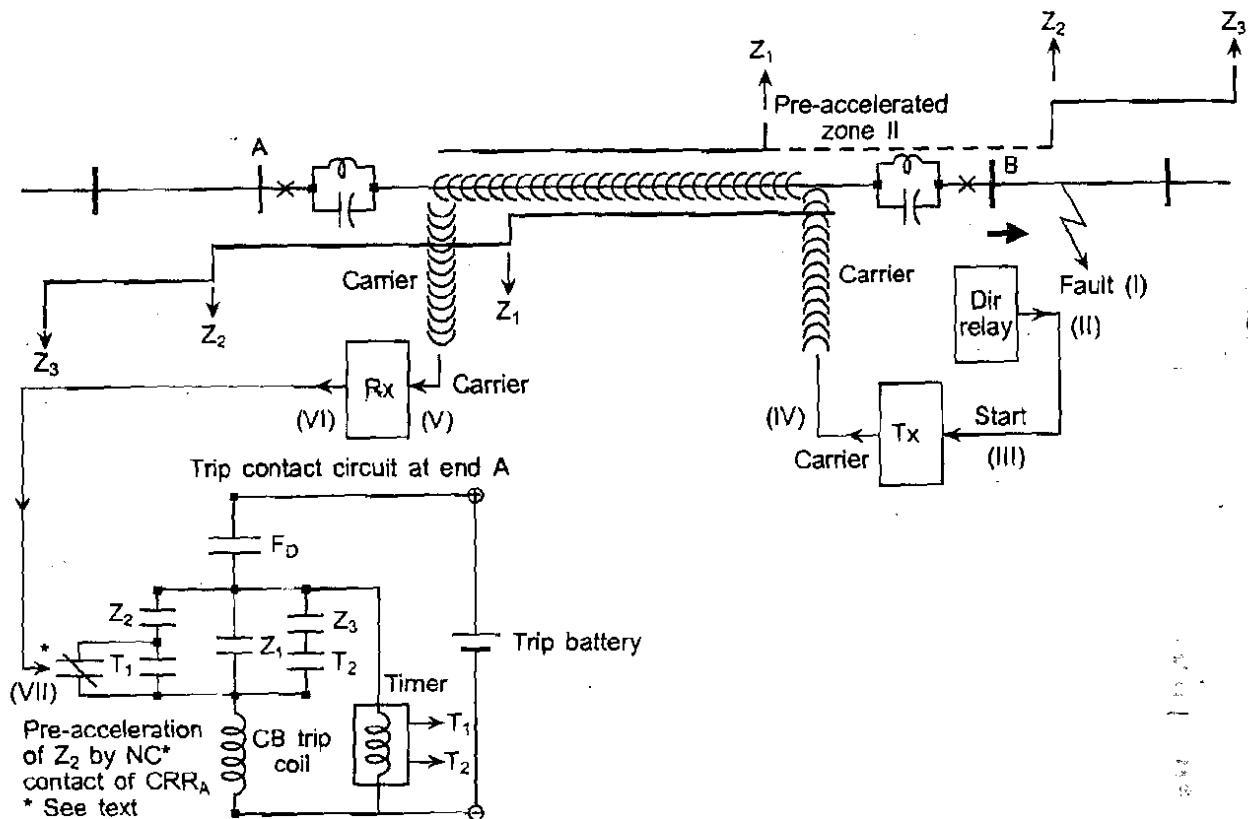


Figure 7.6 Pre-acceleration of zone II.

This has been a rather idealistic discussion of the operation of the system. In actual practice, Z₂ operation should not be made instantaneous. If Z₂ is made instantaneous then it will not give chance to the directional relay to operate and de-accelerate the Z₂ time, in case, the fault is beyond the bus. We have to allow for the following delays:

1. Operating time of directional relay T_{dir}
2. Propagation time of carrier over the length of the line T_{prop}
3. Operating time of the carrier receiver T_{CRR_A}

Thus, zone II should be pre-accelerated to an operating time of:

$$T_{pre-accelerated} \geq T_{dir} + T_{prop} + T_{CRR_A}$$

This is, however, not shown in the figure.

It can be seen that the carrier is required for blocking the instantaneous operation of the pre-accelerated zone. This is an example of a *blocking carrier*.

7.6 Phase Comparison Relaying (Unit Scheme)

In this type of relaying, we exploit the phase shift undergone by the current at the end which is nearest to the fault, as the fault changes from internal to external. The end, which is far from the fault, cannot discern any change in the phase of the fault current as the fault changes from internal to external but the end which is closer to the fault sees a sharp, almost 180° change in the phase of current.

The local and remote end currents can be arranged to be out of phase for external fault or load condition as shown in Figure 7.7(a). This can be achieved by selecting the appropriate end of the CT winding as the reference. The phase shift will, however, not be exactly 180° , but may lag or lead this position by a small angle $\pm \delta$ representing the load being carried over the line.

As the fault changes from an external fault to an internal one, the current at the nearest end will undergo an approximately 180° change in its phase and will now be more or less in phase with the remote end current as shown in Figure 7.7(b). Thus, if we measure the phase shift between the currents at the two ends, then we can easily decide whether the fault is internal or external.

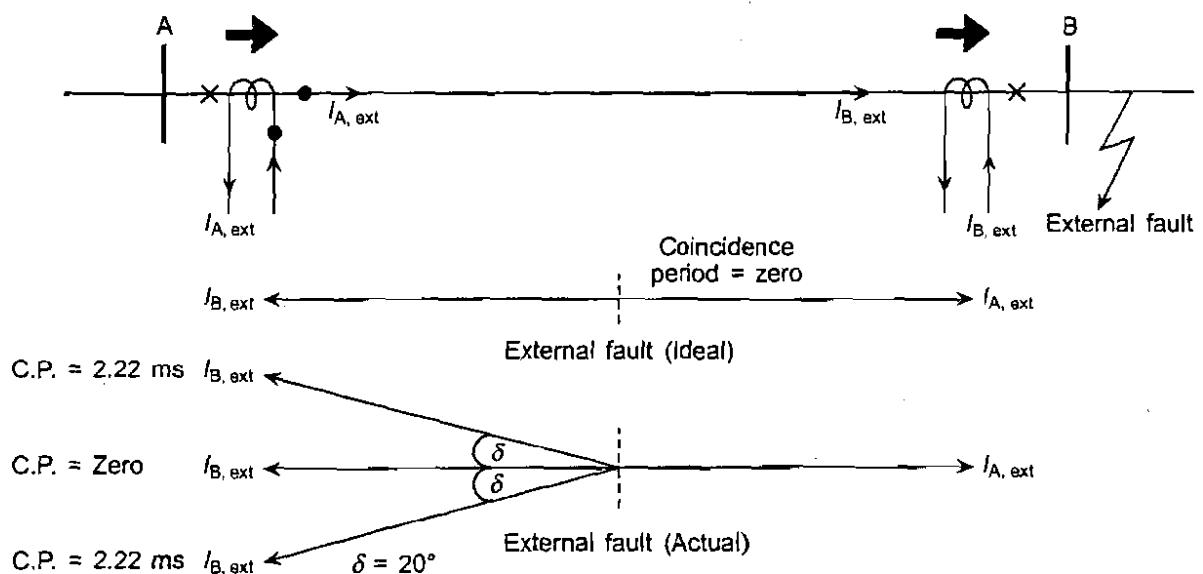


Figure 7.7(a) Phase comparison relaying (currents shown on the CT secondary side).

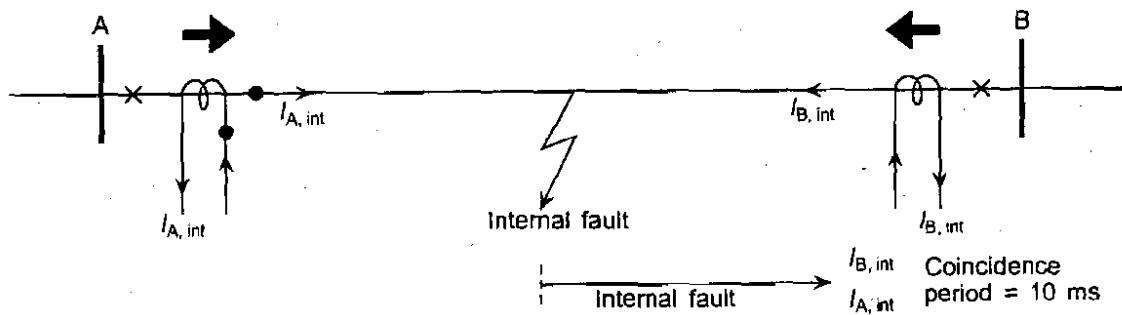


Figure 7.7(b) Phase comparison relaying.

Assuming δ to be, say, 20° then any phase shift between 0 and $\pm 160^\circ$ will indicate an internal fault, as shown in Figure 7.7(c). A phase shift of $\pm \delta$ gives rise to a coincidence period C.P. of

$$\frac{(180 - \delta)(20)}{180} = 2.22 \text{ ms}$$

for phase shift of $\pm 160^\circ$.

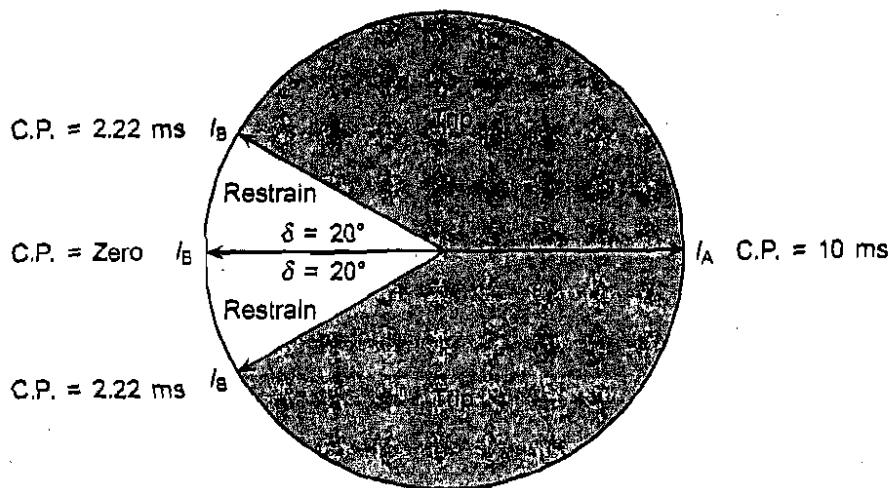


Figure 7.7(c) Phase comparison relaying.

Figures 7.7(d), (e), and (f) show a method for physical implementation of the above mentioned concept.

Figure 7.7(d) shows an internal fault. As shown in the figure, each end periodically sends carrier only during the positive-half of the time period of the power frequency ac wave. This results in generation of a modulated carrier wave. This modulation can be easily recovered back by demodulation to get a square waveform at the output. For an internal fault, the figure shows that the demodulated square waves are exactly coincidental. The coincidence period, thus, is 10 ms (on a 50 Hz basis).

Figure 7.7(e) shows an external fault. Again the two ends generate carrier only during the positive-half of the power frequency wave, generating similar modulated waves. However, because of the phase shift, now, the demodulated square waves do not have any coincidence at all or the coincidence period is nearly zero.

The coincidence period can be easily found by ANDing the two demodulated waves. To see if the coincidence period is greater than a certain threshold, we can either use any digital method or follow the simple expedient of integrating the square wave and comparing it with a preset dc value which represents the desired threshold, as shown in Figure 7.7(e).

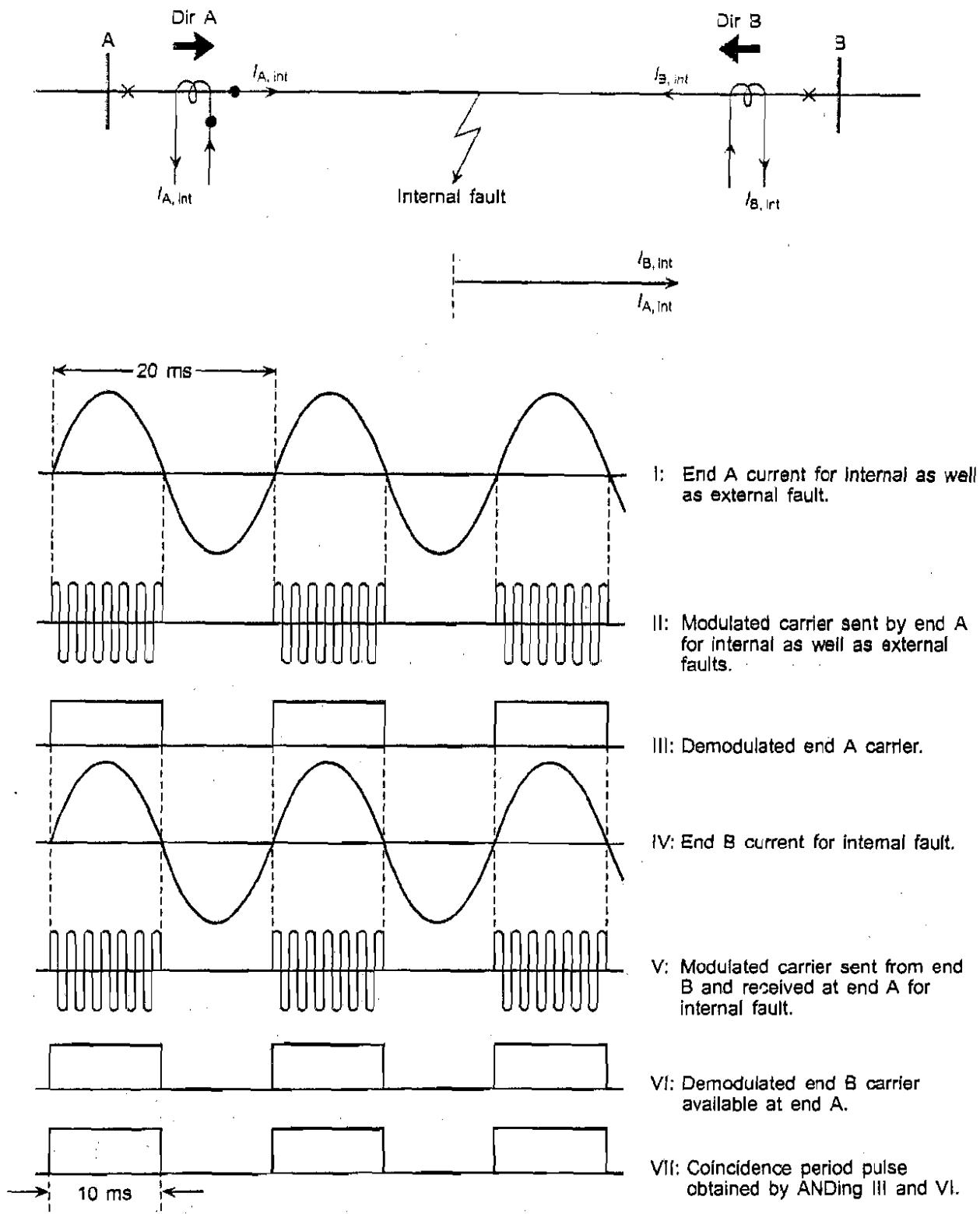


Figure 7.7(d) Phase comparison relaying (internal fault).

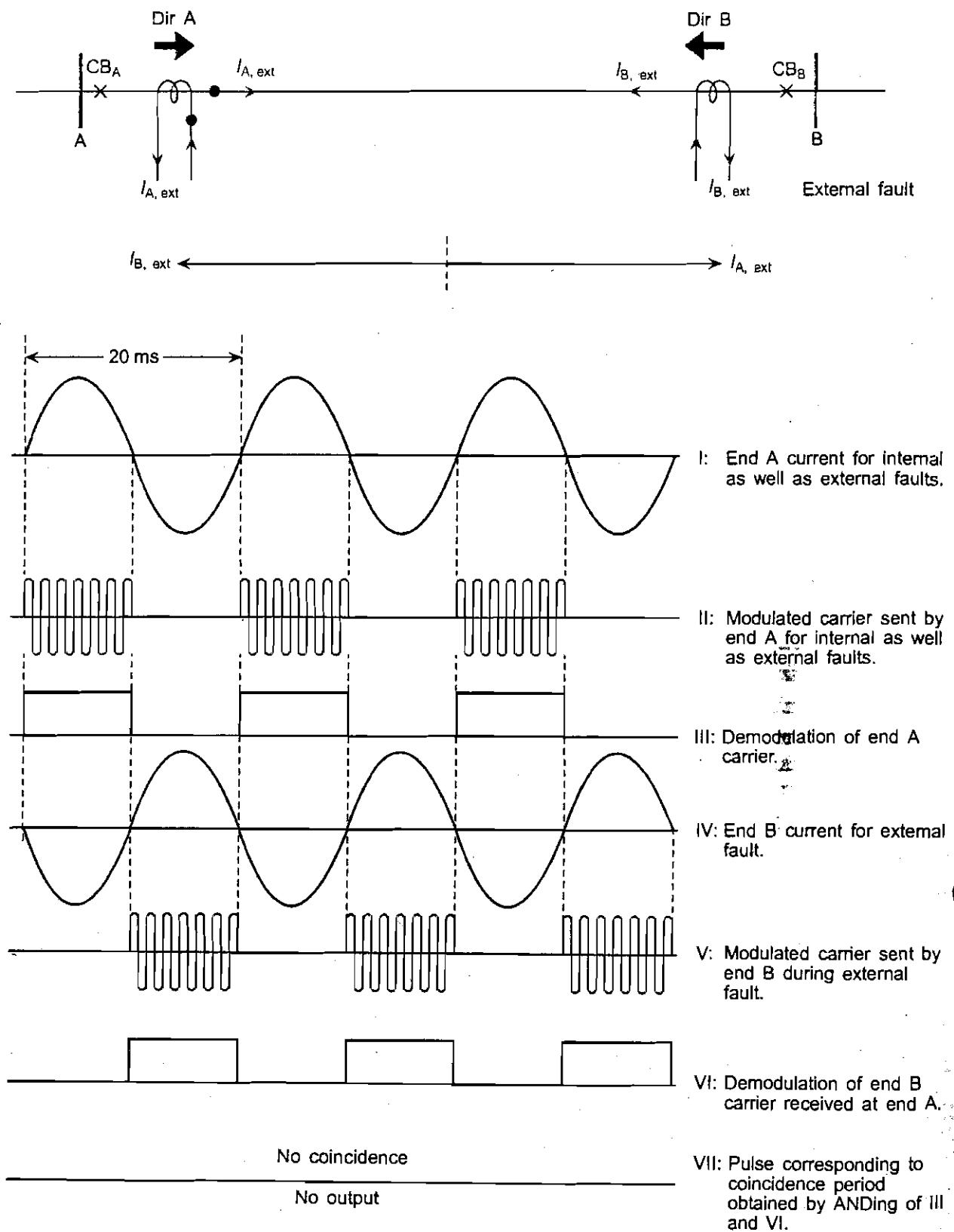


Figure 7.7(e) Phase comparison relaying (external fault).

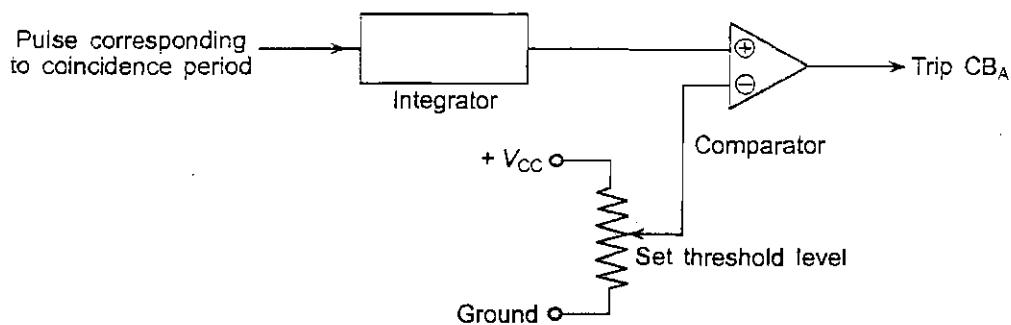


Figure 7.7(f) Hardware to measure coincidence period.

Review Questions

1. What do you mean by reclosure?
2. What is the motivation for using reclosure?
3. Differentiate between reclosure in case of low-voltage systems and high-voltage systems.
4. What is meant by single-shot reclosure and multi-shot reclosure?
5. What is the motivation for using a carrier?
6. What are the various options for implementing the carrier communication channel?
7. What are the advantages of power line carrier?
8. What frequency band is normally used for power line carrier signalling?
9. What is the frequency band used for microwave communication?
10. What is the motivation for coupling the carrier between two of the lines rather than between a line and ground? Which method results in more reliable carrier communication?
11. Explain why only middle 60% of the double-end-fed line gets instantaneous distance protection from both ends in a three-stepped distance scheme.
12. How does the carrier help in overcoming the limitation of the three-stepped distance protection?
13. Explain the difference between transfer trip and permissive inter-trip schemes. Which scheme is more robust?
14. How does the carrier-based acceleration of zone II differ from the transfer trip and permissive inter-trip schemes?
15. Why does sending the carrier over a faulty line need to be avoided?
16. What do you mean by tripping carrier and blocking carrier? Which one is more robust?
17. What do you mean by pre-acceleration of zone II?
18. In practice, the zone II cannot be pre-accelerated to an instantaneous operation. Explain.
19. Explain the operation of the unit type of carrier-based directional protection.
20. Explain the principle of carrier-based phase comparison scheme.

8

Generator Protection

8.1 Introduction

A generator could be part of:

- water turbine based hydropower station
- gas turbine based power station
- steam turbine based thermal power station
- nuclear power station

In all the above installations, the protection of the generator presents a very challenging problem because of its system connections on three different sides as shown in Figure 8.1. On the one side, it is connected to the prime mover and on the other side, it has to run in synchronism with the grid because of its connection to the power system. On yet another (third) side, it is connected to the source of DC excitation. It is thus obvious that generator protection is very complex compared to protection for other elements of the power system.

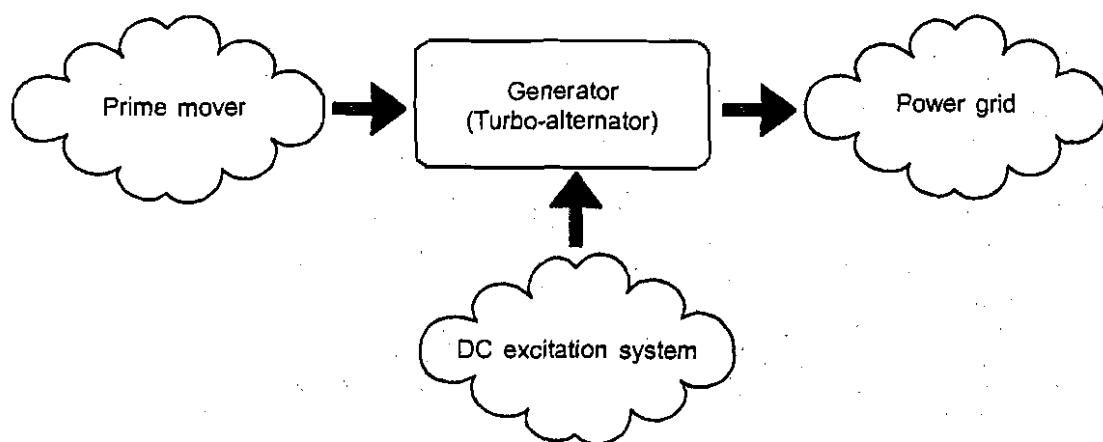


Figure 8.1 Complexities of generator protection.

In this book, we will restrict ourselves to various aspects of protection of a large (200 MW or higher) steam turbine based turbo-alternator.

In case of a fault on a turbo-alternator, it is not enough to open the main circuit breaker connecting it to the power grid. For example, when a turbo-alternator driven by a steam turbine is tripped, the following must be done:

- Steam supply to the turbine is stopped or bypassed.
- Firing of the boiler is stopped.
- Coal mills are stopped.
- Coal supply to the coal mills is stopped.
- Field circuit of the alternator is interrupted.
- Field coils are connected across a resistor to dissipate the stored energy.
- Alternator is kept running at a slow speed (few rpm) with the help of barring gear till it cools down uniformly, so as to avoid uneven expansions.

Putting back the alternator on line is rather a slow process because all the parameters (temperatures and pressures) have to be progressively built up to avoid thermal shock resulting in uneven expansions which might cause unacceptable vibrations. Therefore, unscheduled outage of a thermal power station is avoided as far as possible.

We have to keep in mind that a modern large turbo-alternator is a huge mass rotating at a very high speed (3000 rpm) in a very small air-gap. Thus, apart from the large electrical energies involved, there is tremendous amount of mechanical energy in the form of moment of inertia of the rotating mass and resultant forces on the shaft, the rotor body and the stator structure.

Thus, any slight increase in temperature or uneven heating of the rotor may cause eccentricity, which gets accentuated because of the high speed of rotation and small air-gap. The entire system has, therefore, to be run in a narrow range of various parameters like temperatures and pressures, displacements, flows, voltages, currents, power factor, and so forth. The operation outside the specified parameter range may cause a substantial decrease in the life of the equipment.

Since the power station equipment represents a very high investment of money, the operation of the power plant is very closely monitored and controlled.

Figure 8.2 illustrates the complexities of a turbo-alternator in a more detailed manner.

It is said that running a large power station is like flying a supersonic jet aircraft without any forced landings or crashes!

8.2 Electrical Circuit of the Generator

The electrical circuit of the generator is very simple in spite of the complexity of the overall system. This is shown in Figures 8.3(a), 8.3(b) and 8.3(c). It is to be noted that the generator is never solidly grounded. If it were solidly grounded, the single line-to-ground fault current would be dangerously high. Apart from the high value of fault current, the resulting asymmetry in the rotating magnetic field inside the generator

would cause unacceptably large vibrations and result in mechanical damage to the rotor. Hence, in order to limit the short-circuit current, the neutral of the generator is grounded through a resistance. In order to get a practicable value of the grounding resistor, it is connected through a step-down transformer, known as **grounding transformer**.

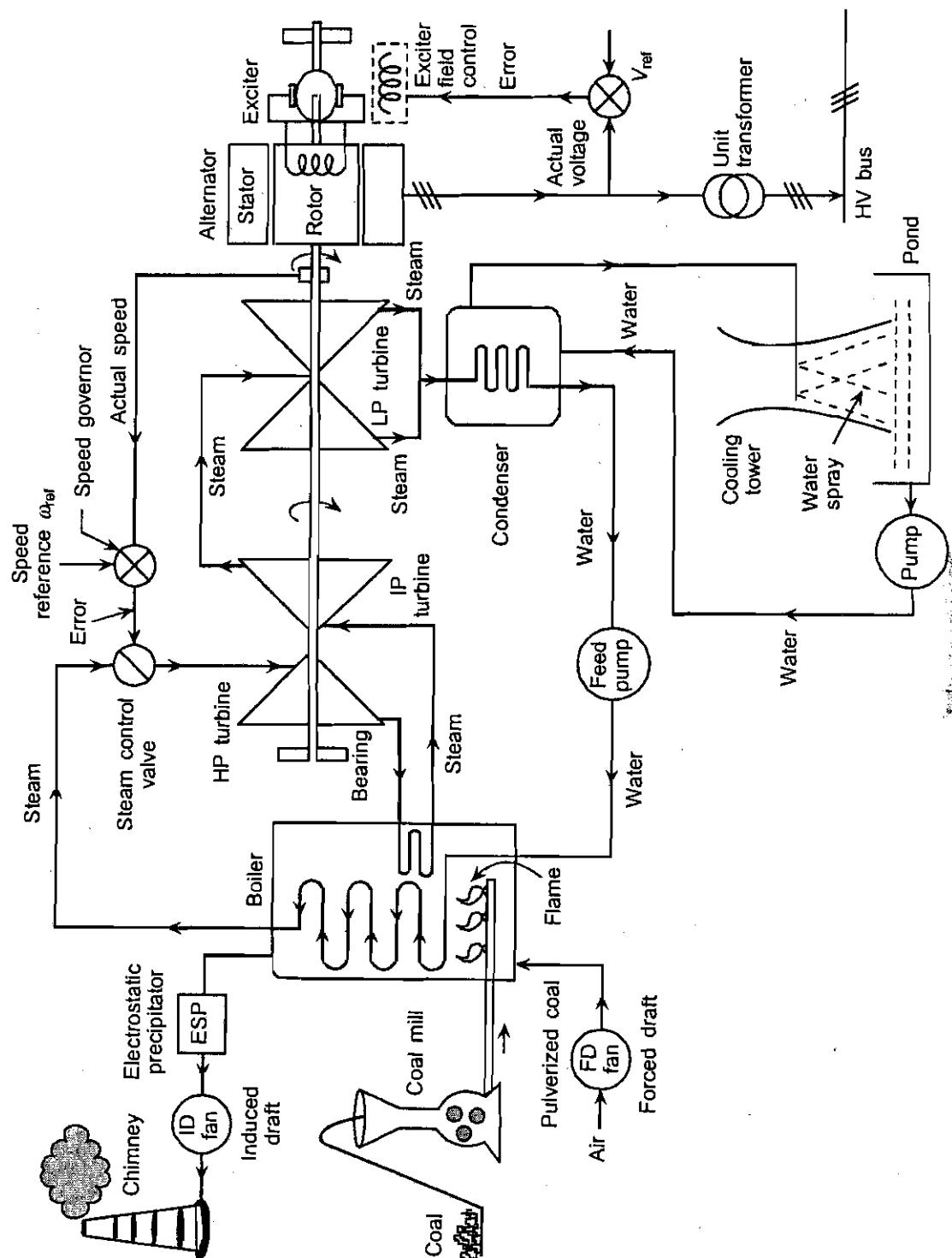


Figure 8.2 Complexities of turbo-alternator protection.

The power plant has a sizeable auxiliary electrical load of its own, of the order of 10% of the power rating of the generator, which is supplied through the *unit auxiliary transformer (UAT)*. It is to be noted that these auxiliaries require power even before the generator can be started, run up to speed and synchronized with the grid. Hence, there is the switching facility to energize the UAT directly from the grid.

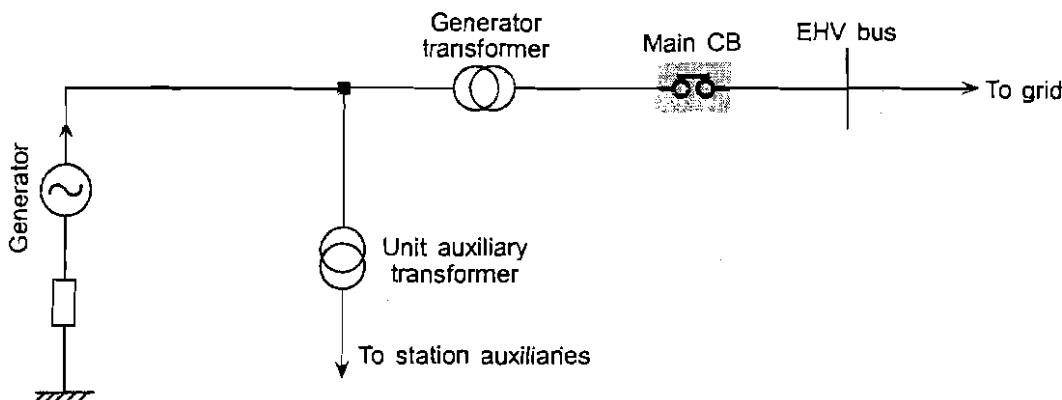


Figure 8.3(a) Alternator unit auxiliary transformer and main CB.

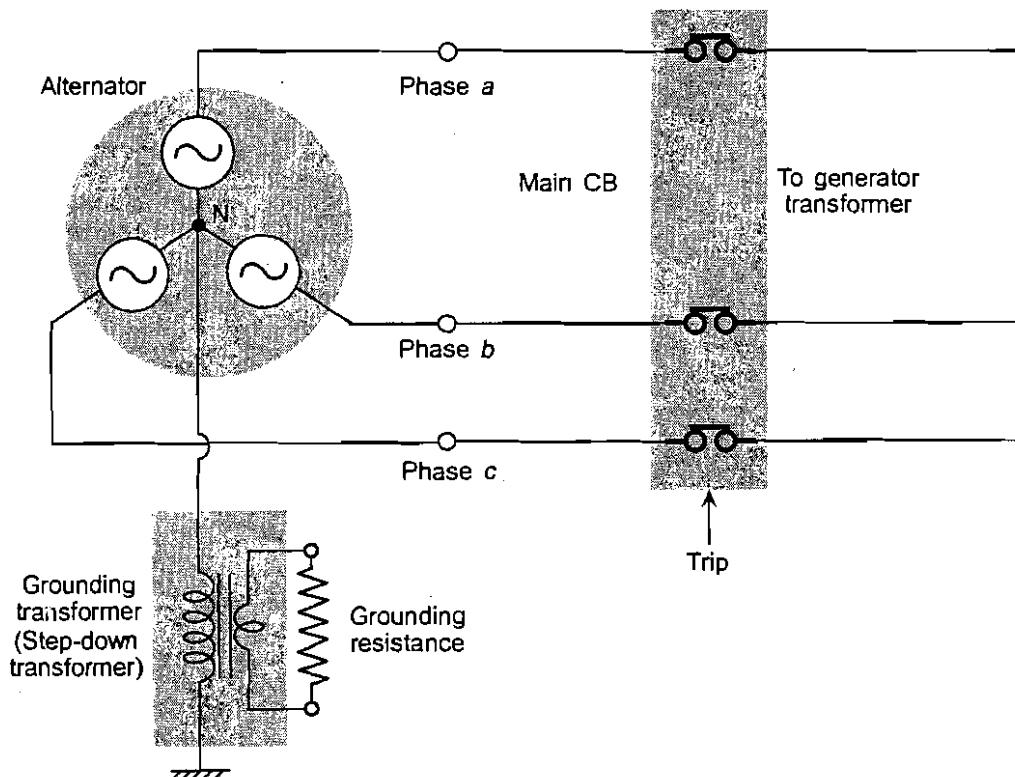


Figure 8.3(b) Alternator and neutral grounding transformer.

The rotor of the generator houses the field winding. A separate dc generator, which is mounted on the turbo-alternator shaft, feeds the field. The dc system is kept floating with respect to the ac ground, i.e. neither the +ve nor the -ve terminal is grounded. The field interrupter and the arrangement for field suppression is also shown in Figure 8.3(c).

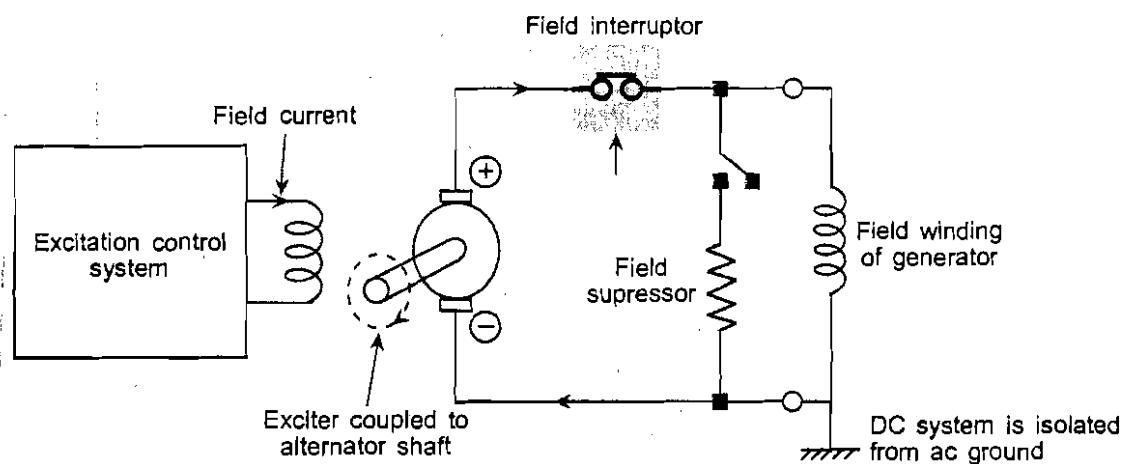


Figure 8.3(c) Electrical circuit of the exciter of the generator.

8.3 Various Faults and Abnormal Operating Conditions

In addition to various electrical faults, a generator goes through many abnormal operating conditions, which need to be understood. Figure 8.4(a) and Figure 8.4(b) show the hierarchy of the electrical faults and abnormal operating conditions.

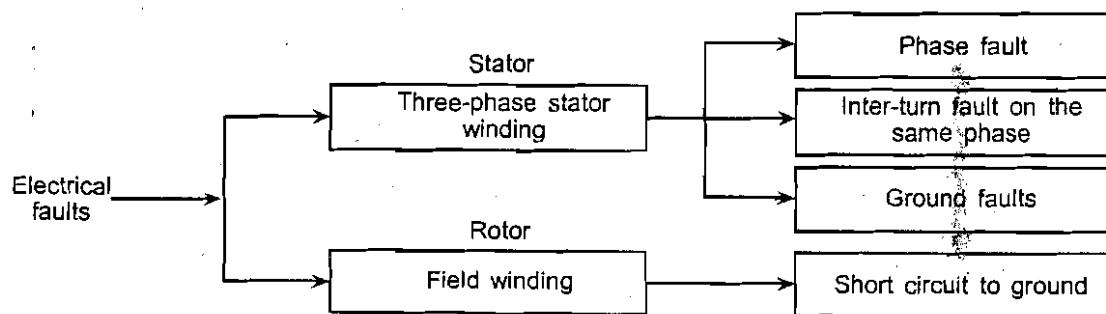


Figure 8.4(a) Various electrical faults on a turbo-alternator.

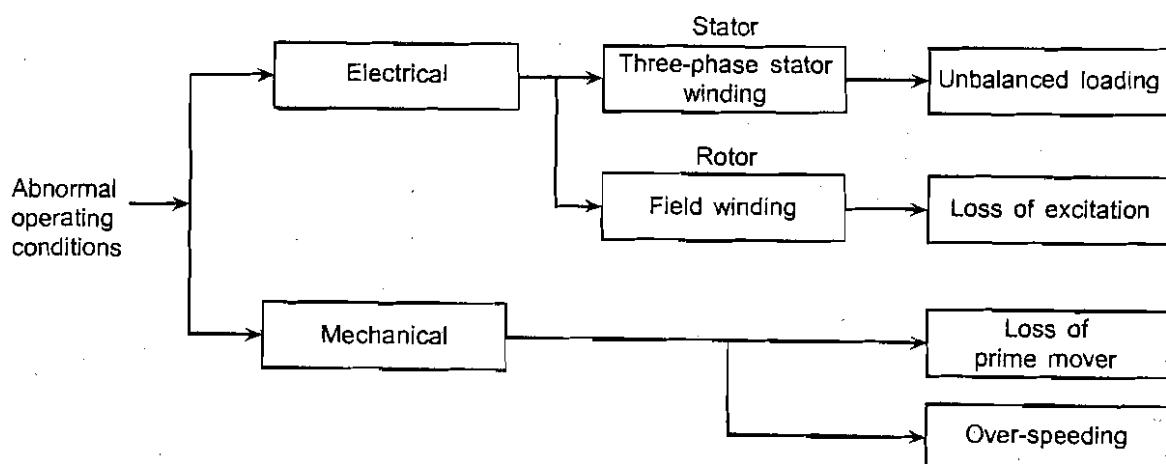


Figure 8.4(b) Various abnormal operating conditions of a turbo-alternator.

8.3.1 Stator Faults

The three-phase armature winding on the stator can develop phase as well as ground faults. Another possibility is inter-turn faults between turns of the same phase.

8.3.2 Stator Phase and Ground Faults

Phase and ground faults on the stator armature winding can be easily detected by a conventional percentage differential protection scheme as shown in Figure 8.5. This type of scheme is also known as *longitudinal differential scheme* in order to differentiate it from another differential scheme, known as *transverse differential scheme* which is used to detect inter-turn faults.

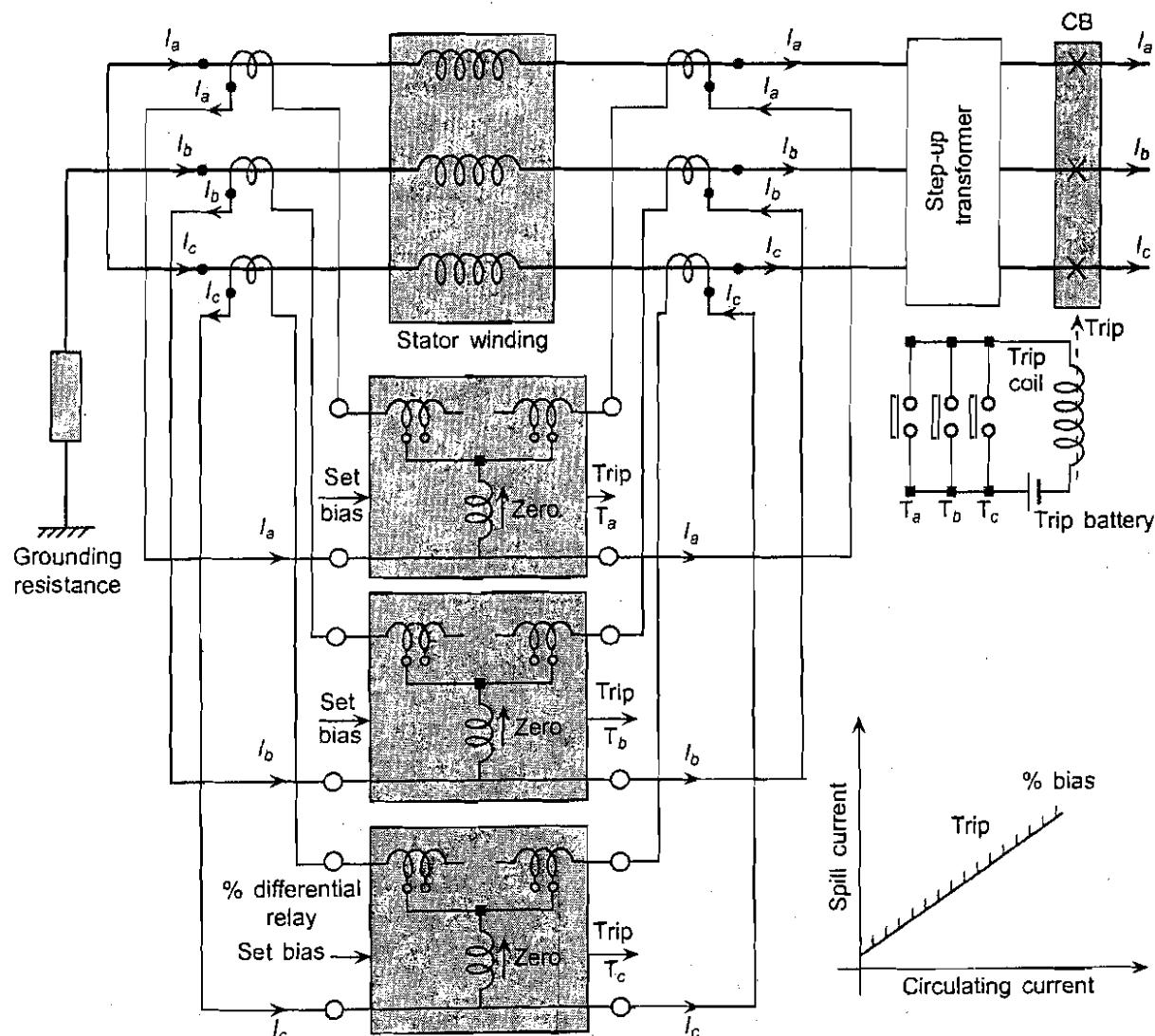


Figure 8.5 Longitudinal percentage differential protection.

It may be noted that there are differences between the differential protection of a power transformer and that of a generator as shown in Table 8.1. As a result of these

differences, the percentage bias setting for the generator differential relay is quite small compared to that for the power transformer.

Table 8.1 Difference between transformer and generator differential protection

<i>Power transformer</i>	<i>Generator</i>
Primary and secondary voltages are in general different	Same voltage for CTs on two sides of the generator winding
Turns-ratio of the CTs are different because of ratio of transformation of the transformer	Turns-ratio of CTs on the two sides of the generator winding is same
Tap changer may be present	No such device is present

This gives rise to a larger spill current, during normal load and external faults, in case of the transformer differential protection than in case of the generator differential protection. Normally, the percentage bias setting of 5–10% is adequate for longitudinal differential protection of the generator stator winding whereas a setting of 20–40% may be required in case of power transformers.

The longitudinal differential scheme caters for phase as well as ground faults on the stator winding. However, it is unable to detect the inter-turn faults between the turns of the same phase. This is discussed in the following Section 8.3.3.

8.3.3 Transverse Differential Protection

In order to apply this type of protection, a special type of split winding is required as shown in Figure 8.6. Current in each parallel section is now compared with that in the other section. If there is an inter-turn fault in one section then the currents will differ and flow as spill current through the OC relay, as shown in Figure 8.6.

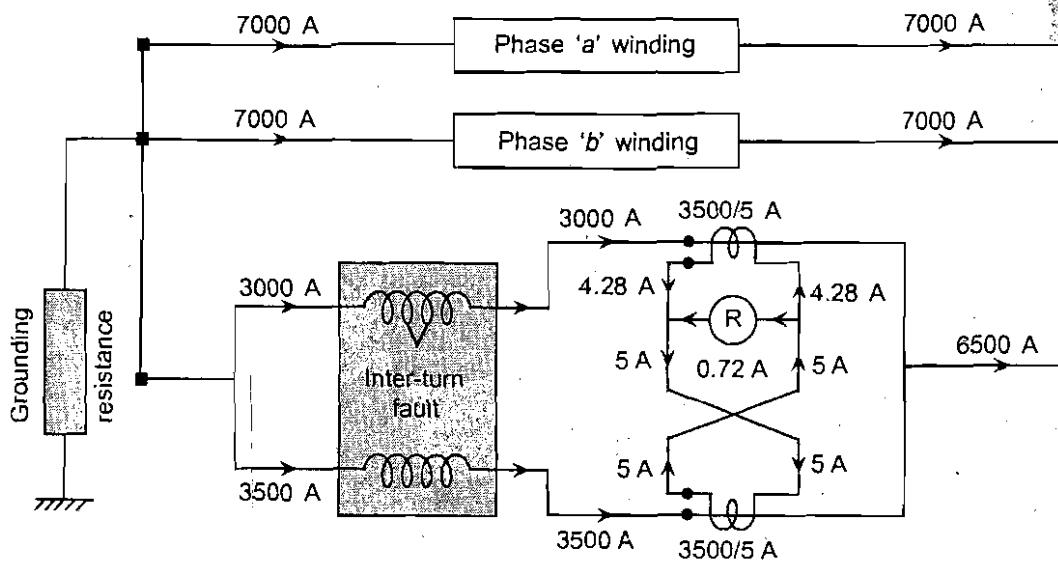


Figure 8.6 Transverse protection of generator winding.

In Figure 8.6, only the winding with the inter-turn fault is shown in detail. The half of the winding in which there is an inter-turn fault is shown to carry 3000 A whereas the

healthy half carries 3500 A. As seen from the figure, the current entering the phase c winding, as a whole, is 6500 A which is the same as that leaving it. Therefore, a longitudinal differential relay would be incapable of detecting such faults.

However, because of the splitting of the winding and transverse connection of the CTs, there is a spill current of 0.72 A in the transverse differential relay. Thus, a setting of, say, 0.5 A will be enough to detect such an inter-turn fault.

8.4 Rotor Faults

The rotor carries the field winding which is kept isolated from the ground. Neither the positive nor the negative terminal of the dc supply is grounded. Thus, any ground fault on the rotor field winding does not affect the working of the alternator. However, a subsequent fault would cause a section of the rotor winding to be short circuited, giving rise to a secondary flux which opposes the main flux in the proximity of the shorted turns, causing distortion in the distribution of main flux. The flux will get concentrated on one pole but dispersed over the other and intervening surfaces. The resulting asymmetry in the electromagnetic forces will cause severe vibrations of the rotor. In a modern turbo-alternator, the inertia of rotation is very large and the rotor-to-stator clearances are very small, therefore, there is a likelihood of permanent damage to the turbo-alternator. Instances have been reported where, during rotor faults, because of severe mechanical stresses structural damage was caused.

In the light of the above, the very first fault on the field winding must be detected and the set tripped in a controlled manner. An arrangement for rotor earth fault detection and protection is shown in Figure 8.7, wherein an external voltage source is superimposed

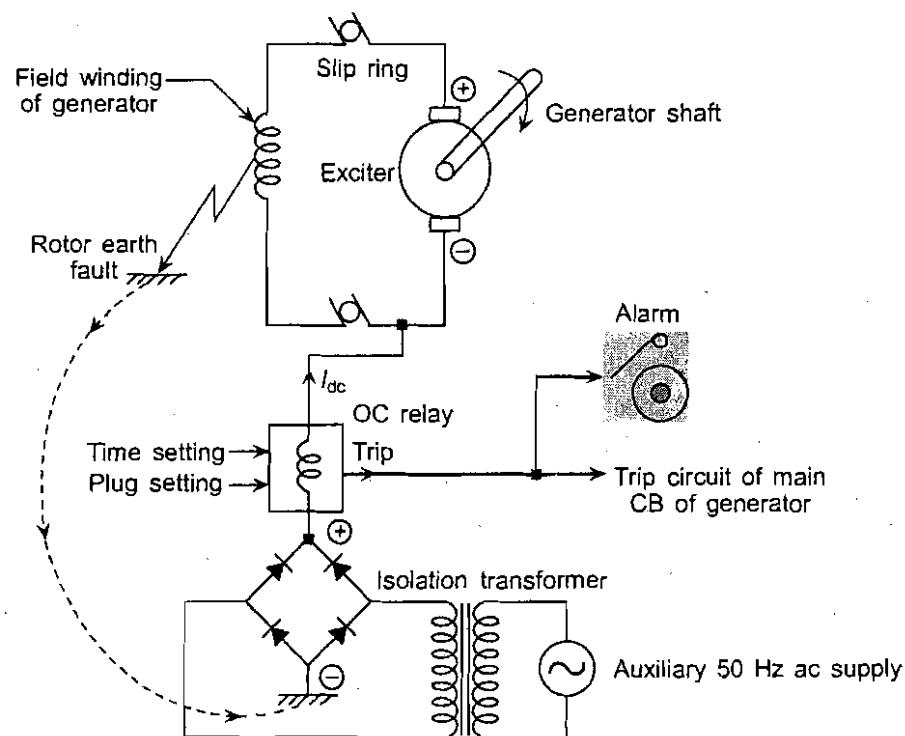


Figure 8.7 Protection against rotor faults.

on the rotor circuit. This external voltage source is grounded so that the very first rotor earth fault causes a dc fault current to flow which is easily detected by an OC relay.

8.5 Abnormal Operating Conditions

As pointed out earlier, a generator cannot be considered in isolation because of a very large number of other equipment connected to it. Even though there is no electrical fault in the generator, if one of its associated equipment develops a fault, then it has serious implications for the generator. Every auxiliary equipment connected to the generator is a likely source of trouble. There are a large number of possible faults, as well as combinations of faults, on these equipment, that threaten the operation of the generator. Instances where there is no direct electrical fault in the generator but one or more of its associated equipment develop a fault or an abnormality, may lead to an abnormal operating condition, which may or may not be serious. However, all abnormal operating conditions need to be detected as quickly and as sensitively as possible so that the corrective action can be taken and a possible shutdown averted or anticipated.

In the following sections, we consider some prominent abnormal operating conditions that need to be carefully considered while providing protection to the generator.

8.5.1 Unbalanced Loading

If there is an unbalanced loading of the generator then the stator currents have a negative sequence component. The stator field due to these negative sequence currents, rotates at synchronous speed but in a direction opposite to the direction of the field structure on the rotor. Thus, the negative sequence stator armature mmf rotates at a speed $-N_S$ while the rotor field speed is $+N_S$. Therefore, there is a relative velocity of $2N_S$ between the two. This causes double frequency currents, of large amplitude, to be induced in the rotor conductors and iron. Recall that the eddy current loss component of iron loss in the rotor is proportional to $f^2(B_{\max})^2$ while the hysteresis loss is proportional to $f(B_{\max})^n$ where $n = 1.6$ to 2 depending upon the core material. Therefore, both the eddy current as well as the hysteresis losses increase due to these double frequency induced currents in the rotor. This is shown in Figure 8.8.

Thus, if the stator carries unbalanced currents, then it is the rotor, which is overheated. How long the generator can be allowed to run under unbalanced loading, depends upon the thermal withstand capacity of the machine, which in turn depends upon the type of cooling system adopted. The rate of heat generation is proportional to $I_2^2 R$ while the heat energy is proportional to $I_2^2 R t$, where t is the time and I_2 is negative sequence current. Since the capacity of a particular machine, to safely dissipate energy, is limited to a certain value k , we can write

$$I_2^2 R t = k$$

Assuming R to be a constant, and $K = k/R$, we get the thermal characteristics of the machine as

$$I_2^2 t = K$$

In other words, the time t for which the offending current I can be allowed to flow should be less than or equal to K/I_2^2 .

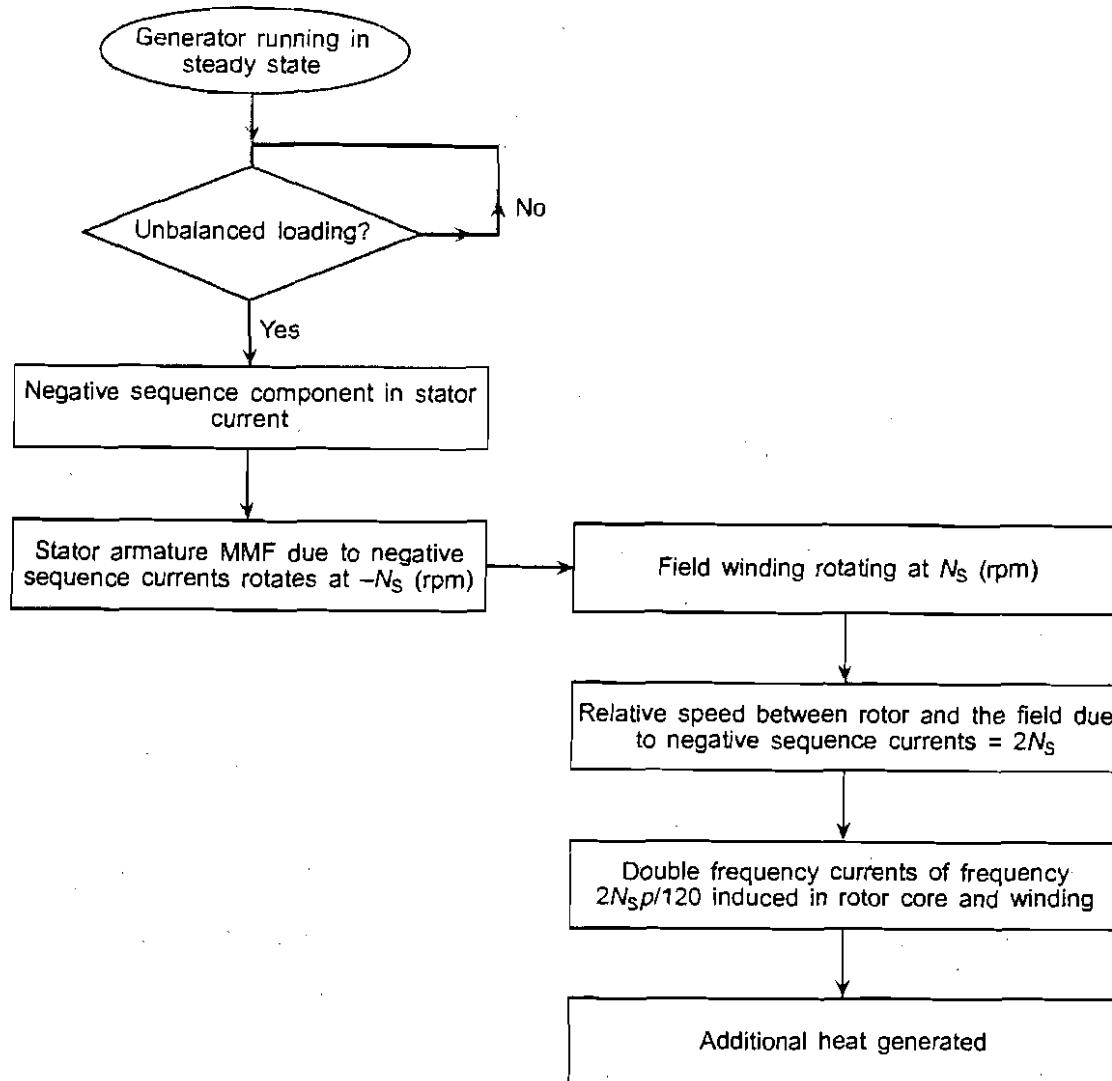


Figure 8.8 Unbalanced loading of stator causes the rotor to overheat.

Thus, the current-time characteristic can be written as

$$t \leq \frac{K}{I_2^2}$$

The readers will recall that this characteristic is similar to that of the inverse time over-current relay. Thus an inverse type of over-current relay, which is fed with the negative sequence component of stator current, gives protection against unbalanced loading of the generator.

The preceding discussion suggests that if we could, somehow, extract the negative sequence component of the stator current then the protection against unbalanced loading can be implemented by applying the inverse-time OC relay as shown in Figure 8.9.

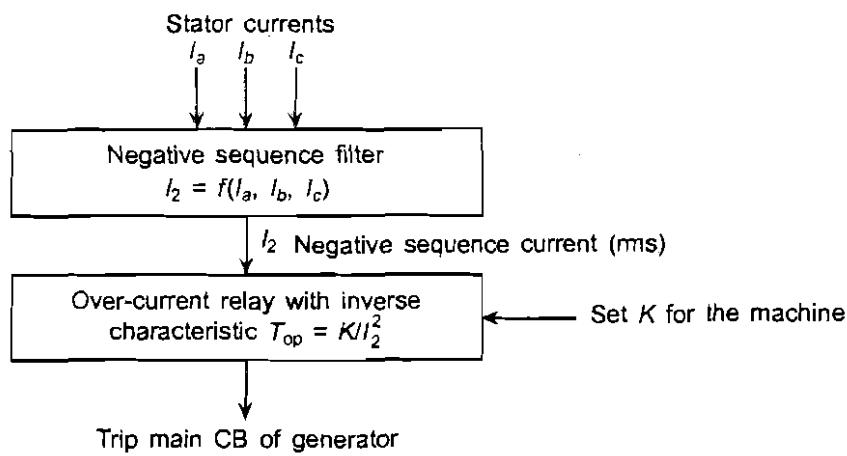


Figure 8.9 Logic of the protection against unbalanced loading.

8.5.2 Over-speeding

Consider that a turbo-alternator is supplying its rated real electrical power P_e to the grid. Its mechanical input P_m is nearly equal to P_e (except for the losses) and the machine runs at constant synchronous speed N_s .

Now, consider that due to some fault the generator is tripped and disconnected from the grid. Thus, P_e becomes zero. However, the mechanical power input P_m cannot be suddenly reduced to zero. Therefore, we land up in a situation where the generator has full input mechanical power but no output electrical power. This would cause the machine to accelerate to dangerously high speeds, if the mechanical input is not quickly reduced by the speed-governing mechanism.

The protection against such an eventuality can be provided by sensing the over-speeding and taking steps such as operating the steam valve so as to stop steam input to the turbine. The speed-governing mechanism or the speed governor of the turbine is basically responsible for detecting this condition. The over-speeding can also be detected either by an over-frequency relay or by monitoring the output of the tachogenerator mounted on the generator shaft. The logic of protection against over-speeding is shown in Figure 8.10.

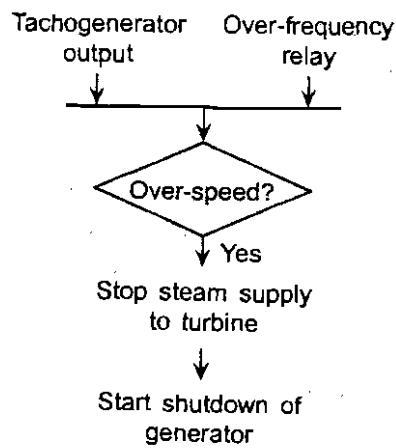


Figure 8.10 Protection against over-speeding.

8.5.3 Loss of Excitation

There are several possible causes due to which field excitation may be lost, namely:

- Loss of field to main exciter
- Accidental tripping of the field breaker
- Short circuit in the field winding
- Poor brush contact in the exciter
- Field circuit breaker latch failure
- Loss of ac supply to excitation system

The generator delivers both real as well as reactive power to the grid. The real power comes from the turbine while the reactive power is due to the field excitation. Consider a generator delivering the complex power, $S = P_e + jQ_e$, to the grid.

Corresponding to real power P_e , there is the shaft mechanical power input P_m and corresponding to reactive power Q_e , there is the field current I_f as shown in Figure 8.11(a) and (b).

Now, consider that the field excitation is lost while the mechanical input remains intact. Since the generator is already synchronized with the grid, it would attempt to remain synchronized by running as an *induction generator*. As an induction generator, the machine speeds up slightly above the synchronous speed and draws its excitation from the grid. This is shown in Figure 8.11(b). Operation as an induction generator necessitates the flow of slip frequency current in the rotor, the current flowing in the damper winding and also in the slot wedges and the surface of the solid rotor body.

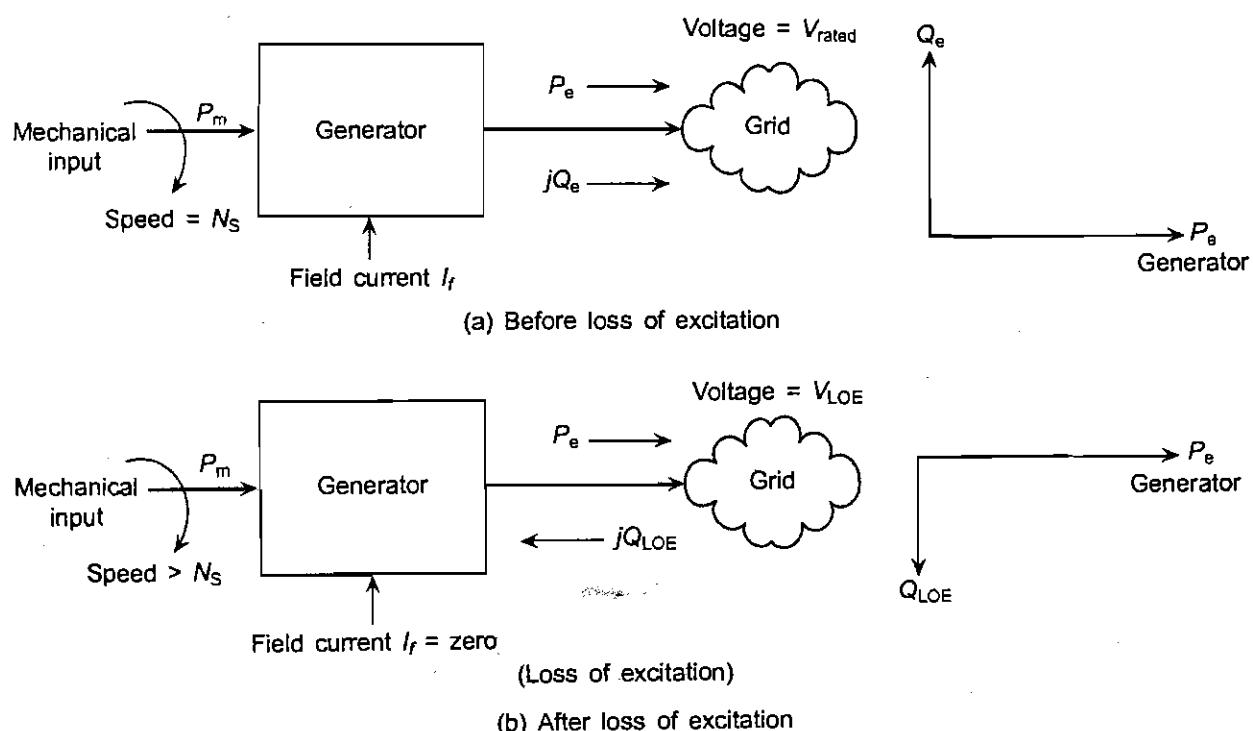


Figure 8.11 Loss of excitation.

Now, there are two possibilities. Either the grid is able to meet this reactive power demand fully or meet it partially. If the grid is able to fully satisfy this demand for reactive power, the machine continues to *deliver* active power of P_e MW but *draws* reactive power of Q_{LOE} MVA and there is no risk of instability. However, the generator is not designed as an induction machine, so abnormal heating of the rotor and overloading of the stator winding will take place.

If the grid were able to meet the reactive power demand only partially then this would be reflected by a fall of the generator terminal voltage. The generator would be under excited. There are certain limits on the degree to which a generator can be operated within the under-excited mode. Therefore, the operation in case of loss of excitation must be quickly detected and checked to avert any shutdown of the generator.

The simplest method by which loss of excitation can be detected is to monitor the field current of the generator. If the field current falls below a threshold, a *loss of field* signal can be raised. A complicating factor in this protection is the slip frequency current induced in the event of loss of excitation and running as an induction generator.

The quantity which changes most when a generator loses field excitation is the impedance measured at the stator terminals. On loss of excitation, the terminal voltage begins to decrease and the current begins to increase, resulting in a decrease of impedance and also a change of power factor.

Thus, loss of excitation can be unambiguously detected by a mho relay located at the generator terminals as shown in the following Section 8.5.4.

8.5.4 Protection Against Loss of Excitation Using Offset Mho Relay

During normal steady-state operation, the impedance seen from the stator terminals, i.e. the apparent impedance lies in quadrant I, of the R - X plane as shown in Figure 8.12.

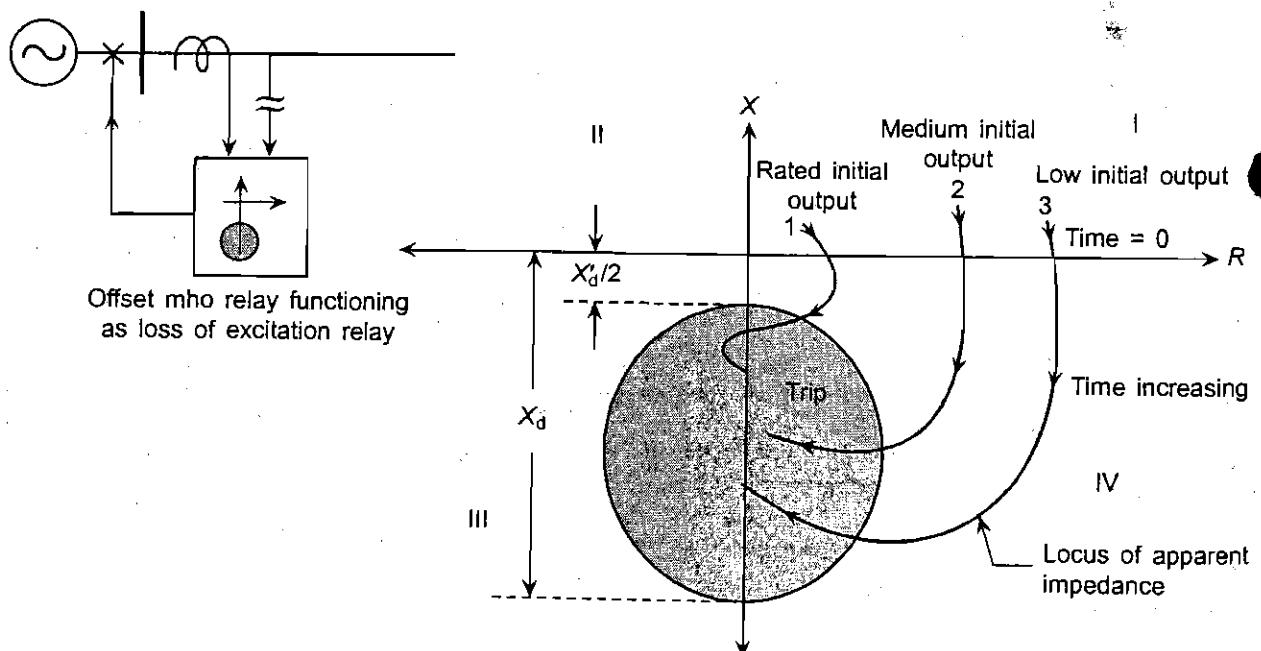


Figure 8.12 Protection against loss of excitation.

After the loss of excitation, the apparent impedance enters quadrant IV. The exact locus of the apparent impedance and the rate at which it is traced out depends upon the initial complex power that was being delivered by the generator. If the initial power output was high then the locus is traced out quickly. However, if the initial power output was low then the locus is traced out rather slowly (taking up to a few seconds).

In order to keep the generator online as long as it is safe, the generator may not be instantaneously tripped in case of loss of excitation. As soon as loss of excitation is detected by the relay, an alarm may be sounded and an attempt may be made to see if excitation can be restored.

A mho type distance relay with offset characteristic may be used for protection against loss of excitation. The offset is by an amount equal to $X_d/2$. The impedance setting of the relay is $|X_d|$ at an angle of -90° as shown in Figure 8.12. In order to give time for change over to the standby exciter by the control circuitry, the relay operation can be delayed by about 0.5–3 s.

8.5.5 Loss of Prime Mover

In case of loss of prime mover, i.e. loss of mechanical input, the machine continues to remain synchronized with the grid, running as a synchronous motor. The machine, now, draws a small amount of active power (compared to its rating) from the grid in order to drive the turbine and meet the losses taking place in the machine. At the same time, the machine supplies reactive power to the grid since its excitation is intact. This is depicted in Figure 8.13(a) and (b). Running in this mode is not harmful to the generator, but is definitely harmful to a prime mover like a steam turbine.

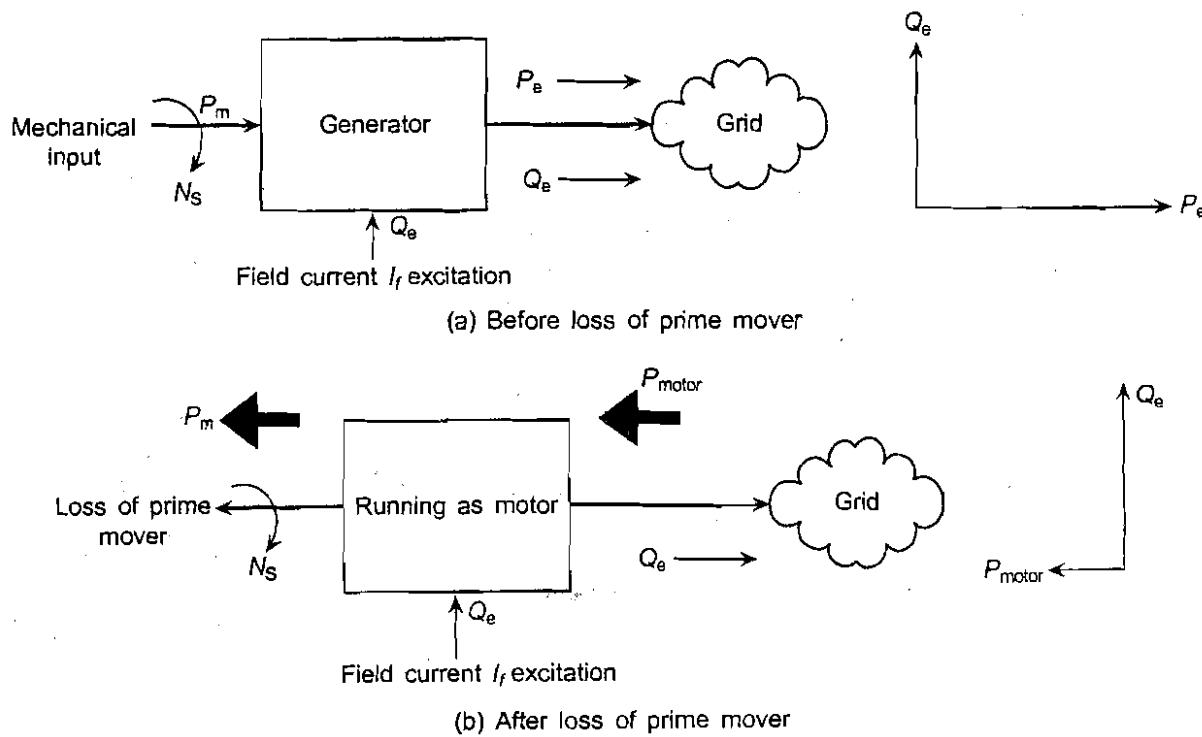


Figure 8.13 Loss of prime mover.

Normally, loss of steam supply to the turbine causes loss of prime mover. When the machine runs as a motor, there is a churning of trapped steam in the turbine causing objectionable temperature rise and damage to the blades. Therefore, the loss of prime mover needs quick detection followed by tripping of generator.

When the prime mover is lost, the generator starts drawing real power from the grid, supplying the reactive power to the grid as before. The real power drawn from the grid is quite small compared with the generator rating. The generator draws real power which is just enough to meet the losses and the load put on it by the turbine. Hence, the magnitude of stator current is smaller than when it was generating, but the stator current undergoes 180° phase shift as shown in Figure 8.14.

This suggests that if we use a directional relay with an MTA of 180° (using generator phase angle conventions) as shown then it would detect the loss of prime mover as the current phasor would reverse and enter the trip region. However, the magnitude of this reversed current phasor is quite small compared to the forward current as the generator draws just enough real power to meet the losses and drive the turbine. Hence, the directional relay for detecting the loss of prime mover needs to have a high degree of sensitivity compared to directional relays used for over-current application.

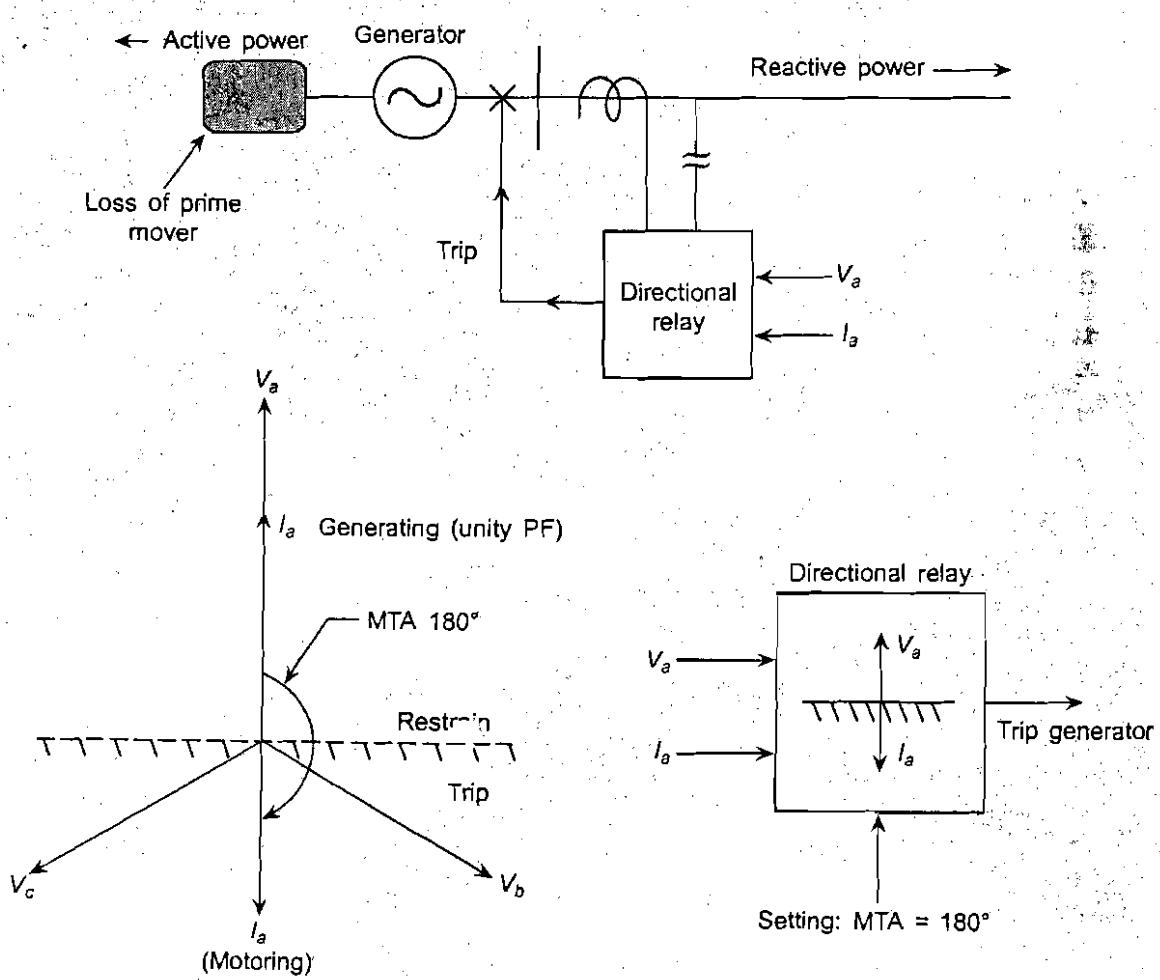


Figure 8.14 Directional relay for protection against loss of prime mover.

Review Questions

1. Discuss the scenario that the turbo-alternator presents to the protection engineer.
2. Tripping the main circuit breaker is not enough protection for a generator. Explain.
3. What are the various faults to which a turbo-alternator is likely to be subjected?
4. Differentiate between longitudinal and transverse differential protection.
5. Why conventional differential protection cannot detect inter-turn faults on the same phase?
6. What are the typical values of % bias used for generator protection? How does this setting compare with that of similar protection for transformer?
7. What special type of winding construction is required in case of transverse differential protection?
8. What are the various abnormal operating conditions to which a modern turbo-alternator is likely to be subjected?
9. Why the first ground fault on the rotor does not cause any damage while a second fault can be catastrophic?
10. What do you mean by loss of excitation (LOE) (in the context of generator protection)?
11. Why does a generator need to be tripped in case of loss of excitation?
12. Why is loss of excitation difficult to detect by monitoring the field current?
13. How does a LOE distance relay work?
14. What causes over-speeding? Explains the remedial action that needs to be taken to prevent over-speeding.
15. What causes loss of prime mover?
16. Can a generator be allowed to run with its prime mover lost? If not, why?
17. How is loss of prime mover detected? What are the problems encountered in implementing this protection?

9

Induction Motor Protection

9.1 Introduction

A stupendous number of induction motors are being used in the industry. The induction motor is truly the *workhorse* of the modern age. Even though the speed control of induction motor is not simple and efficient, the reason for the motor's popularity is its ruggedness and simplicity. However, with the introduction of power electronic controllers, the ease of speed/torque control of the induction motor is now comparable with that of the dc motor.

Induction motors come in a wide range of ratings, from fractional horsepower motors used in tools and domestic appliances to motors of megawatt rating used for boiler feed pump in thermal power stations. A broad classification is presented in Table 9.1.

Table 9.1 Broad classification of induction motors

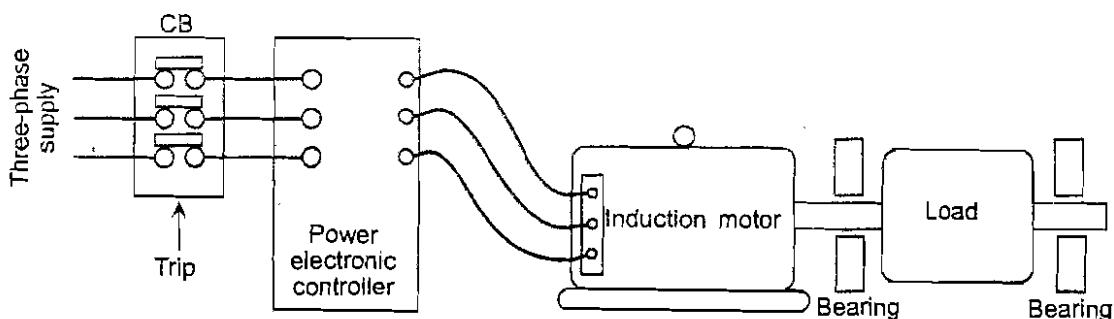
Small	Medium	Big
FHP $< 1 \text{ kW}$	$> 50 \text{ HP}$ $> 40 \text{ kW}$	$> 1500 \text{ HP}$ $> 1000 \text{ kW}$

It is not possible to make any general statements about the protection of induction motor, since the protection scheme depends on the size (horsepower/kW rating) of the motor and its importance in the system. This is the reason why induction motor protection has not been standardized to the extent that other protection schemes have been.

However, regardless of what protection we may provide, all motors, big or small, are subjected to similar faults and abnormal operating conditions.

9.2 Various Faults and Abnormal Operating Conditions

The induction motor cannot be considered in isolation. On the one side, it is connected to the supply, possibly through some kind of power electronic controller and on the other side, it is mechanically coupled to the load. Therefore, the induction motor is subjected to a large number of faults and abnormal operating conditions as depicted in Figure 9.1.



Supply	Motor	Load
1. Fault on motor terminals	1. Phase faults	1. Failure of bearing
2. Unbalanced supply voltage	2. Ground faults	2. Prolonged overload
3. Single phasing	3. Inter-turn faults	3. Rotor jam
4. Reduced supply voltage		
5. Reversal of phases		

Figure 9.1 Abnormal operating conditions and faults experienced on induction motors.

9.3 Starting Current

An induction motor draws a very large starting current, of the order of 6 to 8 times the full-load current if started direct-on-line. The amplitude of the starting current may be comparable to fault current. Therefore, the over-current protection provided to the motor must be able to discriminate between a genuine fault and an over-current due to starting of the motor. Hence, coordination between the starting characteristic of the motor and the over-current relay is required. Figure 9.2 shows the starting current superimposed on the thermal capability curve of the motor, and the characteristic of an over-current relay, which might be used for protection of the motor. It can be seen from Figure 9.2 that the OC relay characteristic must be above the starting characteristics but below the thermal characteristics of the motor. This will ensure that the protective relay does not operate during starting phase the motor but will positively operate when the load exceeds the motor's thermal capability.

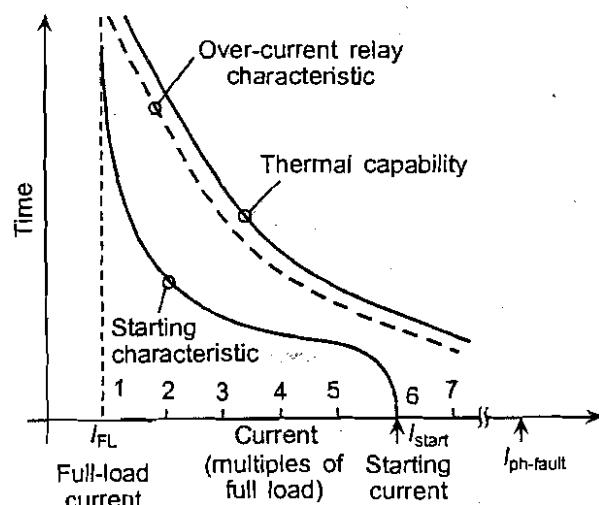


Figure 9.2 Starting and thermal characteristics of induction motor.

9.4 Electrical Faults

9.4.1 Fault on Motor Terminals

The phase-fault current at the terminals of a motor is considerably larger than any normal current such as starting current or any internal-fault current. Hence, a high set instantaneous over-current relay is recommended for fast, reliable, inexpensive and simple protection.

9.4.2 Phase Faults Inside the Motor

Protection against phase faults as well as ground faults can be provided using either fuses or over-current relays depending upon the voltage rating and size of the motor. Most motors will be protected by HRC fuses (Figure 9.3). The fusing current should be greater than the starting current of the motor. The fuse operating time should be less than the permissible *locked rotor time* of the motor. The locked rotor time is the time for which the rotor can be safely stalled with full supply voltage applied to the stator.

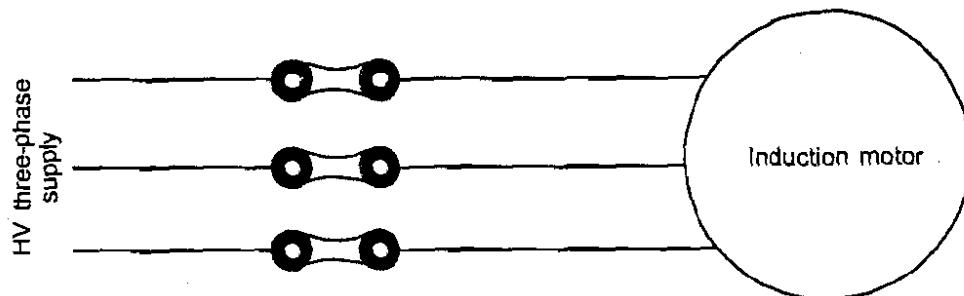


Figure 9.3 HRC fuses for protection of induction motor.

Big motors, which are high voltage motors, will need to be provided with an over-current protection for increased accuracy of protection as shown in Figure 9.4. The thermal capability characteristic of the motor should be kept in mind while applying over-current protection. The OC relay characteristic should be below the thermal capability characteristic as shown in Figure 9.2.

In case of high impedance ground faults inside the motor, the fault current may happen to be less than the full-load current. Such faults are difficult to detect using over-current approach. A current balance type of protection caters for such faults as explained in Section 9.4.3.

In case of big motors whose kVA rating is more than half of the supply transformer kVA rating, the current for a three-phase fault may be less than five times the current for locked rotor condition. In such cases, it is recommended to use percentage differential protection as shown in Figure 9.5. If the motor kVA rating is less than half of the supply transformer kVA rating, over-current relays can be relied upon. The logic for this criterion can be explained as follows:

Assume a motor is connected to a supply transformer with 8% impedance. The maximum fault current at the transformer secondary with an infinite source is:

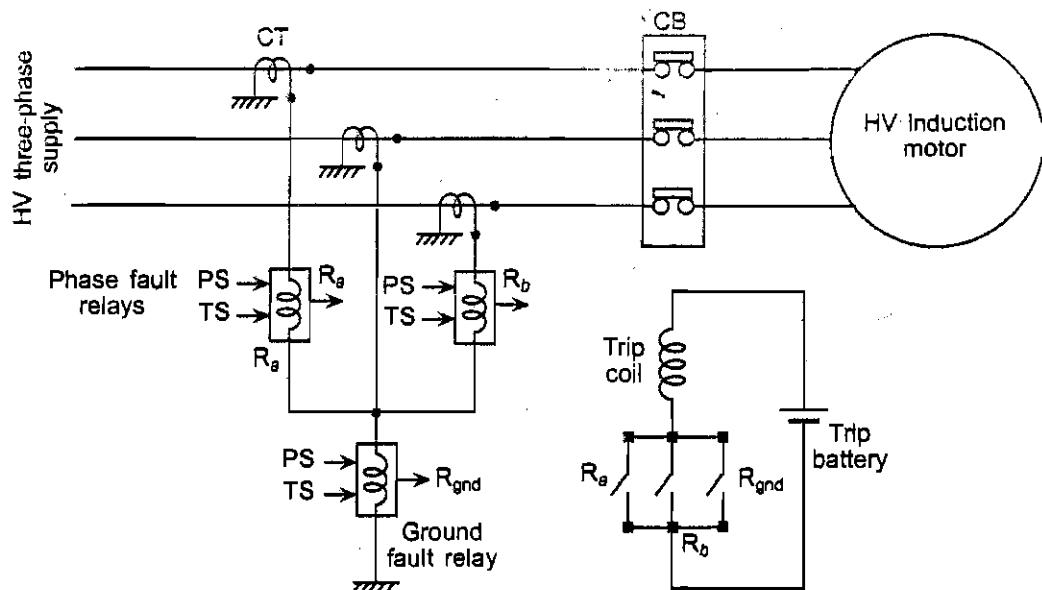


Figure 9.4 Phase fault and ground fault protection of HV induction motor.

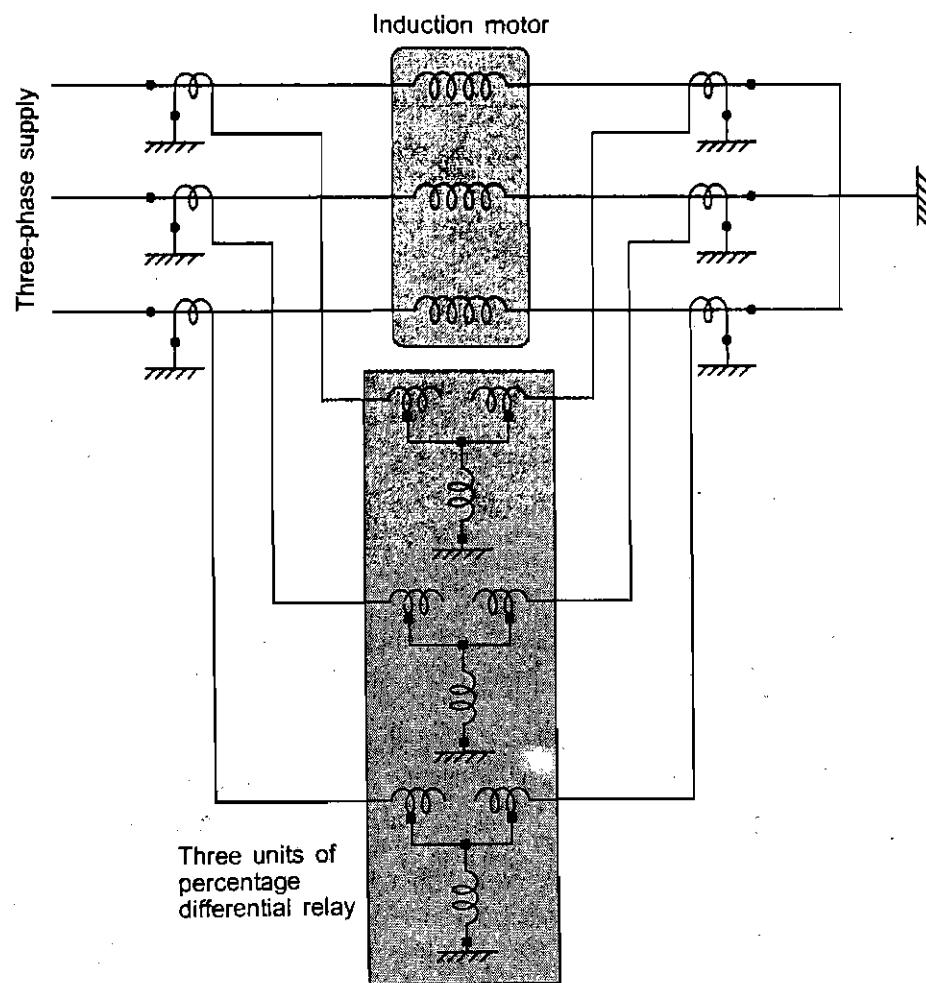


Figure 9.5 Percentage differential relay for protection of induction motor.

$$I_{3\text{-ph}} = \frac{1}{0.08} = 12.5 \text{ per unit on transformer base}$$

The maximum motor starting current in this case is

$$I_{LR} = \frac{1}{0.08 + X_M}$$

where X_M is the motor impedance. In order that $(I_{3\text{-ph}}/I_{LR}) > 5$, X_M must be greater than 0.32 per unit on the transformer kVA base.

If the motor has a full-voltage starting current of six times the full load, then $X_M = 1/6 = 0.167$ on the motor rated kVA base. With a motor kVA of half of the transformer kVA, an X_M of 0.167 would be 0.333 on the transformer base, which is greater than 0.32. Clearly, this rule of thumb should only be applied when there is no appreciable deviation from the parameters assumed above.

9.4.3 Ground Faults Inside the Motor

Figure 9.6 shows an arrangement for detecting high impedance ground faults. The three-phase line conductors carrying current to the motor form the primary of a transformer. The secondary consists of a pick-up coil wound on the core.

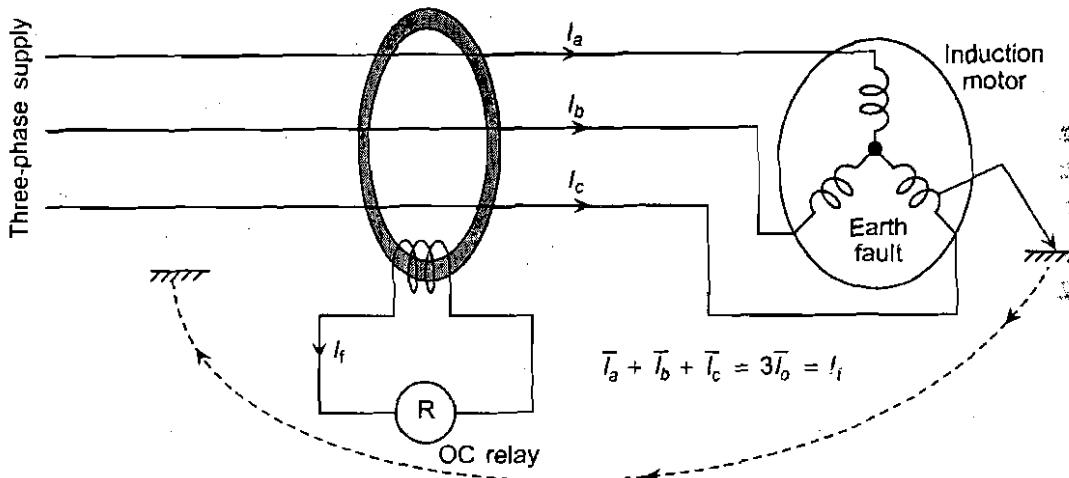


Figure 9.6 Earth fault protection for induction motor.

When the motor is running normally, the instantaneous sum of all the three line currents is zero. Thus, there is no net flux in the core. Hence, the pick-up coil does not have any voltage induced in it.

Now, consider a ground fault as shown. The three line currents do not sum up to zero. Thus, there is a net primary mmf proportional to the fault current I_f , returning to the supply neutral through the fault path. There is, thus, a flux in the CT core. The pick-up coil has a voltage induced which can be sensed by an electronic circuitry or the pick-up coil can be made to drive the operating coil of a sensitive relay.

If an electronic circuit is used to sense the voltage developed by the pick-up coil, the current balance relay described above can be made extremely sensitive and can detect earth fault currents down to a few tens of milliamperes. Very high sensitivity, however, is likely to cause some nuisance tripping.

9.4.4 Inter-turn Faults

Inter-turn faults on the same phase are difficult to detect because they do not cause appreciable change in the current drawn by the motor. However, such faults cause hot spots to develop, leading to deterioration of insulation.

No specific protection against inter-turn faults is needed for most motors except very big motors. Embedded temperature detectors may be relied upon to provide protection against inter-turn faults.

9.5 Abnormal Operating Conditions from Supply Side

An induction motor is subject to many abnormal operating conditions as far as the electric supply side is concerned. In some cases, quick disconnection of the motor may be needed and, in others, only an alarm may be sounded for an operator to take corrective action or be ready for shutdown.

9.5.1 Unbalanced Supply Voltage

Large induction motors are very sensitive to unbalances in supply voltage. The negative sequence component, which comes into picture because of the unbalance in the supply, is particularly troublesome. This is because the motor offers very small impedance to the negative sequence currents. In fact, the negative sequence impedance is less than the positive sequence standstill-impedance as shown in Figure 9.7. Thus, a 4% negative sequence supply voltage causes more than 24% negative sequence current to be drawn by the motor, if the starting current of the motor is six times the full-load current. This causes increased heating of the stator.

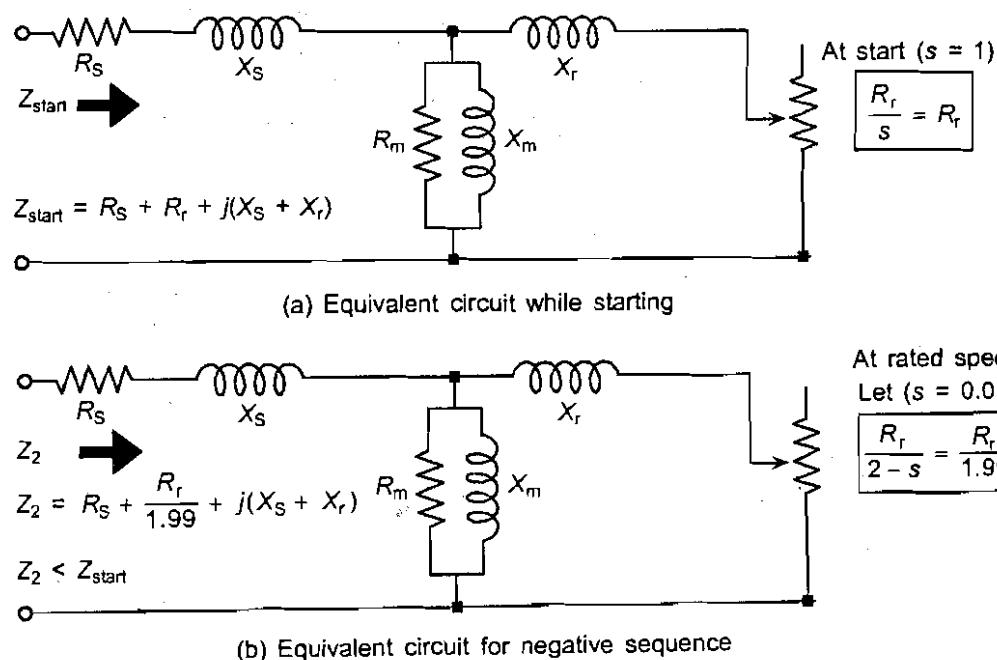


Figure 9.7 Equivalent circuit of induction motor.

Further, the magnetic field due to negative sequence rotates at synchronous speed N_S in a direction opposite to that of the rotor which is rotating at a speed equal to (sN_S) , where s is the slip of the motor. This causes currents of $[f(2 - s)]$ frequency, i.e. almost double the supply frequency, to be induced in the rotor circuit. Because of skin effect, the rotor offers five to ten times its normal resistance to these double frequency currents, thus, causing excessive heating of the rotor.

Therefore, for large motors any unbalance in the supply voltage needs to be quickly detected and corrective action taken. A scheme for detecting unbalanced supply voltage is shown in Figure 9.8.

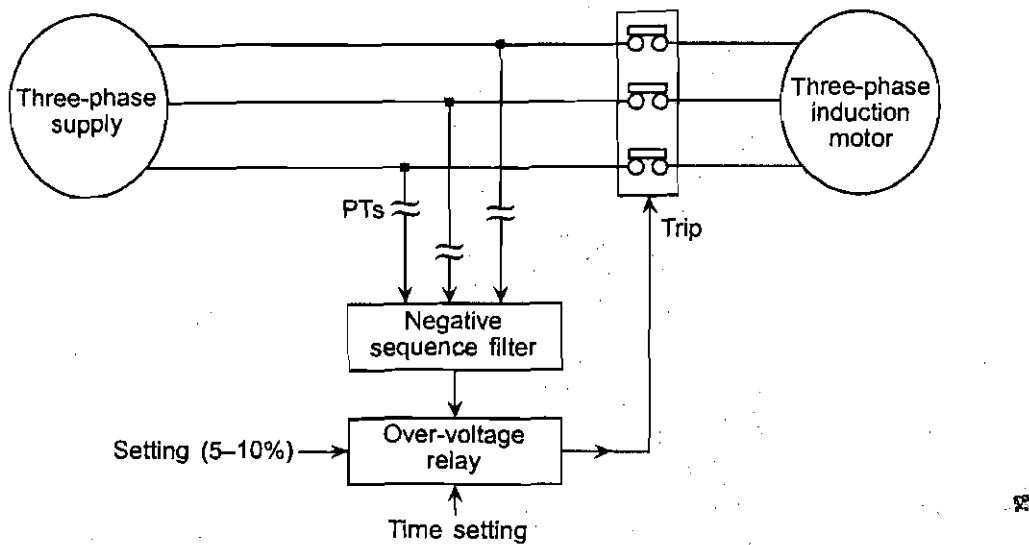


Figure 9.8 Negative sequence voltage relay for protection against unbalance in supply voltage.

There are certain situations where the negative sequence relay does not operate correctly. For example, if there is an open circuit fault between the supply and the relay then the relay measures the negative sequence voltage across the motor, which is substantial and, therefore, the relay operates correctly. This is shown in Figure 9.9.

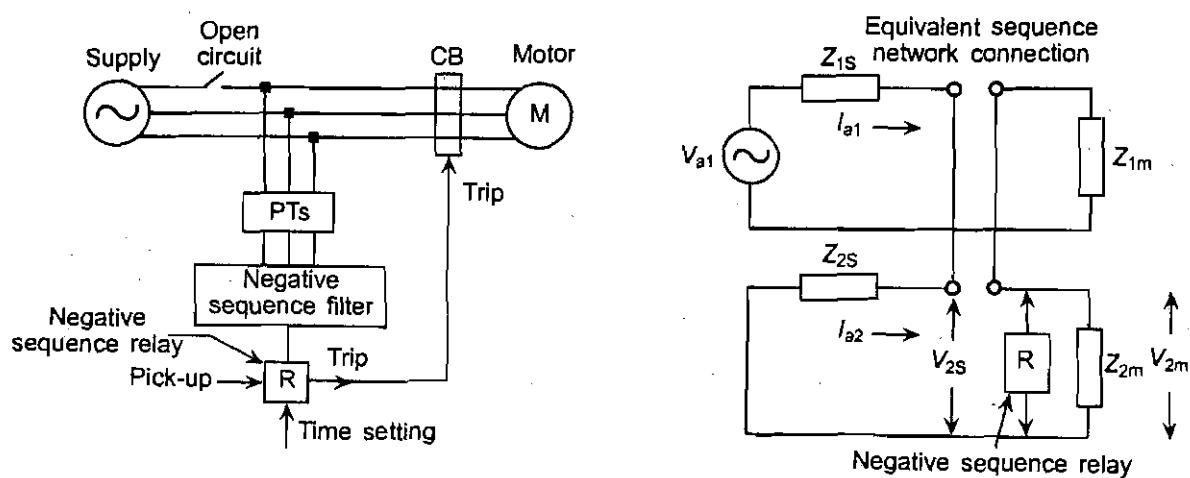


Figure 9.9 Negative sequence voltage relay correctly detects an open circuit between supply and relay.

However, if the open circuit is between the relay and the motor then the negative sequence relay ends up measuring the negative sequence component of the supply voltage, which is very small and does not cause the relay to pick up as shown in Figure 9.10.

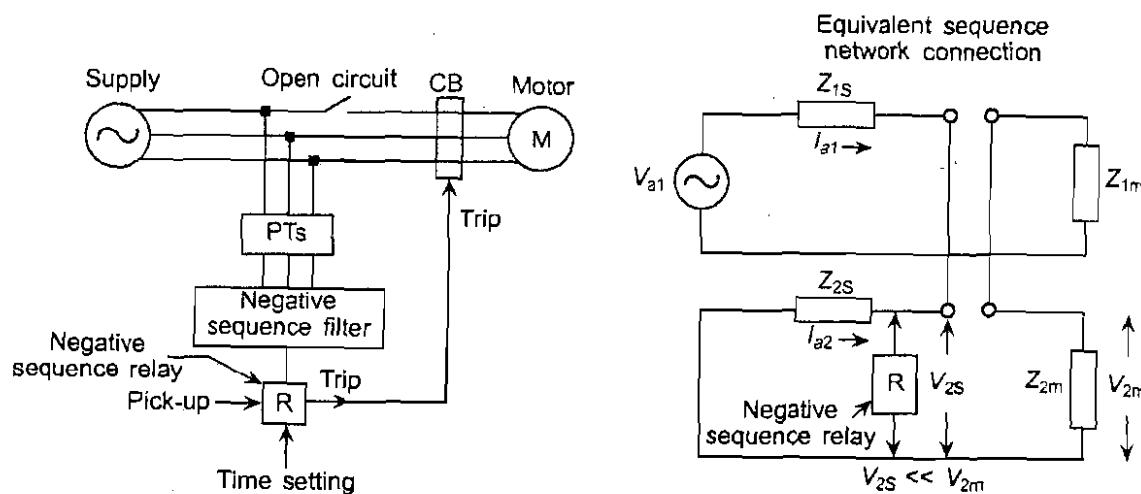


Figure 9.10 Negative sequence voltage relay fails to detect an open circuit between relay and motor.

For positive detection of such faults, we need to detect the negative sequence component in the line currents. This is described in Section 9.5.2.

9.5.2 Single Phasing

Single phasing can occur because of a non-closure of one pole of a three-phase contactor or circuit breaker, a fuse failure or similar causes.

Single phasing causes negative sequence current to flow. The motor has a limited ability to carry negative sequence currents, because of thermal limitations.

Single phasing causes the motor to develop insufficient torque, leading to stalling, making the motor to draw excessive current and finally leads to burn out unless the motor is tripped.

Thus, there is a thermal limit on the amount of the negative sequence current that can be safely carried by the motor. The quantity $I_2^2 t$ represents the energy liberated as heat due to negative sequence current I_2 .

$I_2^2 t = 40$ is conventionally used as the thermal capability of motor to carry negative sequence current.

Figure 9.11 shows the characteristic of a relay for detecting imbalance in the line currents. The relay consists of two units. One unit balances I_a against I_b while the other balances I_b against I_c . When the currents become sufficiently unbalanced, torque is developed in one or both units causing the relay to trip. The relay can be set to pick up when negative sequence current $I_2 = 5\text{--}30\%$ of the full-load current.

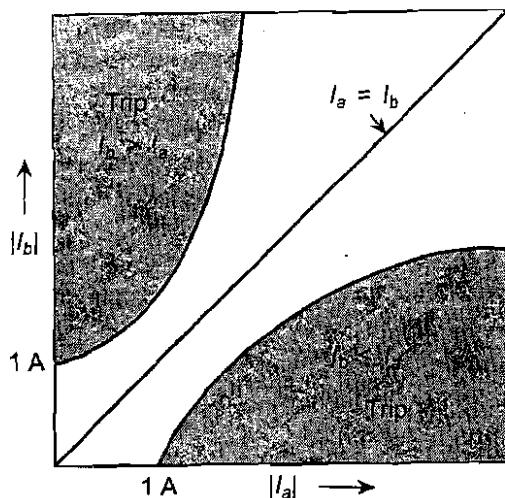


Figure 9.11 Negative sequence current relay to detect single phasing.

9.5.3 Reduction in Supply Voltage

The torque developed by an induction motor is proportional to the square of the applied voltage, therefore, any small reduction in voltage has a marked effect on the developed torque. The reduced torque may cause the motors to lose speed and draw more current.

Large motors should be disconnected when a severe low voltage condition persists for more than a few seconds.

Under-voltage relays may be used for protection against reduced supply voltage.

9.5.4 Reversal of Phases

When there is a reversal of phase sequence, possibly due to reversal of phases, the motor rotates in a direction opposite to its normal direction of rotation. In several applications, such as hoists and elevators, this is a serious hazard. In such situations, a phase sequence detector, which is generally a part of under-voltage/over-voltage, or a negative phase sequence protection scheme, can be used to instantaneously trip the motor.

9.6 Abnormal Operating Conditions from Mechanical Side

9.6.1 Failure of Bearing and Rotor Jam

Bearing failure or rotor jam causes excessive load torque on the motor. This is reflected in the increase in stator current. In order to discriminate between rotor jam and other operating conditions that can also cause over-current, the high current is not recognized as a jam condition unless the motor has reached its rated speed and the current is in excess of 20% of full load persisting for at least twice the locked rotor time setting.

9.6.2 Overload

Thermal overload relays offer good protection against short, medium, and long duration overloads but may not provide protection against heavy overloads shown in Figure 9.12.

The long time induction over-current relays provide good protection against heavy overloads but over-protection against light and medium overloads, as shown in Figure 9.13. Therefore, a combination of both the relays provides adequate protection as shown in Figure 9.14.

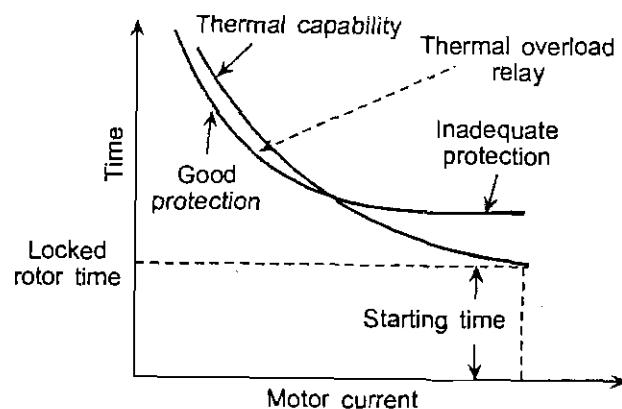


Figure 9.12 Thermal overload relays offer good protection against short, medium, and long duration overloads.

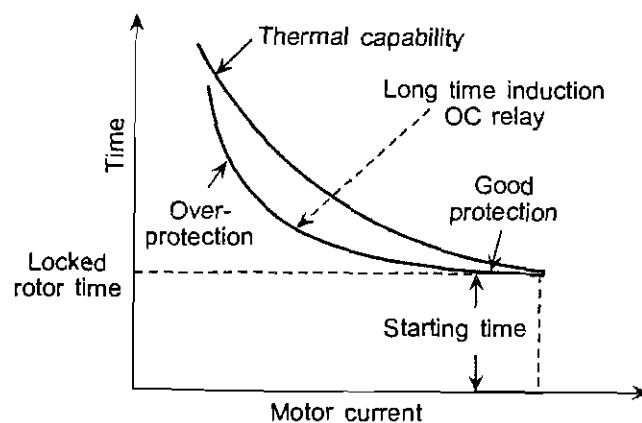


Figure 9.13 Long time induction OC relays offer good protection against heavy overloads.

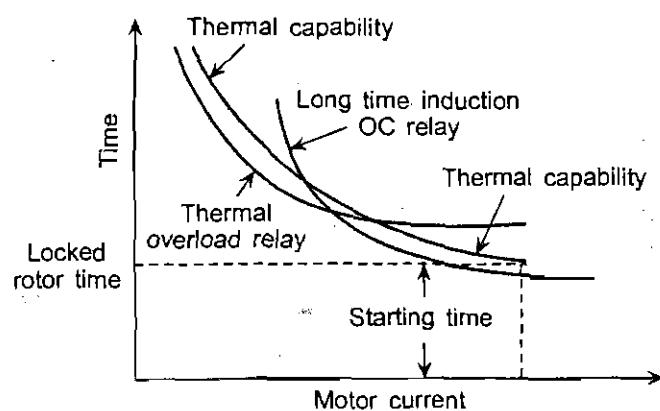


Figure 9.14 Combination of thermal overload relays and OC relays provides complete thermal protection.

Resistance temperature detector relays (RTDs)

These relays operate from one or more RTDs that monitor the temperature of the machine winding, motor or load bearings or load case. They are usually applied to large motors of 1500 HP and above.

Figure 9.15 shows an RTD which is embedded in the machine connected to a Wheatstone bridge. The arms of the bridge are adjusted so that the bridge is balanced at normal temperature. A sensitive relay in the form of a contact making dc galvanometer may be connected as a detector.

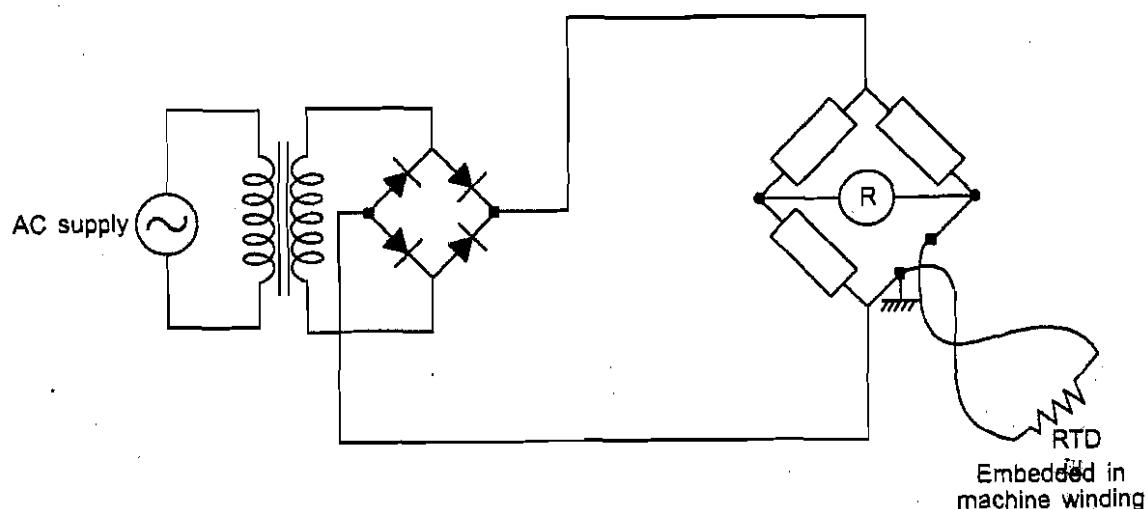


Figure 9.15 RTD embedded in the machine connected to a bridge

The RTD is an excellent indicator of average winding temperature, however, it is influenced by ambient temperature, ventilation conditions and recent loading history. Several types of RTDs are available for use in temperature monitoring, namely $10\ \Omega$ copper, $100\ \Omega$ nickel, $120\ \Omega$ nickel, $120\ \Omega$ platinum.

Thermal replica relays

Replica type relays are designed to replicate, within the relay operating unit, the heating characteristics of the machine. Thus, when current from the CT secondary passes through the relay, its time over-current characteristic approximately parallels that of the machine capability curve at moderate overload.

The thermal replica relays are recommended when the embedded temperature detectors are not available, otherwise the RTD input type relays may be used.

Replica relays are typically temperature compensated and operate in a fixed time at a given current regardless of relay ambient variations. Although this characteristic is desirable for the stated condition, it produces under-protection for high motor ambient and over-protection for low motor ambient.

9.7 Data Required for Designing Motor Protection Schemes

The following data is required for designing the various motor protection schemes:

- HP rating
- Supply voltage
- Full-load current
- Permissible continuous allowable temperature rise
- Locked rotor current
- Permissible maximum time with locked rotor
- Accelerating time
- Starting voltage

Review Questions

1. What are the various abnormal operating conditions from supply side to which an induction motor is likely to be subjected?
2. What are the various abnormal operating conditions from the load (mechanical) side to which an induction motor is likely to be subjected?
3. Why is an induction motor very sensitive to unbalance in supply voltage?
4. What are the consequences of running an induction motor on unbalanced supply voltage?
5. What are the effects of running an induction motor at reduced supply voltage?
6. Why is protection of an induction motor against reversal of phase sequence required?
7. What kind of protection is provided to an induction motor against overload?
8. How is the thermal replica relay used to protect the induction motor?
9. What are the effects of single phasing on the induction motor?
10. What is the effect of blocked rotor on the motor? What protection is provided against blocked rotor?
11. Why a negative sequence voltage relay cannot detect single phasing between relay and motor but can detect single phasing between the supply and the relay?
12. What data is required for designing a scheme for motor protection?

10

Static Comparators as Relays

10.1 Comparison vs Computation

An over-current relay compares the magnitude of the current in its current coil with a set value and operates if the current is more than the set value. A directional relay compares phase angle of the measured quantity (i.e. current) with a reference phasor (i.e. voltage) and operates if this phase angle exceeds a predetermined threshold. A simple impedance relay compares the torque generated by the current (operating torque) with the torque generated by the voltage (restraining torque) at the relay location and operates if the operating torque is greater than the restraining torque. All the relays perform some or the other kind of comparison. Thus, at the heart of any relay, is always a *comparator*. Historically, these comparators were implemented using electromechanical technology. But eventually the electromechanical relays gave way to the solid-state relays.

An alternative strategy to comparison is to perform direct numerical computation. However, in the past, when electromechanical relays were being widely used it was not possible to perform the numerical computation in a relay. The comparators helped in avoiding direct numerical computation. The relays based on comparators were found to be quite simple and robust. This gave rise to the technology of protective relays built around comparators.

The metaphor of the comparator-based relay was so powerful that long after numerical computation became easily possible in protective relays, the engineers continued to implement the comparator-based relays in their relaying algorithms.

The comparator-based relays are very attractive because of their inherent simplicity and low cost. However, they suffer from the drawback that (since a comparator-based relay essentially gives a go-no-go type of decision) the fault cannot be precisely located.

The comparators can be classified into two types; those based on comparison of amplitude and those based on comparison of phase angle.

10.2 Amplitude Comparator

The amplitude comparator has two inputs, S_o and S_r , and a trip output. Both the inputs

are phasors. The input phasor S_o is called the *operating quantity* and the input phasor S_r is called the *restraining quantity*. The amplitude comparator follows the simple law (Figure 10.1)

If $|S_o| > |S_r|$ then trip; else restrain

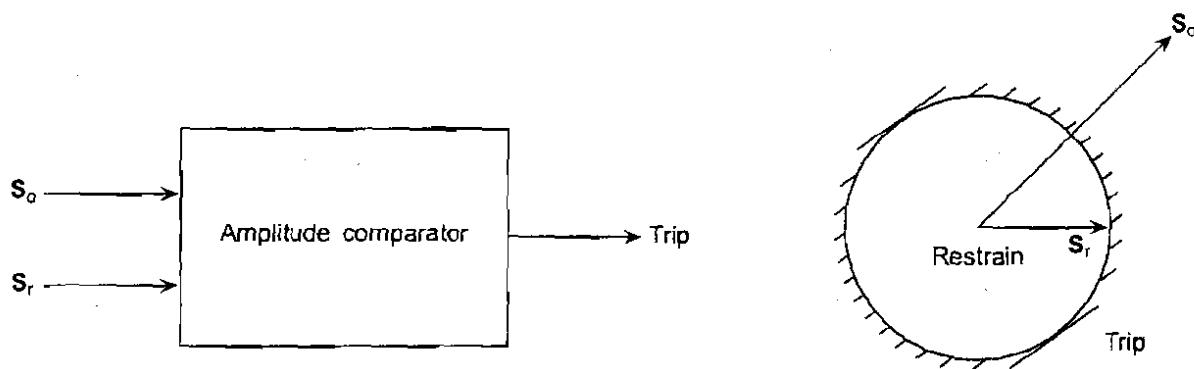


Figure 10.1 Amplitude comparator.

Some specific instances where the amplitude comparator gives the trip output are shown in Figure 10.2(a), which emphasize the fact that the amplitude comparator responds only to amplitude and is blind to the phase angle between the inputs.

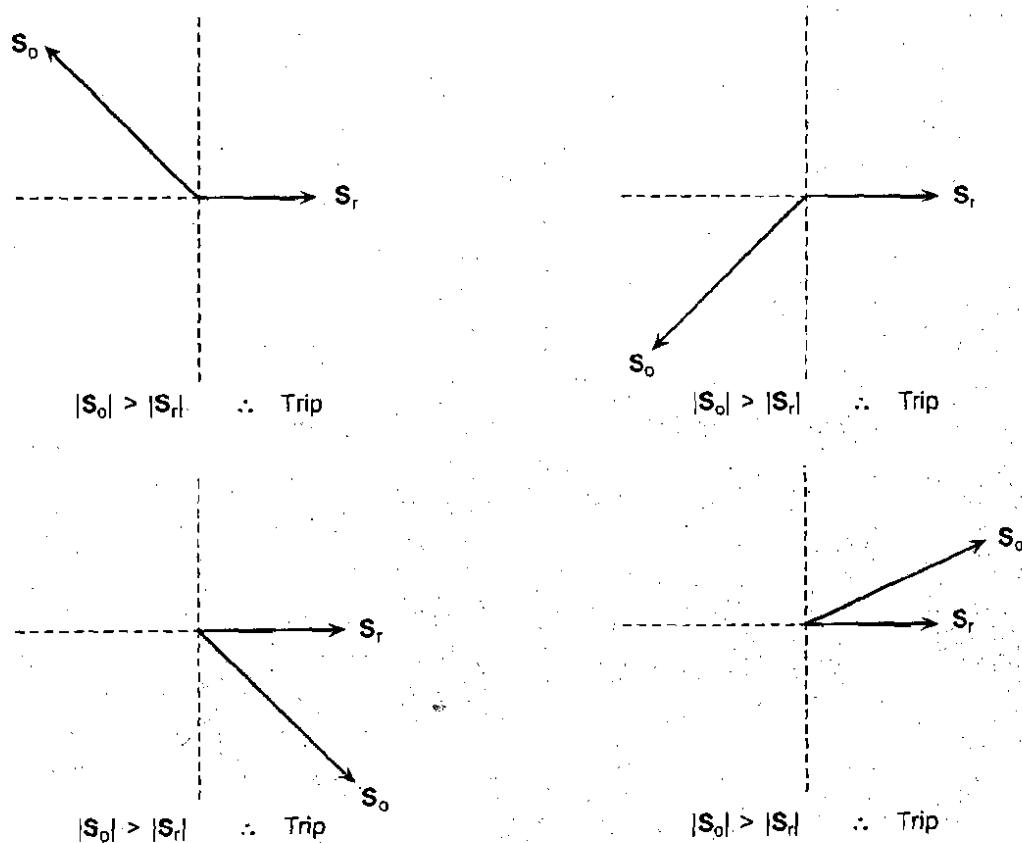


Figure 10.2(a) Inputs to amplitude comparator resulting in trip output.

Figure 10.2(b) shows some specific instances where the amplitude comparator is caused to restrain. It again emphasizes the fact that amplitude comparator responds only to amplitude and is blind to the phase angle between the inputs.

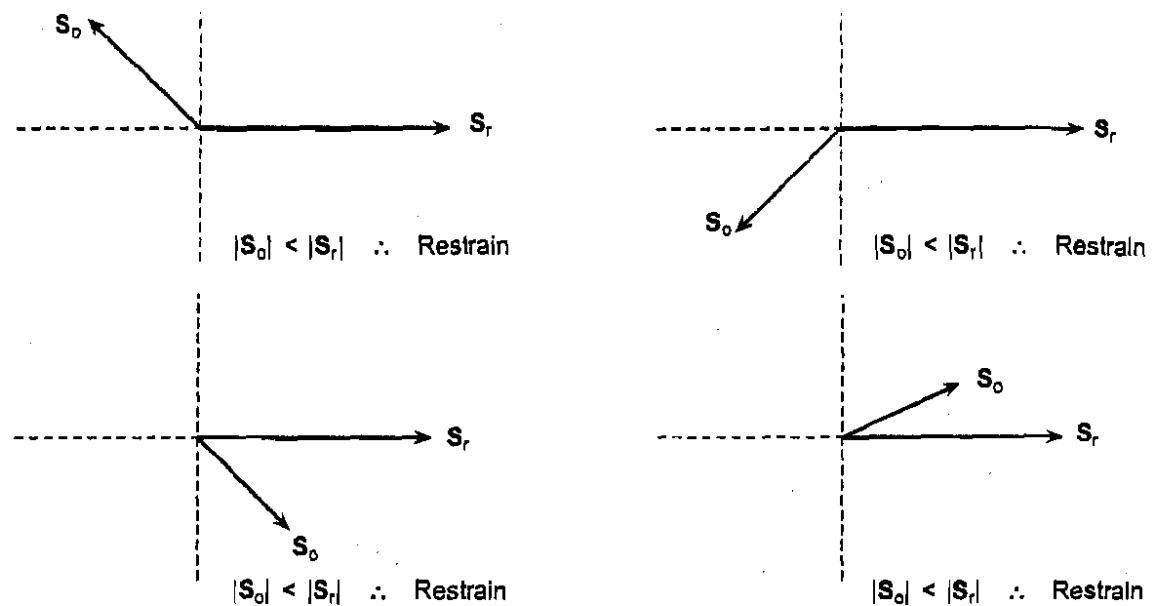


Figure 10.2(b) Inputs to amplitude comparator causing it to restrain.

Further, some specific instances where the amplitude comparator is on the verge or threshold of tripping, are shown in Figure 10.2(c), which again emphasizes the fact that amplitude comparator responds only to amplitude and is blind to the phase angle between the inputs.

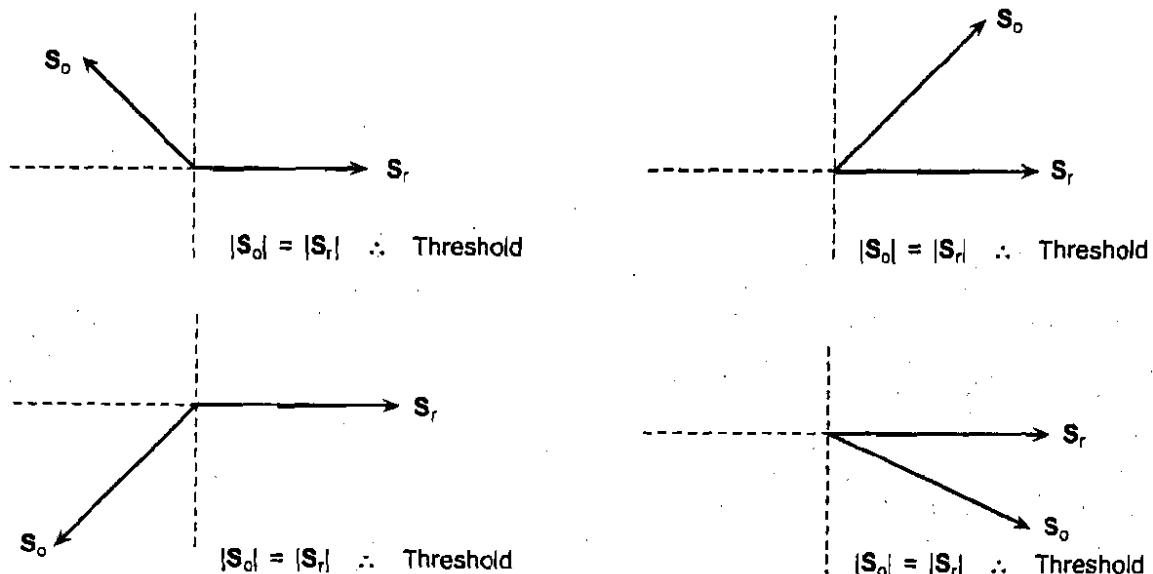


Figure 10.2(c) Inputs to amplitude comparator causing it to be on the threshold.

10.3 Phase Comparator

Phase comparators are of two types: the cosine type and the sine type.

10.3.1 The Cosine-type Phase Comparator

The cosine-type phase comparator has two phasors S_p and S_m at its input and has a trip output. The input-phasor, designated as S_p , is the *polarizing or reference input*. The input-phasor, designated as S_m , is called the *measured input*. The cosine-type phase comparator follows the trip law:

$$\text{If } -90^\circ < \text{Arg}(S_m/S_p) < +90^\circ \text{ then trip; else restrain}$$

This is shown in Figure 10.3.

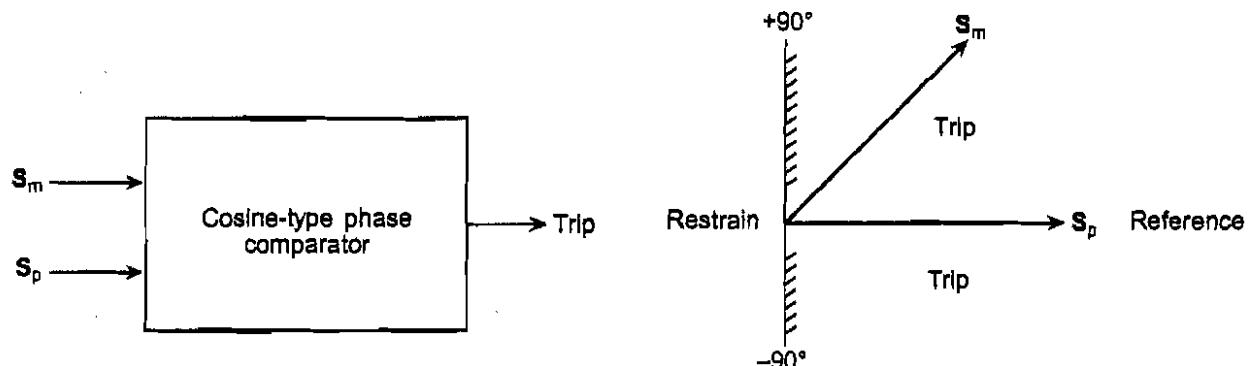


Figure 10.3 Cosine-type phase comparator.

Some specific instances where the cosine-type phase comparator gives the trip output are shown in Figure 10.4(a), which emphasize the fact that phase comparator responds only to phase angle and is blind to the relative amplitudes of the two inputs.

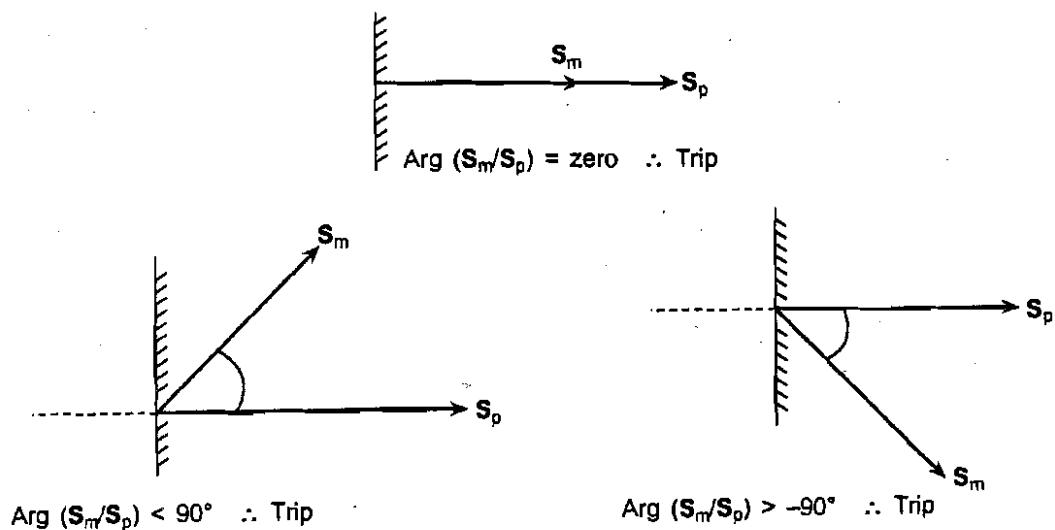


Figure 10.4(a) Inputs to cosine-type phase comparator resulting in trip output.

Some specific instances, where the cosine-type phase comparator is caused to restrain are shown in Figure 10.4(b), which further emphasize the fact that the phase comparator responds only to phase angle and is blind to the relative amplitudes of the two inputs.

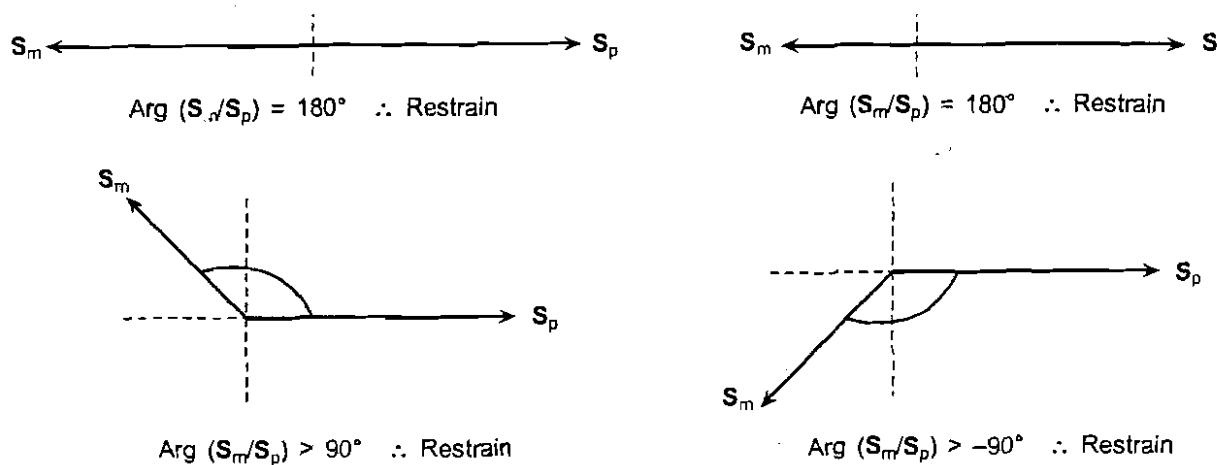


Figure 10.4(b) Inputs to cosine-type phase comparator causing it to restrain.

Further, some specific instances where the cosine-type phase comparator remains on the threshold of operation are shown in Figure 10.4(c), again emphasizing the fact that the phase comparator responds only to phase angle and is blind to the relative amplitudes of the two inputs.

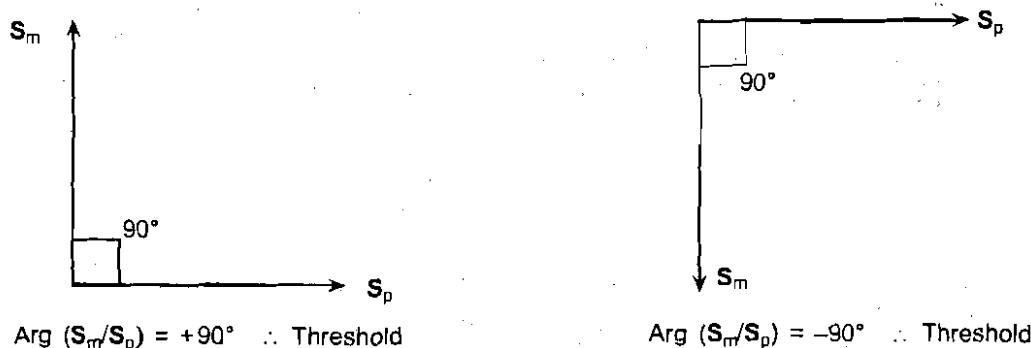


Figure 10.4(c) Inputs to cosine-type comparator causing it to be on threshold.

10.3.2 The Sine-type Phase Comparator

The sine-type phase comparator has two phasors S_p and S_m at its input and has a trip output. The input phasor, designated as S_p , is the *polarizing or reference input*. The input phasor, designated as S_m , is called the *measured input*. The sine-type phase comparator follows the trip law:

$$\text{If } 0^\circ < \text{Arg}(S_m/S_p) < 180^\circ \text{ then trip; else restrain}$$

Figure 10.5 shows the various cases of input to the sine-type phase comparator, which result in trip, restrain, or threshold output. It emphasizes the fact that, ideally, the phase comparator is sensitive only to the phase of the signals and ignores their magnitudes.

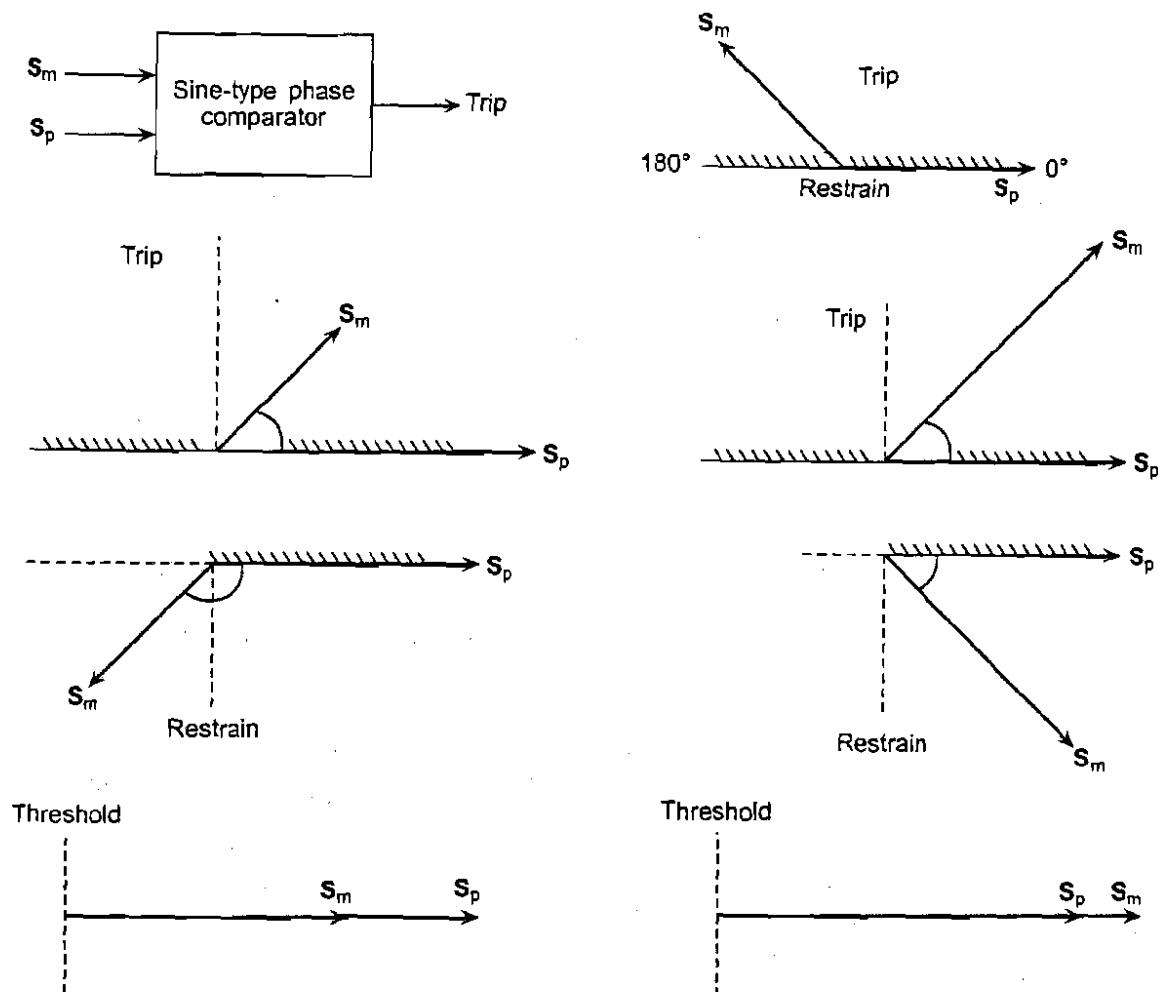


Figure 10.5 Sine-type phase comparator: trip, restrain and threshold conditions.

10.4 Duality Between Amplitude and Phase Comparators

There is a relationship of duality between the amplitude and phase comparators. If the inputs of an amplitude comparator are modified according to the theorem of duality then they become suitable as inputs for a phase comparator and vice versa. In the discussion that follows, unless otherwise explicitly specified, we mean cosine comparator when we mention phase comparator. Let S_o and S_r be the original inputs to an amplitude comparator. If we derive S_m and S_p from S_o and S_r such that

$$S_m = (S_o + S_r) \quad \text{and} \quad S_p = (S_o - S_r)$$

and feed these to a phase comparator, then the output of the phase comparator would be exactly the same as that of the original amplitude comparator (see Figure 10.6).

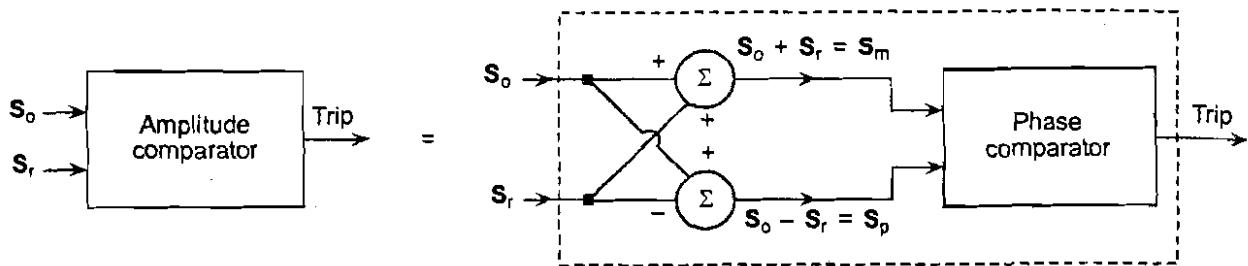


Figure 10.6 Duality between amplitude and phase comparators.

Similarly, let S_m and S_p be the original inputs to a phase comparator, then if we derive S_o and S_r from S_m and S_p such that

$$S_o = (S_p + S_m) \quad \text{and} \quad S_r = (S_p - S_m)$$

and feed these to an amplitude comparator, then the output of the amplitude comparator would be exactly the same as that of the original phase comparator (see Figure 10.7). Thus, we can generalize the duality theorem as follows:

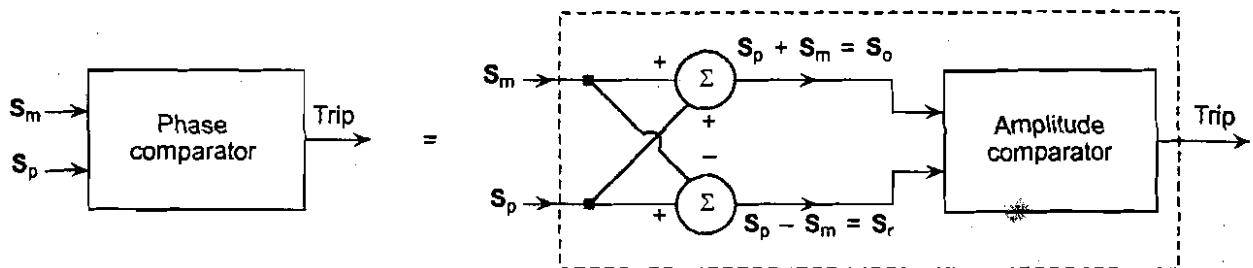
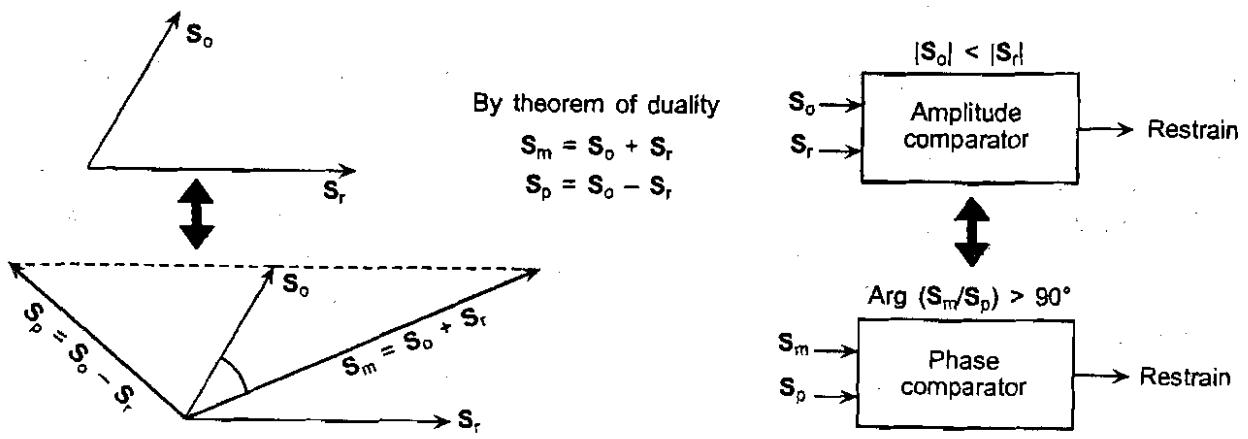


Figure 10.7 Duality between phase and amplitude comparators.

The two signals, obtained by adding and subtracting the inputs to a comparator, are the inputs suitable for its dual. If such signals are fed to the dual, the output would remain unchanged.

The duality theorem can be easily and elegantly proved with the help of graphical construction as shown in Figure 10.8.

Figure 10.8 Duality between amplitude and phase comparators for $|S_o| < |S_r|$.

In Figure 10.8, we can see that $|S_o| < |S_r|$. Therefore, an amplitude comparator would restrain. The geometrical construction shows, how the S_m and S_p are synthesized, by addition and subtraction of $|S_o|$ and $|S_r|$. It can also be easily seen that since $\text{Arg}[(S_o + S_r)/(S_o - S_r)] > 90^\circ$, the dual-phase comparator would also restrain if fed with such signals.

In Figure 10.9, we can see that $|S_o| > |S_r|$. Therefore, an amplitude comparator would operate (trip). The geometrical construction shows, how S_m and S_p are synthesized, by addition and subtraction of S_o and S_r . It can also be easily seen that since $\text{arg}[(S_o + S_r)/(S_o - S_r)] < 90^\circ$, the dual-phase comparator would also operate (trip) if fed with such signals.

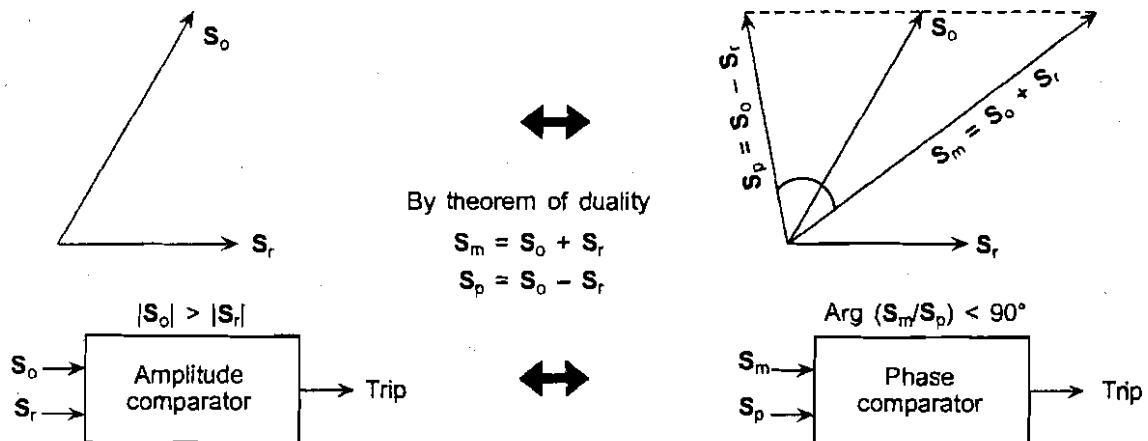


Figure 10.9 Duality between amplitude and phase comparators for $S_o > S_r$.

In Figure 10.10, we can see that $\text{arg}(S_m/S_p) > 90^\circ$. Therefore, a phase-type comparator (cosine-type) would restrain. The geometrical construction shows that the signals S_o and S_r can be synthesized by addition and subtraction of S_m and S_p . It can also be easily seen that since $|S_o| < |S_r|$, the dual-amplitude comparator would also restrain if fed with such signals.

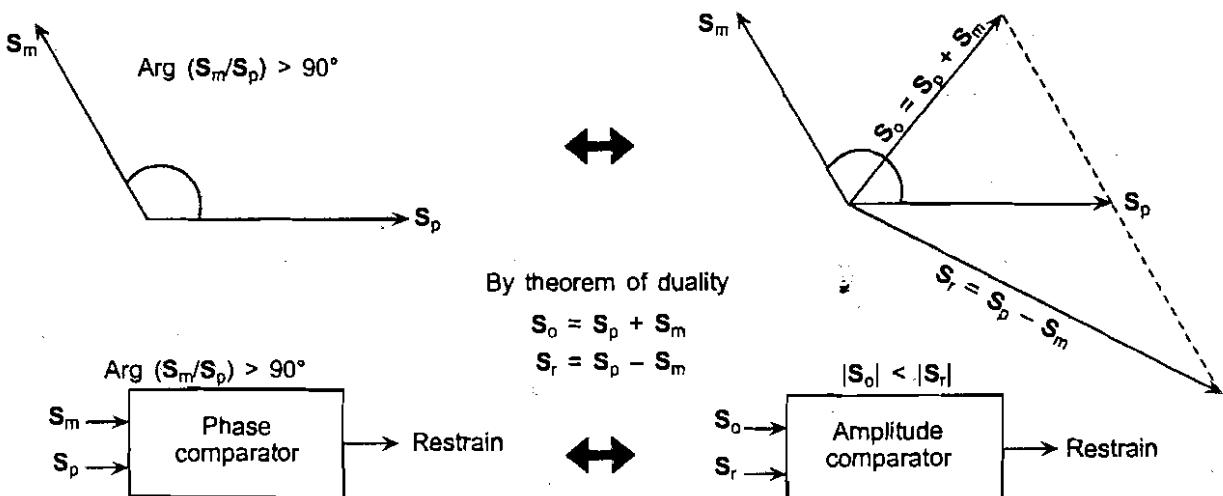


Figure 10.10 Duality between phase comparator and amplitude comparator for $\text{arg}(S_m/S_p) > 90^\circ$.

In Figure 10.11, we can see that $\arg(S_m/S_p) < 90^\circ$. Therefore, a phase comparator would operate (trip). The geometrical construction shows, how the signals S_o and S_r are synthesized by the addition and subtraction of S_m and S_p . It can also be easily seen that since $|S_o| > |S_r|$, the dual-phase comparator would also operate (trip) if fed with such signals.

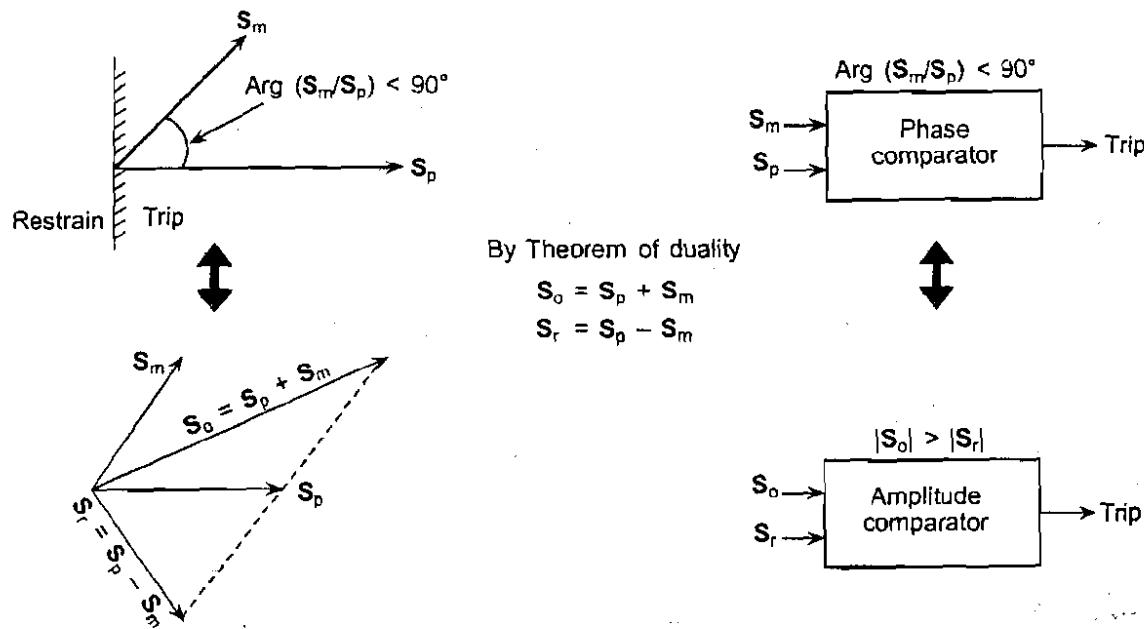


Figure 10.11 Duality between phase comparator and amplitude comparator for $\arg(S_m/S_p) < 90^\circ$.

Similarly, it can be shown that the duality holds good when the comparator is on threshold of operation. Thus, if the original inputs to an amplitude comparator cause it to remain on the threshold of operation then the modified inputs to its dual-phase comparator would also cause it to remain on the threshold of operation.

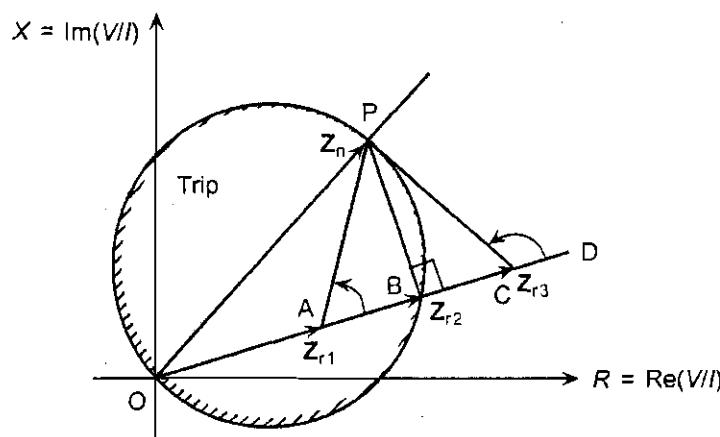
10.5 Synthesis of Various Distance Relays Using Static Comparators

It is possible to synthesize a variety of relays using static comparators. We develop here, a purely geometric method for deriving inputs suitable for the synthesis of various distance relays. The method consists of locating two phasors, involving Z_r the impedance seen by the relay and Z_n , the setting of the relay, such that the phase angle between them crosses $\pm 90^\circ$ as the impedance seen by the relay moves from the trip to the restrain region. These two phasors, in principle, are suitable for driving a phase comparator (cosine-type). Next, we convert these two phasors into two voltages suitable for feeding a practical electronic circuit.

10.5.1 Synthesis of Mho Relay Using Static Phase Comparator

Figure 10.12 shows the synthesis of a mho relay using a phase comparator. The mho relay to be synthesized has a setting of $|Z_n| \angle \theta_n$. The characteristic to be synthesized is thus

a circle with diameter as phasor Z_n . Now, let the impedance seen by the relay be Z_r represented by point A in Figure 10.12. Since the impedance phasor lies within the trip region, the relay must issue the trip output. It can be easily seen from the figure that the phasor $(Z_n - Z_{r1})$, represented by line AP, leads the phasor Z_{r1} by an angle which is definitely less than 90° . The figure shows that as the impedance seen by the relay moves towards the boundary between the trip and restrain regions, the angle between $(Z_n - Z_r)$ and Z_r moves towards 90° . When the phasor representing the impedance seen by the relay, lies on the boundary, this angle is exactly 90° (for example, the angle between PB and OB = 90°). For all impedances lying outside the trip region, i.e. in the restraining region, the angle between $(Z_n - Z_r)$ and Z_r is always greater than 90° (for example, the angle between CP and CD).



$$OA = |Z_{r1}| \rightarrow \text{Trip}$$

$$AP = |Z_n - Z_{r1}|$$

$$OB = |Z_{r2}| \rightarrow \text{Threshold}$$

$$BP = |Z_n - Z_{r2}|$$

$$OC = |Z_{r3}| \rightarrow \text{Restrain}$$

$$CP = |Z_n - Z_{r3}|$$

$$\text{Arg} \frac{|Z_n - Z_{r1}|}{|Z_{r1}|} = \angle BAP < 90^\circ \rightarrow \text{Trip}$$

$$\text{Arg} \frac{|Z_n - Z_{r2}|}{|Z_{r2}|} = \angle CBP = 90^\circ \rightarrow \text{Threshold}$$

$$\text{Arg} \frac{|Z_n - Z_{r3}|}{|Z_{r3}|} = \angle DCP > 90^\circ \rightarrow \text{Restrain}$$

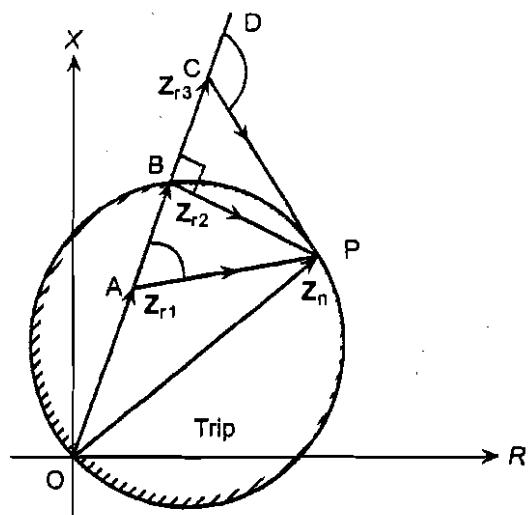
Trip law:

$$\text{If } \text{Arg} \frac{|Z_n - Z_r|}{|Z_r|} < 90^\circ; \text{ then trip}$$

Figure 10.12 Synthesis of mho relay using cosine-type phase comparator.

Similar analysis shows that even if the impedance seen by the relay is on the other side of Z_n as shown in Figure 10.13, as long as it is in the trip region, the angle between $(Z_n - Z_r)$ and Z_r is always greater than -90° . The angle hits 90° for boundary conditions

and becomes less than -90° as the impedance seen by the relay moves into the restraining region.



$$OA = |Z_{r1}| \rightarrow \text{Trip}$$

$$OB = |Z_{r2}| \rightarrow \text{Threshold}$$

$$OC = |Z_{r3}| \rightarrow \text{Retain}$$

$$AP = |Z_n - Z_{r1}|$$

$$BP = |Z_n - Z_{r2}|$$

$$CP = |Z_n - Z_{r3}|$$

$$\text{Arg} \frac{|Z_n - Z_{r1}|}{|Z_{r1}|} = \angle PAB > -90^\circ \rightarrow \text{Trip}$$

$$\text{Arg} \frac{|Z_n - Z_{r2}|}{|Z_{r2}|} = \angle PBC = 90^\circ \rightarrow \text{Threshold}$$

$$\text{Arg} \frac{|Z_n - Z_{r3}|}{|Z_{r3}|} = \angle PCD < -90^\circ \rightarrow \text{Retain}$$

Trip law:

$$\text{If } \text{Arg} \frac{|Z_n - Z_r|}{|Z_r|} > -90^\circ; \text{ then trip}$$

Figure 10.13 Synthesis of mho relay using phase comparator.

Thus, the phasors $(Z_n - Z_r)$ and Z_r obey the law of cosine-type phase comparison. Therefore, if $(Z_n - Z_r)$ and Z_r are used as inputs to a cosine comparator, the resulting entity would behave exactly like a mho relay.

However, there is a practical problem here. The problem is that the electronic circuit of the comparator accepts only voltage signals at its input. We, therefore, need to convert these two impedance phasors into voltage signals.

If we multiply both $(Z_n - Z_r)$ and Z_r by the current at the relay location I_r , then we get $(I_r Z_n - I_r Z_r)$ and $Z_r I_r$. Note that $Z_r I_r$ is nothing but the voltage at the relay location V_r . The two modified signals therefore are:

$$(I_r Z_n - V_r) \text{ and } V_r$$

Thus, we find that $(I_r Z_n - V_r)$ and V_r are the two voltage signals which can be fed to a cosine-type comparator for synthesis of a mho relay with a setting of Z_n .

This is shown in Figure 10.14.

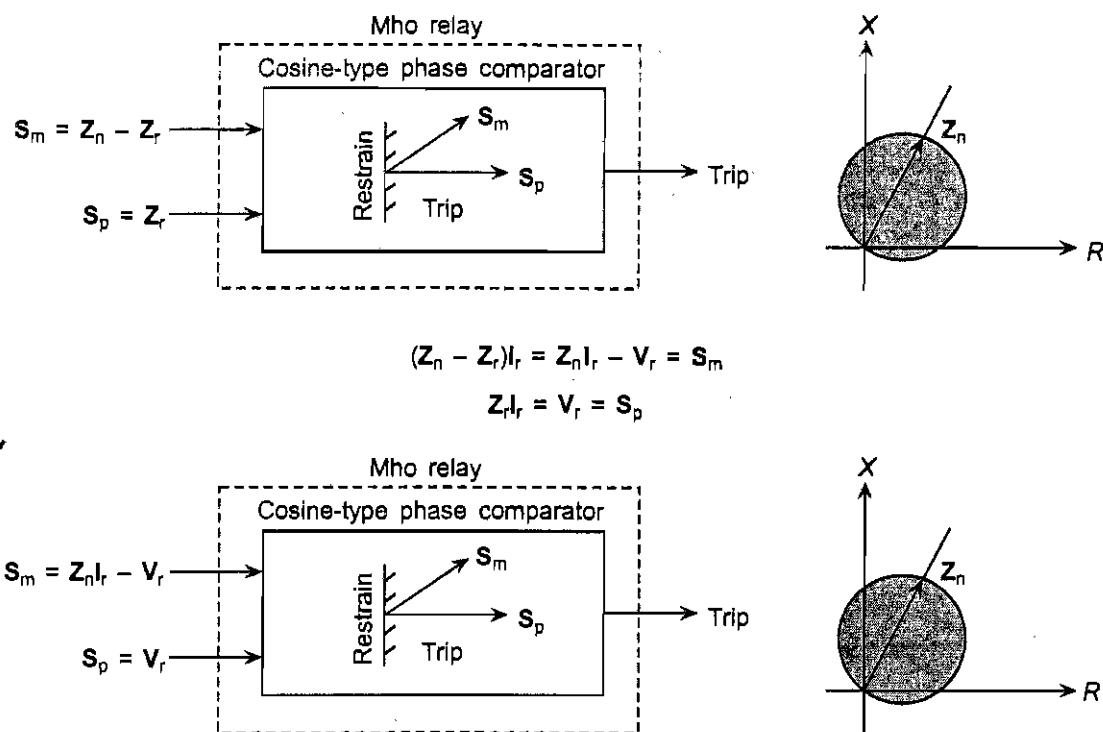


Figure 10.14 Deriving practical signals for mho relay synthesis.

At the relay location, we have the signals V_r and I_r readily available. In order to form S_p and S_m inputs suitable for synthesis of mho relay, we will have to mix them using suitable hardware to get the required signals.

The circuit arrangement for mixing the relay voltage and current signals is shown in Figure 10.15.

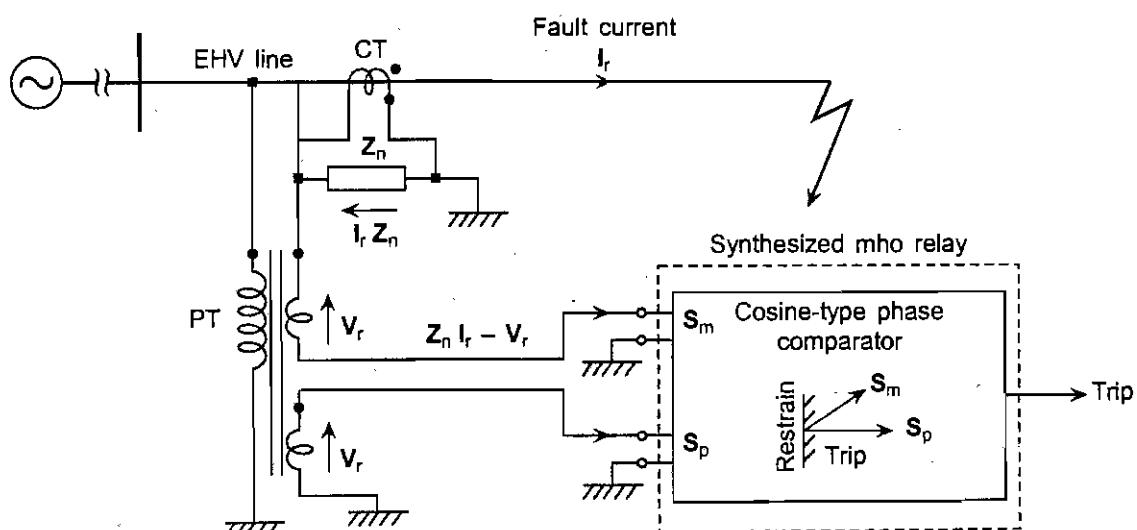
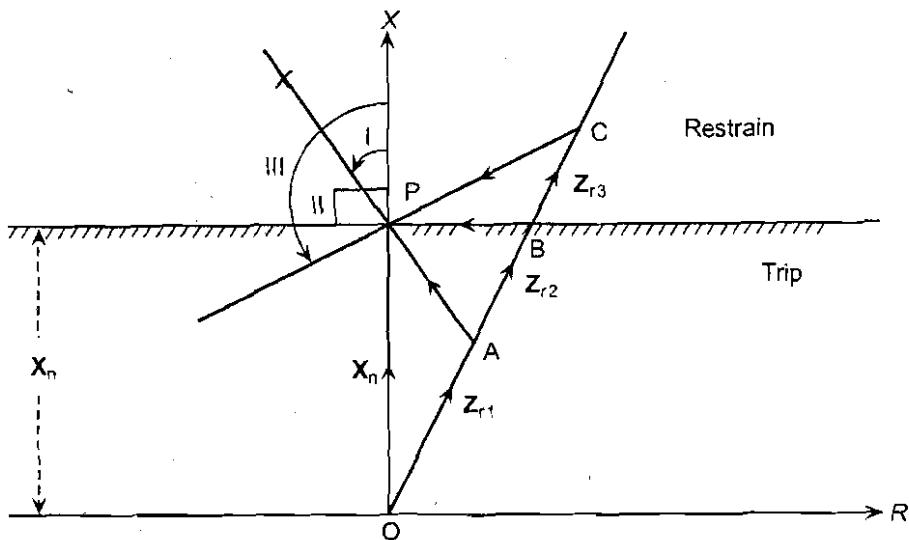


Figure 10.15 Mho relay synthesis using cosine-type phase comparator.

10.5.2 Synthesis of Reactance Relay Using Cosine-type Phase Comparator

Figure 10.16 shows the synthesis of a reactance relay using a phase comparator. The reactance relay to be synthesized has a setting of jX_n . The characteristic to be synthesized is thus a straight line parallel to the R -axis (abscissa), with an intercept of $|X_n|$ on the X -axis (ordinate). Let the impedance seen by the relay be Z_{rl} , which lies within the trip region at point A. Let us construct the phasor $(X_n - Z_{rl})$ represented by line AP. It can be easily seen that $(X_n - Z_{rl})$ leads X_n by an angle which is definitely less than 90° . Now, as the impedance seen by the relay moves towards the boundary of the trip region, the angle between $(X_n - Z_{rl})$ and X_n approaches 90° . When the impedance lies on the boundary, the angle becomes exactly equal to 90° . For all points lying in the restraining region, the angle becomes greater than 90° .



$$OP = |X_n| = \text{Setting}$$

$$OA = |Z_{r1}| \rightarrow \text{Trip}$$

$$OB = |Z_{r2}| \rightarrow \text{Threshold}$$

$$OC = |Z_{r3}| \rightarrow \text{Restrain}$$

$$AP = |X_n - Z_{r1}|$$

$$BP = |X_n - Z_{r2}|$$

$$CP = |X_n - Z_{r3}|$$

$$\text{Arg} \frac{|X_n - Z_{r1}|}{|X_n|} = \angle OPA = \angle I < 90^\circ \rightarrow \text{Trip}$$

$$\text{Arg} \frac{|X_n - Z_{r2}|}{|X_n|} = \angle OPB = \angle II = 90^\circ \rightarrow \text{Threshold}$$

$$\text{Arg} \frac{|X_n - Z_{r3}|}{|X_n|} = \angle OPC = \angle III > 90^\circ \rightarrow \text{Restrain}$$

Trip law:

$$\text{If } \text{Arg} \frac{X_n - Z_r}{X_n} < 90^\circ; \text{ then trip}$$

Figure 10.16 Deriving inputs for synthesis of reactance relay.

Similar analysis shows that if the impedance seen by the relay lies to the left of the jX_n phasor, the angle between $(X_n - Z_{r1})$ and X_n is greater than -90° , as long as the impedance falls within the trip region. It is exactly equal to 90° for impedance lying on the boundary and is less than -90° for all impedances lying in the restraining region to the left of the jX_n phasor. This is shown in Figure 10.17.

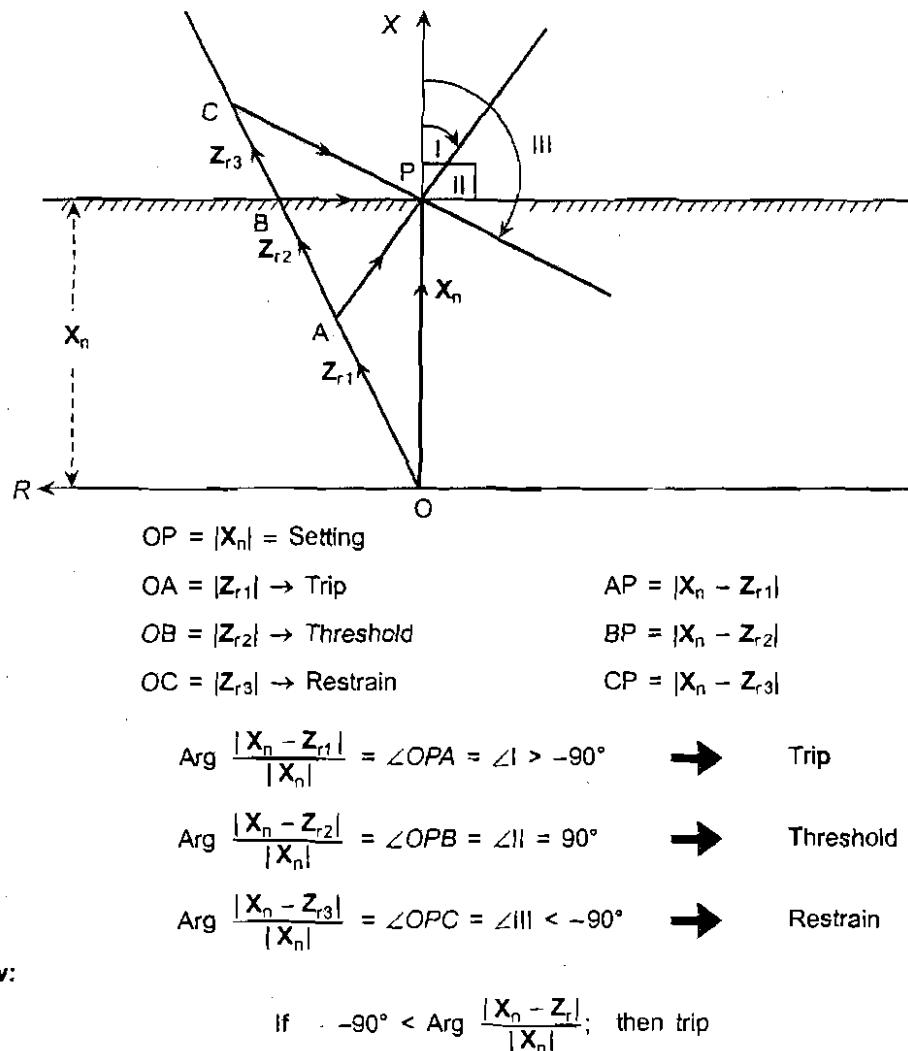


Figure 10.17 Deriving inputs for synthesis of reactance relay.

Thus $(X_n - Z_{r1})$ and X_n seem to be suitable for feeding to a cosine-type phase comparator for synthesizing the reactance relay.

As discussed earlier, electronic circuits, which are used to implement the cosine-type comparator, need voltage signals. Therefore, we can get voltage signals from these two inputs by multiplying each of them by I_r , the current at the relay location. The modified signals that we thus get are $(X_n I_r - Z_{r1} I_r)$ and $X_n I_r$. This is shown in Figure 10.18.

Note that $Z_{r1} I_r$ is nothing but the voltage at the relay location, i.e. V_r . Thus, the final inputs to the cosine comparator for synthesis of reactance relay are:

$$S_p = X_n I_r \quad \text{and} \quad S_m = (X_n I_r - V_r)$$

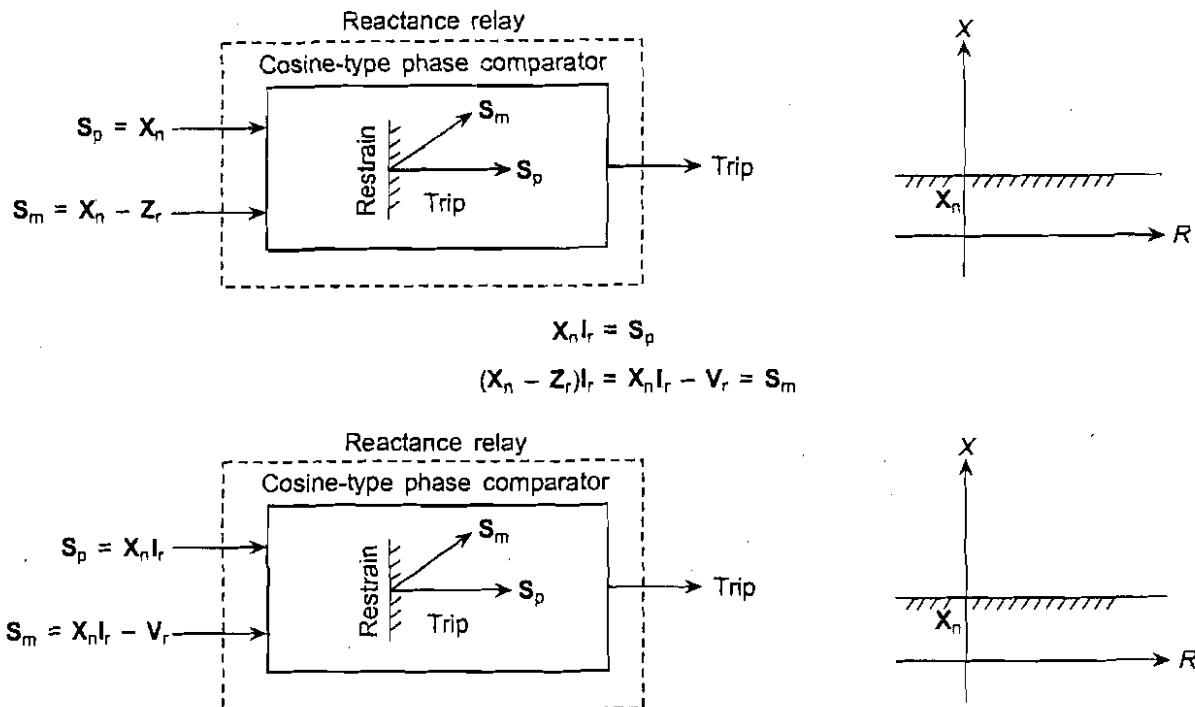


Figure 10.18 Deriving practical signals for reactance relay synthesis.

10.5.3 Synthesis of Simple Impedance Relay Using Amplitude Comparator

The simple impedance relay is inherently based on an amplitude comparator. If the magnitude of the impedance seen by the relay $|Z_r|$ is less than the setting of the relay $|Z_n|$, then the relay issues a trip output. Thus, the simple impedance relay can be most easily synthesized by an amplitude comparator with the following signals:

$$\begin{aligned} \text{Operating Signal } S_o &= Z_n \\ \text{Restraining Signal } S_r &= Z_r \end{aligned}$$

In order to make the inputs suitable for driving an electronic amplitude comparator circuit, we multiply each of them by I_r to get the modified signals:

$$S_o = Z_n I_r \quad \text{and} \quad S_r = Z_r I_r = V_r$$

This is shown in Figure 10.19.

10.6 Development of an Electronic Circuit for Implementing a Cosine-type Phase Comparator

There are various ways in which a cosine-type phase comparator might be implemented using an electronic circuit. The approach described here is based on measuring the coincidence period between the two waveforms whose phase difference is to be measured. One can measure either the *positive* or the *negative coincidence period*.

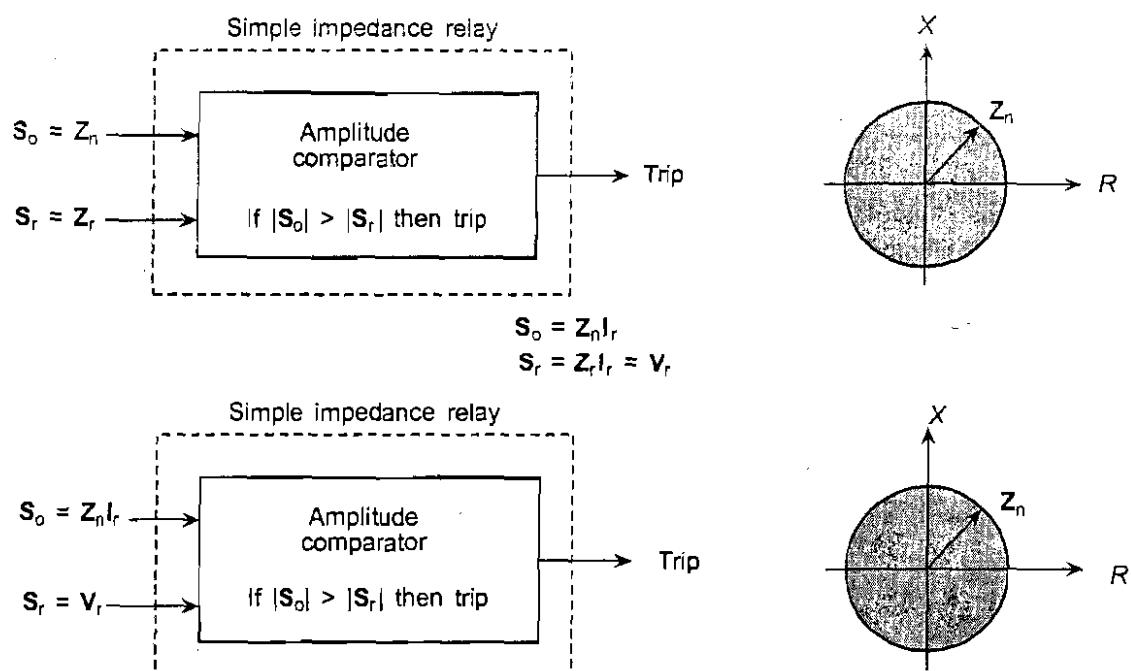


Figure 10.19 Synthesis of simple impedance relay using amplitude comparator.

The positive coincidence period is defined as that time during which both the waves are of positive polarity. The negative coincidence period is defined on similar lines.

In the case of two pure sine waves, the positive and the negative coincidence periods are equal.

By measuring the coincidence period, we have essentially converted the problem of phase angle measurement into that of time period measurement. Observation of the waveforms of Figure 10.20 shows that, considering 50 Hz power frequency, the

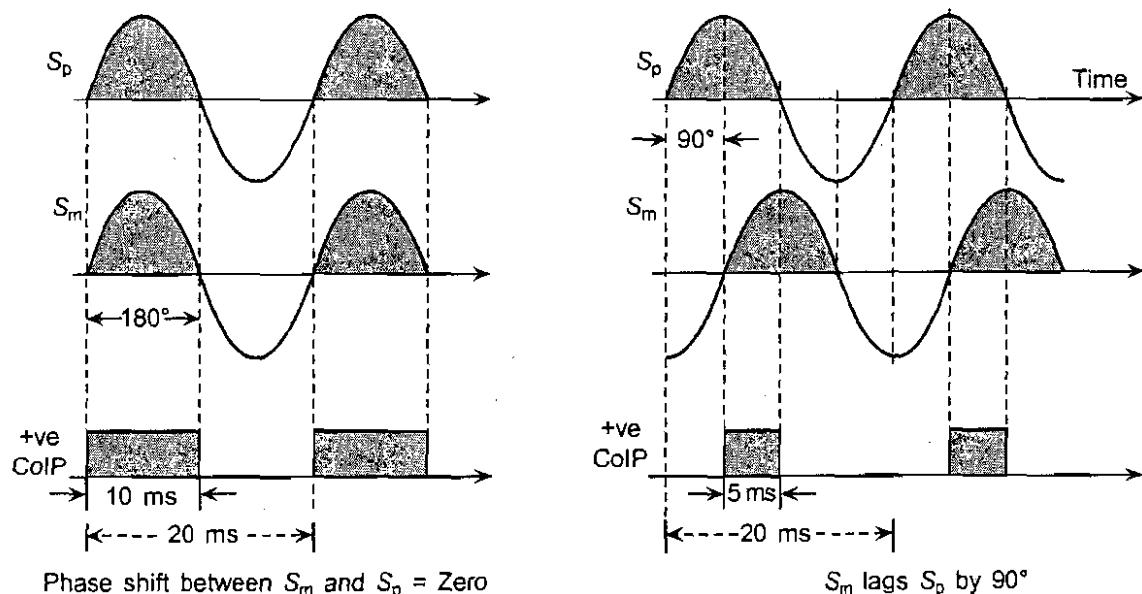


Figure 10.20 Coincidence period for phase shift of 0° and 90° lag.

coincidence period is always greater than 5 ms (or $T/4$ s where T is the time period of the power frequency) if the S_m wave is within $\pm 90^\circ$ of the S_p wave or within the trip region of the phase comparator. Thus, implementing a cosine-type comparator boils down to generating a pulse whose width is proportional to the phase difference between the two input waves. Next, we should have an arrangement to measure the width of this pulse. If the pulse width is greater than 5 ms (or $T/4$ s) then a trip output should be issued. If the width of the coincidence period pulse is less than 5 ms then output should be restrained.

Figure 10.20 shows that the coincidence period pulse is of 10 ms duration when the two inputs are in phase. As S_m starts lagging S_p , the coincidence period decreases. When S_m lags S_p by 90° , the coincidence period falls exactly to 5 ms.

Figure 10.21 shows that the coincidence period pulse is of zero duration when the two inputs are out of phase by 180° . As S_m starts leading S_p , the coincidence period increases. When S_m leads S_p by 90° , the coincidence period builds up to exactly 5 ms.

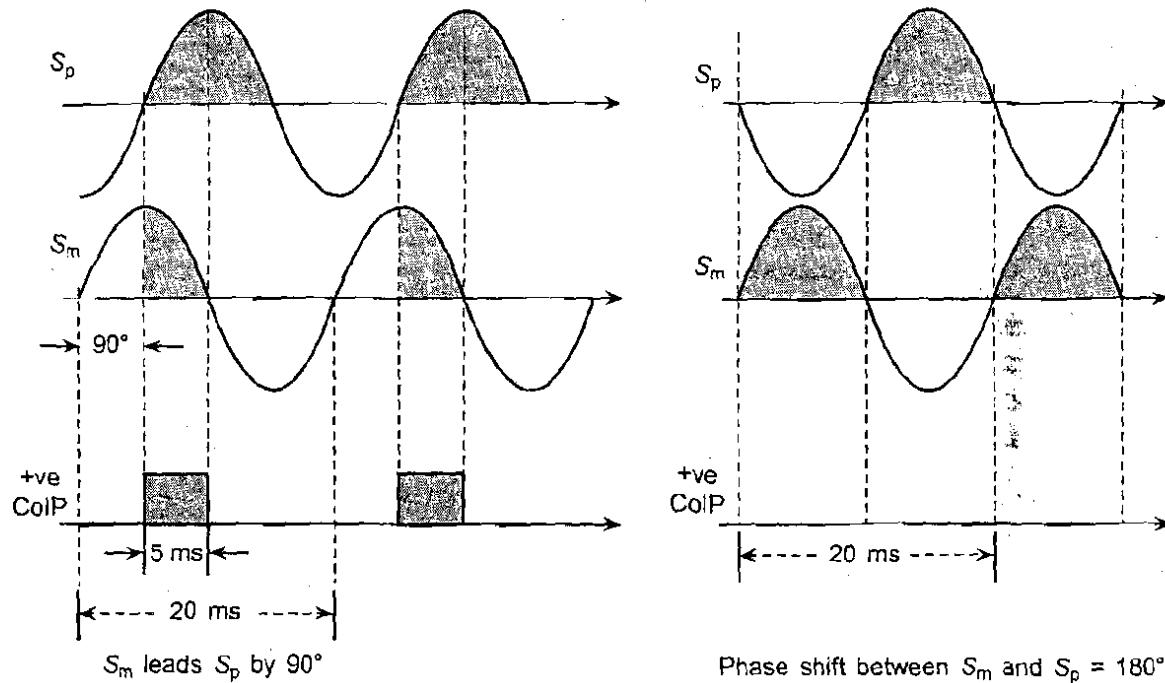


Figure 10.21 Coincidence period for phase shift of 90° lead.

The variation of coincidence period with the phase shift between the two signals S_p and S_m , with S_p as the reference phasor, is shown in Figure 10.22.

It can thus be seen that for tripping condition, the coincidence period is always greater than 5 ms. For restraining condition, the coincidence period is always less than 5 ms. For boundary of tripping or verge condition, the coincidence period is exactly equal to 5 ms.

The above analysis clearly suggests that if we can devise a circuit which is able to generate a pulse whose width is equal to the actual coincidence period between the two signals, and check whether the pulse width is greater than 5 ms, then we can easily implement a cosine-type phase comparator. Thus, we need not measure the absolute value of pulse width but should only be able to compare it with a 5 ms time period. This has

the advantage of avoiding actual measurement. We thus circumvent the measurement problem by using a comparator.

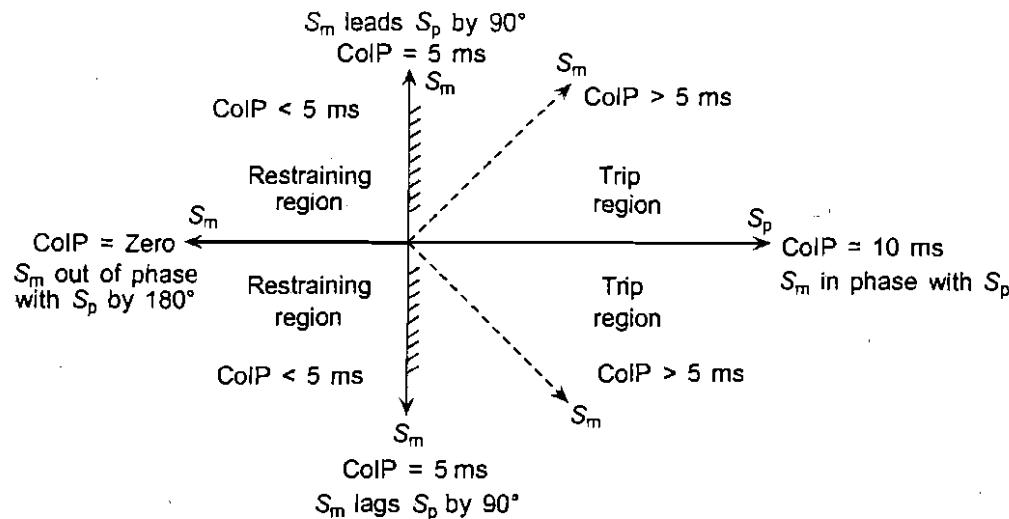


Figure 10.22 Variation of coincidence period with phase shift (superimposed on cosine-type phase comparator characteristic).

Figure 10.23 shows the block diagram of a cosine comparator based on comparison of positive coincidence period. The input signals are first rectified to remove the negative excursions. The resulting waves are converted to blocks by passing them through a zero-crossing detector. We thus get two square waves whose high time is equal to the time for which the original waves were positive. The coincidence period is detected by logical ANDing of these two signals. The width of the resulting pulse is equal to the positive

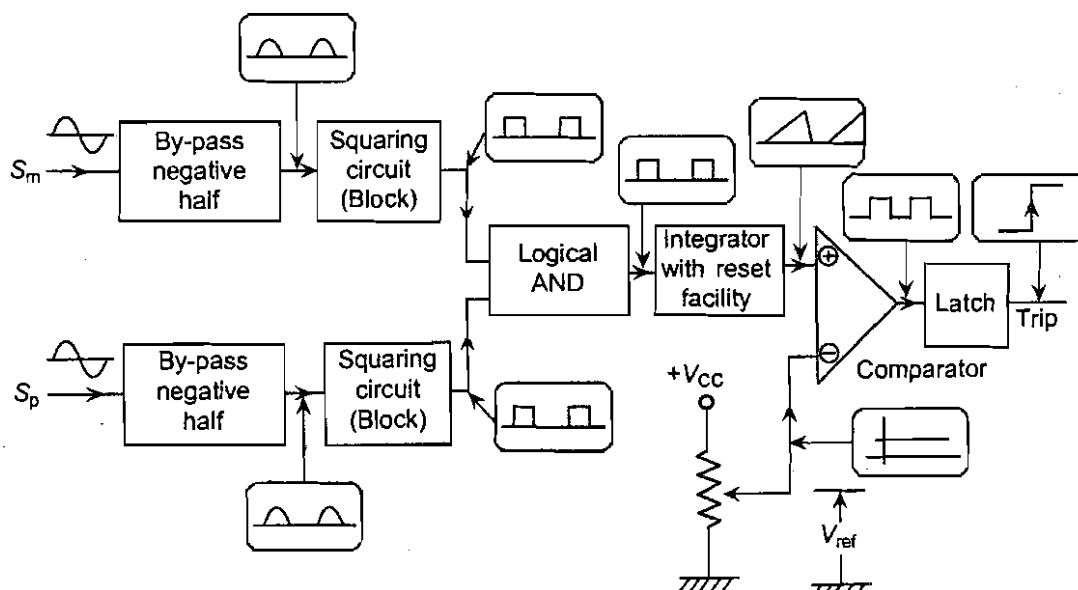


Figure 10.23 Block diagram of static cosine-type phase comparator based on coincidence principle.

coincidence period between the two signals. This pulse is then integrated and the output of the integrator is compared with the expected output for a pulse of 5 ms duration. This expected output is pre-calculated and set up on the potentiometer as V_{ref} .

If the coincidence period is more than 5 ms then the output of the integrator is more than V_{ref} and the comparator is triggered into high output state. The output of the comparator can be treated as the trip output.

If the coincidence period is less than 5 ms, the output of the integrator never reaches the level of V_{ref} , thus the comparator output remains low.

The waveforms at various points are briefly shown in Figure 10.23 and in more detail in Figure 10.24.

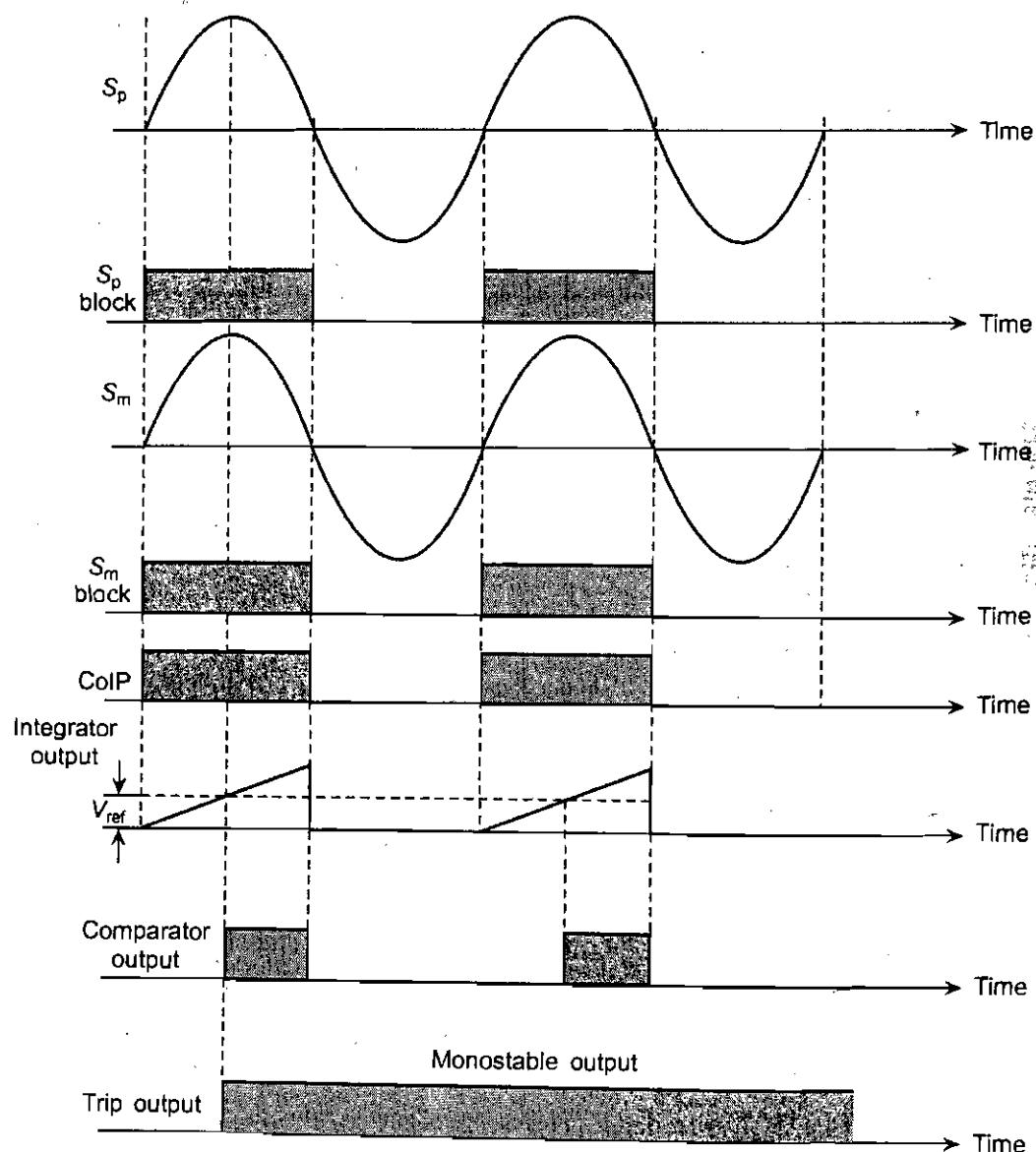


Figure 10.24 Waveforms for cosine-type phase comparator based on comparison of coincidence period.

Figure 10.24 shows that the inputs S_m and S_p to the cosine-type phase comparator are in phase. The coincidence period is, therefore, 10 ms. The integrator output, therefore, exceeds the reference voltage V_{ref} and the comparator is triggered into a high output state, thus issuing a trip output. This low-to-high transition of the comparator is latched by a re-triggerable monostable so that it remains continuously high.

Figure 10.25 shows an implementation of cosine comparator which is built around the quad comparator integrated circuit (IC) LM 339. The comparator IC works on a single (unipolar) dc supply.

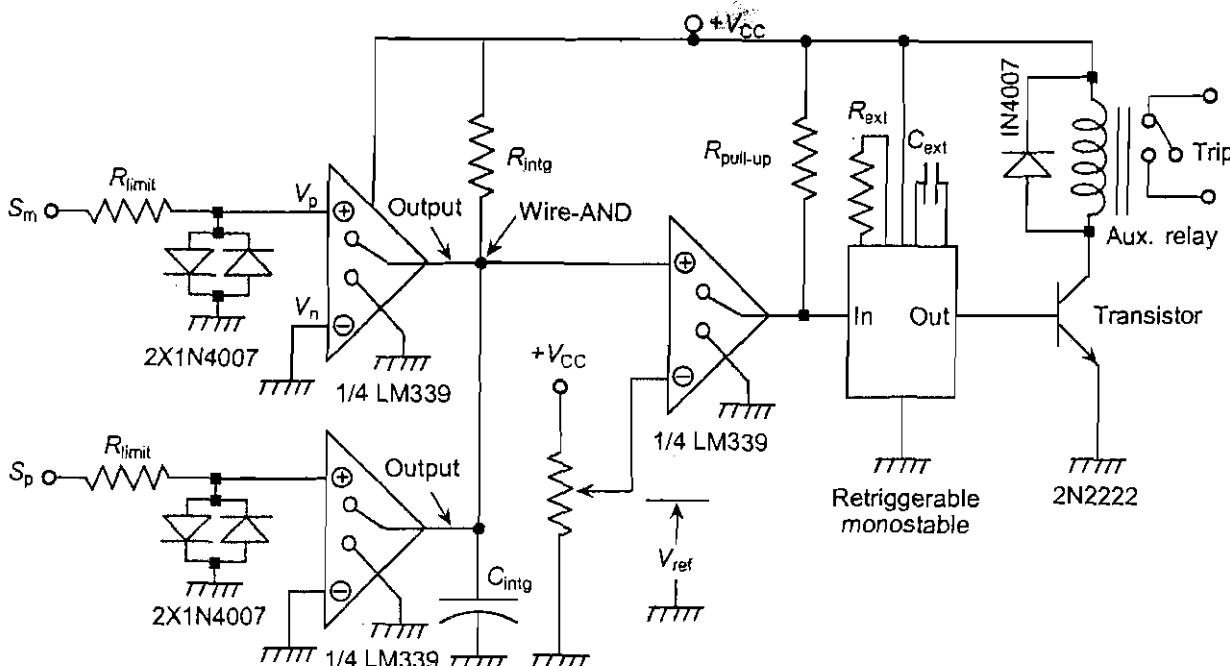


Figure 10.25 An integrated circuit comparator-based circuit for cosine-type phase comparator based on coincidence principle.

The input signals are clipped to safe values before feeding to the IC input. The first two comparators work as zero-crossing detectors producing a square wave during the positive excursion of their respective inputs. The output of LM 339 IC is of pen-collector type.

The comparator IC follows the following law:

If $V_p > V_n$ then the output point floats.

If $V_p < V_n$ then the output point is effectively connected to ground.

This is shown with the help of a switch inside the IC in Figure 10.25.

The outputs of the two zero-crossing detectors are *wire-ANDED* by physically connecting them together. Thus, the output is high if and only if both the zero-crossing detector outputs are high. Thus, in effect, we get the coincidence period pulse at the wire-ANDing point. Further, since both the outputs float during the coincidence period, the C_{intg} can charge through R_{intg} , for a time equal to the coincidence period. The voltage across the integrator capacitor is thus proportional to the coincidence period. This voltage

is compared with a preset value obtained with the help of the potentiometer. The preset value is same as the value that the integrator capacitor would reach for a coincidence period of 5 ms, corresponding to phase difference of 90° (either 90° lag or lead). Thus, if the coincidence period is more than 5 ms, the integrator develops a higher voltage than the reference voltage and we get a trip output. In order to latch the output to a steady high value, a re-triggerable monostable circuit is used.

10.7 An Electronic Circuit for Implementing a Sine-type Phase Comparator

Recall that a sine comparator issues a trip output if S_m leads S_p by any angle between 0° and 180° . In order to develop an electronic circuit for implementing a sine-type phase comparator, refer to Figure 10.26, where S_m is shown to lag S_p . This is the phase relationship for which the sine comparator should restrain.

For this condition, it is seen that there is no coincidence between the spike and the block. In fact, for any angle of lag of S_m with respect to S_p , it can be seen that there is no coincidence between the spike and the block.

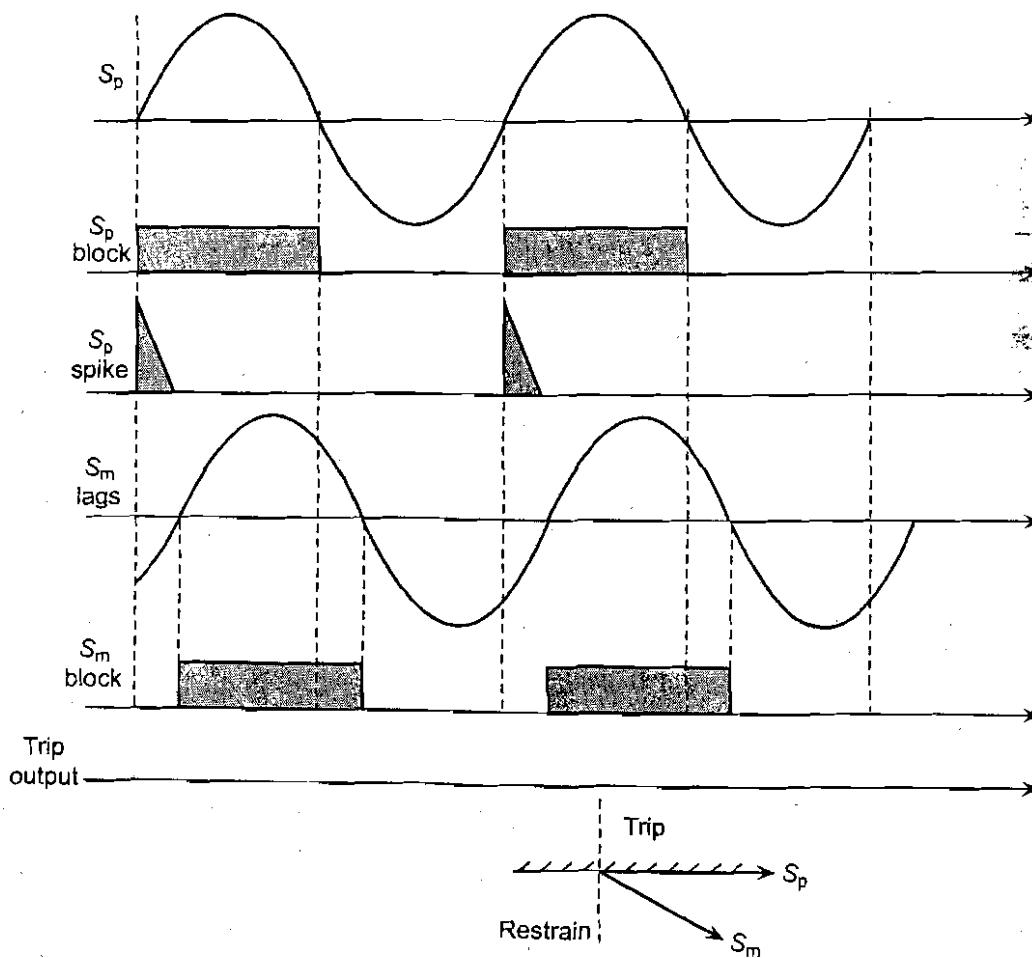


Figure 10.26 Relationship between spike and block for S_m lagging S_p .

Figure 10.27 shows that if S_m leads S_p , then there is always a coincidence between the spike and the block, whatever be the angle of lead. This is the phase relationship for which we want the sine comparator to trip.

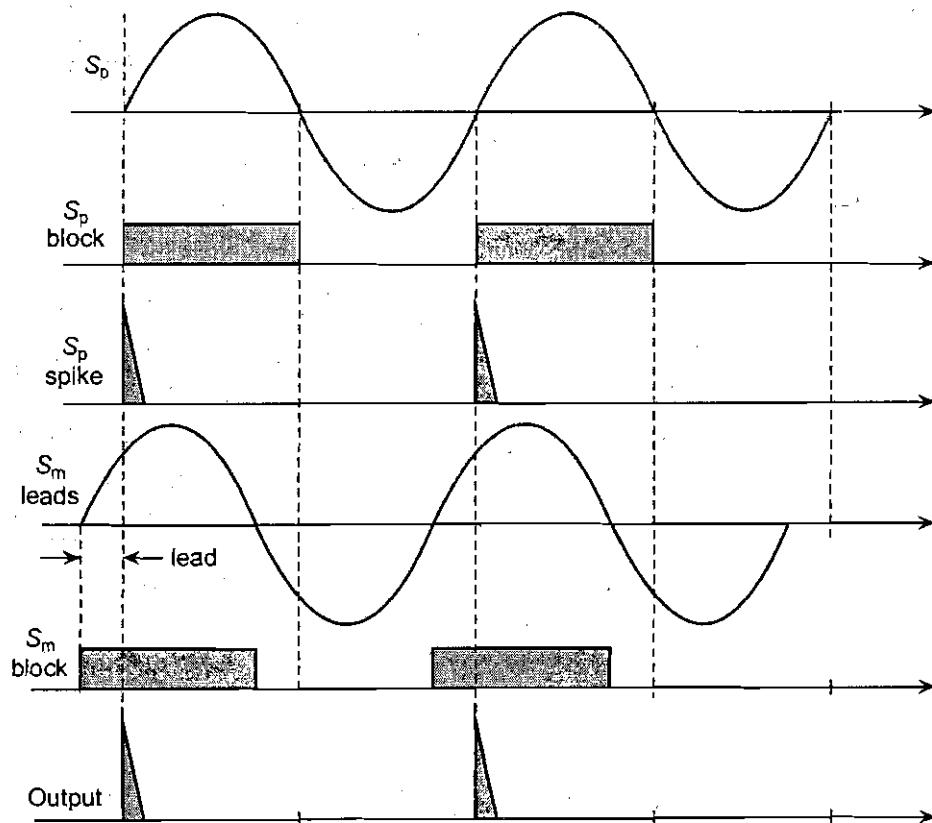


Figure 10.27 Relationship between block and spike for S_m leading S_p .

The above relationship between the spike and the block can be utilized to implement the sine-type phase comparator as shown in the block diagram of Figure 10.28.

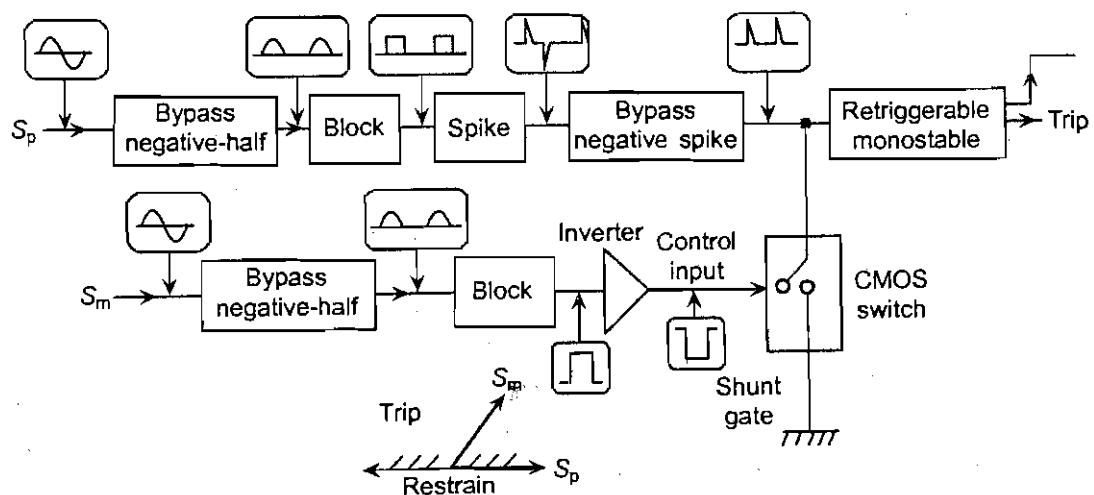


Figure 10.28 Block diagram of sine-type phase comparator based on coincidence between spike and block.

The shunt switch is operated by the control voltage. If the control voltage is high, the shunt switch is ON, thus bypassing the spike to ground.

It can be seen from the figure that when S_m lags S_p , the block is low when the spike appears. However, the inverter makes the control voltage high, thus the switch is closed, bypassing the spike to ground. This is the restraining region of the relay.

However, when S_m leads S_p , there is a coincidence between the spike and the block. The block remains high when the spike appears. The inverter, however, makes the control voltage low. Thus, the shunt switch remains open and the spike is allowed to hit the output terminal. This is the trip region of the sine-type phase comparator.

This is one of the many possible ways in which a sine-type phase comparator can be implemented.

10.8 Synthesis of Quadrilateral Distance Relay

The fault characteristic of a transmission line is a quadrilateral because of the arcing fault resistance. All the conventional distance relays, such as simple impedance, reactance and mho, encompass much more area on the R - X diagram than this quadrilateral. An ideal distance relay should have a characteristic which snugly fits around the quadrilateral. Such a relay, called a **quadrilateral relay**, whose characteristic is shown in Figure 10.29, is very stable on power swing because it encompasses minimum area on the R - X plane. Note that the quadrilateral is shown slightly enlarged so as to positively encompass the fault area.

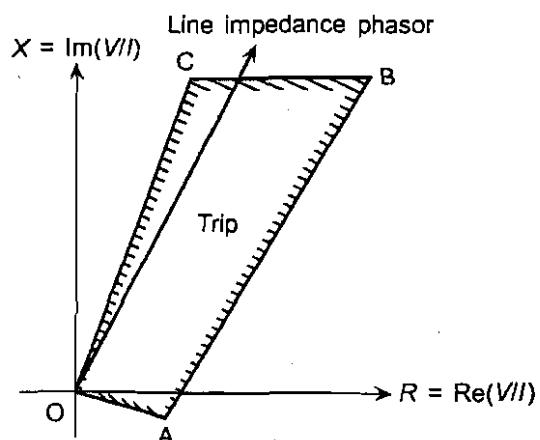


Figure 10.29 Characteristic of quadrilateral distance relay.

Such a characteristic can be synthesized by AND compounding the trip outputs of four different two-input relays shown in Figure 10.30. We need to synthesize the following characteristics:

- Characteristic 1: Reactance relay with setting of X_{n1}
- Characteristic 2: Angle-impedance relay with setting of Z_{n2}
- Characteristic 3: Directional relay with MTA of $-\theta_2$
- Characteristic 4: Directional relay with MTA of θ_1

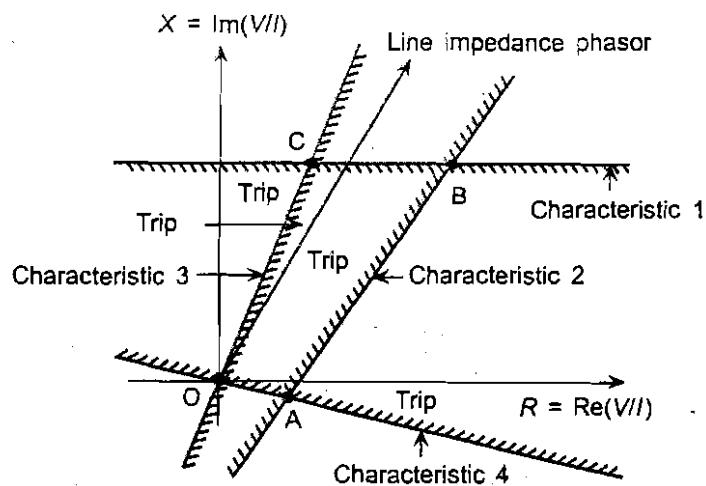


Figure 10.30 The four characteristics to be synthesized.

We can synthesize all the four characteristics by using a $\pm 90^\circ$ cosine-type phase comparator.

Characteristic	Polarizing qty.	Measured qty.
Reactance	$IX_{n1} - V$	IX_{n1}
Angle impedance	$IZ_{n2} - V$	IZ_{n2}
Directional with MTA = θ_1	$V \angle -\theta_1$	I
Directional with MTA = $-\theta_2$	$V \angle \theta_2$	I

Figure 10.31 shows the synthesis of the reactance and angle-impedance characteristics using cosine comparator.

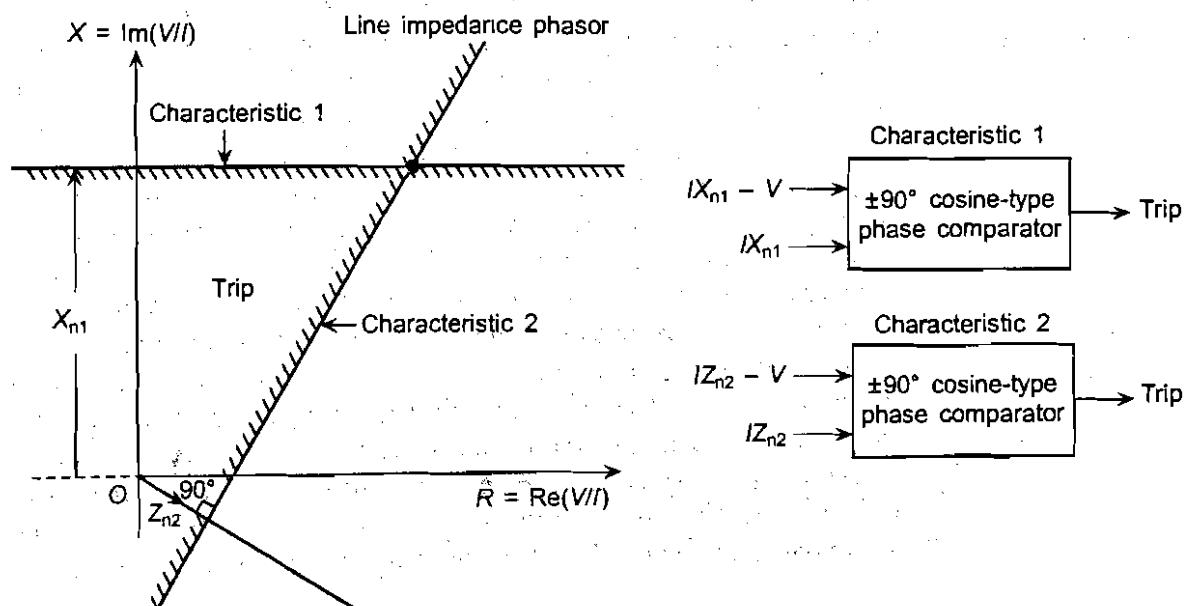


Figure 10.31 Synthesis of reactance and angle-impedance characteristics.

Figure 10.32 shows the synthesis of directional characteristic with MTA of θ_2 .

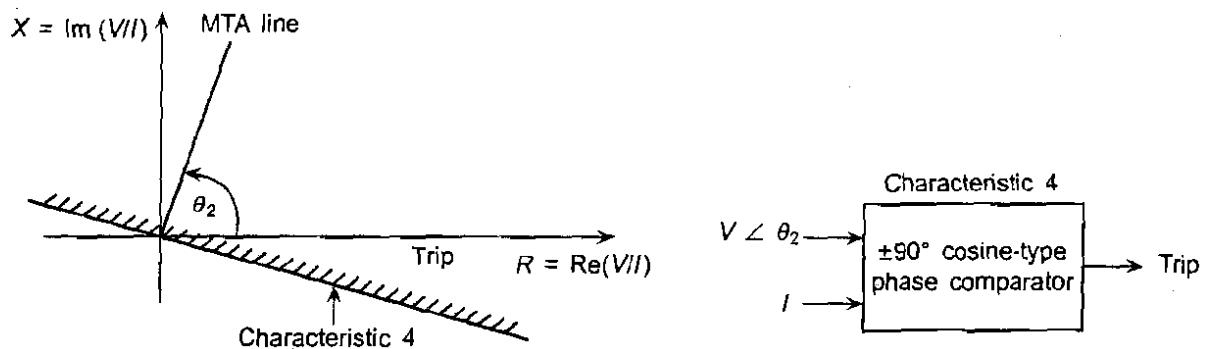


Figure 10.32 Synthesis of directional characteristic with MTA of θ_2 .

Figure 10.33 shows the synthesis of directional characteristic with MTA of θ_1 .

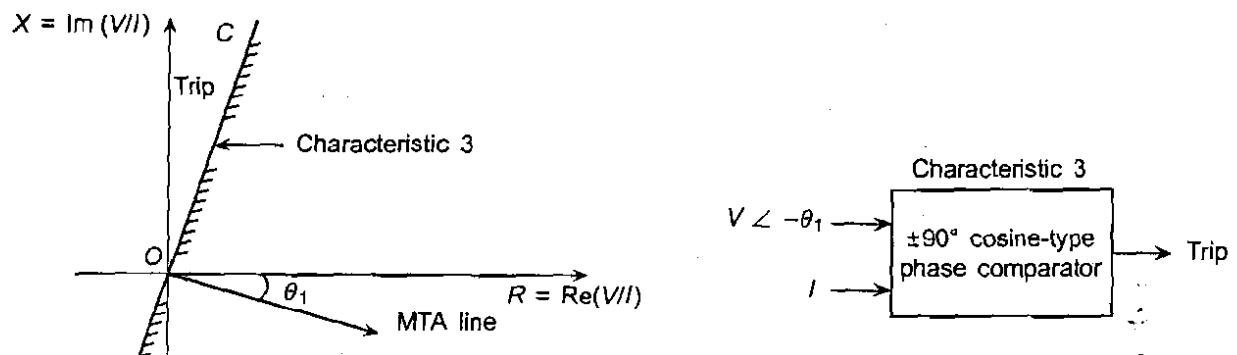


Figure 10.33 Synthesis of directional characteristic with MTA of θ_1 .

Figure 10.34 shows the ANDing of the four characteristics to synthesize the desired quadrilateral characteristics.

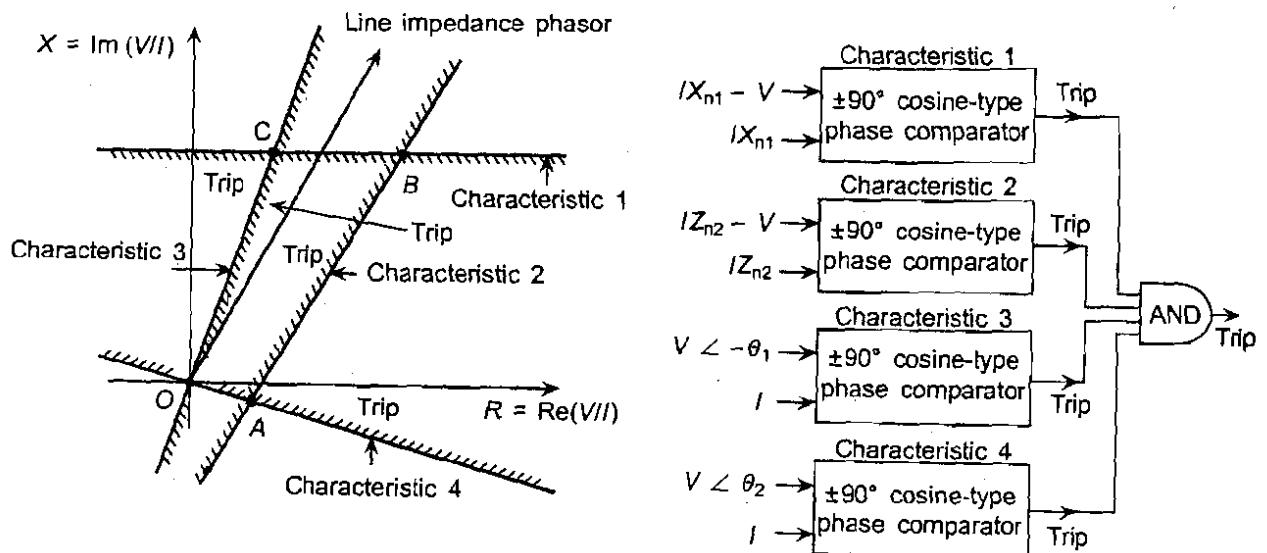


Figure 10.34 ANDing of the four characteristics to synthesize the quadrilateral characteristic.

Review Questions

1. List the advantages of static relays.
2. Describe how comparison can circumvent direct computation in protective relays.
3. What is the price to be paid for not implementing direct numerical computation?
4. Define the characteristics of amplitude comparator.
5. Define the characteristics of cosine- and sine-type phase comparators.
6. What is the theorem of duality?
7. Give graphical proof of the theorem of duality.
8. Suggest different methods to implement static comparators, than those given in the text.
9. How will you synthesize a mho relay using an amplitude comparator?
10. How will you synthesize a reactance relay using an amplitude comparator?
11. How will you synthesize a directional relay with an MTA of τ using a cosine-type phase comparator?
12. When the input signal to the cosine-type phase comparator contains a dc offset, how does the performance of the relay get affected?
13. What is the remedy for the above problem?
14. What is the effect of noise and harmonics on the performance of the cosine and sine type phase comparators described in the text?
15. Suggest a method to make the static comparators immune, to a large extent, to all non-fundamental components.
16. A generalized phase comparator can have a phase angle margin of $+\alpha, -\beta$. The cosine-type phase comparator is a special case where $\alpha = \beta = 90^\circ$. How will the mho relay characteristic appear if the phase angle margin is changed to $\pm 45^\circ$?

11 Numerical Protection

11.1 Introduction

Protective relays, which started out as *meters with contacts*, have undergone tremendous evolution over the years. They were soon replaced by electromechanical relays which were sensitive and accurate. When vacuum tubes were in vogue, protection engineers implemented relays using vacuum tubes. Within a year of invention of the *transistor*, its use in protective relays was reported. With the development of large-scale integrated circuits, these were extensively used in the protective relays. The microprocessor that was invented around 1971 revolutionized the electronics scene in its entirety and the development of a microprocessor-based relay followed soon thereafter. However, a subtle shift in the paradigm takes place when we move on to the microprocessor-based relay, which works on numbers representing instantaneous values of the signals. Hence, the name **numerical relay**. Other popular nomenclatures for such relays are **digital relay**, **computer-based relay** or **microprocessor-based relay**.

In numerical relays, there is an additional entity, the software, which runs in the background and which actually runs the relay. With the advent of numerical relays, the emphasis has shifted from hardware to software. Hardware is more or less the same between any two numerical relays. What distinguishes one numerical relay from the other is the software.

The conventional non-numerical relays are go-no-go devices. They perform comparison rather than straight numerical computation. In fact, the conventional relay cleverly bypasses the problem of computation by performing comparison. The numerical relay does not have any such limitation because of its ability to perform real-time computation. Thus, the relay engineer need not merely implement the old relaying concepts but can devise entirely new computation-based concepts.

The modern numerical relay has thus evolved from a *torque balancing device* to a *programmable information processor*.

We can implement an existing relaying concept using the numerical technique. However, the possibilities of developing a new numerical relay are almost endless and there is very little standardization. The process of development of a new numerical relay is shown in the flowchart of Figure 11.1

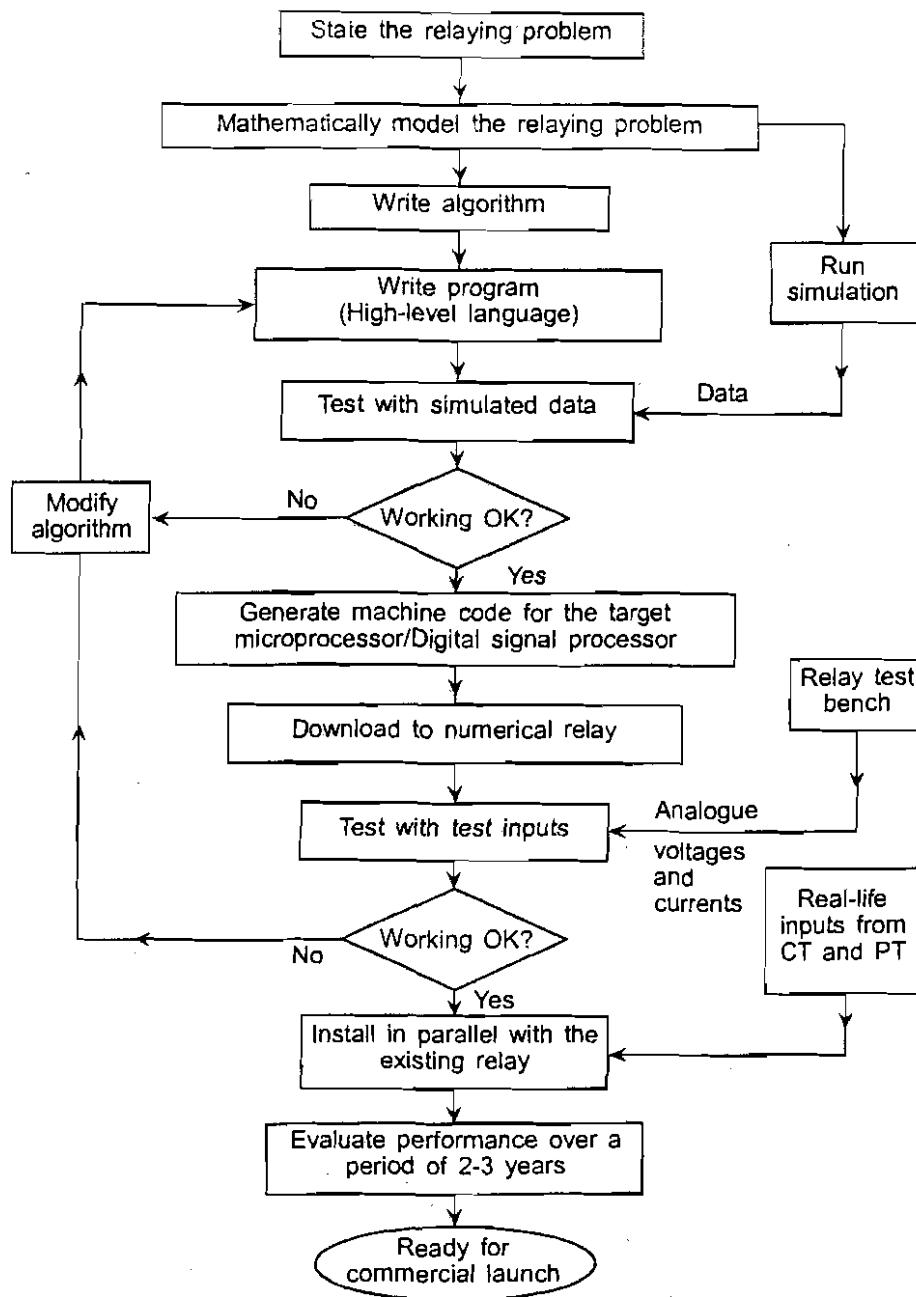


Figure 11.1 Development cycle of a new numerical relay.

11.2 Block Diagram of Numerical Relay

Figure 11.2 shows the block diagram of a numerical relay. The signals from the CTs and PTs cannot be sampled directly and converted to the digital form. This is to make sure that the signal does not contain frequency components having a frequency greater than one half of the sampling frequency. This limit is enforced by the Shannon's sampling theorem.

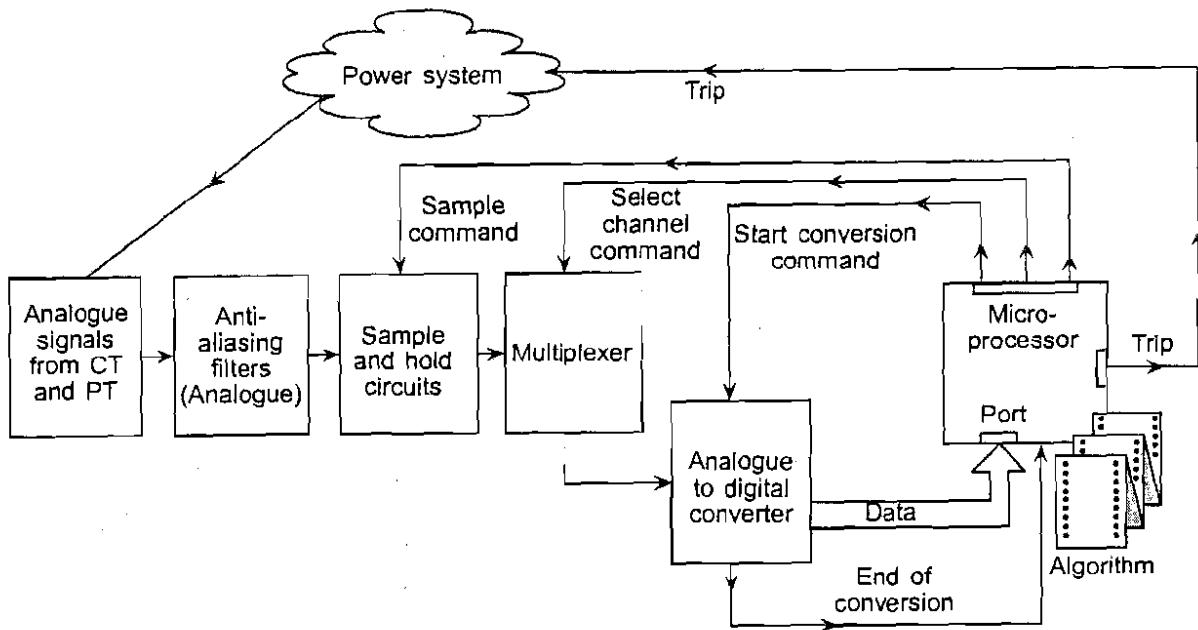


Figure 11.2 Block diagram of numerical relay.

Therefore, the signals are first passed through a low-pass filter, which has to be an analogue type of filter, because digital processing can only take place after the frequency spectrum of the signal is properly shaped.

Next, the analogue signal is sampled and held constant during the time the value is converted to digital form. The sample and hold circuit is an absolute must. The range of frequencies that can be handled by the analogue-to-digital converter (ADC) without the sample and hold (S/H) circuit is extremely low as shown in Table 11.1.

Table 11.1 Comparison of maximum allowable frequency with and without S/H

Without S/H circuit	With S/H circuit
$1. \frac{dv}{dt_{\max}} = \frac{V_{\text{full scale}}}{2^n T_{\text{ADCConv}}}$ <p>where T_{ADCConv} is the conversion time of the ADC.</p> $2. f_{\max} = \frac{1}{2\pi 2^n T_{\text{ADCConv}}}$ <p>$n = \text{ADC word length} = 16 \text{ bits}$ $T_{\text{ADCConv}} = 10 \mu\text{s} \text{ (Typical)}$ $V_m = V_{\text{full scale}}$ Gives: $f_{\max} = 0.24 \text{ Hz}$ Thus, without S/H, the ADC can handle only extremely low frequencies.</p>	$1. \frac{dv}{dt_{\max}} = \frac{V_{\text{full scale}}}{2^n T_{\text{S/H aperture}}}$ <p>where $T_{\text{S/H aperture}}$ is the acquisition time of the S/H circuit.</p> $2. f_{\max} = \frac{1}{2\pi 2^n T_{\text{S/H aperture}}}$ <p>$n = \text{ADC word length} = 16 \text{ bits}$ $T_{\text{S/H aperture}} = 250 \text{ ps} \text{ (Typical)}$ $V_m = V_{\text{full scale}}$ Gives: $f_{\max} = 9.7 \text{ kHz}$ With S/H, the same ADC can now handle much higher frequencies.</p>

The sampled and held value is passed on to the ADC through a multiplexer so as to accommodate a large number of input signals. The sample and hold circuit and the ADC work under the control of the microprocessor and communicate with it with the help of control signals such as the *end-of-conversion* signal issued by the ADC. The ADC passes on the digital representation of the instantaneous value of the signal to the microprocessor via an input port. The output of the ADC may be 4, 8, 12, 16, or 32 bits wide or even wider. The wider the output of the ADC, the greater its resolution.

The incoming digital values from the ADC are stored in the RAM of the microprocessor and processed by the relay software in accordance with an underlying relaying algorithm. The microprocessor issues the trip signal on one of the bits of its output port which is then suitably processed so as to make it compatible with the trip coil of the CB. The microprocessor can also be used to communicate with other relays or another supervisory computer, if so desired. The relaying program or the relay software, which resides in the EPROM, can only be upgraded or modified by authorized personnel. Thus, new features and functionalities can be added to an existing relay by upgrading its software.

A numerical relay can be made to run a program which periodically performs a self-diagnostic test and issues an alarm signal if any discrepancy is noticed. Other features like a watch-dog timer can also be implemented, which issues an alarm if the microprocessor does not reset it, periodically, within a stipulated time of a few milliseconds. This gives an increased user confidence and improves the reliability of the relay.

11.3 Sampling Theorem

The sampling theorem states that in order to preserve the information contained in a signal of frequency ω_{signal} , it must be sampled at a frequency at least equal to or greater than twice the signal frequency. Thus, we must have

$$\omega_{\text{sampling, min}} \geq 2\omega_{\text{signal}} \quad (11.1)$$

The lower limit on sampling frequency, equal to $2\omega_{\text{signal}}$, is known as the Nyquist limit. If the signal is sampled below the Nyquist limit, it gives rise to the phenomenon of aliasing. *Aliasing is the phenomenon of the given signal being lost in the process of digitization, and its place being taken by a different lower frequency wave.*

The above signal refers to a pure sinusoid, which contains only one frequency component ω_{signal} . However, when the signal is distorted, as most real-life signals are, then the Nyquist frequency is equal to $2\omega_{\text{signal, max}}$, where $\omega_{\text{signal, max}}$ is the highest frequency component contained in the signal. Thus, the allowable sampling frequencies are those equal to or greater than $2\omega_{\text{signal, max}}$. Therefore, we have

$$\omega_{\text{sampling, min}} \geq 2\omega_{\text{signal, max}} \quad (11.2)$$

The proof of the sampling theorem can be seen from Figure 11.3.

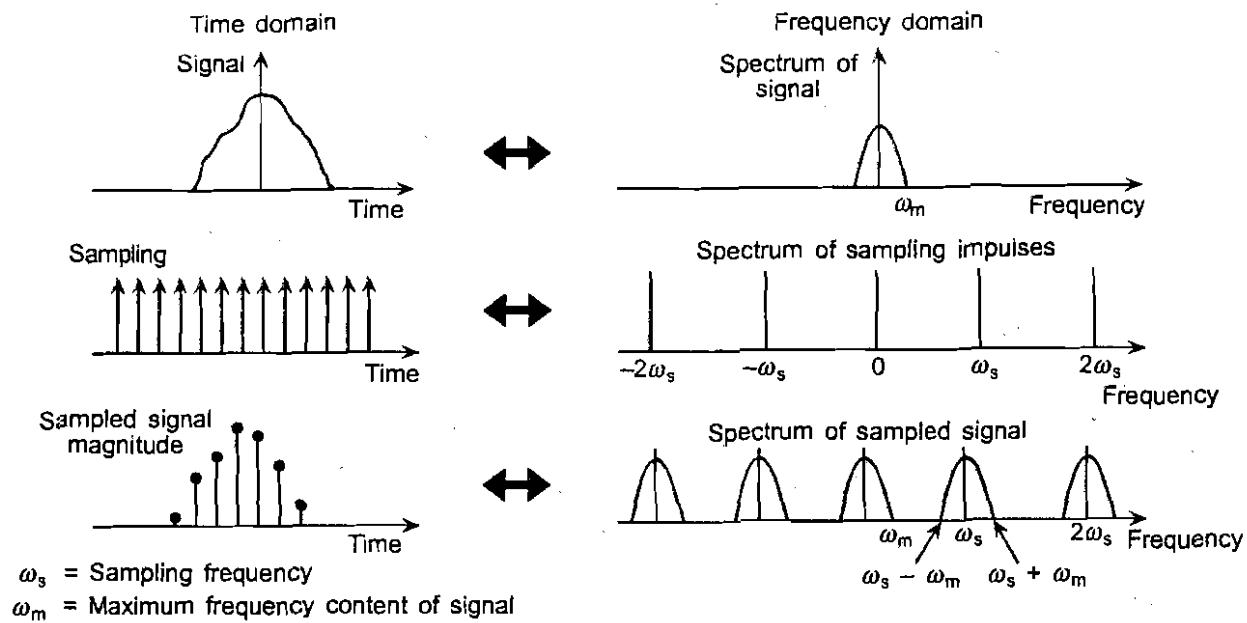


Figure 11.3 Proof of sampling theorem.

The signal has a frequency spectrum which extends up to ω_m . The sampling impulses, which appear at a frequency of ω_s , have a repetitive frequency spectrum which repeats at a spacing of ω_s . In the process of sampling, the sampling frequency gets modulated by the signal. The spectrum of the sampled signal has peaks around 0, $\pm\omega_s$, $\pm 2\omega_s$, $\pm 3\omega_s$, and so on. In order that the envelope of modulation remains distinct, the envelopes should not overlap. This will be so provided if

$$\omega_s - \omega_m > \omega_m$$

or

$$\omega_s > 2\omega_m$$

Therefore, we have

$$\omega_{\text{sampling, min}} > 2\omega_{\text{signal, max}}$$

If the samples of signal, which is sampled below the Nyquist rate, are fed to a digital to analogue converter (DAC), then the DAC does not reproduce the original analogue signal, instead it recreates a different low frequency signal as shown in Figure 11.4. The information contained in the original waveform is thus lost.

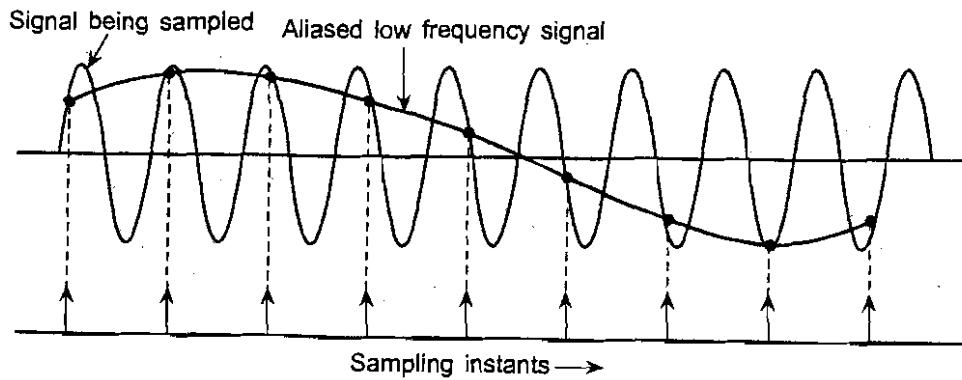


Figure 11.4 Phenomenon of aliasing.

Protective relaying signals contain dc offset, a number of harmonics and random noise, whose spectrum extends from dc to several megahertz. Thus, in order to preserve information in such signals, we will need an impractically high sampling frequency. In order to get around this problem, the signal is first passed through a low-pass filter to shape its frequency spectrum, i.e. remove all frequencies above the cut-off frequency, so that the minimum (Nyquist) sampling rate comes down to a manageable value as shown in Figure 11.5. The cut-off frequency is decided so that frequencies of interest are retained in the sampled version of the signal.

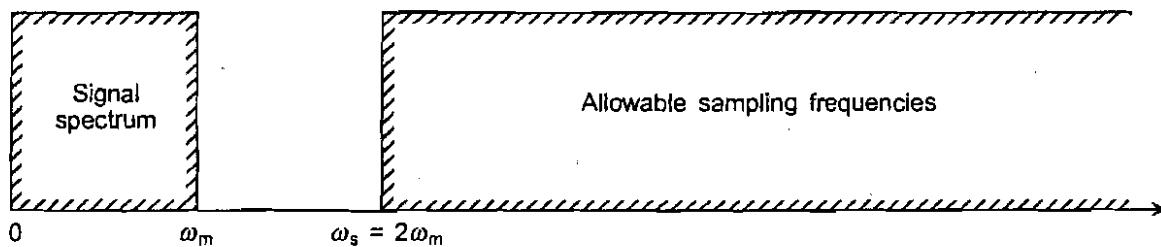


Figure 11.5 Minimum sampling frequency.

The above discussion would be applicable, however, if an ideal low-pass filter, which totally rejects all signals above the cut-off frequency, were available. Such filters do not exist! What we get is a finite roll-off in the stop band. Thus, the Nyquist sampling rate has to be pushed further away and a much higher minimum sampling frequency has to be used in practice as shown in Figure 11.6.

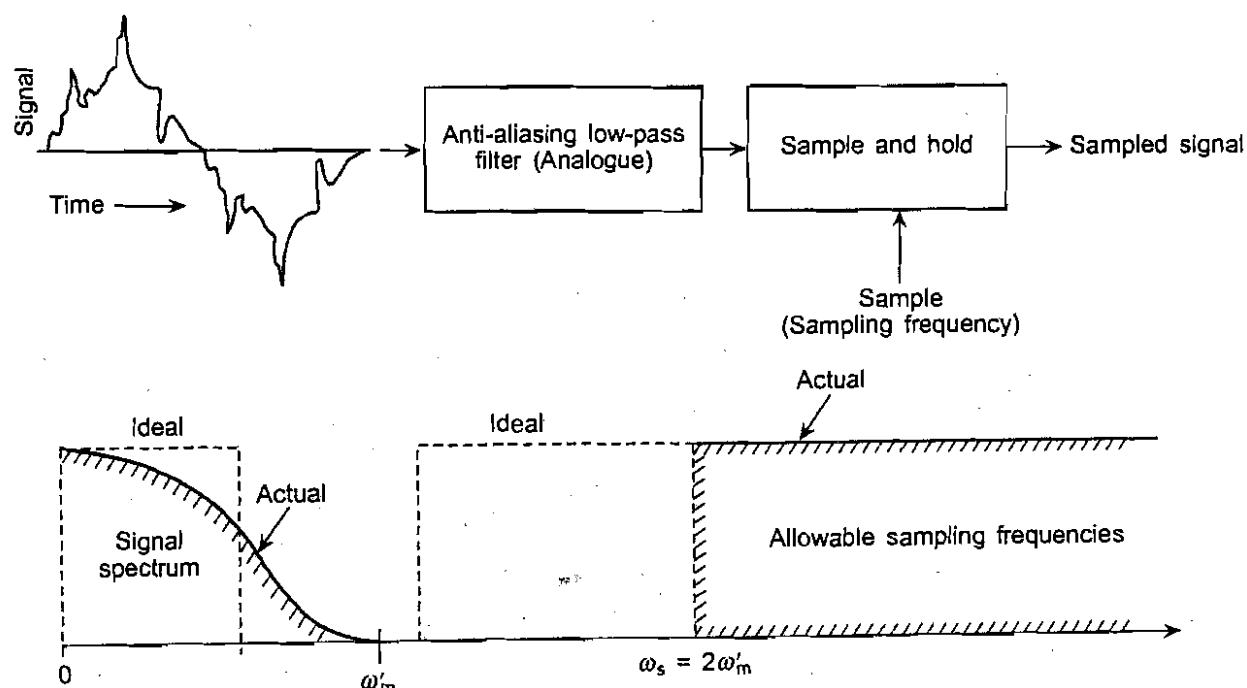


Figure 11.6 Practical limit on minimum sampling frequency.

11.4 Correlation with a Reference Wave

The mathematical operation of correlating a given signal waveform with a set of orthogonal reference waveforms is the basis of a large family of very useful transformations. Fourier analysis is a special case of such transformations wherein the orthogonal reference waves are sine and cosine waves. When the reference wave is the square wave with amplitude of unity, the analysis is known as *Walsh analysis*.

When the analysis is done with respect to the scale and position of the reference (non-sinusoidal) wave, the analysis is known as *wavelet analysis*. *Haar analysis* is the simplest type of wavelet analysis.

Expansion of a given function in various orthogonal sets of functions plays an important role in the processing of signals. It will be pertinent here to briefly review the concept of orthogonal sets of functions. An infinite set of real functions $\phi_0(t)$, $\phi_1(t)$, $\phi_2(t), \dots, \phi_n(t)$ is called *orthogonal* in an interval $[a, b]$ if

$$\int_a^b \phi_n(t) \phi_m(t) dt = 0, \text{ where } n \neq m \quad (11.3)$$

Assuming that

$$\int_a^b \phi_n^2(t) dt = K \neq 0 \quad (11.4)$$

i.e. none of the functions of the set are identically equal to zero. It is known from mathematics that if functions $\phi_n(t)$ are continuous, an arbitrary piecewise-continuous function $f(t)$ satisfying the condition

$$\int |f(t)|^2 dt < \infty \quad (11.5)$$

may be expressed as the sum of the series

$$f(t) = c_0 \phi_0(t) + c_1 \phi_1(t) + \dots + c_n \phi_n(t) \quad (11.6)$$

Let us multiply both sides of Eq. (11.6) by $\phi_n(t)$ and integrate between a and b . All the terms of the form $\int_a^b c_m \phi_m(t) \phi_n(t) dt$ are zero if $m \neq n$, because of the orthogonality of the functions $\phi_m(t)$ and $\phi_n(t)$. The only term remaining on the right-hand side of this equation will be

$$\int_a^b c_n \phi_n(t) \phi_n(t) dt = c_n \int_a^b \phi_n^2(t) dt = c_n K \quad (11.7)$$

where

$$K = \int_a^b \phi_n^2(t) dt \quad (11.8)$$

from which we get an important expression

$$c_n = \frac{1}{K} \int_a^b f(t) \phi_n(t) dt \quad (11.9)$$

The series of Eq. (11.6) with coefficients c_n defined by Eq. (11.9) is called the *generalized Fourier series* in a given set of $\phi_n(t)$.

The generalized Fourier series has the following important property: For a given set of functions $\phi_n(t)$ and with a certain definite number of terms in the series given by Eq. (11.9), it gives the best approximation (i.e. with a minimum mean squared error) of the given function $f(t)$. This means that the mean squared error:

$$M = \int_a^b \left[f(t) - \sum_{n=0}^N a_n \phi_n(t) \right]^2 dt \quad (11.10)$$

is minimal when $a_n = c_n$.

11.4.1 Fourier Analysis of Analogue Signals

When expanding a periodic oscillation $f(t)$ in terms of trigonometric functions, if we take the following orthogonal set

$$1, \cos \omega_1 t, \sin \omega_1 t, \cos 2\omega_1 t, \sin 2\omega_1 t, \dots, \cos n\omega_1 t, \sin n\omega_1 t \quad (11.11)$$

which can be more compactly written in the complex form as

$$e^{-j2\omega_1 t}, e^{-j\omega_1 t}, 1, e^{j\omega_1 t}, e^{j2\omega_1 t} \quad (11.12)$$

then the interval of orthogonality coincides with the fundamental period $T = 2\pi/\omega_1$ of the function $f(t)$.

Thus, using Fourier complex series, we can write

$$\begin{aligned} f(t) &= \dots + c_{-2} e^{-j2\omega_1 t} + c_{-1} e^{-j\omega_1 t} + c_0 + c_1 e^{j\omega_1 t} + c_2 e^{j2\omega_1 t} + \dots \\ &= \sum_{n=-\infty}^{\infty} c_n e^{jn\omega_1 t} \end{aligned} \quad (11.12a)$$

The trigonometric representation of the Fourier series is

$$\begin{aligned} f(t) &= a_0 + a_1 \cos \omega_1 t + a_2 \cos 2\omega_1 t + \dots + a_n \cos n\omega_1 t + \dots \\ &\quad + b_1 \sin \omega_1 t + b_2 \sin 2\omega_1 t + \dots + b_n \sin n\omega_1 t \end{aligned} \quad (11.13)$$

The series of Eqs. (11.12a) and (11.13) are known as **Fourier complex series** and **Fourier trigonometric series**, respectively.

$$f(t) = F_0 + F_1 + F_2 + \dots + F_n$$

where F_0 is the dc component and the other components are:

$$F_1 = a_1 \cos \omega_1 t + j b_1 \sin \omega_1 t, \quad F_2 = a_2 \cos 2\omega_1 t + j b_2 \sin 2\omega_1 t, \quad \text{and so on.}$$

Given a signal $f(t)$, *Fourier analysis* is the process of finding the values of the Fourier coefficients, a_0, a_1, \dots, a_n and b_1, b_2, \dots, b_n , which represent the amplitudes and phase

angles of various frequency components contained in the signal. It is to be noted that the frequency of the fundamental (hence its time period) is known apriori.

Thus, the amplitude of the n th harmonic is

$$F_n = \sqrt{a_n^2 + b_n^2} \quad (11.14)$$

and its phase angle is

$$\theta_n = \tan^{-1}\left(\frac{b_n}{a_n}\right) \quad (11.15)$$

The Fourier coefficients can be easily found by using Eq. (11.9) and using the following trigonometric identities:

$$\int_0^T \sin(m\omega_1 t) dt = 0, \quad \text{all } m \quad (11.16)$$

and

$$\int_0^T \cos(n\omega_1 t) dt = 0, \quad \text{all } n \neq 0 \quad (11.17)$$

Since the average value of a sinusoid over m or n complete cycles in the period T is zero, the following three cross-product terms are also zero for the stated relationship of m and n :

$$\int_0^T \sin(m\omega_1 t) \cos(n\omega_1 t) dt = 0, \quad \text{all } m, n \quad (11.18)$$

$$\int_0^T \sin(m\omega_1 t) \sin(n\omega_1 t) dt = 0, \quad m \neq n \quad (11.19)$$

$$\int_0^T \cos(m\omega_1 t) \cos(n\omega_1 t) dt = 0, \quad m \neq n \quad (11.20)$$

Non-zero values for the integrals result when m and n are equal; thus

$$\int_0^T \sin^2(m\omega_1 t) dt = \frac{T}{2}, \quad \text{all } m \quad (11.21)$$

$$\int_0^T \cos^2(n\omega_1 t) dt = \frac{T}{2}, \quad \text{all } n \quad (11.22)$$

Thus, the coefficients a_0 , a_n , and b_n are

$$a_0 = \frac{1}{T} \int_0^T f(t) dt \quad (11.23)$$

$$a_n = \frac{2}{T} \int_0^T f(t) \cos(n\omega_1 t) dt \quad (11.24)$$

$$b_n = \frac{2}{T} \int_0^T f(t) \sin(n\omega_1 t) dt \quad (11.25)$$

Figure 11.7 shows the input and the output of a Fourier analysis.

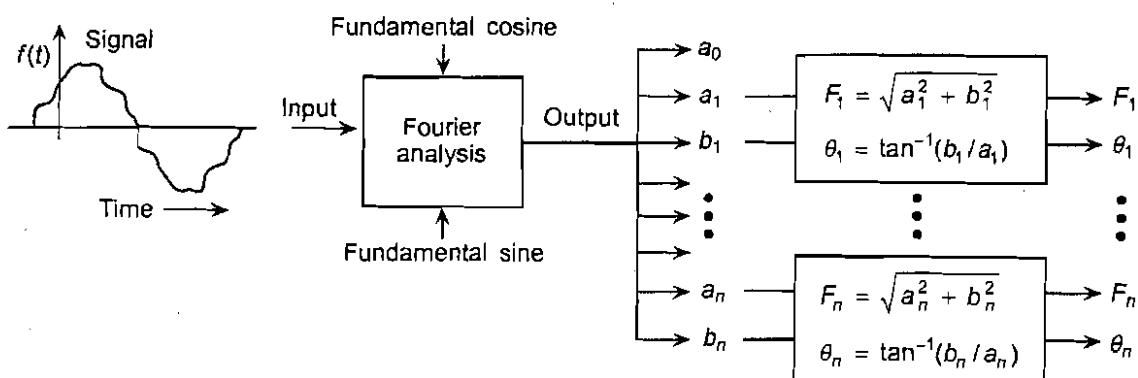


Figure 11.7 Input output of Fourier analysis.

Fourier analysis of discrete signals

The above Fourier analysis assumes that the signal being processed is continuous and extends from $t = -\infty$ to $t = \infty$. However, for practical reasons, we can analyze the signal over only a finite duration. The Fourier analysis of finite-duration continuous (analogue) signals is known as *Fourier Transform* and its counterpart in the discrete digital domain is known as *Discrete Fourier Transform* (DFT).

Numerical relays work with the digitized version of the analogue signal. Therefore, the Fourier analysis described for analogue signals has to be suitably modified. The modification consists in replacing the respective entities with their discrete counterparts, as shown in Table 11.2.

Table 11.2 Analog vs discrete domain

Analog domain	Digital or discrete domain
Continuous signal $f(t)$, where t can take any value and, therefore, $f(t)$ can take any value from an infinite set of numbers.	Discrete signal $f(k \Delta t)$, where k is the sample number which is a positive integer and Δt is the sampling interval, i.e. the time period between two consecutive samples.
Continuous time t	Integer sample number k
Integration \int	Summation Σ
Time period T	Number of samples per cycle N
Integration between infinite limits	Summation of finite samples

The time Δt is the time period corresponding to the sampling frequency, hence

$$\Delta t = \frac{1}{f_{\text{sampling}}} = T_{\text{sampling}}$$

since there are N samples per cycle of fundamental, we get

$$NT_{\text{sampling}} = N\Delta t = T_1 = \frac{2\pi}{\omega_1}$$

Noting that k is the sample number and N is the number of samples per cycle, the expressions for evaluating the Fourier coefficients in the discrete domain can be obtained from those for the continuous domain by making substitutions shown in Table 11.2.

Table 11.3 lists the expressions for evaluating discrete Fourier coefficients alongside those of continuous Fourier coefficients so that the readers can easily associate the discrete expressions with the more familiar continuous expressions.

Table 11.3 Discrete Fourier transform coefficients

<i>Continuous</i>	<i>Discrete</i>
$a_0 = \frac{1}{T} \int_0^T f(t) dt$	$a_0 = \frac{1}{N} \sum_{k=1}^N f(k\Delta t)$
$a_n = \frac{2}{T} \int_0^T f(t) \cos(n\omega_1 t) dt$	$a_n = \frac{2}{N} \sum_{k=1}^N f(k\Delta t) \cos(n\omega_1 k\Delta t)$
$b_n = \frac{2}{T} \int_0^T f(t) \sin(n\omega_1 t) dt$	$b_n = \frac{2}{N} \sum_{k=1}^N f(k\Delta t) \sin(n\omega_1 k\Delta t)$

In order to process a signal, we consider the signal over a finite duration, known as a *window*. The implicit assumption is that the signal samples are zero uniformly outside the window. The process of windowing and finding the discrete Fourier transform is shown in Figure 11.8. Since we are applying the Fourier transform only to samples which occur within a window of 1 cycle, this is known as a *full cycle window*.

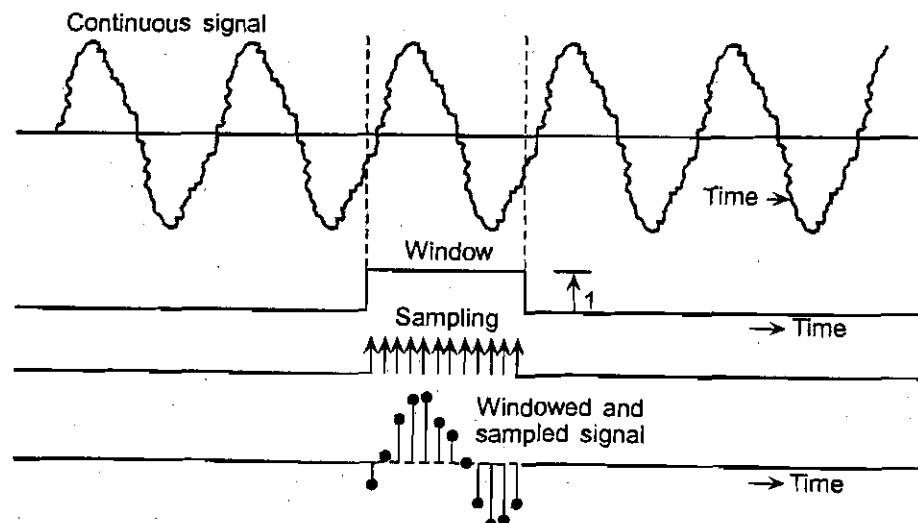


Figure 11.8 Windowing and sampling of a continuous signal.

Windowing is a mathematical operation, in time domain, of multiplying all samples outside the window by zero and those within the window by unity. Every operation in the time domain has its repercussions in the frequency domain. It is, therefore, only natural that windowing affects the frequency domain picture, and may depict some frequencies which were not present in the original signal! In order to faithfully preserve the information content, windowing should be done in a manner, as unobtrusive as possible. Fortunately, windows can be shaped in such a way that the effect in frequency domain is minimal. Various early researchers have proposed window shapes to meet a variety of criteria. Interested readers may refer to any standard text on Digital Signal Processing for more information on this very interesting topic.

Figure 11.9 shows the process of computing the Fourier transform. Samples of the signal denoted by $f(k \Delta t)$ are stored in the memory of the computer. The samples of the fundamental sine and cosine waves, known as *weights*, are precalculated and also stored in the memory. The Fourier transform is the process of multiplying the sample with the corresponding weight and accumulating the sum. When the process is complete we get one estimate of the magnitude of the desired frequency component and its phase angle. In protective relaying application, the process continues in an infinite loop. The time window is continuously kept sliding forward. In the meanwhile, the results of the Fourier transform are passed on to a relaying program which may further perform over-current, directional, differential or any other type of relaying function. Thus, the process is similar to a machine which keeps on running.

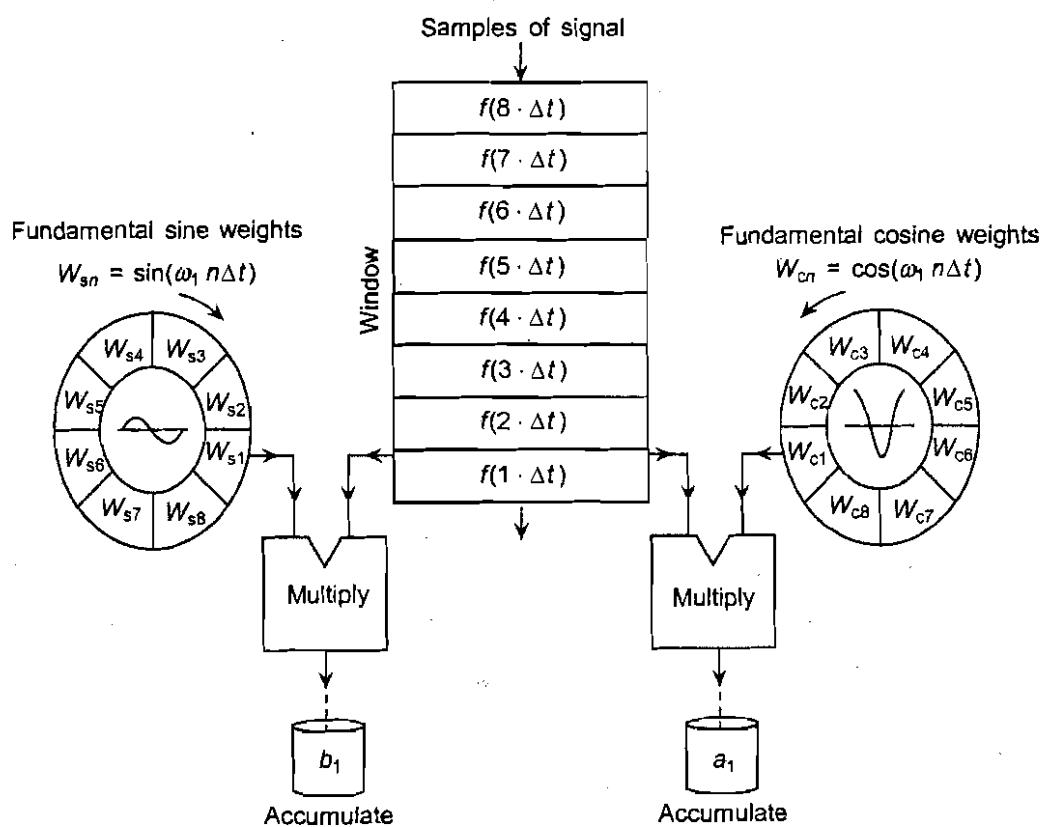


Figure 11.9 The discrete Fourier machine for eight samples/cycle.

The same process has been depicted in the flowchart of Figure 11.10. If we wish to extract other frequency components then the corresponding weights need to be precalculated and stored.

For example, to extract the second harmonic, the weights will be the samples of second harmonic sine and cosine waves $W_2 \sin(n)$ and $W_2 \cos(n)$.

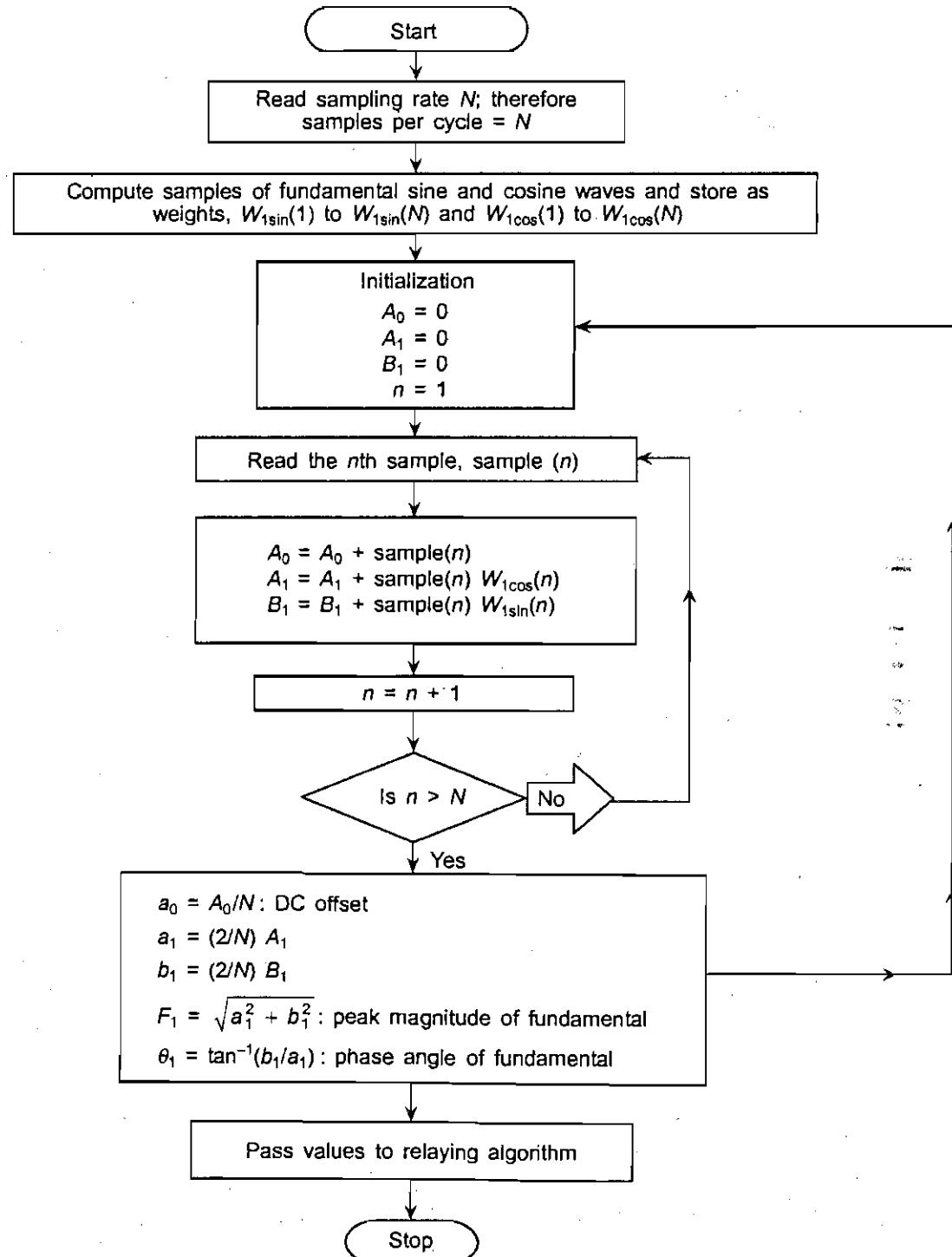


Figure 11.10 Flow chart for the computation of Discrete Fourier Transform.

Walsh analysis

In Walsh analysis, the reference correlating functions are square waves of unit amplitude as shown in Figure 11.11. In terms of Walsh functions, a periodic function $f(t)$ can be expanded over the interval $(t_1, t_1 + T)$ as follows:

$$f(t) = \sum_{k=0}^{\infty} W_k \text{Wal}(k, t/T)$$

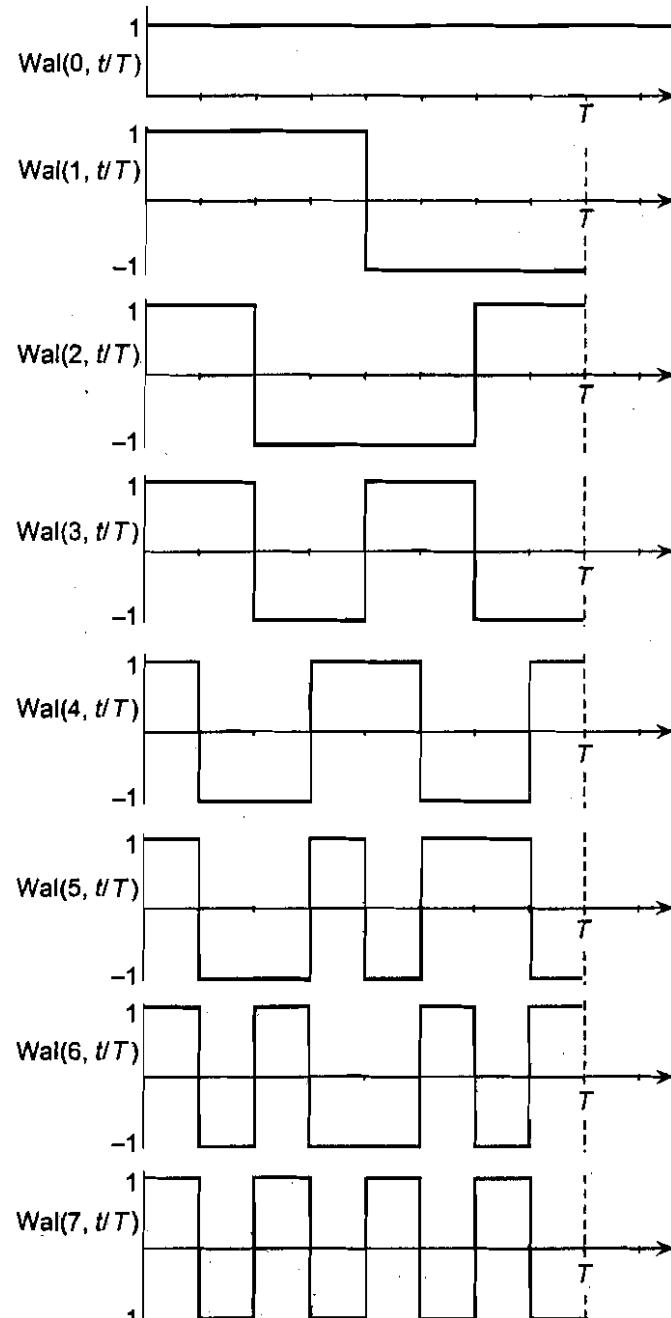


Figure 11.11 First eight Walsh functions.

where the Walsh coefficients W_k are given by

$$W_k = \frac{1}{T} \int_{t_1}^{t_1+T} f(t) \text{Wal}(k, t/T) dt$$

Note that the weights, $\text{Wal}(k, t/T)$, are all, either +1 or -1; thus making the Walsh transform computationally very efficient as multiplication by floating point numbers is avoided and only additions and subtractions of the samples are required to be done.

Walsh transform gained popularity during the initial years of numerical relaying because at that time the microprocessors were not able to perform floating point arithmetic. However, the modern microprocessors and the digital signal processors (DSP) can routinely perform high speed, high precision, floating point arithmetic, hence Walsh approach seems to have taken a back seat.

Another factor limiting the proliferation of Walsh analysis is that the electrical circuit theory is deeply rooted in the sine waves. Thus, in order to relate to concepts such as impedance, we have to come back to Fourier domain. This involves another transformation from the Walsh to the Fourier domain, which is computationally intensive. Thus, the initial advantage of Walsh analysis, being computationally easy, is to some extent lost.

All the same, Walsh analysis opens up a fresh viewpoint and leads to many new interesting possibilities. The interested reader may refer to standard texts on digital signal processing.

Wavelet analysis

When we perform conventional Fourier analysis, we get the information about the frequencies that are present in the signal. However, all clues about the time, at which these frequencies appear, are lost.

Thus, if we were to perform Fourier analysis of an orchestra, we would name with confidence, all musical instruments which were being played, but not the respective times at which these were being played!

Conventional Fourier analysis does not preserve any information about *time* but gives very detailed information about *frequency*.

Discrete Fourier transform, on the other hand, preserves some information about time since the location of the time-window is known. However, the time-window size is fixed. In order to increase the precision of information about time, the time-window needs to be made smaller. However, as we make the time-window small, the information about the low frequencies loses its precision.

Continuous Wavelet analysis attempts to remove this lacuna of Fourier analysis and gives information about the frequencies and the times at which they appear. This is achieved by using a family of correlating functions which have well marked attributes of *position* and *scale*. The position attribute is analogous to the time domain of Fourier analysis while the scale attribute is analogous to the frequency domain.

Discrete Wavelet analysis is a discrete implementation of the continuous wavelet transform.

Wavelet analysis is very useful for analyzing signals generated by a non-stationary phenomenon whereas Fourier analysis is suitable for stationary phenomenon.

During the immediate post-fault conditions or other disturbed conditions like power swings, the power system gives rise to non-stationary signals. In the steady state (both pre-fault and post-fault), the signals are stationary.

Recently researchers have started reporting a number of Wavelet based approaches for data compression and recognition of certain fault signatures like high impedance faults or magnetizing current inrush. However, the applications are still in their infancy and are being investigated.

Interested readers may refer to advanced texts on image processing for more detailed information on the theory of Wavelets.

11.5 Least Error Squared (LES) Technique

As pointed out in Section 11.4, the least error squared technique is directly related to the Fourier technique. If a given function were to be synthesized by using a dc component, a sine wave of fundamental frequency and harmonics of this fundamental, then the amplitudes of various components given by the Fourier analysis are the ones which give the least squared error.

We can directly find out the amplitudes of the components by using the LES technique. To illustrate the LES technique, let us assume that the fault current consists of:

- A dc offset
- A fundamental component
- Other harmonic components of higher order

The LES technique helps us in estimating the values of these components.

The assumed signal is:

$$i(t) = K_1 e^{-t/\tau} + \sum_{n=1}^N K_{2n} \sin(n\omega_1 t + \theta_n) \quad (11.26)$$

For the sake of illustration, assuming that the current consists of a dc offset, the fundamental and a third harmonic component, we can write

$$i(t) = K_1 e^{-t/\tau} + K_{21} \sin(\omega_1 t + \theta_1) + K_{23} \sin(3\omega_1 t + \theta_3) \quad (11.27)$$

We can represent $e^{-t/\tau}$ as a sum of an infinite series, i.e.

$$e^{-t/\tau} = 1 - \frac{t}{\tau} + \frac{t^2}{2!\tau^2} - \frac{t^3}{3!\tau^3} + \dots \quad (11.28)$$

Assuming that truncating the series for $e^{-t/\tau}$, to the first three terms, gives adequate accuracy, we get

$$\begin{aligned} i(t) &= K_1 - \frac{K_1}{\tau} t_1 + \frac{K_1 t^2}{2! \tau^2} + K_{21} \cos \theta_1 \sin \omega_1 t + K_{21} \sin \theta_1 \cos \omega_1 t \\ &\quad + K_{23} \cos \theta_3 \sin 3\omega_1 t + K_{23} \sin \theta_3 \cos 3\omega_1 t \end{aligned} \quad (11.29)$$

In Eq. (11.29), let us denote the unknowns by x and the knowns by a , as follows:

<i>Unknowns</i>	<i>Knowns</i> (These can be precalculated)
$x_1 = K_1$	$a_{11} = 1$
$x_2 = K_{21} \cos \theta_1$	$a_{12} = \sin \omega_1 t$
$x_3 = K_{21} \sin \theta_1$	$a_{13} = \cos \omega_1 t$
$x_4 = K_{23} \cos \theta_3$	$a_{14} = \sin 3\omega_1 t$
$x_5 = K_{23} \sin \theta_3$	$a_{15} = \cos 3\omega_1 t$
$x_6 = -K_1/\tau$	$a_{16} = t$
$x_7 = K_1/2\tau^2$	$a_{17} = t^2$

Thus, we can write

$$\begin{aligned} i(t_1) &= a_{11}x_1 + a_{12}x_2 + a_{13}x_3 + a_{14}x_4 + a_{15}x_5 + a_{16}x_6 + a_{17}x_7 \\ i(t_2) &= a_{21}x_1 + a_{22}x_2 + a_{23}x_3 + a_{24}x_4 + a_{25}x_5 + a_{26}x_6 + a_{27}x_7 \\ &\vdots \quad \vdots \\ i(t_7) &= a_{71}x_1 + a_{72}x_2 + a_{73}x_3 + a_{74}x_4 + a_{75}x_5 + a_{76}x_6 + a_{77}x_7 \end{aligned} \quad (11.30)$$

We can express Eq. (11.30) in matrix form as

$$\begin{bmatrix} i(t_1) \\ i(t_2) \\ i(t_3) \\ i(t_4) \\ i(t_5) \\ i(t_6) \\ i(t_7) \end{bmatrix} = \begin{bmatrix} a_{11} & a_{12} & a_{13} & a_{14} & a_{15} & a_{16} & a_{17} \\ a_{21} & a_{22} & a_{23} & a_{24} & a_{25} & a_{26} & a_{27} \\ a_{31} & a_{32} & a_{33} & a_{34} & a_{35} & a_{36} & a_{37} \\ a_{41} & a_{42} & a_{43} & a_{44} & a_{45} & a_{46} & a_{47} \\ a_{51} & a_{52} & a_{53} & a_{54} & a_{55} & a_{56} & a_{57} \\ a_{61} & a_{62} & a_{63} & a_{64} & a_{65} & a_{66} & a_{67} \\ a_{71} & a_{72} & a_{73} & a_{74} & a_{75} & a_{76} & a_{77} \end{bmatrix} \begin{bmatrix} x_1 \\ x_2 \\ x_3 \\ x_4 \\ x_5 \\ x_6 \\ x_7 \end{bmatrix} \quad (11.31)$$

which in shorthand notation can be written as

$$[i]_{7 \times 1} = [A]_{7 \times 7} [x]_{7 \times 1} \quad (11.32)$$

Thus, we can find the unknowns $[x]_{7 \times 1}$ as

$$[x]_{7 \times 1} = [A]_{7 \times 7}^{-1} [i]_{7 \times 1} \quad (11.33)$$

If we are interested in the fundamental, then since

$$x_2 = K_{21} \cos \theta_1 \quad (11.34)$$

$$x_3 = K_{21} \sin \theta_1 \quad (11.35)$$

Amplitude of fundamental, $F_1 = \sqrt{x_2^2 + x_3^2}$ (11.36)

Phase angle of fundamental, $\theta_1 = \tan^{-1}\left(\frac{x_3}{x_2}\right)$ (11.37)

The same technique can be applied to the samples of the voltage waveform to extract the fundamental and other higher frequency components of voltage.

Once equipped with the above information, we can perform a variety of relaying functions such as over-current relaying, differential relaying, detecting magnetizing in-rush by extracting the second harmonic component, estimating impedance up to fault location, i.e. performing distance relaying or fault location.

11.6 Digital Filtering

Filtering is a very important and the most frequently needed operation in numerical relaying. We are familiar with the analogue filters consisting of $R-L-C$ circuits and active filters using operational amplifiers. However, there are certain drawbacks associated with analogue and active analogue filters, namely:

- They are bulky, specially inductors require a large space.
- High precision components are needed, making them expensive.
- Their characteristics drift with respect to time and temperature.
- Filters for very low frequencies need impractically high component values.
- Their characteristics are limited to the certain well known conventional characteristics.
- They are not adaptable, i.e. they cannot change their characteristics in response to the input signal.
- They are not programmable.

Digital filters offer advantages with respect to all of the above points. The most important advantage of digital filters is that they do not require high precision and high quality $R-L-C$ components. All types of digital filters require the same basic hardware consisting of anti-aliasing filters, sample and hold circuits and analogue-to-digital converters. The underlying software decides the filtering action. Thus, *the digital filter exists in software*. This has several advantages, for example, it is easy to change the characteristics of the filter by simply using another program. Digital filters do not need any tuning and maintenance. There is no ageing and no drift caused by time or temperature.

11.6.1 Simple Low-pass Filter

If we form the output by simply taking the running average of last two samples then the simple mathematical operation has the effect of performing a low-pass filtering operation. The filter can be expressed mathematically as

$$y_n = \frac{x_n + x_{n-1}}{2} \quad (11.38)$$

Consider a signal as shown in Figure 11.12. At sample number 3, there is a large noise signal of positive polarity. At sample number 4, there is a noise signal of equal magnitude but of opposite polarity. Thus, we have a high frequency noise signal riding over the low frequency information-carrying-signal. Now, since the output signal is formed by taking a running average, the effect of a positive spike followed by a negative spike, is totally cancelled out and we get a smoother signal as shown in Figure 11.12.

Thus, we have got rid of the high frequency signal, allowing only low frequencies to pass. This amounts to low-pass filtering.

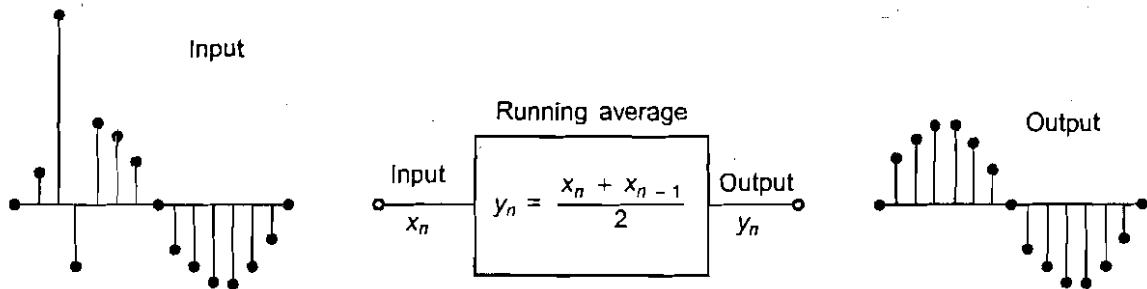


Figure 11.12 A simple running average filter works as a low-pass filter.

11.6.2 Simple High-pass Filter

If the output sequence is formed by taking a running difference of the samples of the input sequence then it has the effect of high-pass filtering as shown in Figure 11.13. The filter can be expressed mathematically as

$$y_n = \frac{x_n - x_{n-1}}{2} \quad (11.39)$$

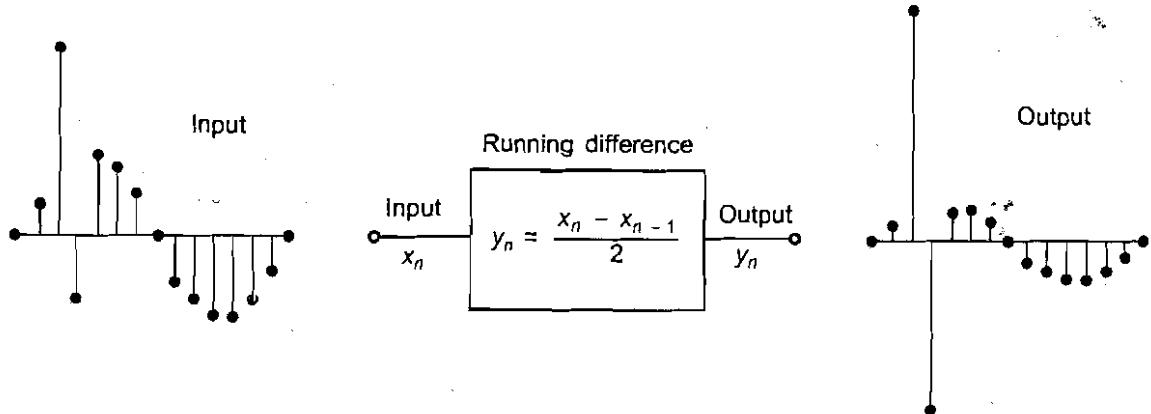


Figure 11.13 A simple running difference filter works as a high-pass filter.

The high-pass filtering takes place when any sudden changes of sign of the samples get amplified as a result of taking the difference. Slowly varying samples of signal almost cancel out each other in the output. Thus, only the high frequency component appears at the output.

11.6.3 Finite Impulse Response (FIR) Filters

Digital filters are linear systems. The impulse response completely characterizes any linear system. If the impulse response has a finite number of terms then the filter is known as the *finite impulse response filter*. Figure 11.14 shows the block diagram of a digital filter with finite impulse response.

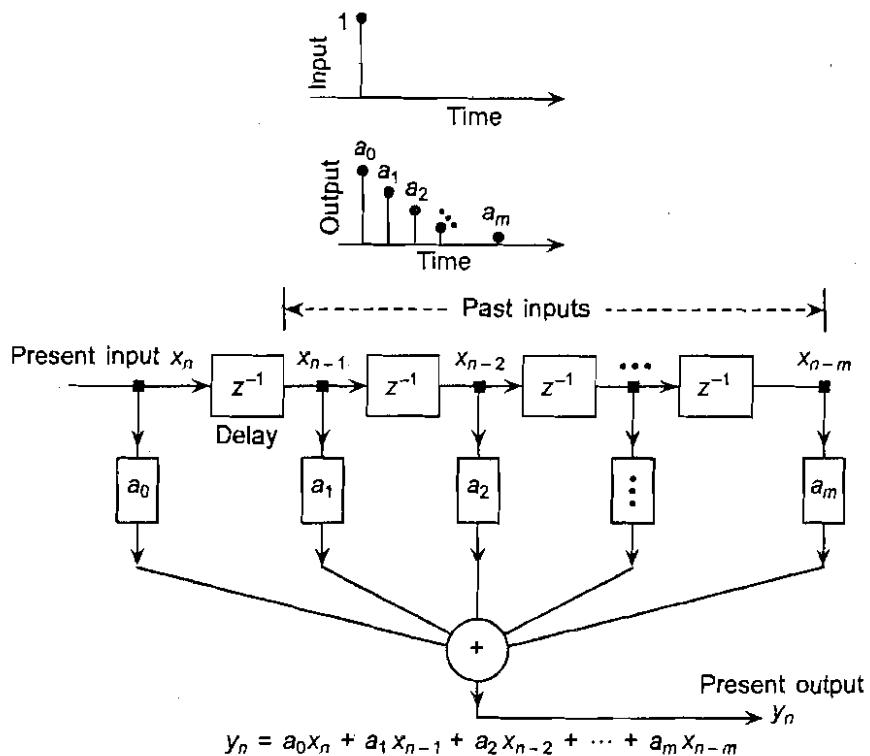


Figure 11.14 Block diagram of FIR digital filter (canonical).

The filter generates the output samples by forming a weighted sum of the input sample and a limited number of previous input samples. The weights are nothing but the samples of impulse response of the filter. Thus, the output of an FIR filter of length m is given by performing the convolution of the incoming sequence of samples with the impulse response of the filter. The n th output will be given by

$$y(n) = a_0x_n + a_1x_{n-1} + \dots + a_mx_{n-m} \quad (11.40)$$

Note that the above filter will need memory to store m samples and $(m + 1)$ number of coefficients.

The frequency response of the above filter is given by

$$f(j\omega) = \sum_{n=0}^m e^{(-j\omega n \Delta t)} a_m \quad (11.41)$$

Thus, the frequency response depends upon the frequency ω of the input signal, the sampling interval Δt and the set of coefficients a_m . The following important points are worth noting:

1. The frequency response of a digital filter is a periodic function with a period equal to $2\pi/\Delta t$
2. The frequency response, given by the function $f(j\omega)$, is the Fourier transform of the impulse response (a_0, \dots, a_m) of the digital filter.

The transfer function of the filter in the z -domain is given by

$$\frac{Y(z)}{X(z)} = \frac{a_0 z^m + a_1 z^{m-1} + a_2 z^{m-2} + \dots + a_m}{z^m} \quad (11.42)$$

11.6.4 Infinite Impulse Response (IIR) Filter

This filter is characterized by the fact that the n th sample of the output is formed by using the previous values of both inputs and outputs. The coefficients a_0, \dots, a_m are similar to those of the FIR filter. The coefficients b_0, \dots, b_k form the *recursive part* of the filter. Figure 11.15 shows a canonical implementation of the digital filter with infinite impulse response (IIR). There are, however, many alternative ways in which these filters can be implemented.

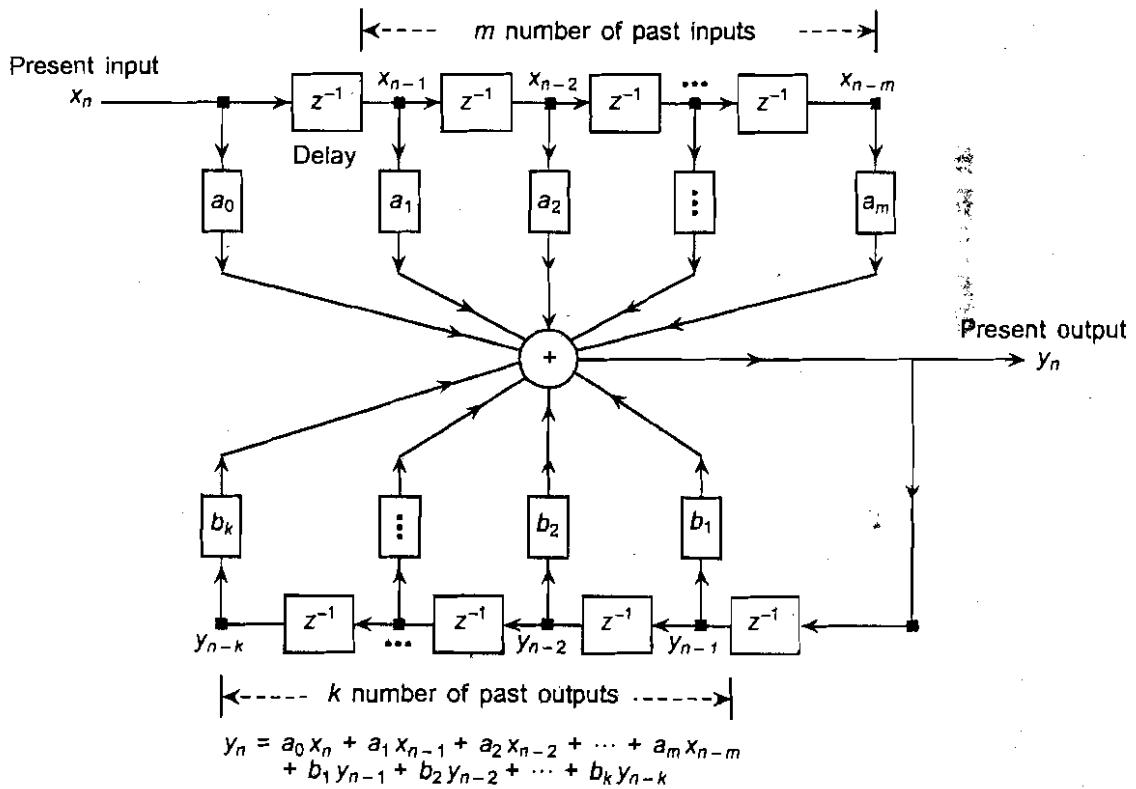


Figure 11.15 Block diagram of IIR digital filter (canonical).

The output at the n th sampling instant is given by

$$y_n = a_0 x_n + a_1 x_{n-1} + \dots + a_m x_{n-m} + b_1 y_{n-1} + b_2 y_{n-2} + \dots + b_k y_{n-k} \quad (11.43)$$

Note that the output at any sampling instant is a function of m number of past inputs and k number of past outputs. Thus this type of filter has feedback, hence the filter is also known as **recursive** (which literally means running backwards).

The transfer function of the filter in the z -domain is given by

$$\frac{Y(z)}{X(z)} = \frac{a_0 + a_1 z^{-1} + a_2 z^{-2} + \dots + a_m z^{-m}}{1 - b_1 z^{-1} - \dots - b_k z^{-k}} \quad (11.44)$$

A recursive digital filter is stable if the output of the filter is a non-increasing sequence, i.e. for n tending to infinity y_n should not exceed some positive number M , irrespective of the choice of initial conditions.

11.6.5 Comparison Between FIR and IIR Filters

The following table lists several important issues concerning the FIR and IIR filters.

<i>FIR Filter</i>	<i>IIR Filter</i>
Output is a function of past m inputs. Therefore, non-recursive.	Output is a function of past m inputs as well as k past outputs. Therefore, recursive.
Finite impulse response. Always stable since there is no feedback.	Infinite impulse response. Because of feedback, possibility of instability exists.
Has less number of coefficients. Transfer function has only the numerator terms.	Has more number of coefficients. Transfer function has both the numerator and denominator terms.
Higher-order filter required for a given frequency response.	Lower-order filter required for a given frequency response.
Has linear phase response.	Has nonlinear phase response.
$y_n = a_0 x_n + a_1 x_{n-1} + \dots + a_m x_{n-m}$	$y_n = a_0 x_n + a_1 x_{n-1} + \dots + a_m x_{n-m} + b_1 y_{n-1} + b_2 y_{n-2} + \dots + b_k y_{n-k}$
$\frac{Y(z)}{X(z)} = \frac{a_0 z^m + a_1 z^{m-1} + a_2 z^{m-2} + \dots + a_m}{z^m}$	$\frac{Y(z)}{X(z)} = \frac{a_0 + a_1 z^{-1} + a_2 z^{-2} + \dots + a_m z^{-m}}{1 - b_1 z^{-1} - \dots - b_k z^{-k}}$
Very simple to implement.	Not as simple as the FIR filter.

11.7 Numerical Over-current Protection

Numerical over-current protection is a straightforward application of the numerical relay. Here we describe a possible method of implementing a numerical over-current relay.

The algorithm first reads all the settings such as the type of characteristics to be implemented, the pick-up value I_{pu} , the time multiplier setting in case of inverse time over-current relay or the time delay in case of DTOC relay.

The algorithm of a numerical over-current relay will first extract the fundamental component of the fault current I_{rms} , from the post-fault samples of current and establish its rms value. Full cycle window Fourier transform may be used for this purpose as it

effectively filters out the dc offset. It will then compare this fundamental component I_{rms} with the pick-up setting and compute the plug setting multiplier, given by $(I_{\text{rms}}/I_{\text{pu}})$ at which the relay will be operating.

Equipped with the PSM value, the relay will either compute or look up the required time delay depending upon the type of over-current characteristic that is being implemented. The algorithm will then cause the relay to go into a wait state for a time equal to the operating time.

At the end of this time delay, the relay will once again evaluate the rms value of the fundamental to find if the fault has already been cleared by some other relay. If the fault current still persists then the relay will issue a trip output. This signal will be suitably processed to make it compatible with the trip coil of the circuit breaker. The algorithm of a typical over-current relay is shown in Figure 11.16.

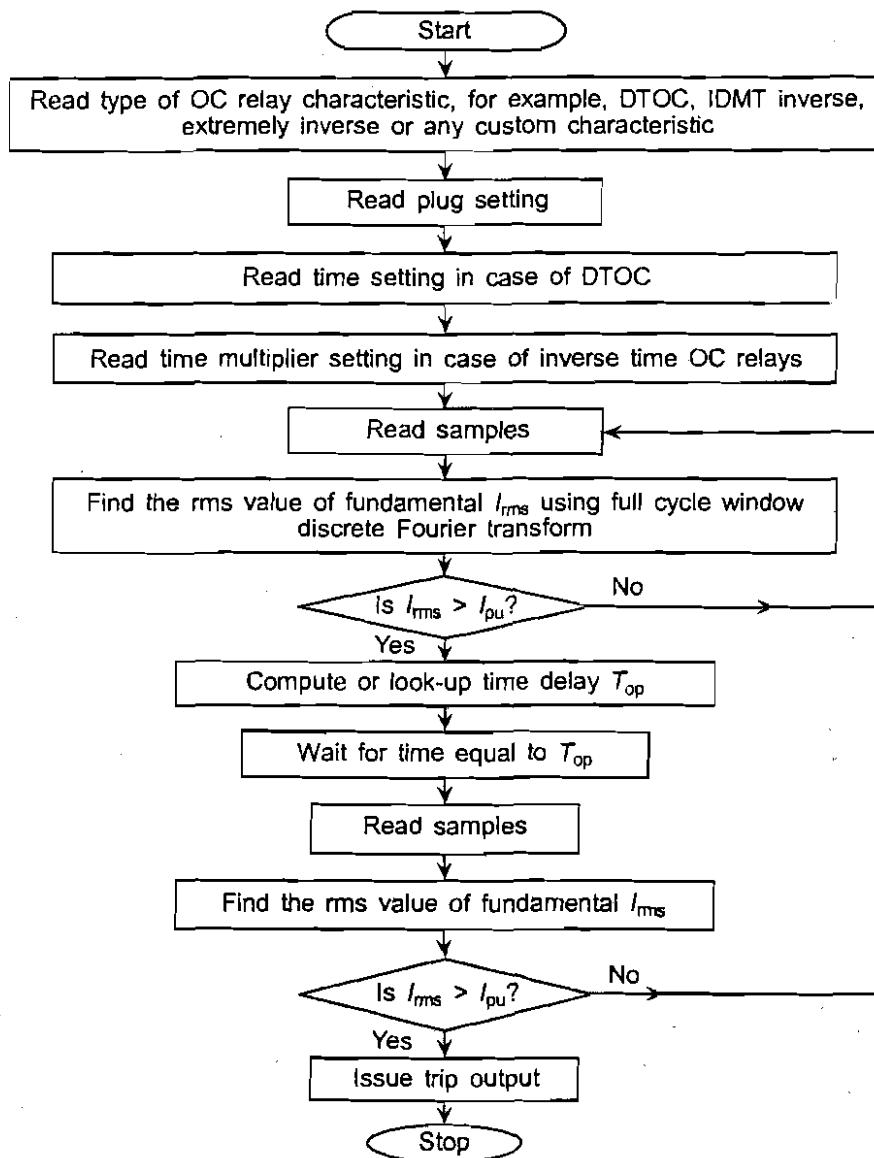


Figure 11.16 Flowchart for a numerical over-current relay algorithm.

11.8 Numerical Transformer Differential Protection

Figure 11.17 shows the conceptual block diagram for numerical protection of a transformer. The idea is to estimate the phasor value of the current on both sides of the transformer and find the phasor difference between the two. If the magnitude of this difference is substantial, an internal fault is indicated and the trip signal should be issued. The above is a description of the simple differential scheme. All the reasons that prompt us to go in for the percentage differential relay exist here as well. Therefore, the numerical relay algorithm should be made to implement the percentage differential relay.

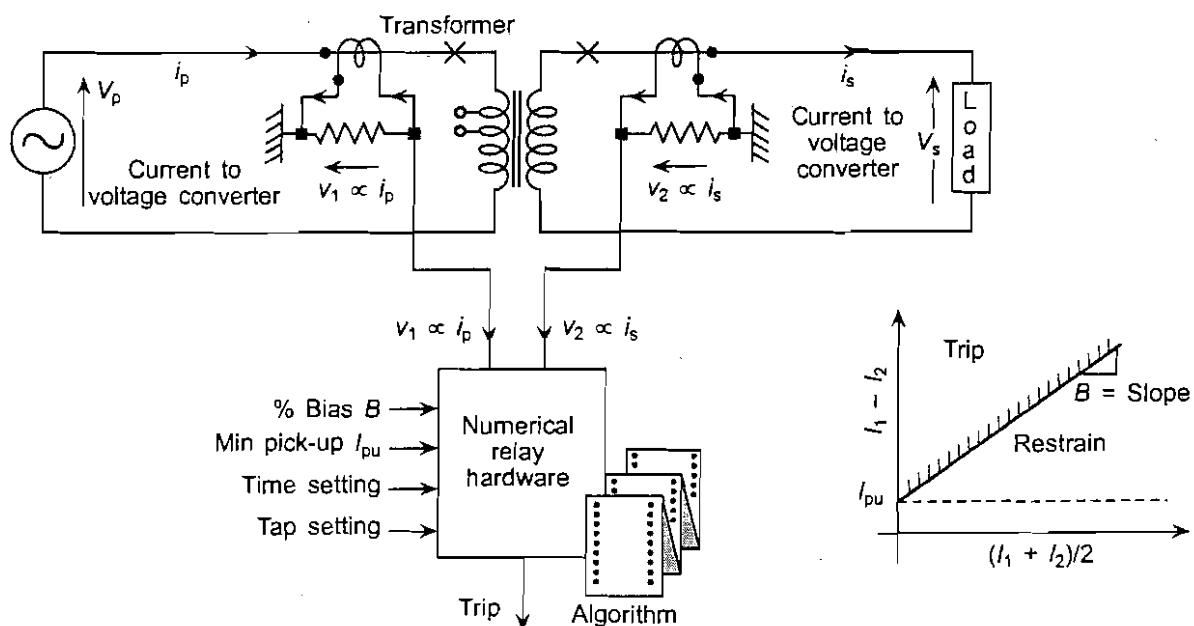


Figure 11.17 Block diagram of numerical protection of transformer.

Algorithm for percentage differential relay will consist of the following steps:

- Read percentage bias B and minimum pick-up I_{pu} .
- Read i_p samples \rightarrow Estimate phasor \mathbf{I}_p using any technique.
- Read i_s samples \rightarrow Estimate phasor \mathbf{I}_s using any technique.
- Compute spill current $I_{spill} = \mathbf{I}_p - \mathbf{I}_s$.
- Compute circulating current $I_{circulating} = (\mathbf{I}_p + \mathbf{I}_s)/2$.
- If $I_{spill} > (BI_{circulating} + I_{pu})$ then trip, else restrain.

11.9 Numerical Distance Protection of Transmission Line

11.9.1 Mann and Morrison Method

Let voltage at the relay location be described by

$$v = V_m \sin(\omega t + \theta_v) \quad (11.45)$$

and the current by

$$i = I_m \sin(\omega t + \theta_i) \quad (11.46)$$

It may be noted that voltage and current are assumed to be pure sinusoids.

Let v' and i' represent the derivatives of voltage and current, respectively. Then we can write

$$v' = \omega V_m \cos(\omega t + \theta_v) \quad (11.47)$$

or

$$\frac{v'}{\omega} = V_m \cos(\omega t + \theta_v)$$

and

$$i' = \omega I_m \cos(\omega t + \theta_i) \quad (11.48)$$

or

$$\frac{i'}{\omega} = I_m \cos(\omega t + \theta_i)$$

Combining expressions for v and (v'/ω) , we get

$$V_m = \sqrt{v^2 + \frac{v'^2}{\omega^2}} \quad (11.49)$$

Similarly

$$I_m = \sqrt{i^2 + \frac{i'^2}{\omega^2}} \quad (11.50)$$

Further, the phase angles can be found as follows:

$$\theta_v = \tan^{-1}\left(\frac{\omega v}{v'}\right) \quad (11.51)$$

$$\theta_i = \tan^{-1}\left(\frac{\omega i}{i'}\right) \quad (11.52)$$

The phase angle between the relay voltage and relay current will be given by

$$\theta = \theta_v - \theta_i \quad (11.53)$$

Note that this analysis refers to continuous signals. However, the same can be adapted for numerical relaying by substituting sample values instead of instantaneous values and numerically computed derivatives instead of continuous derivatives. The numerical derivatives at the n th sampling instant, v'_n and i'_n can be written as

$$v'_n = \frac{v_{n+1} - v_{n-1}}{2\Delta t} \quad (11.54)$$

Similarly

$$i'_n = \frac{i_{n+1} - i_{n-1}}{2\Delta t} \quad (11.55)$$

Substituting Eqs. (11.54) and (11.55) in the expressions for V_m and I_m , we get

$$V_m = \sqrt{v_n^2 + \frac{(v_{n+1} - v_{n-1})^2}{(2\Delta t\omega)^2}} \quad (11.56)$$

$$I_m = \sqrt{i_n^2 + \frac{(i_{n+1} - i_{n-1})^2}{(2\Delta t\omega)^2}} \quad (11.57)$$

$$\theta_v = \frac{\omega v_n 2\Delta t}{v_{n+1} - v_{n-1}} \quad (11.58)$$

$$\theta_i = \frac{\omega i_n 2\Delta t}{i_{n+1} - i_{n-1}} \quad (11.59)$$

$$\theta = \theta_v - \theta_i \quad (11.60)$$

Thus, using a window of three samples, we can estimate the peak and hence the rms values of voltage and current at the relay location as well as the phase angle between them. In other words, the phasors for voltage and current can be estimated.

We can keep on sliding the window to make a running estimate of rms value of current, rms value of voltage, phase angle between voltage and current and, hence compute the apparent impedance seen from the relay location.

The algorithms appear to be very attractive because of their simplicity. However, closer examination reveals that the Mann and Morrison method is based on the following assumption:

Waveforms of both the voltage and current consist of undistorted sine waves of fundamental frequency which is accurately known and is constant.

Obviously, the above assumption will be seldom, if ever, true in a power system relaying scenario. Thus, the method will introduce significant errors if the assumption is not true. How then can we use the method in practice?

We can use the method in practice, provided we operate as close to the assumption as possible. This can be achieved by heavily filtering the voltage and the current waveforms so as to remove all traces of dc offsets, harmonics and noise. Thus, the price for the simplicity of the method has to be paid in terms of complex preprocessing of the voltage and current signals.

In order to make a robust relay based on the above algorithm, we will have to employ additional methods to make sure that stray noise signals do not cause false tripping. One such method is to increment a counter every time the estimated value is such that tripping is called for. The actual trip output is issued only if this counter reaches a predetermined threshold. If the counter does not reach the threshold, it is reset to zero after a predetermined time-out. The counter threshold depends upon the expected level of noise at the particular location and has to be determined empirically.

11.9.2 Differential Equation Method

In this method, the faulted line is modelled as a lumped series $R-L$ circuit. The distributed nature of the line parameters as well as the shunt capacitance are neglected. Thus, we can relate the voltage and current at the relay location and the resistance and inductance up to the fault location with the help of the differential equation:

$$v = i_x R + L \frac{di_y}{dt} \quad (11.61)$$

where

i_x is the current in the faulted phase

i_y is the function of all the three-phase currents

R and L are the functions of resistance and inductance of the transmission line up to the fault location.

In order to keep things simple while developing the concept, we first consider a single-phase transmission line.

Application to single-phase transmission line

Consider a single-phase transmission line fed from one end. Let us assume a ground fault at a certain distance x from the sending end. The transmission line can be modelled as a series $R-L$ circuit. This is shown in Figure 11.18.

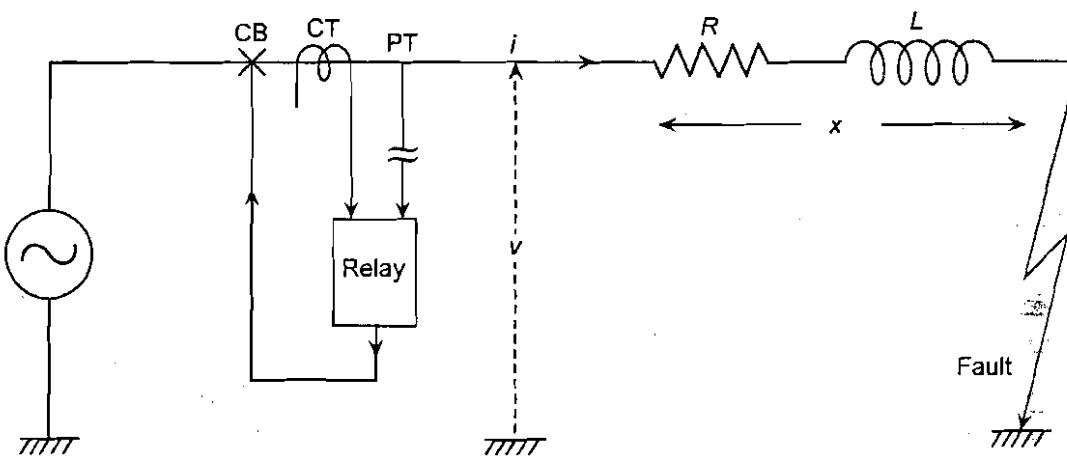


Figure 11.18 Faulted transmission line modelled by lumped series $R-L$ circuit.

The voltage and current at the relay location are v and i , respectively. For the loop formed by the equivalent circuit of the faulted line, using KVL, we can write

$$v = Ri + L \frac{di}{dt} \quad (11.62)$$

Though Eq. (11.62) is a differential equation, the numerical values of v and i are known and the numerical value of di/dt can be computed, the equation, in fact, is a linear algebraic equation in two unknowns, R and L . We, therefore, need one more equation in v and i to solve for the two unknowns. Writing Eq. (11.62) for two different sampling instants n and $n + 1$ as shown in Figure 11.19, we get

$$v_n = Ri_n + L \frac{di_n}{dt} \quad (11.63)$$

$$v_{n+1} = Ri_{n+1} + L \frac{di_{n+1}}{dt} \quad (11.64)$$

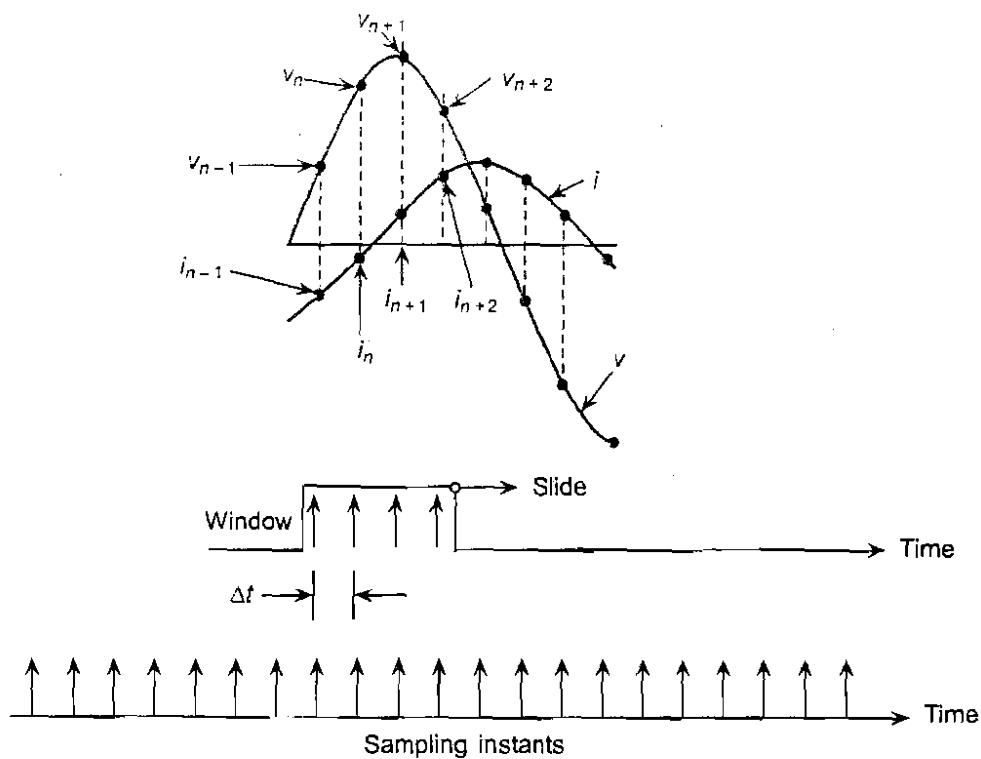


Figure 11.19 Numbering of samples of voltage and current for differential equation algorithm.

From Figure 11.19, we can easily see that the numerical derivative of the current at instants n and $n + 1$ is

$$\frac{di_n}{dt} = \frac{i_{n+1} - i_{n-1}}{2\Delta t} \quad (11.65)$$

$$\frac{di_{n+1}}{dt} = \frac{i_{n+2} - i_n}{2\Delta t} \quad (11.66)$$

where Δt is the sampling interval.

Expressing the simultaneous algebraic Eqs. (11.63) and (11.64) in matrix notation and solving for the unknowns R and L , we get

$$\begin{bmatrix} v_n \\ v_{n+1} \end{bmatrix} = \begin{bmatrix} i_n & \frac{i_{n+1} - i_{n-1}}{2\Delta t} \\ i_{n+1} & \frac{i_{n+2} - i_n}{2\Delta t} \end{bmatrix} \begin{bmatrix} R \\ L \end{bmatrix} \quad (11.67)$$

$$\begin{bmatrix} R \\ L \end{bmatrix} = \begin{bmatrix} i_n & \frac{i_{n+1} - i_{n-1}}{2\Delta t} \\ i_{n+1} & \frac{i_{n+2} - i_n}{2\Delta t} \end{bmatrix}^{-1} \begin{bmatrix} v_n \\ v_{n+1} \end{bmatrix} \quad (11.68)$$

$$\begin{bmatrix} R \\ L \end{bmatrix} = \frac{1}{D} \begin{bmatrix} \frac{i_{n+2} - i_n}{2\Delta t} & \frac{-(i_{n+1} - i_{n-1})}{2\Delta t} \\ -i_{n+1} & i_n \end{bmatrix} \begin{bmatrix} v_n \\ v_{n+1} \end{bmatrix} \quad (11.69)$$

where

$$D = \frac{i_{n+2} - i_n}{2\Delta t} i_n - \frac{i_{n+1} - i_{n-1}}{2\Delta t} i_{n+1}$$

From which we get

$$R = \frac{(i_{n+2} - i_n)v_n - (i_{n+1} - i_{n-1})v_{n+1}}{i_n(i_{n+2} - i_n) - i_{n+1}(i_{n+1} - i_{n-1})} \quad (11.70)$$

$$L = 2\Delta t \frac{i_n v_{n+1} - i_{n+1} v_n}{i_n(i_{n+2} - i_n) - i_{n+1}(i_{n+1} - i_{n-1})} \quad (11.71)$$

A window of four samples is seen to be adequate for computing one estimate of the values of R and L . In order to make the method more robust, the window can be shifted further and another estimate can be made. If the fault is a metallic fault, the estimated values will converge on to a stable value.

Application to three-phase transmission line

The above discussion referred to a single-phase transmission line. However, in practice, the power transmission lines are always three-phase in nature. It will be pertinent, therefore, to see how we can apply the differential equation approach to a three-phase transmission line. Consider the model of the three-phase transmission line shown in Figure 11.20. The elemental length dx of any phase is assumed to have a resistance, an inductance and a mutual inductance parameter associated with it. The shunt capacitance is neglected.

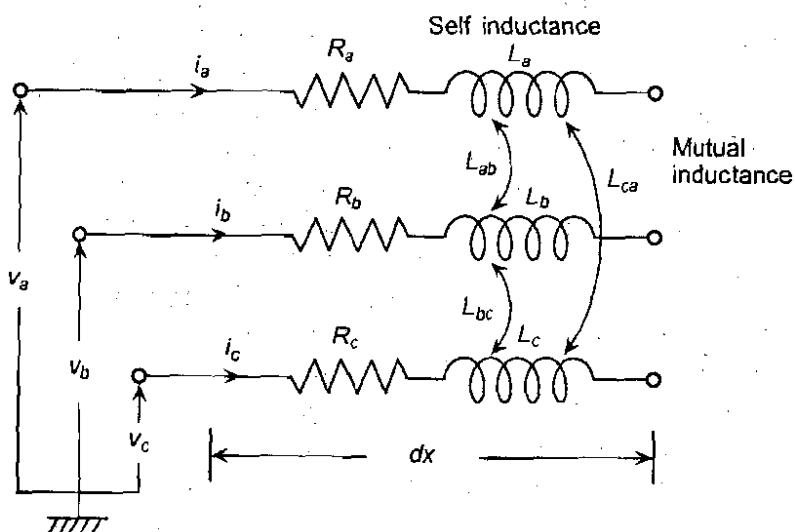


Figure 11.20 Model of three-phase line.

The voltage drop across the infinitesimal length dx , of phase a can be written as

$$dv_a = (R_a i_a dx) + (L_a dx) \frac{di_a}{dt} + (L_{ab} dx) \frac{di_b}{dt} + (L_{ac} dx) \frac{di_c}{dt} \quad (11.72)$$

or

$$\frac{dv_a}{dx} = \left(R_a + L_a \frac{d}{dt} \right) i_a + \left(L_{ab} \frac{di_b}{dt} \right) + \left(L_{ac} \frac{di_c}{dt} \right) \quad (11.73)$$

Similarly the voltage and current relationships for phases b and c can be written as

$$\frac{dv_b}{dx} = \left(L_{ba} \frac{di_a}{dt} \right) + \left(R_b + L_b \frac{d}{dt} \right) i_b + \left(L_{bc} \frac{di_c}{dt} \right) \quad (11.74)$$

$$\frac{dv_c}{dx} = \left(L_{ca} \frac{di_a}{dt} \right) + \left(L_{cb} \frac{di_b}{dt} \right) + \left(R_c + L_c \frac{d}{dt} \right) i_c \quad (11.75)$$

If the line is assumed to be ideally transposed, we have

$$R_a = R_b = R_c = R_s \quad (11.76)$$

$$L_a = L_b = L_c = L_s \quad (11.77)$$

$$L_{ab} = L_{ac} = L_{ba} = L_{bc} = L_{ca} = L_{cb} = L_m \quad (11.78)$$

where

R_s , L_s are the series resistance and self-inductance per unit length of each phase

L_m is the mutual inductance per unit length between any two phases.

By substituting Eqs. (11.76) to (11.78) into Eqs. (11.73) to (11.75), we obtain

$$\frac{dv_a}{dx} = \left(R_s + L_s \frac{d}{dt} \right) i_a + \left(L_m \frac{di_b}{dt} \right) + \left(L_m \frac{di_c}{dt} \right) \quad (11.79)$$

$$\frac{dv_b}{dx} = \left(L_m \frac{di_a}{dt} \right) + \left(R_s + L_s \frac{d}{dt} \right) i_b + \left(L_m \frac{di_c}{dt} \right) \quad (11.80)$$

$$\frac{dv_c}{dx} = \left(L_m \frac{di_a}{dt} \right) + \left(L_m \frac{di_b}{dt} \right) + \left(R_s + L_s \frac{d}{dt} \right) i_c \quad (11.81)$$

Now, the self- and mutual-parameters are related to the zero and positive sequence parameters as follows:

$$L_0 = L_s + 2L_m \quad (11.82)$$

$$R_1 = R_s \quad (11.83)$$

$$L_1 = L_s - L_m \quad (11.84)$$

and

$$i_0 = \frac{i_a + i_b + i_c}{3} \quad (11.85)$$

where

R_1 , L_1 are positive sequence resistance and inductance, respectively

L_0 is the zero sequence inductance

i_0 is the zero sequence current.

By combining Eqs. (11.79) to (11.81) and Eqs. (11.82) to (11.85), we obtain

$$\frac{dv_a}{dx} = \left(R_1 + L_1 \frac{d}{dt} \right) i_a + (L_0 - L_1) \frac{di_0}{dt} \quad (11.86)$$

$$\frac{dv_b}{dx} = \left(R_1 + L_1 \frac{d}{dt} \right) i_b + (L_0 - L_1) \frac{di_0}{dt} \quad (11.87)$$

$$\frac{dv_c}{dx} = \left(R_1 + L_1 \frac{d}{dt} \right) i_c + (L_0 - L_1) \frac{di_0}{dt} \quad (11.88)$$

Equations (11.72) to (11.75) can be used to compute the voltage drop between the relay location and the fault point for different types of faults as shown next.

Single-phase to ground fault. Assume a metallic single-phase to ground fault on phase a at a distance x from the relay location. The instantaneous value of voltage v_a at the relay location can be calculated using Eqs. (11.72) and (11.73) for untransposed lines and Eqs. (11.79) to (11.81) for ideally transposed lines.

Using the instantaneous values of the voltages, currents and the rate of change of currents, the voltage v_a can be obtained by using Eqs. (11.72) to (11.73) as shown below:

$$v_a = xR_a i_a + xL_a \frac{d}{dt} \left(i_a + \frac{L_{ab}}{L_a} i_b + \frac{L_{ac}}{L_a} i_c \right) \quad (11.89)$$

or

$$v_a = xR_a i_x + xL_a \frac{di_y}{dt} \quad (11.90)$$

where

$$i_x = i_a \quad (11.91)$$

and

$$i_y = i_a + \left(\frac{L_{ab}}{L_a} \right) i_b + \left(\frac{L_{ac}}{L_a} \right) i_c \quad (11.92)$$

Equations relating to the transposed lines can be expressed in the same way and in this case Eqs. (11.79) to (11.81) can be used to obtain the following relationship:

$$v_a = xR_s i_x + xL_s \frac{di_y}{dt} \quad (11.93)$$

where

$$i_x = i_a \quad (11.94)$$

and

$$i_y = i_a + \left(\frac{L_m}{L_s} \right) i_b + \left(\frac{L_m}{L_s} \right) i_c \quad (11.95)$$

Phase-to-phase and three-phase faults. When the fault involves two or three phases, the voltage between the faulted phases, say a and b , can be found as follows:

$$v_a - v_b = x \left(R_a + L_a \frac{d}{dt} \right) i_a + x L_{ab} \frac{di_b}{dt} - x \left[L_{ba} \frac{di_a}{dt} + \left(R_b + L_b \frac{d}{dt} \right) i_b \right] \quad (11.96)$$

Equation (11.96) can be reduced to the more compact form as

$$v_a - v_b = x R_a i_x + x (L_a - L_{ab}) \frac{di_y}{dt} \quad (11.97)$$

where

$$i_x = i_a - \left(\frac{R_b}{R_a} \right) i_b \quad (11.98)$$

and

$$i_y = i_a - \left[\frac{(L_b - L_{ab}) i_b}{L_a - L_{ab}} \right] \quad (11.99)$$

When the line is assumed ideally transposed, Eq. (11.93) can be written in terms of the difference between the currents on each faulted phase, giving

$$v_a - v_b = x R_1 i_x + x L_1 \frac{di_y}{dt} \quad (11.100)$$

where in this case

$$i_x = i_y = i_a - i_b \quad (11.101)$$

The above analysis shows that the behaviour of the transmission line under fault conditions is governed by a differential equation having the general form of

$$v = R i_x + L \frac{di_y}{dt} \quad (11.102)$$

The measured values of the currents and the voltages are taken in the form of samples and the measurement is usually done simultaneously on all the three phases.

In Eq. (11.102), all the terms except R and L , are either the measured samples or the quantities easily computed from the samples. The values of R and L can be found by solving the simultaneous equations involving R and L . One of the methods, which involves computing the numerical derivatives has already been described in Section 11.9.2.

We can convert the differential equation into an integral equation by integrating both sides, in which case the numerical integration rather than differentiation will have to be performed. Integration, being an inherently low-pass operation, yields better results in the presence of higher frequency components present in the voltage and current waveforms.

11.10 Algorithms and Assumptions

We may easily get bogged down by the sheer number of algorithms for digital protection which have been proposed in the literature. However, algorithms can be broadly classified into time-domain algorithms and frequency-domain algorithms. For example, the solution

of a differential equation is in time domain whereas the Fourier algorithm is in frequency domain.

We must bear in mind that there is no algorithm which can offer a panacea. Underlying every algorithm, is a set of assumptions. The algorithm is good only within the constraints imposed by the assumptions. The effectiveness of an algorithm depends on how far, in practice, the assumptions on which it is based, are close to reality.

For example, if we assume that the signals are undistorted sine waves then we can use very simple algorithms such as those of Mann and Morrison's.

Review Questions

1. Trace the evolution of protective relays.
2. What are the advantages of numerical relays over conventional relays?
3. What paradigm shift can be seen with the development of numerical relays?
4. Draw the block diagram of the numerical relay.
5. What do you mean by aliasing?
6. State and explain Shannon's sampling theorem.
7. What happens if the sampling frequency is less than the Nyquist limit?
8. What are the drawbacks of a very high sampling frequency?
9. Is sample and hold circuit an absolute must?
10. A 12-bit ADC has conversion time of 10 microseconds. What is the maximum frequency that can be acquired without using a sample and hold unit?
11. If a sample and hold circuit of 100 picoseconds is available, how will the maximum frequency found out in Question 10 be affected?
12. Explain the statement that all numerical relays have the same hardware but what distinguishes the relay is the underlying software.
13. Explain the sample and derivative methods of estimating the rms value and phase angle of a signal. Clearly state the underlying assumptions.
14. What do you mean by Fourier analysis? Explain.
15. How does Fourier transform differ from conventional Fourier analysis?
16. What do you mean by a full cycle window?
17. What are the advantages and disadvantages of a half cycle window?
18. What do you mean by a digital filter? Explain.
19. Draw the block diagram of an FIR and an IIR filter.
20. Compare the FIR and IIR filters.
21. Develop the differential equation algorithm for distance protection of a transmission line.
22. For numerical relaying purpose the differential equation gets converted into a linear algebraic equation. Explain.
23. Discuss the methods to find numerical differentiation and numerical integration.
24. How can certain frequencies be filtered out in solving the differential equation by integration?

CT and PT Errors

Appendix A

A.1 Introduction

CTs and PTs are the *eyes and ears* of the protective system. They extract information from the power system and form an important link between the high-voltage high-current power system and the low-voltage low-current protective system. CTs and PTs have two important roles to play, namely:

- Electrically isolate the protective relays from the high-voltage power system for the purpose of safety of the operating personnel.
- Step down the current and voltage to standard values of 1 A, 5 A, 110 V so that the design of relays can be standardized irrespective of the actual primary voltage and current.

A.2 CT Construction

CTs can be constructed as two-winding transformers with independent primary and secondary windings. We can, however, get rid of the primary winding and use the primary conductor itself as a one-turn primary winding, known as *bar-primary*, when the magnitude of the primary current is sufficiently high. In such CTs, the secondary winding can be conveniently put inside the high voltage bushings. The auto-transformer type CTs may also be used in conjunction with two-winding CTs for the purpose of fine tuning the ratio of transformation.

A.3 Measurement CT and Protective CT

CTs are also used for measurement purposes. However, the desired response from measurement CTs under short-circuit conditions (when the primary current is high) is quite different. A protection CT is required to faithfully transform the primary current throughout its entire range from normal load current to short-circuit current. A

measurement CT, on the other hand, is designed to saturate at currents more than around 1.2 times the full-load current, and thus save the measuring instruments from possible damage.

By suitable design, the operating point of the measurement CT is kept near the knee of the excitation characteristic. *The knee point is defined as that point on the excitation characteristic at which 10% increase in excitation voltage results in a 50% increase in the excitation current* (see Figure A.1).

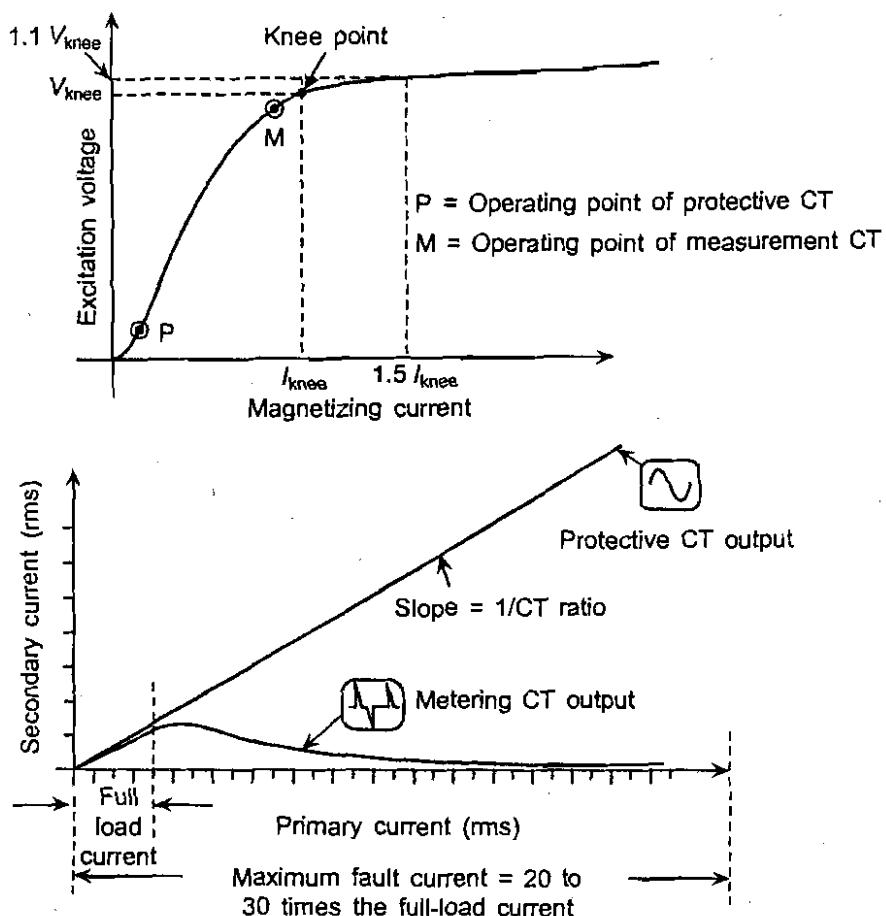


Figure A.1 Difference in the response of a measurement CT and protective CT.

A protective CT is designed to operate much below the knee point so that it maintains its transformation ratio during high magnitude short-circuit currents.

A.4 Steady State Ratio and Phase Angle Errors

A.4.1 Current Transformer

Figure A.2(a) shows the connections of a CT and a PT to supply, load, and relay. The equivalent circuit of the CT is shown in Figure A.2(b). The corresponding phasor diagram is shown in Figure A.2(c).

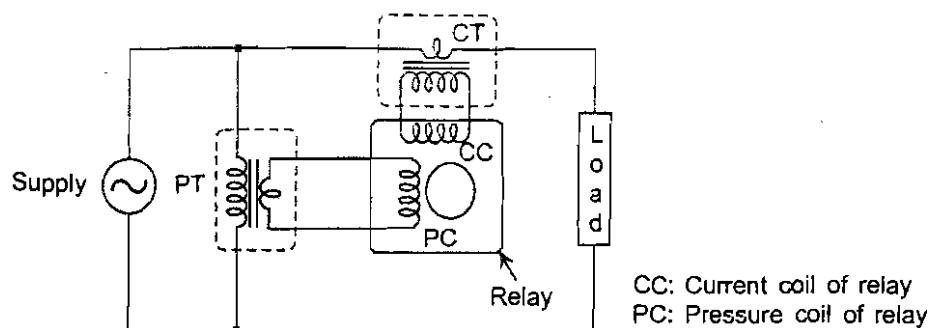


Figure A.2(a) Connections of a CT and a PT to supply, load and relay.

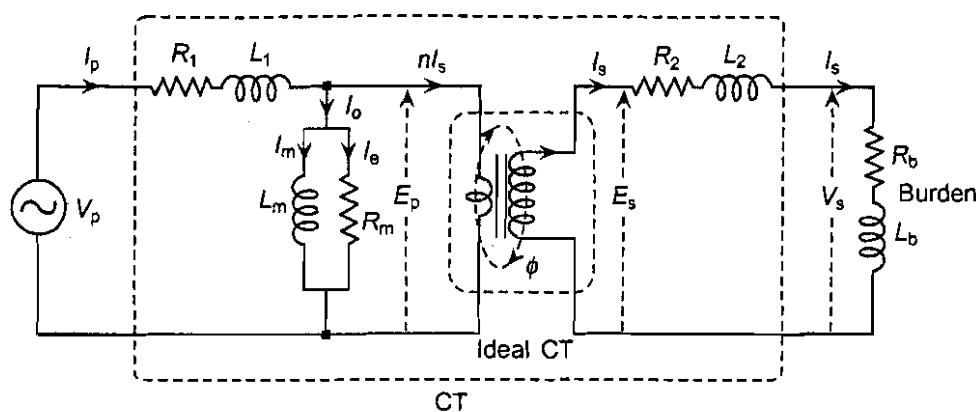


Figure A.2(b) Equivalent circuit of CT.

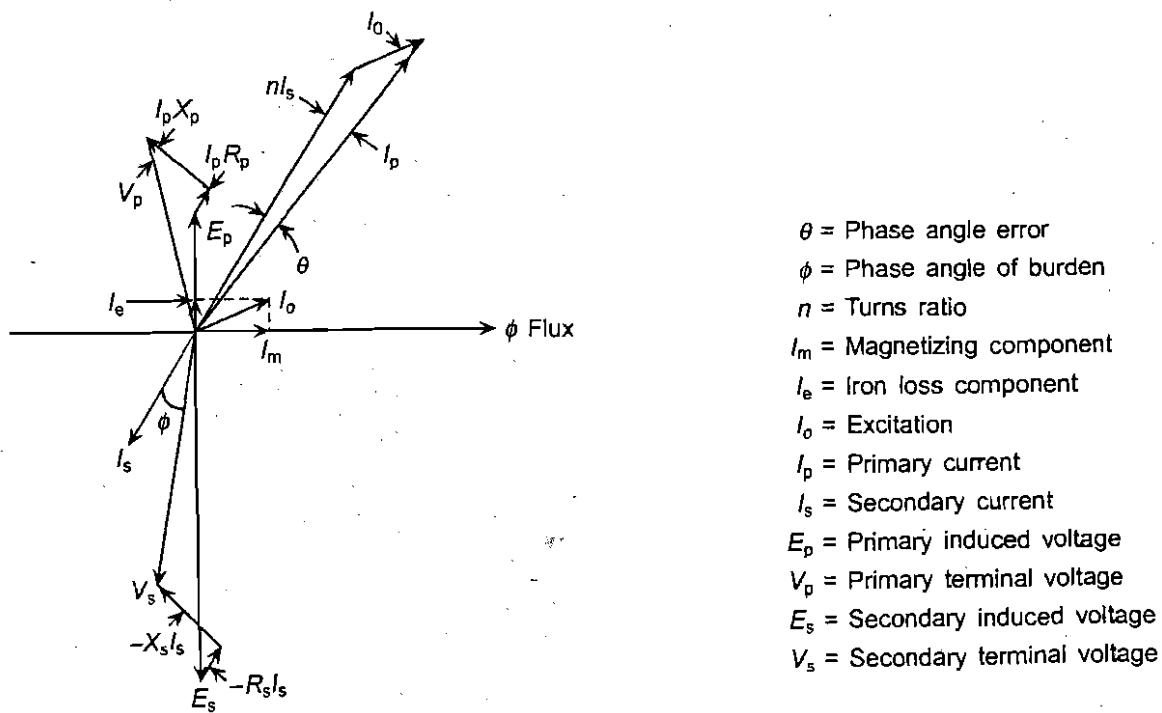


Figure A.2(c) Phasor diagram of CT.

The ratio error which is defined as

$$\text{Ratio error} = \frac{\text{Actual ratio} - \text{Ideal ratio}}{\text{Ideal ratio}}$$

is approximately given by

$$\text{Ratio error} \approx \frac{I_e}{nI_s}$$

as shown in Figure A.3.

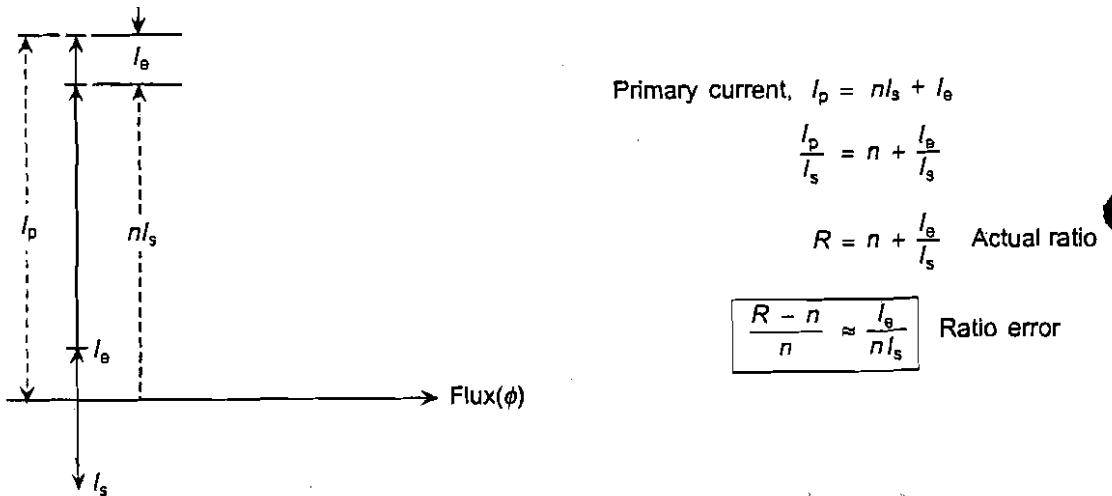


Figure A.3 Approximate method of expressing ratio error.

The *phase angle error* is defined as the *angular difference between the secondary current phasor reversed and the primary current phasor*. If the reversed current phasor leads the primary current phasor then the phase angle error is defined as positive otherwise it is taken as negative. As shown in Figure A.4, the phase angle error is given approximately by

$$\text{Phase angle error} \approx \frac{I_m}{nI_s}$$

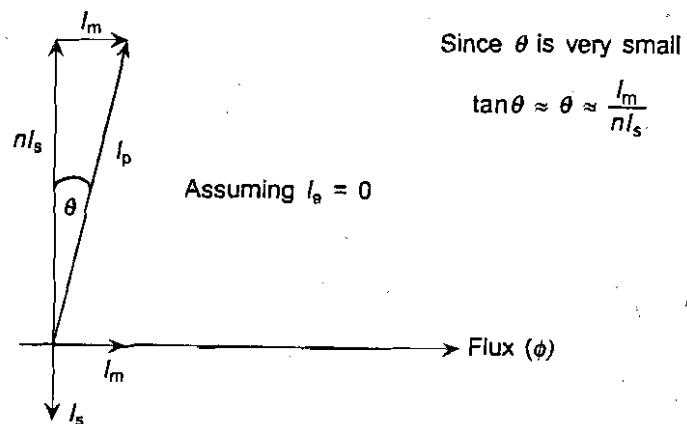


Figure A.4 Approximate method of expressing phase angle error.

A.4.2 Potential Transformer

Potential transformers are much like power transformers operating on very light load. Two types of potential transformers are used in protective systems:

1. Conventional two-winding, electromagnetic type
2. Capacitive voltage divider type, known as capacitive voltage transformer

Electromagnetic potential transformer

We will first consider the conventional electromagnetic type two-winding voltage transformer whose equivalent circuit and phasor diagram are shown in Figures A.5(a) and A.5(b), respectively.

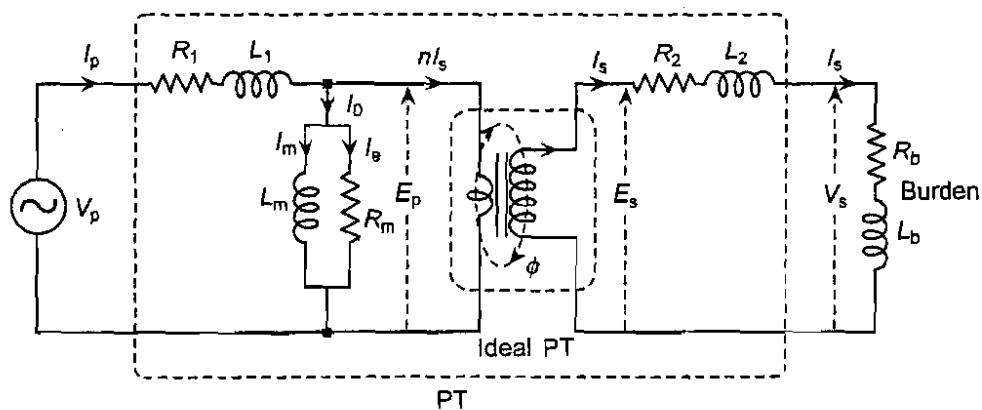


Figure A.5(a) Equivalent circuit of electromagnetic type PT.

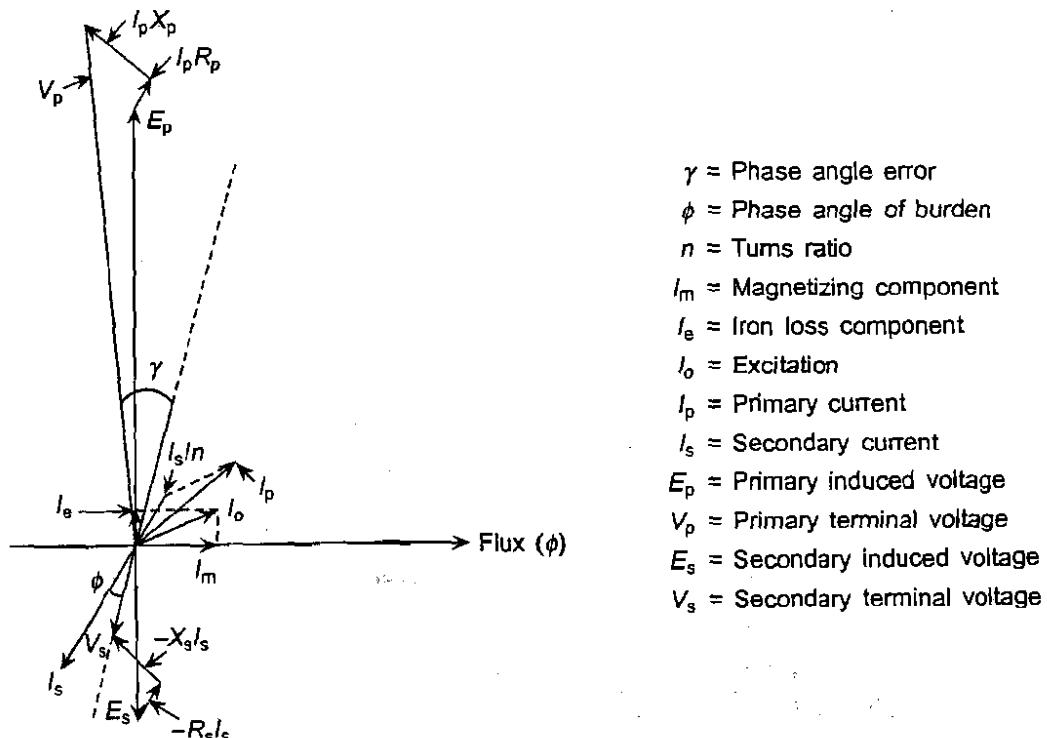


Figure A.5(b) Phasor diagram of electromagnetic PT.

Figure A.5(c) illustrates the ratio and phase angle errors of a PT.

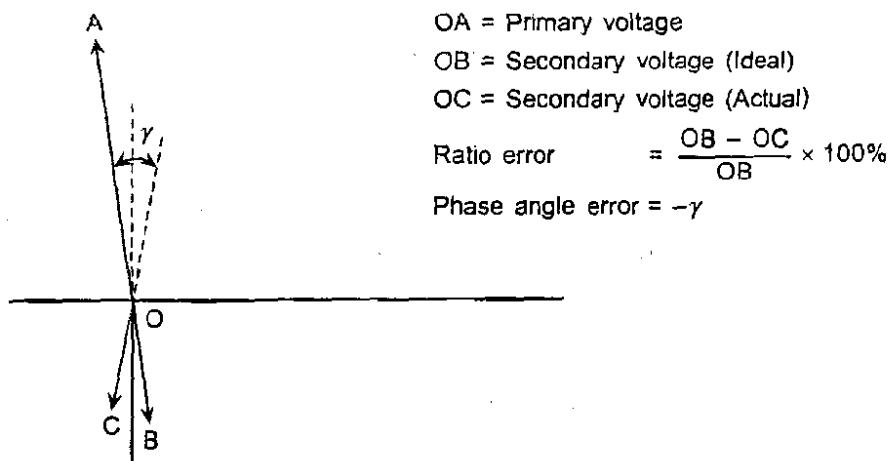


Figure A.5(c) Ratio and phase angle errors of electromagnetic PT.

Capacitive voltage transformer (CVT)

Capacitive voltage transformer consists of a capacitive voltage divider as shown in Figure A.6(a). However, a simple capacitor divider cannot be used as a CVT because the output voltage will depend on the current drawn by the burden. Hence, a tuning coil is used so that it resonates with the equivalent capacitance seen looking into the capacitor potential divider. This makes the output voltage, a constant fraction of line voltage and independent of the current drawn.

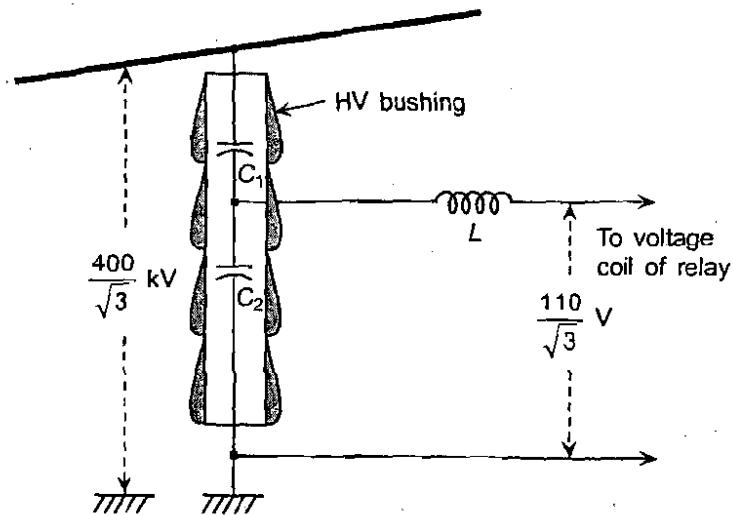


Figure A.6(a) Capacitive voltage transformer.

The thevenin's impedance seen from the primary of electromagnetic PT, into the CVT is shown in Figure A.6(b) and is equal to the LC series circuit, where C is the parallel combination of C_1 and C_2 . Thus, if L is chosen to resonate with C at the system frequency

(50 Hz or 60 Hz), there will be no voltage drop across the LC circuit. Thus, the output of CVT will become independent of the current drawn by the burden.

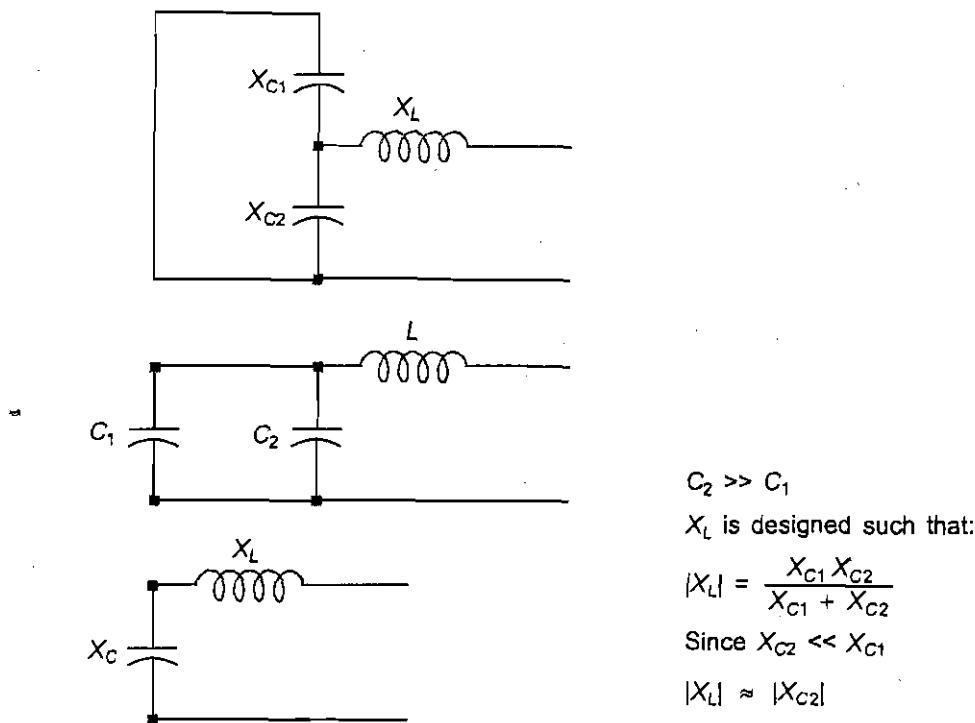


Figure A.6(b) Tuning of the CVT to make output voltage independent of burden.

A.5 Transient Errors in CT

The fault current on the primary side of the CT can, in general, be described as

$$i_p = \frac{E_p}{\sqrt{R^2 + \omega^2 L^2}} [\sin(\omega t + \beta - \alpha) + \sin(\alpha - \beta) e^{-(R/L)t}]$$

where

E_p is the peak system voltage

R, L are system resistance and inductance, respectively.

The peak value of the ac component of the fault current is given by

$$I_m = \frac{E_p}{\sqrt{R^2 + \omega^2 L^2}}$$

where

β is the phase angle representing instant of switching

α is the characteristic angle of the system [$= \tan^{-1}(\omega L/R)$]

Thus, the fault current consists of a steady state ac component and a transient decaying dc offset. The maximum dc offset takes place when $\sin(\alpha - \beta) = 1$ or when $(\alpha - \beta) = \pi/2$. Since we wish to perform the worst case analysis assuming $(\alpha - \beta) = \pi/2$, i.e. $(\beta - \alpha) = -\pi/2$, we get

$$\begin{aligned} i_p &= I_m \left[\sin\left(\omega t - \frac{\pi}{2}\right) + e^{-(R/L)t} \right] \\ &= I_m \left[\sin\left(\omega t - \frac{\pi}{2}\right) + e^{-t/T} \right] \end{aligned}$$

where $T = L/R$ with L and R as the inductance and resistance of the power system, respectively.

Assuming that this primary current is being correctly reproduced at the secondary, the secondary excitation voltage will be

$$e_s = I_m R_t \left[\sin\left(\omega t - \frac{\pi}{2}\right) + e^{-t/T} \right]$$

or

$$e_s = e_{ac} + e_{dc}$$

where

$$e_{ac} = I_m R_t \sin\left(\omega t - \frac{\pi}{2}\right) = -I_m R_t \cos(\omega t) \quad [\text{This is shown in Figure A.7(c)}]$$

$$e_{dc} = I_m R_t e^{-t/T} \quad [\text{This is shown in Figure A.7(a)}]$$

where R_t is the resistance of the CT secondary plus the resistances of the burden.

The mutual magnetic flux of the CT is given by

$$e_s = N_s \frac{d\phi}{dt}$$

or the flux ϕ is given by

$$\phi = \frac{1}{N_s} \int e_s dt$$

Let us find the flux variation to support the dc component of the voltage across the CT secondary. As we know

$$\phi_{dc} = \frac{I_m R_t}{N_s} \int_{t=0}^t e^{-t/T} dt$$

Solving the above integral, we have

$$\begin{aligned} \phi_{dc} &= \frac{I_m R_t}{N_s} \left[-Te^{-t/T} \right]_0^t \\ &= \frac{I_m R_t T}{N_s} \left[1 - e^{-t/T} \right] \quad [\text{This is depicted in Figure A.7(b)}] \end{aligned}$$

$$\text{At } t = 0 \quad \phi_{dc} = 0$$

$$\text{At } t \rightarrow \infty \quad \phi_{dc} = \frac{I_m R_t T}{N_s} = \frac{I_m R_t L}{N_s R}$$

Thus, the decaying dc offset requires flux to increase exponentially and then remain constant at the maximum value.

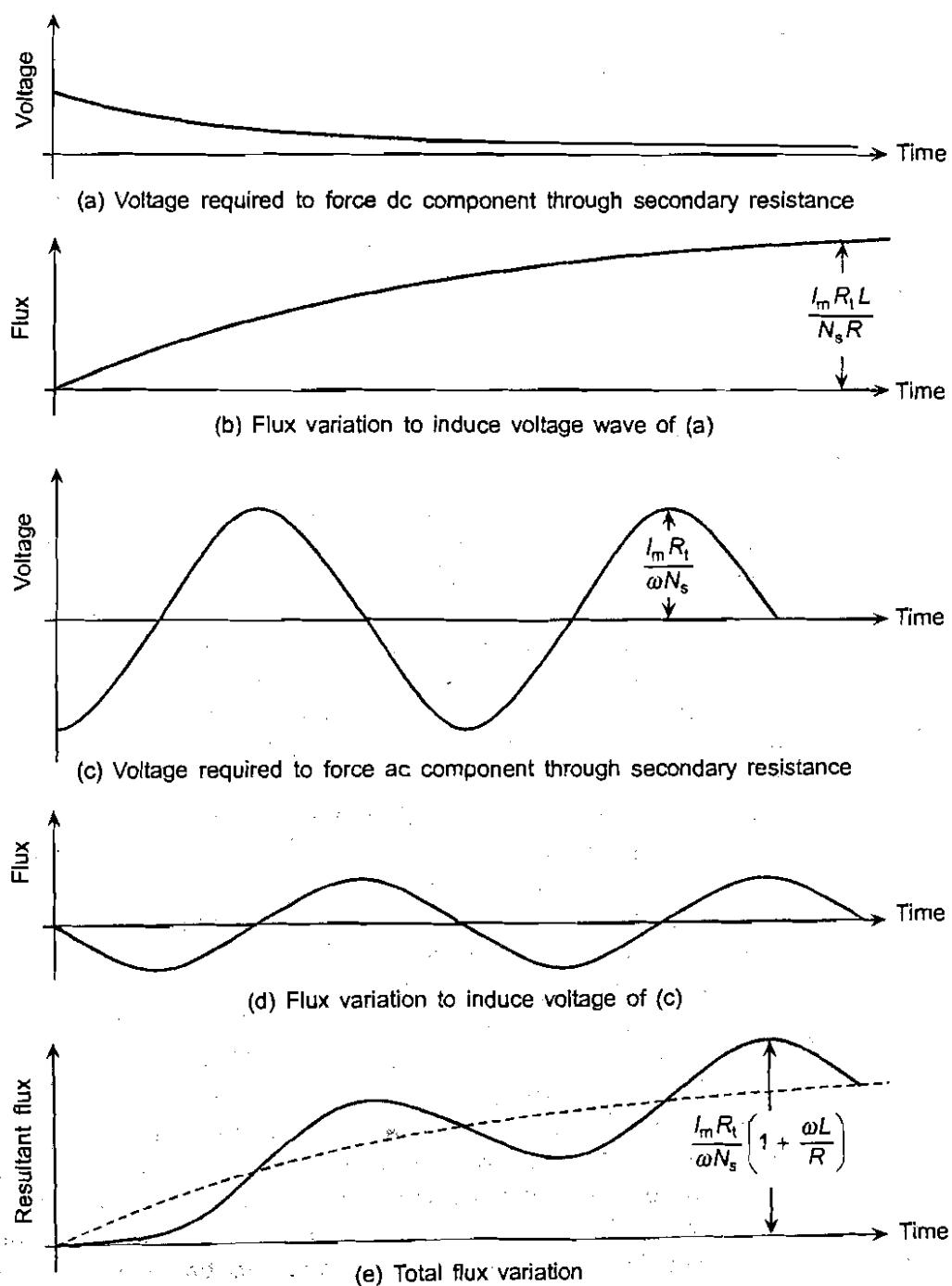


Figure A.7 Transient response of CT.

Now, let us find the flux variation necessary to support the steady-state ac component of the CT secondary voltage. From

$$e_s = I_m R_t \sin\left(\omega t - \frac{\pi}{2}\right)$$

and

$$\phi = \frac{1}{N_s} \int e_s dt$$

we get

$$\begin{aligned} \text{Flux, } \phi_{ac} &= \frac{I_m R_t}{N_s} \int_{t=0}^t \sin\left(\omega t - \frac{\pi}{2}\right) dt \\ &= \frac{I_m R_t}{\omega N_s} \left[-\cos\left(\omega t - \frac{\pi}{2}\right) \right]_0^t \\ &= \frac{I_m R_t}{\omega N_s} (-\sin \omega t) \quad [\text{This is shown in Figure A.7(d)}] \end{aligned}$$

Peak value of ac flux,

$$\phi_{ac,max} = \frac{I_m R_t}{\omega N_s}$$

Thus,

$$\frac{\phi_{dc,max}}{\phi_{ac,max}} = \frac{I_m R_t L}{N_s R} \frac{\omega N_s}{I_m R_t} = \frac{\omega L}{R} = \frac{X_L}{R}$$

If it is desired to reproduce the ac component at the secondary of the CT then the core must be of a sufficiently large size so as not to saturate on total flux of $\phi_{dc,max} + \phi_{ac,max}$ which can be written as

$$\phi_{max} = \left(1 + \frac{X_L}{R}\right) \phi_{ac,max}$$

Thus, the core size has to be increased by (X_L/R) times than that required to reproduce only the ac flux. Since (X_L/R) ratio is typically of the order of 20 to 30, the core size will be substantially large, if designed to reproduce the fully offset current.

Even if the core is not designed to continuously reproduce the fully offset current, still it can reproduce the fault current faithfully till such time as the transient flux reaches saturation. This fits in well with the scenario of high speed protection because we are interested in faithful reproduction of the fault current only for the first few cycles after the fault. There is no harm if the CT introduces large errors after that. This saves us from the expense of over-sized CTs.

A.6 Transient Errors in CVT

Ideally, the low voltage applied to the protective relays should be an exact replica of the primary system voltage. The CVTs lose some fidelity in reproducing transient voltage

variations because of inductive, capacitive, and nonlinear elements in the device. Electromagnetic voltage transformers perform better than CVTs with respect to transient response but cost more at high voltages. A subsidence transient occurs following a fault and as a result of a fault.

It should be noted that the transient response of a CT refers to the ability of the CT to reproduce an offset current wave but the transient response of a CVT refers to its ability to control the tendency to create extraneous frequencies in the output.

A subsidence transient is an error voltage appearing at the output terminals of a CVT resulting from a sudden significant drop in the primary voltage, typically produced by a nearby phase to ground fault. This produces a transient voltage in the secondary that may be damped oscillatory or decaying unidirectional depending upon the design of the CVT, the connected burden and the incidence point on the voltage wave. The apparent impedance to a relay may include errors in both magnitude and phase angle.

Figure A.8 shows the manner in which the secondary voltage may collapse in response to a sudden reduction to zero in primary voltage.

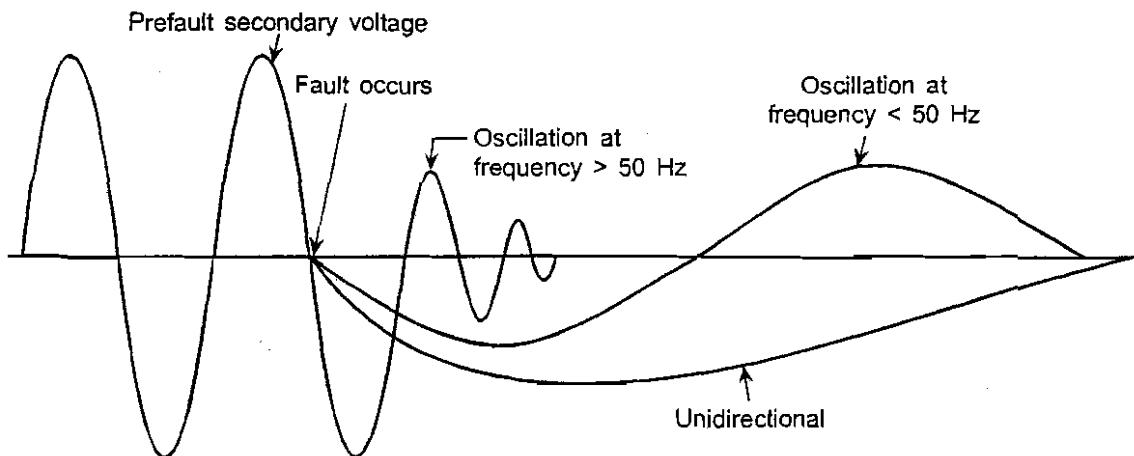


Figure A.8 Transient response of CVT.

A.7 Saturation of CT

Figure A.9 shows the equivalent circuit of CT referred to secondary. As the primary current goes on increasing, the secondary current tends to increase proportionately. The secondary voltage, therefore, increases. This necessitates the establishment of a proportionately large magnitude of flux given by

$$E_s = 4.44 \phi_m fN$$

where f is the frequency and N the number of turns.

As the operating point is near the knee of the excitation characteristic, as shown in Figure A.1, the magnetizing current requirement becomes disproportionately large. Further, since the voltage waveform is sinusoidal, the flux waveform is also sinusoidal. However, because of the nonlinear characteristics the magnetizing current becomes very large with peaky waveform.

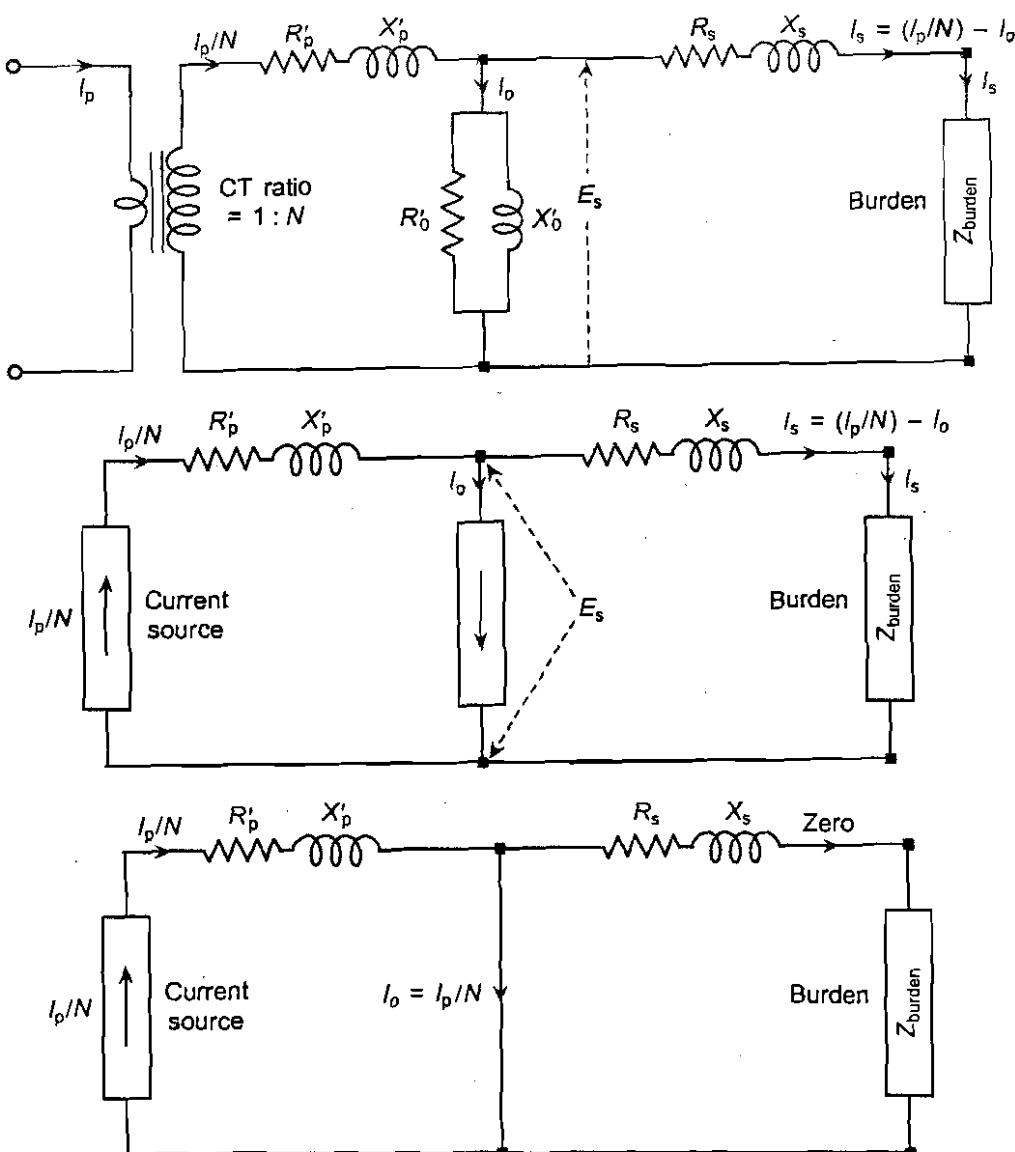


Figure A.9 Equivalent circuit of CT.

As the primary current increases, a stage comes where almost all the transformed secondary current (I_p/N) is used up in exciting the CT core. Thus, the CT cannot deliver any current to the load. However, large voltage spikes are generated around zero-crossing of the flux waveform. The drop in rms value of secondary current as a function of primary current is also shown in Figure A.1.

The actual output waveform of saturated CT is shown in Chapter 5 on busbar protection.

Similar saturation of the CT takes place at normal values of primary current if the burden impedance is increased beyond the design value. The extreme case of increase in burden impedance happens if the burden gets open circuited while the primary is carrying current. Such CT open circuits lead to dangerously high values of secondary voltage, resulting in spark-over and causing the CT to go deep into saturation. The increased iron

loss in this state can also thermally damage the CT. A CT subjected to open circuit can have a large value of remnant flux in it and will therefore give excessive ratio and phase angle errors.

A.8 CT Accuracy Classification

The following table lists the CT accuracy classification.

Class	Ratio error	Phase angle error
S	$\pm 3\%$	2°
T	$\pm 10\%$	6°
U	$\pm 15\%$	9°

Power Swing

Appendix B

B.1 Introduction

In an interconnected power system, under steady state conditions, all the generators run in synchronism. There is a balance between the load and the generation. This state is characterized by constant rotor angles. However, when there is a disturbance in the system, say, shedding of a large chunk of load or tripping of a line, the system has to adjust to the new operating conditions. In order to balance the generation with the load, the rotors need to take on new angular positions. Because of the inertia of the rotating system and their dynamics, the rotors slowly reach their new angular positions in an oscillatory manner. This process of rotor angles reaching their new positions, in a rather slow oscillatory manner, subsequent to some large disturbance is known as *power swing*. The time constants involved in these oscillations are of the order of a few seconds.

B.2 Stable and Unstable Power Swing

Figure B.1(a) shows a simple transmission system. There are two parallel lines over which power $P_{\text{initial},1}$ is being transferred. The power transfer is given by $P_{\text{initial}} = (E_1 E_2 / X_{ll}) \sin \delta_1$ where X_{ll} is the total reactance of the two parallel lines. The rotor angle, at end A, corresponding to this steady state of operation is δ_1 as shown in Figure B.2(a).

Now, let one of the parallel lines be lost, say, because of a fault on the line as shown in Figure B.1(b) and (c). Since the power input to the generator remains the same (assuming no action by the speed governor), the system settles to a new rotor angle δ_2 , which is given by the intersection of the power transfer curve and the input power line as shown in Figure B.2(b). This is a case of *stable power swing*.

The variation of δ with respect to time is also sketched in Figure B.2(c). Next assume a different and higher initial power transfer $P_{\text{initial},2}$ with initial rotor angle at end A to be δ_3 . Since there is no intersection between the power transfer curve with one line out and the power input line, the rotor angle δ keeps increasing without bounds. This is a case of *unstable power swing* as shown in Figure B.2(b).

Figure B.2(c) shows the variation of δ with respect to time for stable and unstable power swing.

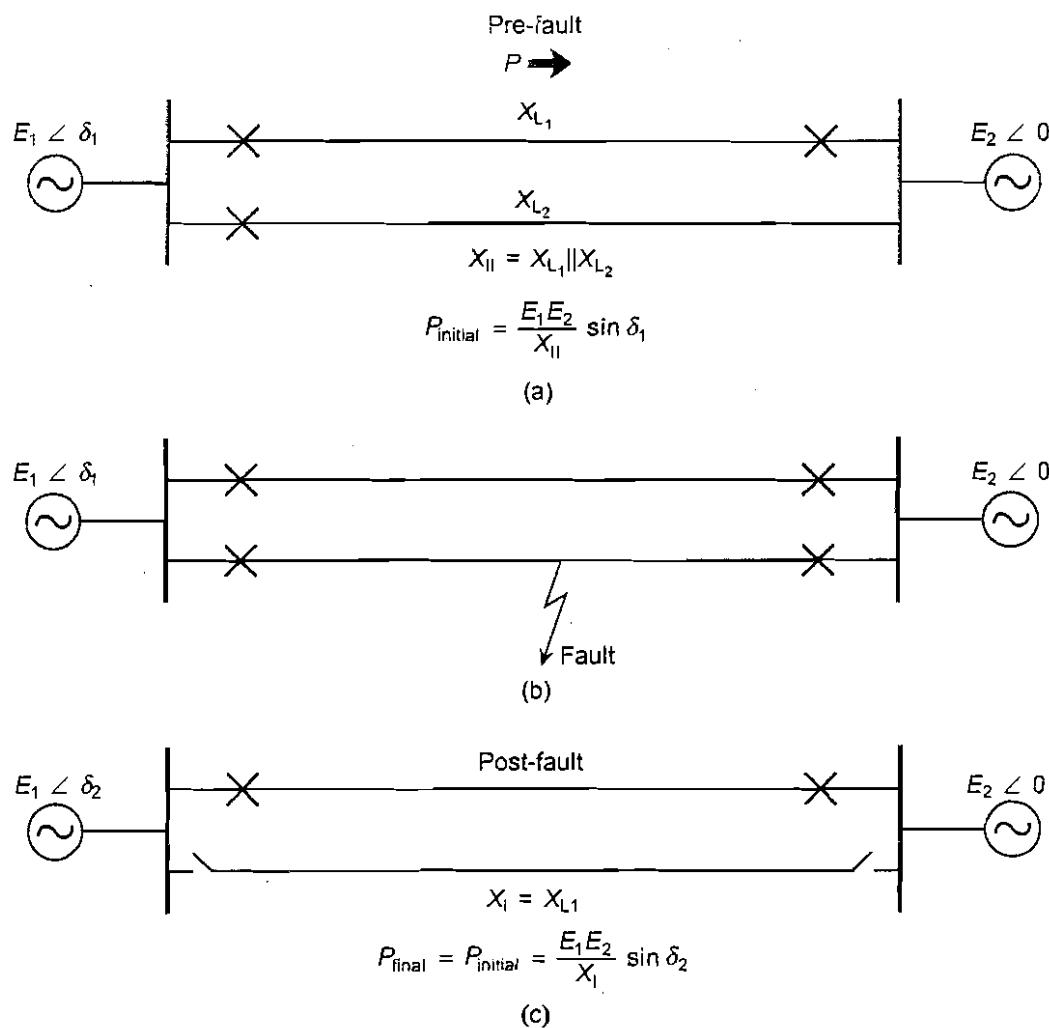


Figure B.1 Power transfer on a parallel line—pre-fault and post-fault.

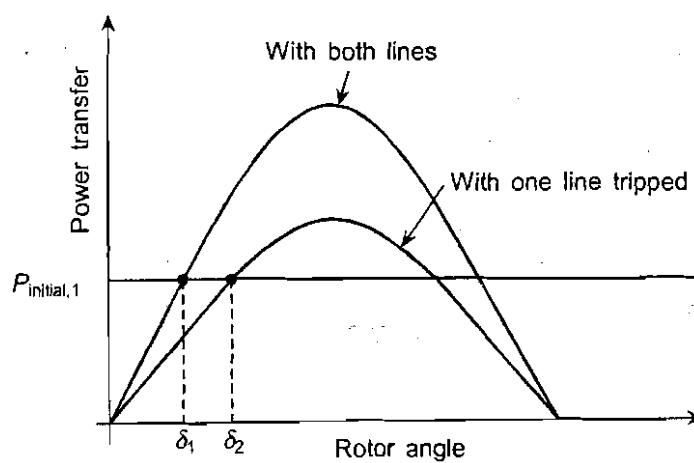


Figure B.2(a) Situation leading to stable power swing.

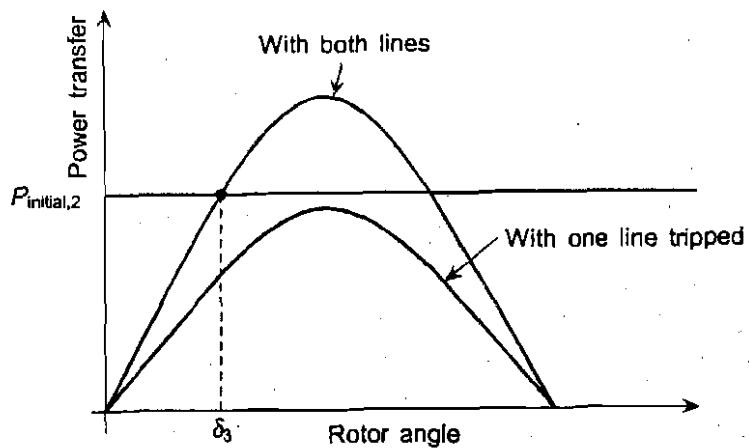


Figure B.2(b) Situation leading to unstable power swing.

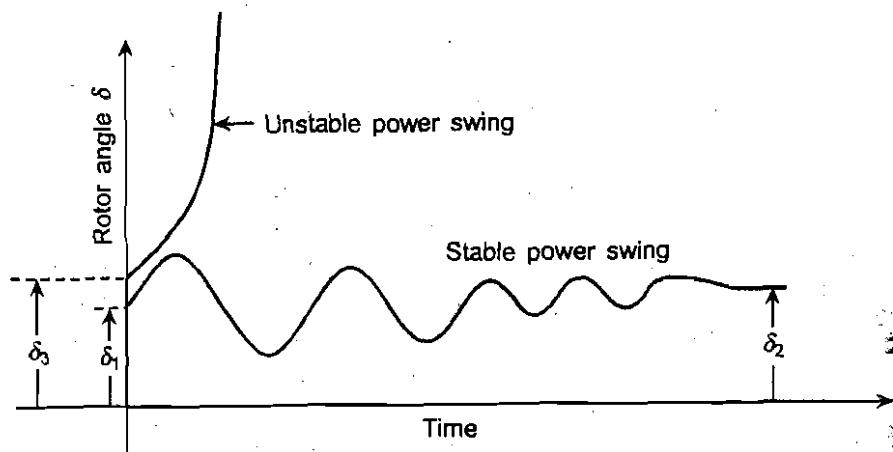


Figure B.2(c) Variation of δ with respect to time for stable and unstable power swing.

Unstable power swing is an indication that the generators are getting out-of-step.

B.3 Impedance Seen by Relay During Power Swing

Figure B.3(a) shows a simple interconnected system for detailed analysis of the power swing phenomenon. Generators A and B are connected through a transmission line. Generator A is exporting power, hence its rotor angle δ is positive. Generator B is importing power, its rotor angle is taken as the reference zero.

Voltage and current at the relay location can be written as

$$I_r = \frac{E_A \angle \delta - E_B \angle 0}{Z_T}$$

where $Z_T = Z_{SA} + Z_L + Z_{SB}$

$$V_r = E_A \angle \delta - I_r Z_{SA}$$

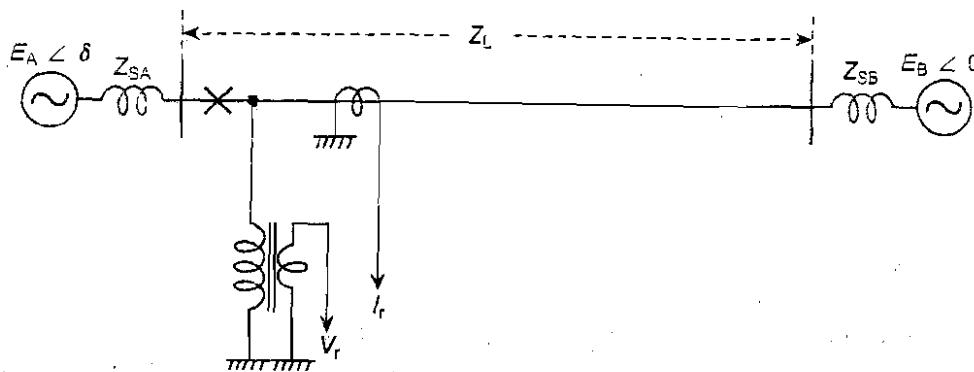


Figure B.3(a) Impedance seen by relay on power swing.

We can rearrange the preceding equations in terms of impedances alone, by dividing by I_r , i.e.

$$Z_T + \frac{E_B \angle 0}{I_r} - \frac{E_A \angle \delta}{I_r} = 0$$

and

$$Z_r = -Z_{SA} + \frac{E_A \angle \delta}{I_r} = f(\delta)$$

(∴ impedance seen by the relay is given by $Z_r = V_r/I_r$)

These equations give us a graphical method, which is more insightful than the analytical method, for constructing impedance triangles and locating Z_r as a function of the rotor angle δ , as shown in Figure B.3(b).

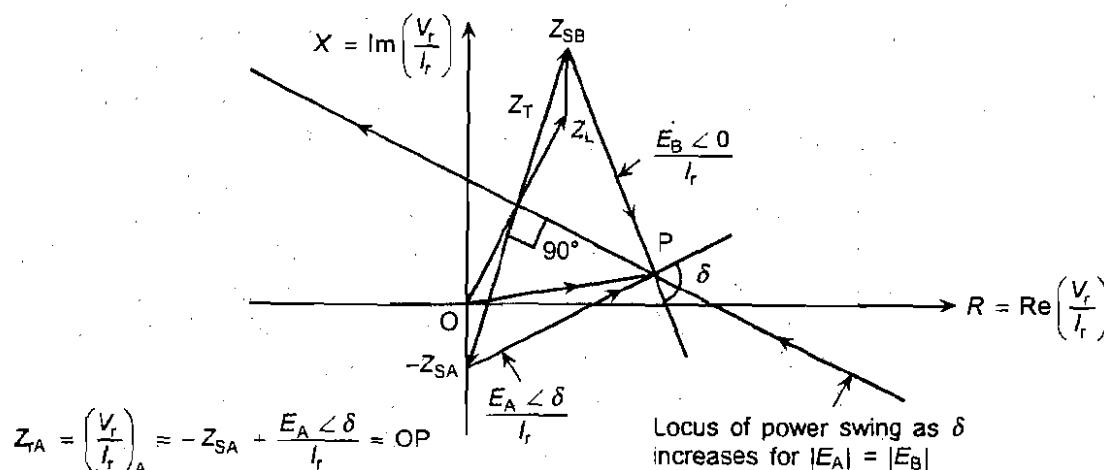


Figure B.3(b) Power swing locus construction.

When δ becomes equal to 180° , the apparent impedance is at the electrical centre of the system, causing the relay to believe that there is a three-phase short circuit there.

In the above analysis, it was assumed that $|E_A| = |E_B|$ for simplicity. However, in practice, the two voltages will be different. Figure B.3(c) shows that when $|E_A|/|E_B| = n$, the locus of power swing is a circle with distance from point B to centre given by

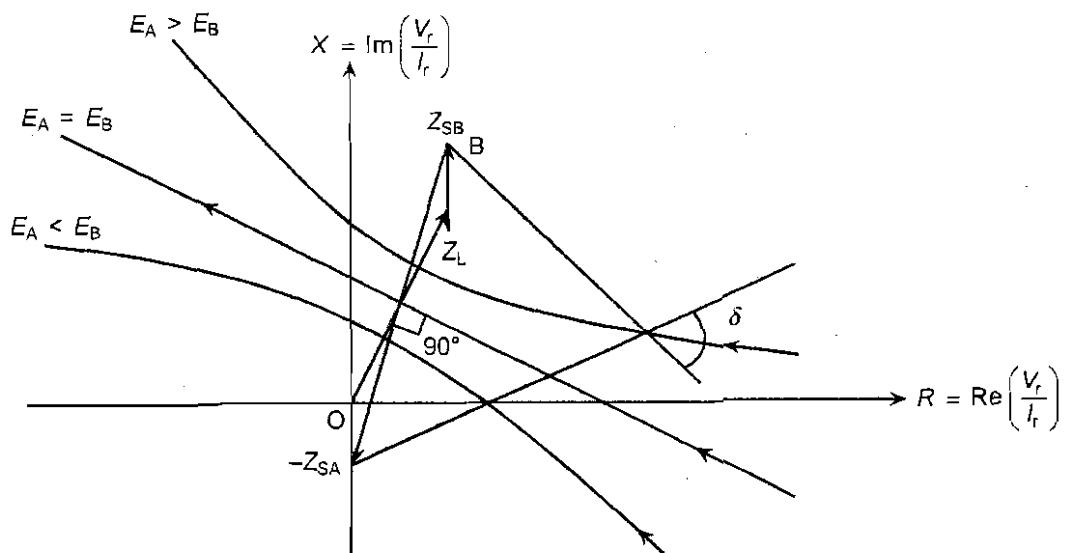


Figure B.3(c) Locus of power swing when $|E_A|/|E_B| = n$.

$$C = \frac{Z_T}{n^2 - 1}$$

The radius of power swing circle is given by

$$\frac{nZ_T}{n^2 - 1}$$

Thus, it can be seen that the impedance seen by the relay is a function of the rotor angle δ . As the rotor angle δ goes on increasing, the apparent impedance approaches the electrical centre of the system. As it does so, it may enter into the relay trip characteristics causing the relay to trip the circuit, thus, adding another shock to the system and causing further instability. Therefore, the protective relay should not trip on stable power swings. This type of scheme is known as *out-of-step blocking scheme*.

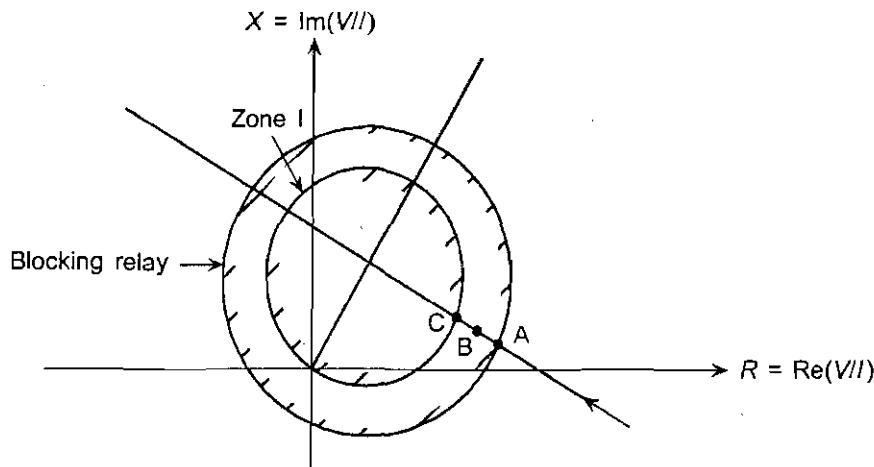
For a large external disturbance, the power swing is unstable and the two machines must be separated. The point of split in a large interconnected system should be decided in advance through system stability studies so that the separated systems have the balance between generation and load. Thus, at the predecided split point, we need a deliberate out-of-step tripping scheme.

B.4 Out-of-step Blocking Scheme

As already pointed out, an out-of-step blocking relay is required where the zone I distance relay is likely to operate but we wish to block the distance scheme at this location so that the system is disconnected elsewhere at the most appropriate point.

Further, the location of the locus of power swing depends upon the source and line impedances ($Z_T = Z_{SA} + Z_L + Z_{SB}$). Although the line impedance is constant, the source impedances are likely to vary over a period of time due to either decrease or increase in the number of generating units or line trippings behind the relay location. Thus, the location of power swing cannot be precisely predetermined.

The power swing is assumed to be in the trip region of zone I, thereby causing the relay to trip and possibly split the system at the wrong place. To avoid this, an out-of-step blocking relay is used as shown in Figure B.4(a). The out-of-step blocking relay has a circular characteristic which is concentric with zone I. Let the power swing enter the blocking relay at $t = 0$. At $t = T_e$, the power swing enters zone I. The whole distance scheme is blocked by the blocking scheme in a time less than T_e . Thus, $T_{\text{blocking}} < T_e$. The trip contact circuit of the three-stepped distance scheme along with the contacts of the blocking relay are shown in Figure B.4(b).



At A, power swing enters the blocking relay at $t = 0$

At B, the distance scheme is completely blocked ($t < T_e$)

At C, power swing enters zone I ($t = T_e$)

Figure B.4(a) Out-of-step blocking arrangement.

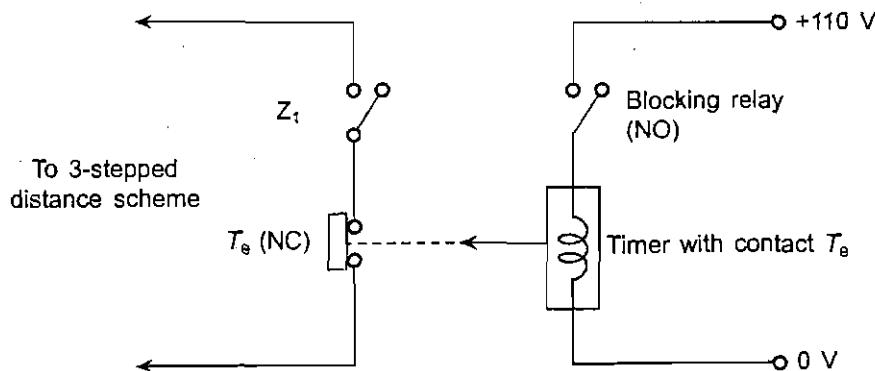


Figure B.4(b) Out-of-step blocking logic.

Since the blocking relay prevents the distance scheme from operating, it is desirable to prove that the blocking relay does not interfere with the distance scheme for genuine internal faults.

Consider an internal line fault. During this fault, the impedance seen by the relay abruptly changes from Z_{load} to Z_{fault} . The blocking relay does see this change in impedance

but by the time it blocks the distance scheme, the distance scheme has already operated. Thus, we take advantage of speed with which impedance change takes place. The power swing is a pretty slow phenomenon compared to short-circuit faults.

B.5 Out-of-step Tripping Scheme

As already pointed, we must isolate the system at certain points in case of out-of-step conditions. This deliberate tripping does not depend upon whether the distance scheme operates or not. For this reason, the power swing whose location is variable, is assumed to be outside zone I as shown in Figure B.5.

The out-of-step tripping scheme consists of two blinder relays B_1 and B_2 having straight line characteristics parallel to the line impedance phasor. The hatching indicates the trip region. The blinders split the $R-X$ diagram into three distinct areas A_1 , A_2 , and A_3 . In case of power swing, the locus enters the three areas in the following sequence:

<i>Direction of power swing</i>	<i>Sequence of traversal of areas</i>	<i>Sequence of contact</i> B_1 status	<i>Sequence of contact</i> B_2 status
Right to left	$A_1 \rightarrow A_2 \rightarrow A_3$	closed \rightarrow open \rightarrow open	closed \rightarrow closed \rightarrow open
Left to right	$A_3 \rightarrow A_2 \rightarrow A_1$	open \rightarrow open \rightarrow closed	open \rightarrow closed \rightarrow closed

We can verify that the out-of-step tripping scheme does not mal-operate for external faults. When there is an external fault, the impedance phasor crosses only one blinder and the sequencing required for tripping is never completed. The only time when the impedance crosses both the blinders is in the case of power swing.

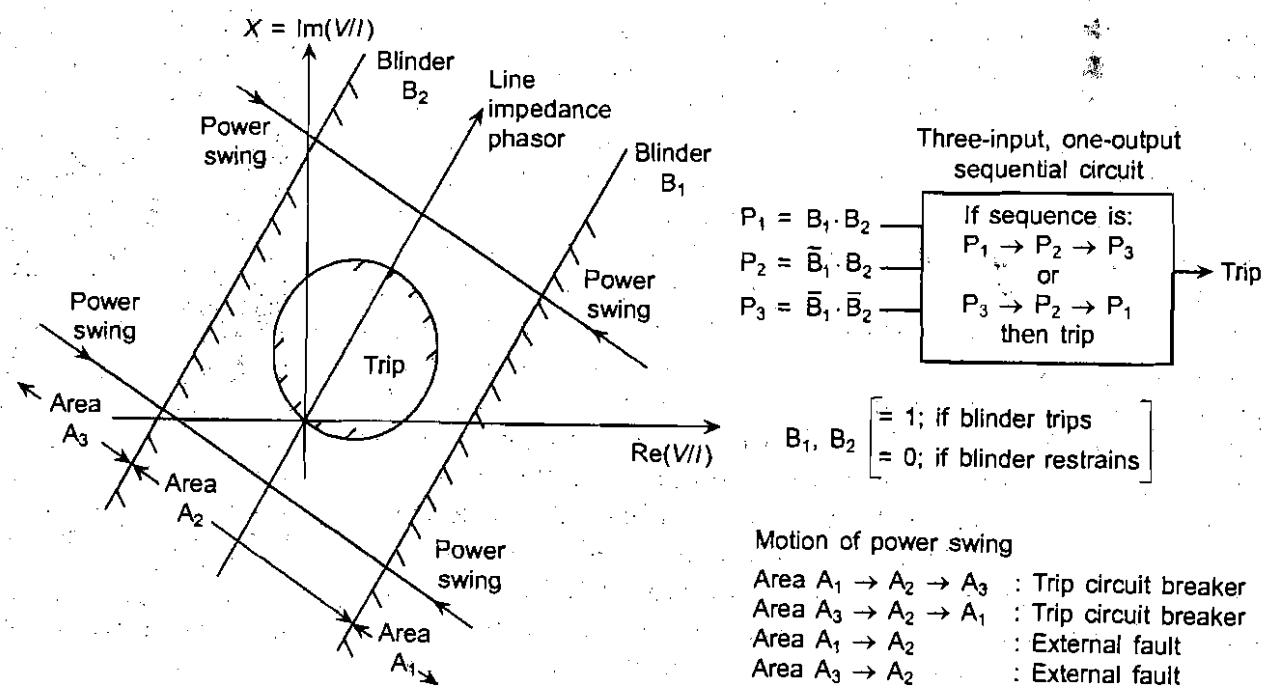


Figure B.5 Out-of-step tripping scheme.

Protection of Longest and Shortest Lines

Appendix C

C.1 Introduction

Distance relays have certain drawbacks which need to be carefully considered while applying them in practical situations. We had not considered the effect of source impedance or source impedance ratio Z_S/Z_L on the performance of distance relays. In this appendix, we will therefore study the effect of source impedance ratio on the performance of distance relays.

C.2 Longest Line That Can Be Protected

The longest line that a relay can protect depends on the relay's performance during stable power swing. If the protected line is subjected to a stable power swing (i.e. it can recover by itself from the swing and maintain synchronization) and the distance relay mal-operates, the relay is incapable of accommodating maximum swing angle δ_{\max} .

It is well known that a long line is less stable than a short line. Figure C.1(a) shows the power angle diagram for long and short lines. The short line has higher P_{\max} than that of long line. For a given mechanical input P_m , the quiescent operating angle for a long line is more than that of a short line, i.e.

$$\delta_{0,\text{long}} > \delta_{0,\text{short}}$$

Therefore, for a disturbance that does not cause instability, the longer line goes through a larger swing angle than does a shorter line. Hence, a long line is more unstable than a short line, i.e.

$$\delta_{\max,\text{long}} > \delta_{\max,\text{short}}$$

The longer the line, the greater is δ_{\max} . It is of interest to note that δ_{\max} , on a stable power swing, can be accommodated by the relay without malfunctioning.

Lines are defined as *short* or *long* on the basis of system impedance ratio Z_S/Z_L , rather than on the basis of their physical length. Z_S is the source impedance or the impedance behind the relay location and Z_L is the line impedance. This is summarized as follows:

Long or short	Simplifying assumption
long line $\rightarrow Z_S/Z_L = \text{small}$	$Z_S = 0$
short line $\rightarrow Z_S/Z_L = \text{large}$	$Z_S = \text{finite}$

Figures C.1(b) and (c) show these two cases with mho relay adjusted to reach 100% of the line length for simplicity. It can be easily seen that the δ_{\max} that the mho relay can accommodate without maloperation, is about 90° for a long line but greater than 90° for a short line. This is exactly opposite of what is needed. A long line goes through a larger value of δ_{\max} and the relay must accommodate it. Hence, there is a limitation to the longest line a relay can protect without maloperation on a stable power swing.

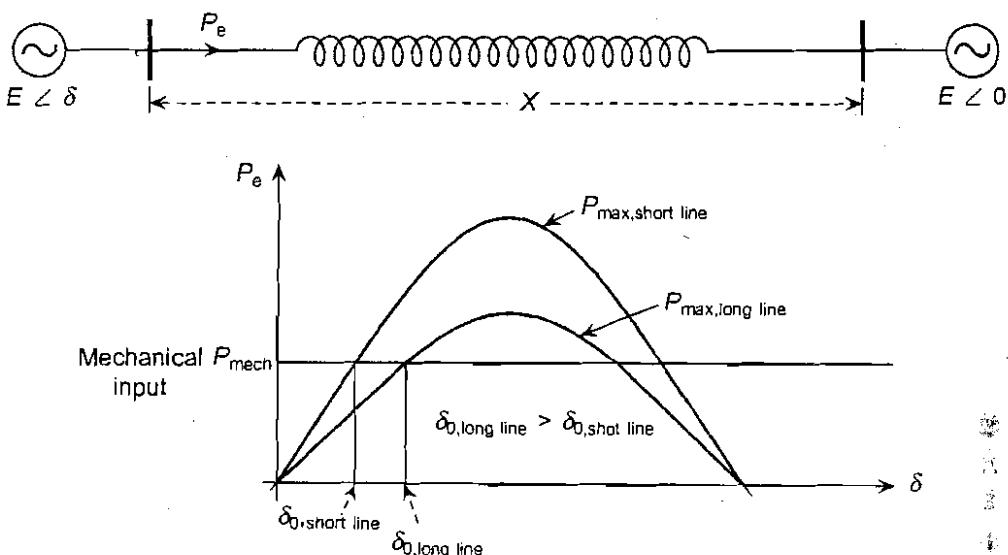


Figure C.1(a) Quiescent operating points for long and short lines.

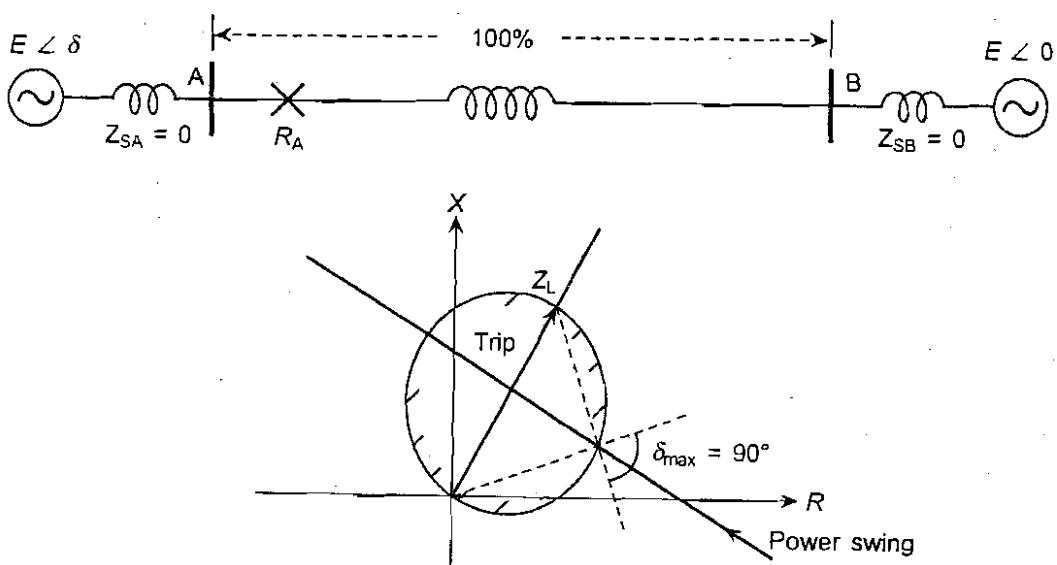


Figure C.1(b) Power angle accommodation in long line.

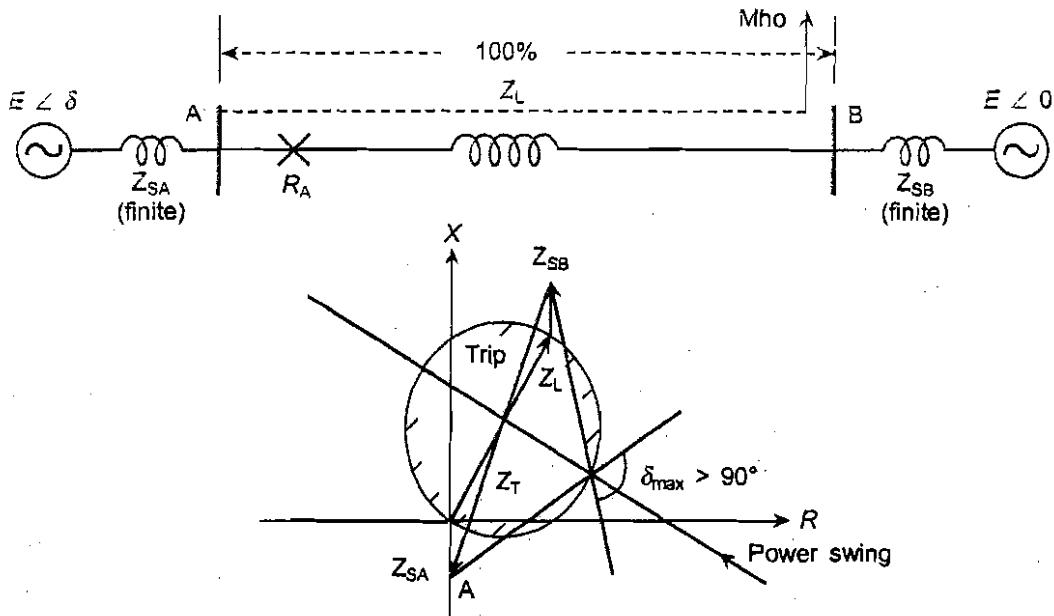


Figure C.1(c) Power angle accommodation in short line.

C.3 Shortest Line That Can Be Protected

Figure C.2(a) shows a single line diagram of a transmission line with CT and PT at the relay location, the impedance behind the relay location being Z_S . The distance relay is energized by V_r and I_r . Assume that the distance relay is of the mho type and is set to reach Z_n along the line. If the fault takes place at the reach point, the relay voltage drops to a value which is a function of Z_S/Z_n . (Note that $Z_n = 0.8Z_L$.)

The larger the value of Z_S/Z_L , the shorter the line. Thus, the shorter the line, the smaller is the voltage V_r fed to the relay. An ideal distance relay is supposed to measure the ratio V/I , irrespective of the individual magnitudes of either V or I . However, in practice, it is not true.

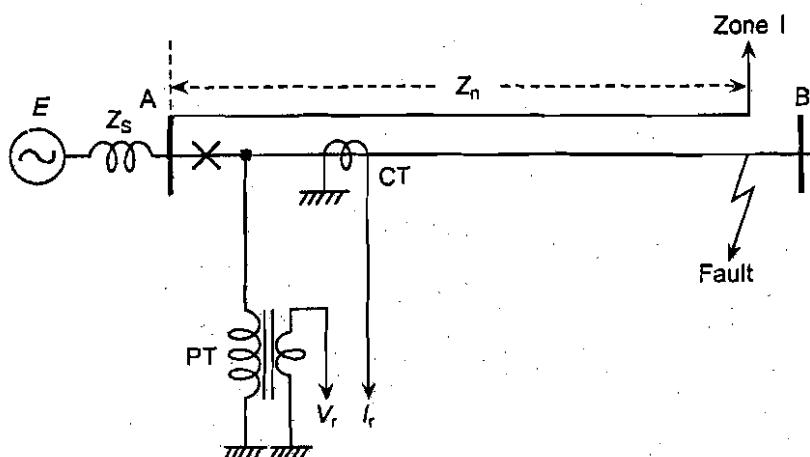


Figure C.2(a) Shortest line that a mho relay can protect.

To find the effect of voltage on the mho relay's reach, consider the torque equation for a mho relay:

If $|Z_n| |V| |I| \cos(\theta_n - \theta_r) > |V|^2$ then trip; else restrain

Considering the restraining spring, the equation is

If $|Z_n| |V| |I| \cos(\theta_n - \theta_r) > |V|^2 + T_{\text{spring}}$ then trip; else restrain

Dividing both sides by $|V| |I|$, we have

$$|Z_n| \cos(\theta_n - \theta_r) > |Z| + \frac{T_{\text{spring}}}{|V| |I|}$$

Substituting $|I| = |V|/|Z|$, we get

$$|Z_n| \cos(\theta_n - \theta_r) > |Z| + \frac{T_{\text{spring}} |Z|}{|V|^2}$$

To find the reach along the diameter, i.e. with $\theta_n = \theta_r$, we get

$$|Z_n| > |Z| \left(1 + \frac{T_{\text{spring}}}{|V|^2} \right)$$

which can be written as

$$|Z| < \frac{|Z_n|}{1 + \frac{T_{\text{spring}}}{|V|^2}}$$

Thus, the actual reach, considering the effect of the restraining spring, is a function of the voltage fed to the relay V .

Figure C.2(b) shows the *reach versus voltage characteristic* of the mho relay. Similar proofs can be developed for other distance relays.

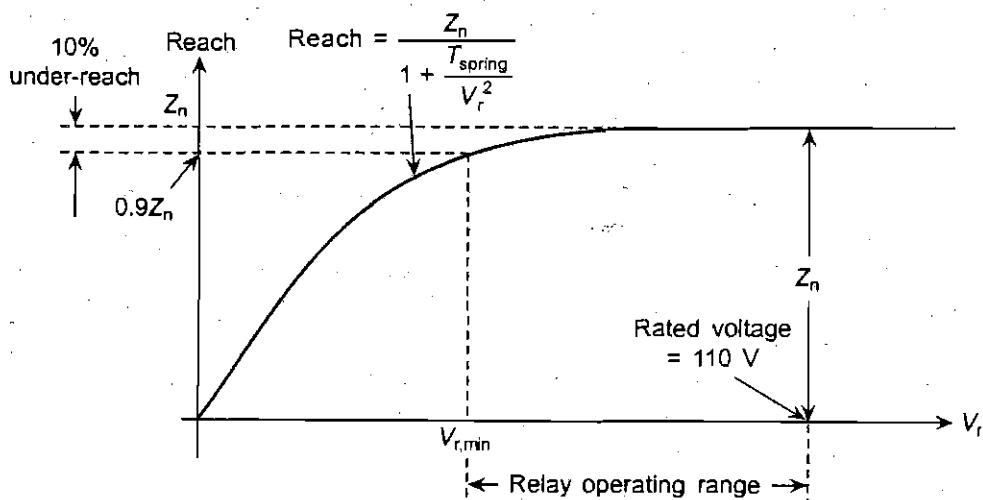


Figure C.2(b) Reach versus relay voltage characteristic.

The reach versus relay voltage characteristic is not very convenient to use, since the reach Z_n is required to be changed depending on the length of the line. To make the actual reach independent of $|Z_n|$, we divide it by $|Z_n|$ and define the accuracy of the distance relay as

$$\text{Accuracy} = x = \frac{\text{Actual reach}}{|Z_n|}$$

To eliminate voltage, for a fault at the reach point, we calculate

$$V_r = E - IZ_S = E - \frac{E}{Z_S + Z_n} Z_S$$

Dividing the numerator and the denominator by Z_n , we have

$$V_r = \frac{1}{1 + \frac{Z_S}{Z_n}} E$$

or

$$V_r = \frac{1}{1 + \text{SIR}} E$$

Thus, instead of plotting *reach* versus *relay voltage*, we plot *accuracy* versus *range*. Note that for a small system impedance ratio (SIR) or range, the relay voltage V_r tends to be equal to the rated voltage E . For a large system impedance ratio or range, $V_r \ll E$.

Figure C.2(c) shows the graph of Figure C.2(b) drawn in terms of *accuracy* versus *range*. It can be seen that higher the source impedance or shorter the line, the lower is the actual reach or the accuracy of the relay.

If one stipulates a limit that the accuracy should not be less than 0.9 (i.e. the actual reach not less than 90% of reach setting) then there is limit to the shortest line that a distance relay can protect.

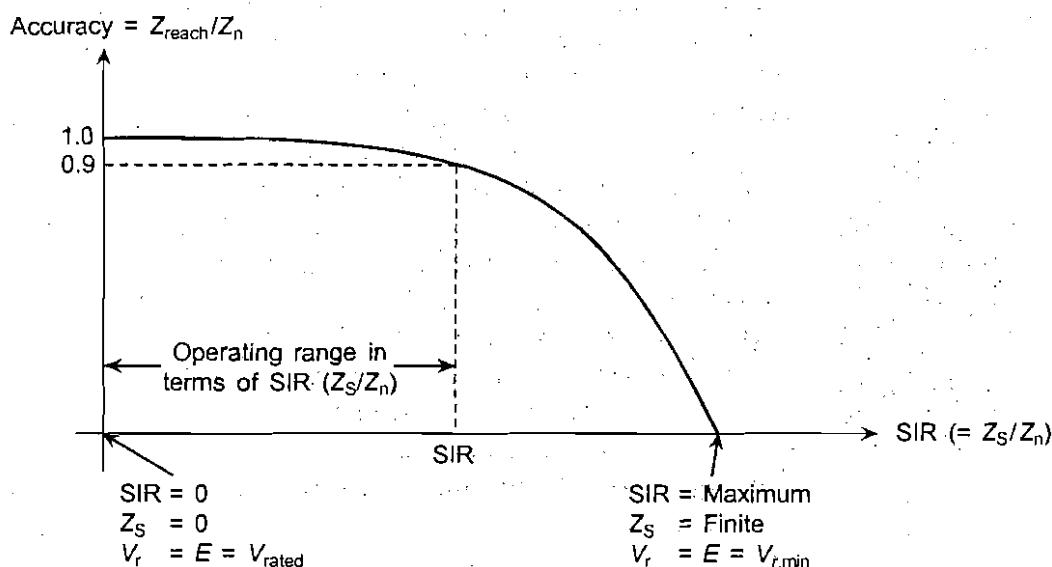
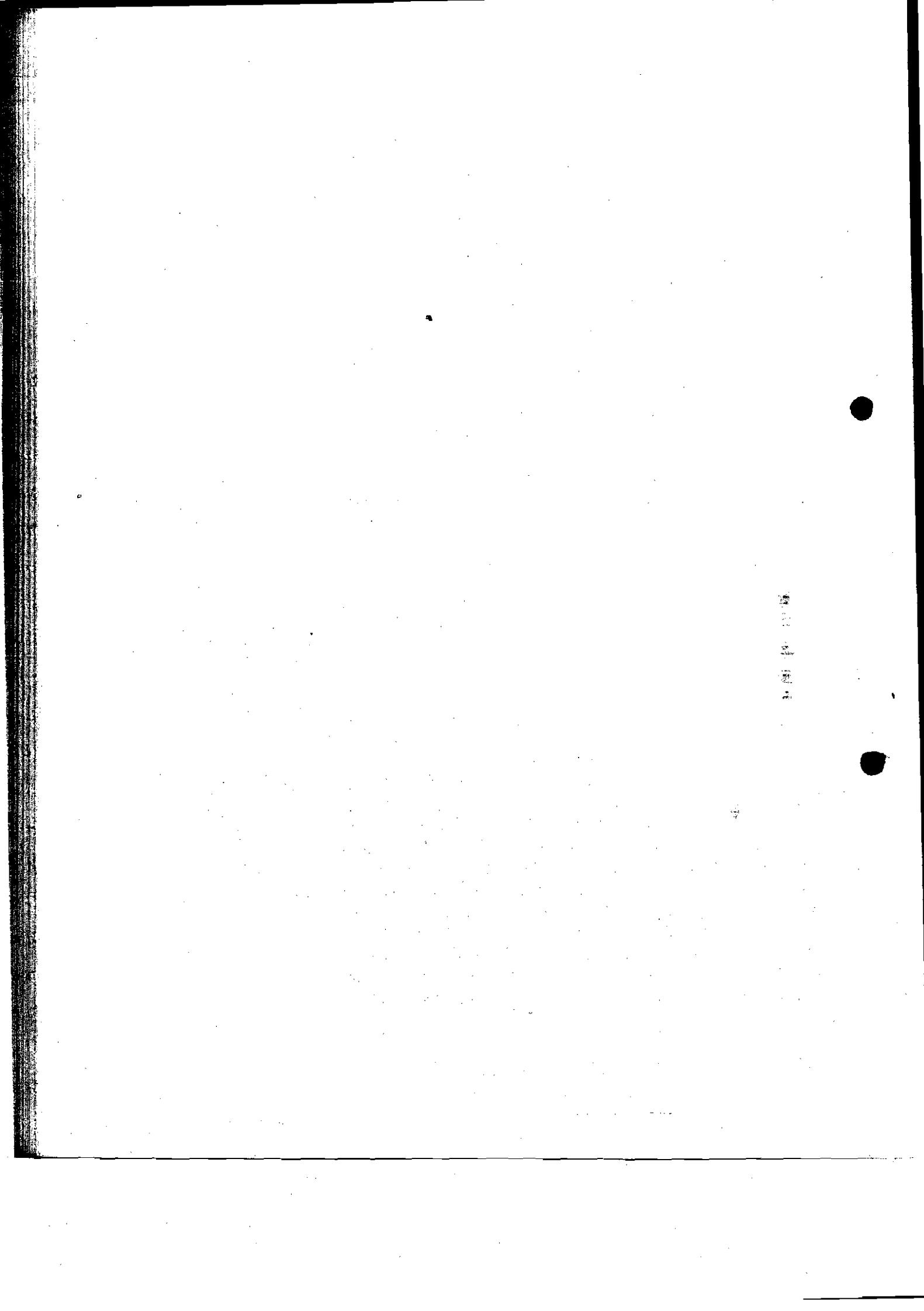


Figure C.2(c) Accuracy versus range graph.



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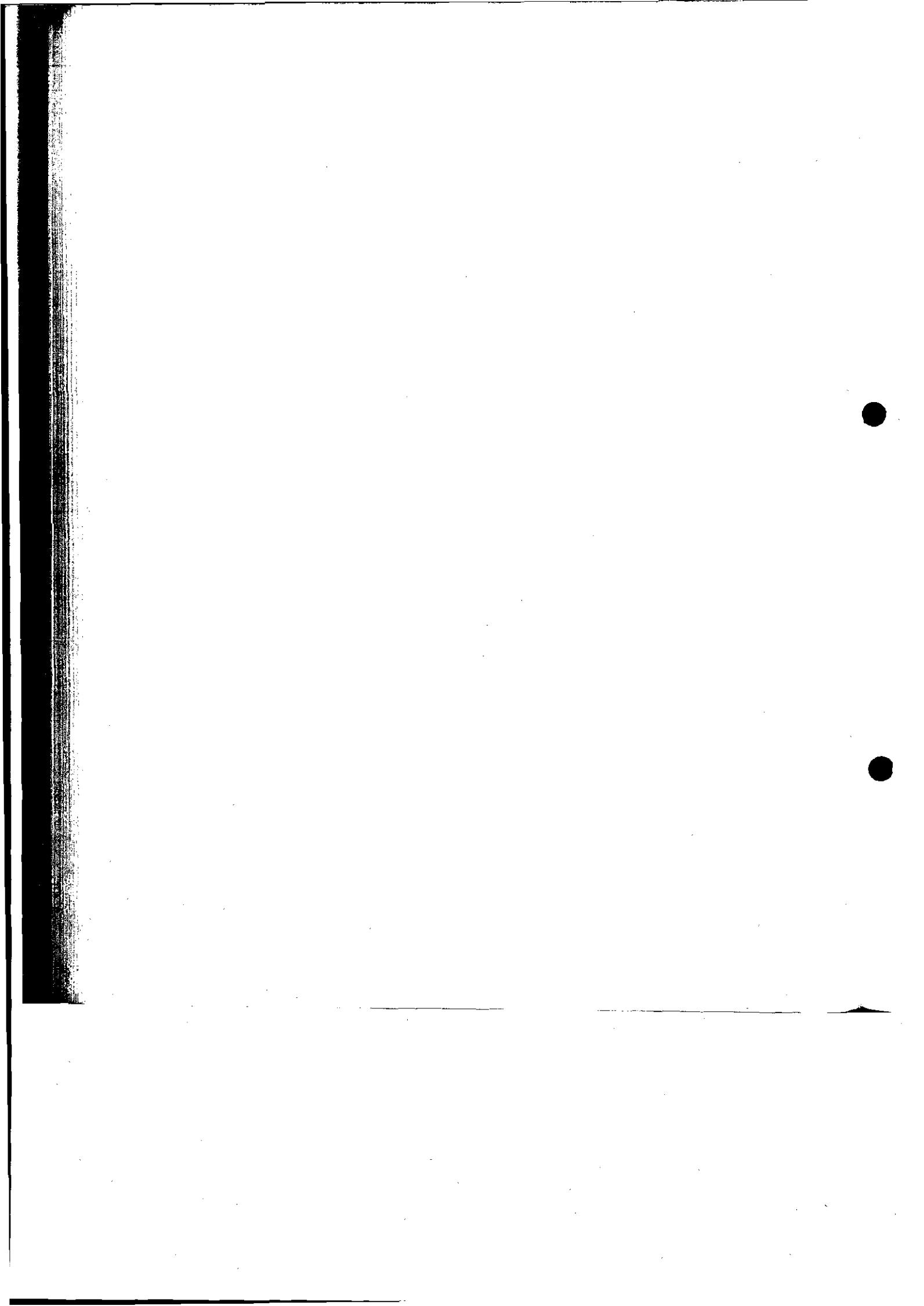
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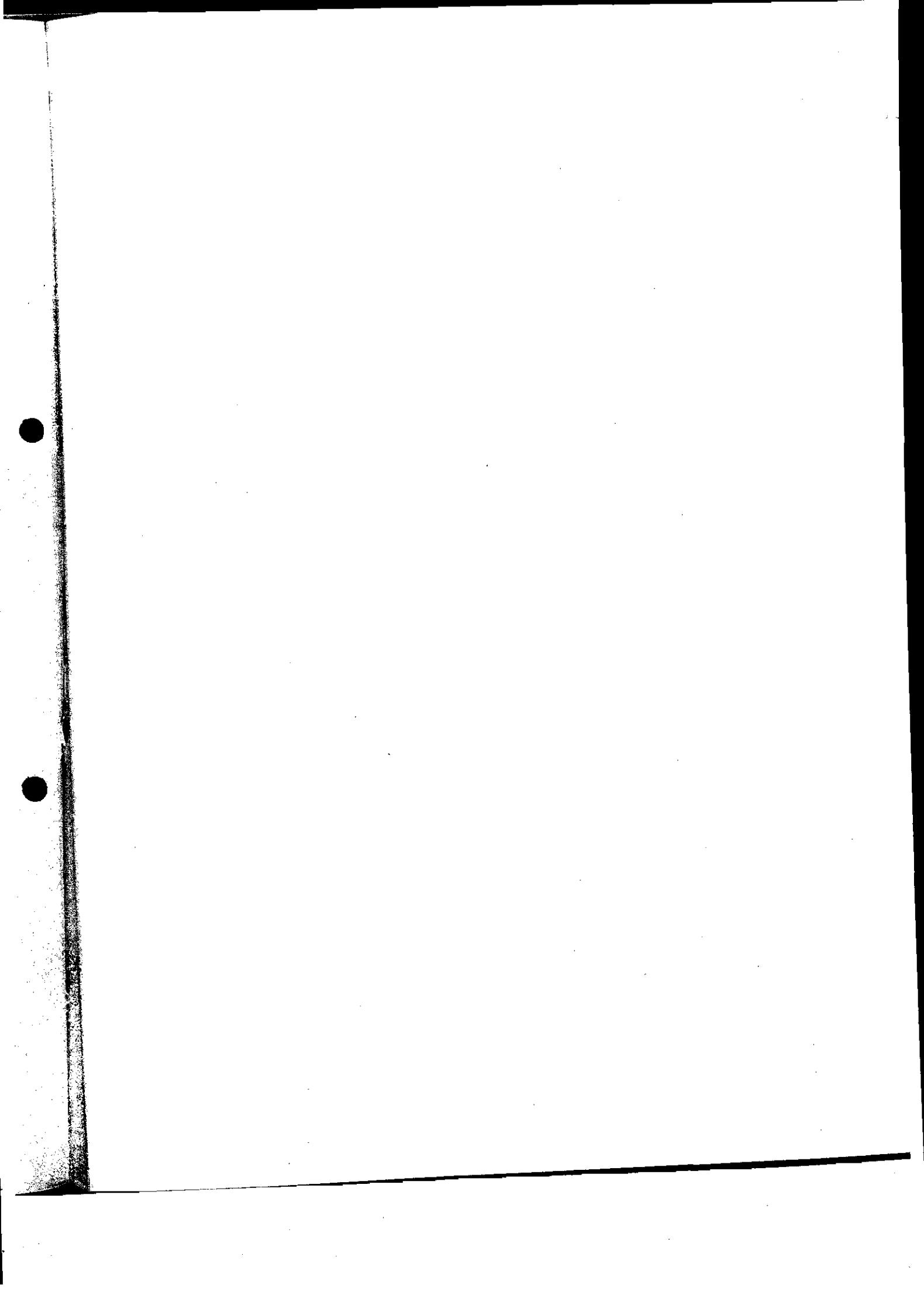
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Fundamentals of Power System Protection

Y.G. Paithankar

S.R. Bhide

The electric power system is a highly complex and dynamic entity. One malfunction or a carelessly set relay can jeopardize the entire grid. Power system protection as a subject offers all the elements of intrigue, drama, and suspense while handling fault conditions in real life.

The objective of this book is to introduce the student to the most relevant concepts and techniques in power system protection. It reflects many years of experience of the authors in teaching this subject matter to undergraduate electrical engineering students.

Written in a simple, clear and down-to-earth style, this state-of-the-art text covers the entire spectrum of protective relays—from electromechanical to numerical—for protection of transmission lines, transformers, busbars, generators, and motors. The presentation is stimulating, analytical but at the same time concise. The students will find the material very friendly and refreshingly simple.

The book has a wealth of useful figures, graphs, and block diagrams to help students assimilate the concepts discussed and develop practical orientation.

KEY FEATURES

- Explains fault characteristics of individual power system elements.
- Provides thorough coverage of tripping characteristics of various protective relays.
- Gives extensive treatment of numerical protection.
- Lays special emphasis on graphical content.
- Figures are richly annotated to make learning easy.

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