SUBSTATION PROTECTION AND MAINTENANCE

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Foreword

Distribution utilities are continuously trying to meet the ever increasing demand from its consumers by improving stability and reliability of the power distribution system. In this scenario, proper implementation of substation protection and maintenance becomes vital.

In view of above, need of a book was felt, which will make all the engineers acquainted with the protection and maintenance practices adopted in grid substations. This book has a radically different approach, in that; it focuses not only on the theoretical concepts but also on the application and implementation aspects of various protection and maintenance techniques used in grid substations. The great value of this book is the rationale underlying all the practical considerations at the implementation stage itself.

The book also dissects the problems that electrical engineers have to deal with everyday in the real world and helps them to reach the best possible solution.

I would like to put on record the hard work put in by Shri. Gaurav for his ingenious efforts in bringing out this comprehensive and up to date document.

Rich experience of Shri. Rizvi is reflected in the masterly compilation and sequence of the subject.

With best wishes

D. Guha
Sr. V.P. / CTS
Reliance Energy

PREFACE

The main objective in the operation of today's electric power system is to meet the demand for power at the lowest possible cost, while maintaining safety. Reliability and continuity are essential goals that a electric power system engineer strives to achieve at all times. Effective maintenance and protection of power systems play a key role in accomplishment of these objectives.

This book aims at developing the qualitative and quantitative understanding of protection and maintenance techniques utilized in the grid substations. For the purpose of working, general principles, construction details, performance and application of various electrical equipments, the subject matter has been divided into 12 chapters and 8 appendices.

Chapter-1 presents an overview of power systems. Chapters 2 to 4 deal with the basic operating principles, maintenance and testing procedures of transformers, circuit breakers and instrument transformers.

Chapters 5 to 7 are devoted to protective relaying. Chapter 5 deals with the fundamental principles of protective relaying whereas chapter-6 describes the various kinds of relays used in power systems. Chapter-7 deals with the relay testing procedures.

Chapters 8 to 11 are devoted to application of protective relays to power system. Chapter-8 deals with the principles of fault level calculation and relay coordination. Chapters 9 to 11 discuss various schemes used for protection of transformers, transmission lines and shunt capacitor banks. Chapter 12 deals with battery and battery chargers.

Appendices provide additional useful information such as Electrical device numbers with their definitions, glossary of important relay terms, line parameters and construction details of cables. Typical test results of power transformer, circuit breaker, current transformer, potential transformer and relays have also been included.

Constructive suggestions and healthy criticism of the book will go a long way in improvement of the text. Such suggestions can be sent to us at the email addresses given below.

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CONTENTS

CHAPTER – 1

COMPONENTS
OF
POWER SYSTEM

1.1 Introduction

The main purpose of power systems is to generate, transmit, and distribute electric energy to customers without interruptions and in the most economical and safe manner. To achieve these objectives, power systems are divided in generation, transmission and distribution subsystems. Generation consists of converting energy from different forms, such as thermal, hydraulic or nuclear, to electrical energy. Transformation consists of changing the voltage levels to those that are convenient for transmitting or distributing electrical energy. The role of transmission is to transport energy from generally geographically far away locations, where electric energy is generated, to load centers where it is consumed. The distribution consists of supplying energy to customers at a convenient voltage level.

1.2 Components of Power System

1.2.1 Generators

An electrical generator is a device that converts mechanical energy to electrical energy, generally using electromagnetic induction. The source of mechanical energy may be a reciprocating or turbine steam engine, water falling through a turbine or waterwheel, a wind turbine, a hand crank, or any other source of mechanical energy.

1.2.2 Transformers

A transformer is an electrical device that transfers energy from one circuit to another by magnetic coupling, without requiring relative motion between its parts. A transformer comprises of two or more coupled windings, and a magnetic core to concentrate magnetic flux. A changing voltage applied to one winding creates a time-varying magnetic flux in the core, which induces a voltage in the other windings. The transformer is one of the simplest of electrical devices, yet transformer designs and materials continue to be improved. Principle of operation of transformers and their construction will be discussed in detail in chapter 2.

1.2.3 Transmission Lines

A transmission line is the material medium that forms all or part of a path from one place to another for directing the transmission of electrical energy. Transmission lines can be classified into two categories i.e overhead lines and underground cables.

a. Overhead Lines

In overhead lines bare conductors are used to transmit electrical energy and air acts as the insulating medium. Necessary insulation between the conductors can be provided by adjusting the spacing between them. Other components of overhead lines are:

1. Supports – They are poles or towers used to keep the conductors at a suitable level above the ground.
2. Insulators – They are attached to supports and insulate the conductors from the ground.
3. Cross Arms – They provide support to the insulators.

b. Cables

An underground cable essentially consists of one or more conductors covered with suitable insulation and surrounded by a protective cover. Although several types of cables are available, the type of cable to be used depends on working voltage and service conditions. The under ground cables have several adavntages such as less liable to damage through storms or lightning, low maintenance cost, less chances of faults, smaller voltage drop and better general appearance. However, their major drawback is that they have a greater installation cost and introduce insulation problems at high voltages compared with equivalent overhead system. For this reason, underground cables are employed where it is impracticable to use overhead lines. Such locations can be thickly populated areas where overhead lines cannot be used for reasons of safety, or around plants and substations or where maintenance conditions do not permit the use of overhead construction. The chief use of underground cables for many years has been for distribution of electric power in congested urban areas at comparatively low or moderate voltages. However, improvements in the design and manufacture have led to the development of cables suitable for use at high voltages. Refer Appendix – C for structural details of cables.

1.2.4 Circuit Breakers

A circuit breaker is an electrical switch designed to protect an electrical circuit from damage caused by overload or short circuit. Unlike a fuse, which operates once and then has to be replaced, a circuit breaker can be reset (either manually or automatically) to resume normal operation. Circuit breakers operate based on different principles associated with physical means of interrupting the flow of power. As a result, vacuum, air blast, and oil filled breakers are commonly used depending on the voltage level and required speed of operation. All breakers try to detect the zero crossing of the current and interrupt the flow at that time since the energy level to be interrupted is at a minimum. Circuit breakers are made in varying sizes, from small devices that protect an individual household appliance up to large switchgear designed to protect high voltage circuits feeding an entire city. High voltage circuit breakers used in distribution system will be discussed in detail in Chapter 3.

1.2.5 Isolators

An isolator does exactly what its name suggests in that it electrically isolates the circuit or circuits that are connected to it. It either isolates circuits that are continually powered or is a key element which enables an electrical engineer to safely work on the protected circuit. Isolator switches may be fitted with the ability for the switch to padlock such that inadvertent operation is not possible. In some designs the isolator switch has the additional ability to earth the isolated circuit thereby providing additional safety. Such an arrangement would apply to circuits which inter-connect power distribution systems where both end of the circuit need to be isolated. Major difference between isolator and circuit breaker is that isolator is an off-load device, whereas circuit breaker is an on-load device.

1.2.6 Current Transformers

Current Transformers (CTs) are used to reduce the current levels from thousands of amperes in power systems to a standard output of either 5 A or 1 A for relaying and metering purposes. Most of the current transformers in use today are simple magnetically coupled iron core transformers. They are input/output devices operating with a hysteresis of magnetic circuit and as such are prone to saturation. The selection of instrument transformers is critical for ensuring a correct protective relaying operation. They need to be sized appropriately to prevent saturation. If there is no saturation, instrument transformers will operate in a linear region and their basic function may be represented via a simple turns ratio. Even though this is an ideal situation, it can be assumed to be true for computing simple relaying interfacing requirements. If remnant magnetism is present in an instrument transformer core, then the hysteresis may affect the time needed to saturate the next time the transformer gets exposed to excessive fault signals. The current transformers come as free standing solutions or as a part of the circuit breaker of power transformer design. If they come preinstalled with the power system apparatus, they are located in the bushings of that piece of equipment. Principle of operation, structure and construction details of CTs will be discussed in detail in chapter 4.

1.2.7 Voltage Transformers

Voltage Transformers are used to step down the power system voltages to levels suitable for measurement and relaying. They come in two basic solutions: inductive voltage transformer (PT) with iron core construction and capacitor coupling voltage transformer (CVTs) that use a capacitor coupling principle to lower the voltage level first and then use the iron core transformer to get further reduction in voltage. Both transformer types are typically free standing. PTs are used frequently to measure voltages at substation busses, whereas CVTs may be used for the same measurement purpose on individual transmission lines. Since the voltage levels in the power system range well beyond kilovolt values, the transformers are used by protective relays. They come in standard solutions regarding the secondary voltage, typically 63.5 V or 110V, depending if either the line to ground or line to line quantity is measured respectively. In an ideal case, both types of instrument transformers are assumed to be operating as voltage dividers and the transformation is proportional to their turns ratio. In practice, both designs may experience specific deviations from the ideal case. In PTs, this may manifest as a nonlinear behavior caused by the effects of the hysteresis. In CVTs, the abnormalities include various ringing effects at the output when a voltage is collapsed at the input due to a close in fault as well as impacts of the stray capacitances in the inductive transformer, which may affect the frequency response. Principle of operation, structure, construction details and behaviour of PTs and CVTs will be discussed in chapter 4.

1.2.8 Relays

Relays are controllers that measure input quantities and compare them to thresholds, commonly called relay settings, which in turn define operating characteristics. The relay characteristics may be quite different depending on the relaying quantity used and the relaying principle employed. In general, the relay action is based on a comparison between the measured quantity and the operating characteristic. Once the characteristic thresholds (settings) are exceeded, the relay assumes that this is caused by the faults affecting the measuring quantity, and it issues a command to operate associated circuit breaker(s). This action is commonly termed as a relay tripping, meaning opening a circuit breaker. The relays may come in different designs and implementation technologies. A complete analysis of fundamental operating principles of various relays is presented in chapter 5. Types of relays used for various protection applications are discussed in detail in chapter 6 whereas chapter 7 deals with the standard procedures for testing protective relays.

1.2.9 Capacitor Banks

Many power system components in a network consume large amounts of reactive power. For example, transmission line shunt reactors, and other industrial and commercial loads need reactive power. Reactive current supports the magnetic fields in motors and transformers. Supporting both real and reactive power with the system generation requires increased generation and transmission capacity, because it increases losses in the network. Shunt-connected capacitors are another way to generate reactive power. Shunt capacitors have the advantage of providing reactive power close to the load centers, minimizing the distance between power generation and consumption, and have low costs. Controlling capacitance in a transmission or distribution network could be the simplest and most economical way of maintaining system voltage, minimizing system losses, and maximizing system capability. Shunt capacitor banks and their protection techniques will be discussed in detail in chapter 11.

1.2.10 Lightning Arresters

Power systems installations are subject to surge voltages originating from lightning disturbances, switching operations, or circuit faults. Some of these transient conditions may create abnormally high voltages from turn to turn, winding to winding, and from winding to ground. The lightning arrester is designed and positioned so as to intercept and reduce the surge voltage before it reaches the electrical system. Lightning arresters are similar to big voltage bushings in both appearance and construction. They use a porcelain exterior shell to provide insulation and mechanical strength, and they use a dielectric filler material (oil, epoxy, or other materials) to increase the dielectric strength. Lightning arresters, however, are called on to insulate normal operating voltages, and to conduct high level surges to ground. In its simplest form, a lightning arrester is nothing more than a controlled gap across which normal operating voltages cannot jump. When the voltages exceeds a predetermined level, it will be directed to ground, away from the various components (including the transformer) of the circuit. There are many variations to this construction. Some arresters use a series of capacitances to achieve a controlled resistance value, while other types use a dielectric element to act as a valve material that will throttle the surge current and divert it to ground.

1.3 Power System Representation

Power systems are extremely complicated electrical networks that are geographically spread over very large areas. For most part, they are also three phase networks – each power circuit consists of three conductors and all devices such as generators, transformers, breakers, disconnects etc. are installed in all three phases. In fact, the power systems are so complex that a complete conventional diagram showing all the connections is impractical. Yet, it is desirable, that there is some concise way of communicating the basic arrangement of power system components. This is done by using Single Line Diagrams (SLD). SLDs are also called One Line Diagrams.

Single Line Diagrams do not show the exact electrical connections of the circuits. As the name suggests, SLDs use a single line to represent all three phases. They show the relative electrical interconnections of generators, transformers, transmission and distribution lines, loads, circuit breakers, etc., used in assembling the power system. The amount of information included in an SLD depends on the purpose for which the diagram is used. For example, if the SLD is used in initial stages of designing a substation, then all major equipment will be included in the diagram – major equipment being transformers, breakers, disconnects and buses. There is no need to include instrument transformers or protection and metering devices. However, if the purpose is to design a protection scheme for the equipment in the substation, then instrument transformers and relays are also included.

Single line diagram of a simple system is shown in figure 1.1. There is no universally accepted set of symbols used for single line diagrams. Often used symbols are shown in figure 1.2. The variations in symbols are usually minor and are not difficult to understand. Concept of bus in single line diagrams is essentially the same as the concept of a node in an electrical circuit. Just keep in mind that there is one bus for each phase. Buses are shown in SLDs as short straight lines perpendicular to transmission lines and to lines connecting equipment to the buses. In actual substations, the buses are made of aluminium or copper bars or pipes and can be several meters long. The impedance of buses is very low, practically zero, so electrically the whole bus is at the same potential. Of course, there is line voltage between the buses of the individual phases.

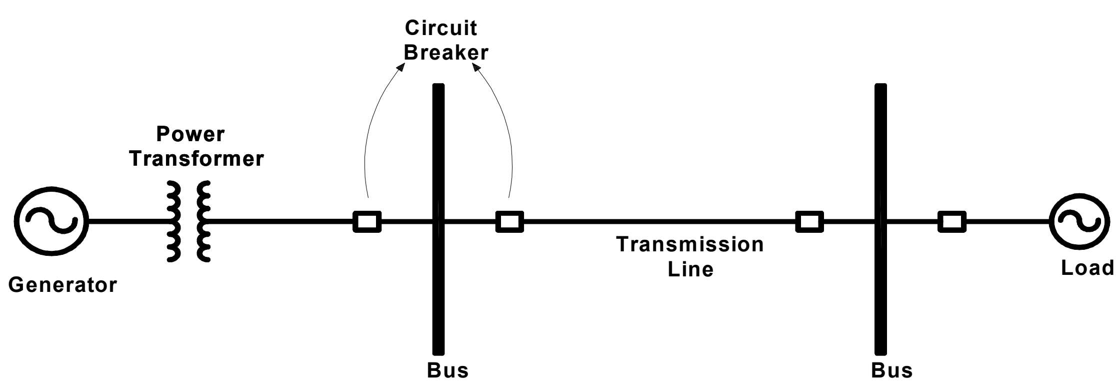


Figure 1.1 - Single Line Representation of a Simple Power Network

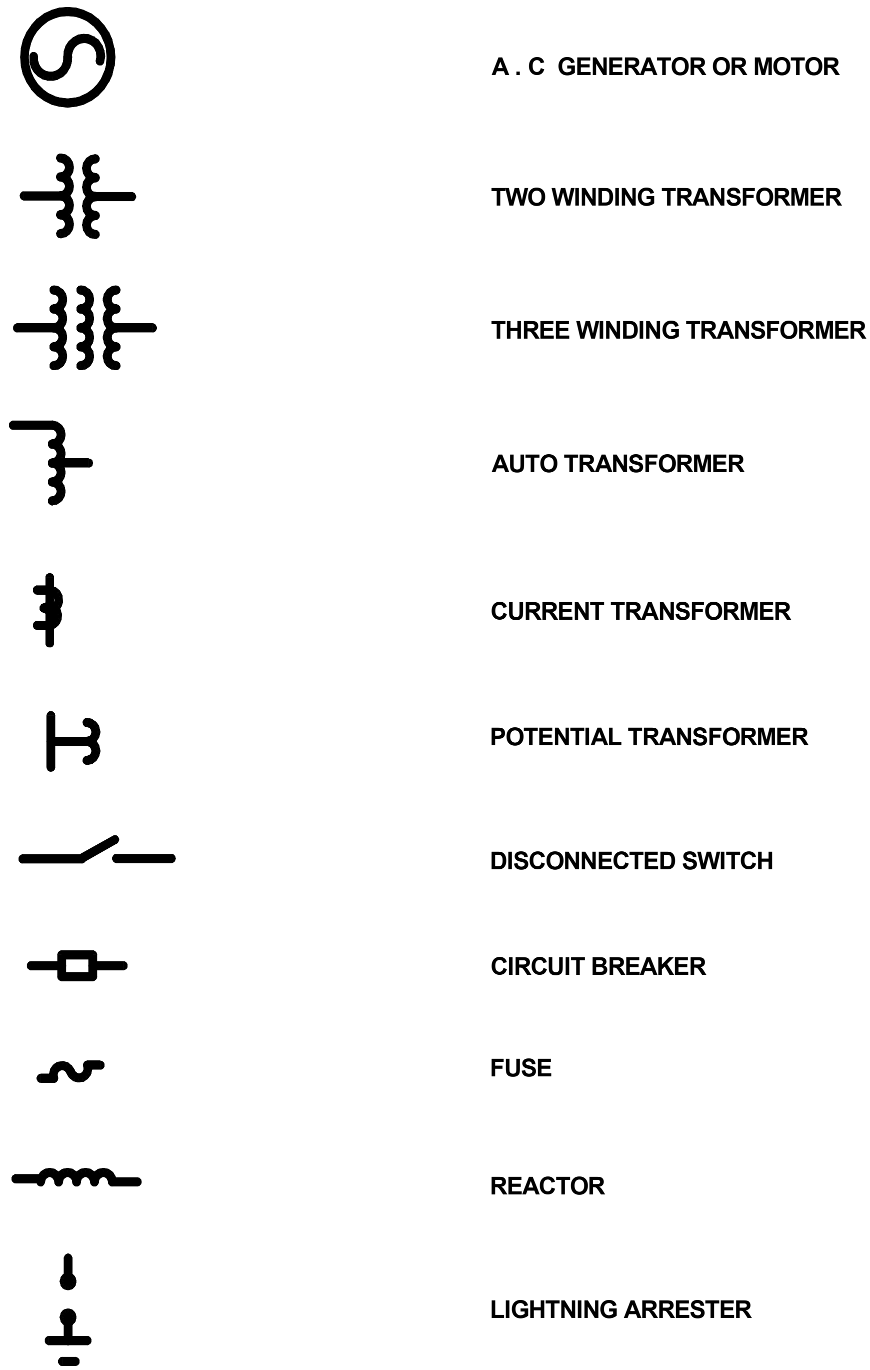


Figure 1.2 – Graphical Symbols for Single Line Diagrams

CHAPTER – 2

TRANSFORMERS

2.1 Introduction

Transformer is a vital link in a power system which has made possible the power generated at low voltages (6600 to 22000 volts) to be stepped up to extra high voltages for transmission over long distances and then transformed to low voltages for utilization at proper load centers. With this tool in hands it has become possible to harness the energy resources at far off places from the load centers and connect the same through long extra high voltage transmission lines working on high efficiencies.

A transformer is a device that uses the action of a magnetic field to change ac electric energy at one voltage level to ac electric energy at another voltage level. It consists of a ferromagnetic core with two or more coils wrapped around it. The common magnetic flux within the core is the only connection between the coils. The source of ac electric power is connected to one of the transformer windings. The second winding supplies power to loads. The winding connected to the power source is called the *primary winding* or *input winding.* The winding connected to the loads is called the *secondary winding* or *output winding.*

2.2 Operating Principle:

Most transformers with iron cores can be considered as *ideal* when you use them. An ideal transformer has no losses, an aim that is closely attained in practice, so the energy transfer from the primary circuit to the secondary circuit is perfect. Figure 2.1 represents a transformer, showing the core with magnetic flux φ, the primary winding of Np turns, and the secondary winding of Ns turns. The reference directions for the voltages and currents at the terminals are shown. All of these quantities are to be considered as phasor amplitudes, varying sinusoidally with time.

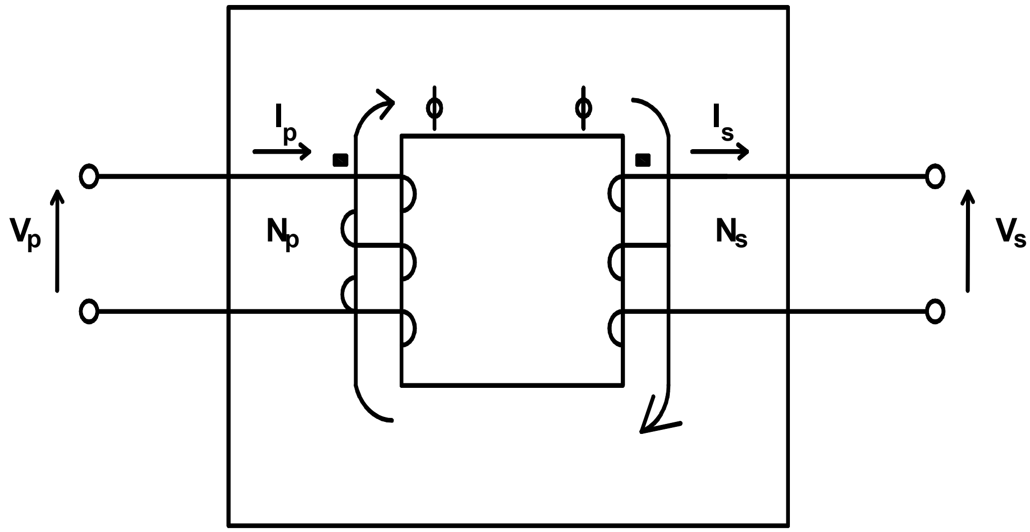


Figure 2.1 Transformer Operating Principle

Note the dots at the terminals of each winding. Currents entering the dotted terminals produce flux in the same direction, the direction shown. In accordance with the energy conservation principle we know that the power at input terminals (primary) must be equal to power at the output terminals (secondary) if there are no losses in the transformer. Thus,

$$Vp.\ Ip = Vs.\ Is$$

The mutual flux φ is the means of transfer of energy from primary to secondary, and links both windings. Thus the voltage induced per turn for primary winding is equal to the voltage induced per turn for the secondary winding. The flux linkage is shown in figure 2.1. In an ideal transformer, this flux requires negligibly small ampere-turns to produce it, so the net ampere-turns, primary plus secondary, is about zero. When a current is drawn from the secondary in the positive direction, ampere-turns decrease substantially. This must be matched by an equal increase in primary ampere-turns, which is caused by an increase in the current entering the primary in the positive direction. In this way, the back-emf of the primary (the voltage induced in it by the flux φ) equals the voltage applied to the primary, as it must. This fundamental explanation can be expressed mathematically as:

$$Np.Ip = Ns.Is$$

In a real transformer, we must include the magnetizing current, as well as the effects of leakage flux. Leakage flux links only one winding, and is completely independent of the other. Its effect is to act like an inductance in series with a winding. In addition, there is the IR drop in the copper of a winding when it carries current. These are the things that make a real transformer behave differently from an ideal transformer. The best way to understand things is to draw an equivalent circuit of real transformer which is shown in figure 2.2. The diagram shows the winding resistances R, and the reactances due to the leakage fluxes X, as well as the magnetizing current Ie. We will assume that the turns ratio is unity for convenience, so the vectors turn out to be about the same lengths on the same scale. If the turns ratio were not unity, the voltages and currents would be reflected into the primary multiplied by the proper ratios.

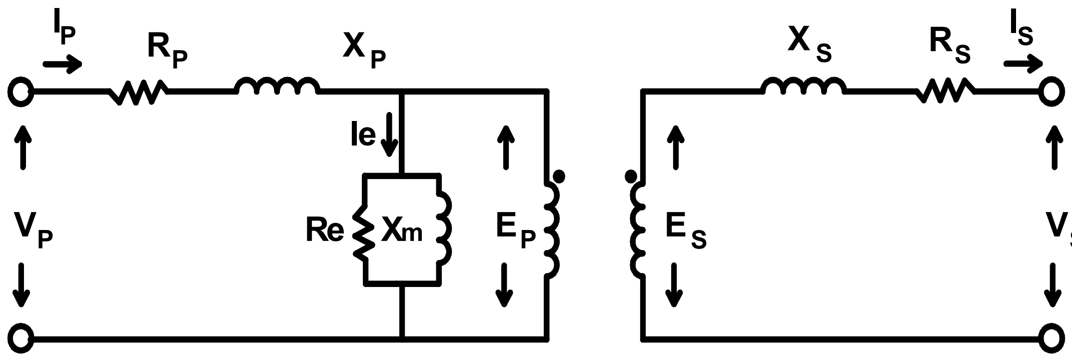


Figure 2.2 Equivalent Circuit of Transformer

The phasor diagram for the transformer at full load is shown in figure 2.3. This complicated diagram can be understood by following through how it was constructed. We start by assuming that the secondary is supplying a current Is at a terminal voltage Vs with phase angle θ. These are the first two phasors drawn. Now, to Vs we add IsRs in phase with Is, and IsXs in quadrature, to find the induced voltage Es in the secondary. The voltage -Ep is induced in the primary. The flux φ is at right angles to Es, as shown. The current Ie is necessary to create the flux, and is drawn with its proper relation to φ. The current Is is reflected to the primary as -Is, and added to Ie to find the total primary current Ip. Now that we know Ip, we can add IpRp and IpXp to -E to find the primary terminal voltage, Vp. In this diagram, the magnetizing current, and the voltages due to leakage flux and winding resistance, are greatly magnified so their effects can easily be seen.

Try to visualize what happens when the secondary current decreases. The difference between the terminal voltage Vs and the induced voltage Es becomes less, and they approach one another. The magnetizing current becomes a larger part of the smaller primary current, which changes in phase accordingly. The flux, of course, remains the same. The input voltage decreases, and becomes equal to Vs.

One of the important characteristics of a transformer is its *regulation*, the change in output voltage between no load and full load, divided by the full-load output voltage (or some such definition), expressed as a percentage. This is practically the same as the difference between the full-load and no load input voltages divided by the no-load input voltage, holding the output voltage constant. Typical power transformer regulation is around 1% or even less at unity power factor, falling off to a few percent at 0.8 pf. Such transformers are called *constant-potential* transformers. Regulation is improved by decreasing leakage flux and winding resistance. If poor regulation is desirable, it can be obtained by increasing the leakage flux without added resistive heating.

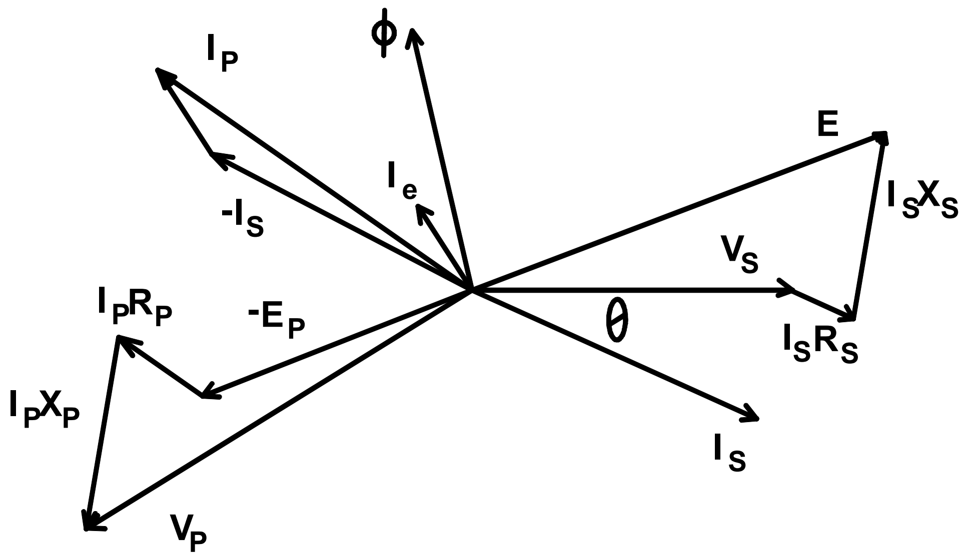


Figure 2.3 – Transformer Phasor diagram

The efficiency of a transformer is quite high, usually over 96% at full load. It increases at partial load, sometimes to over 97%. In fact, a real transformer is not very far from an ideal transformer. It is difficult to measure the efficiency of a transformer directly (by comparing output with input), so the copper and core losses are usually measured or estimated instead.

Following fundamental equations for transformers can be derived from the foregoing discussion:

1. Voltage Transformation Ratio $Vp / Vs = Np / Ns$
2. Current Transformation Ratio $Ip / Is = Ns / Np$
3. Voltage induced in the primary winding can be given as

$$Ep = 4.44 \times f \times A \times Np \times Bmax$$

Similarly the voltage induced in the secondary can be given as

$$Es = 4.44 \times f \times A \times Ns \times Bmax$$

Where f is the system frequency
A is the cross sectional area of the core in square cms
Vp is the primary side voltage
Vs is the secondary side voltage
Ip is the primary side current
Is is the secondary side current
Np is the number of turns in primary winding
Ns is the number of turns in secondary winding
Bmax is the maximum flux density of the core in lines per square cms.

A transformer designed to reduce voltage from primary to secondary is called a step-down transformer. A transformer designed to increase voltage from primary to secondary is called a step-up transformer. Figure 2.4 shows a comparison between currents and voltages of primary and secondary sides of a step down transformer.

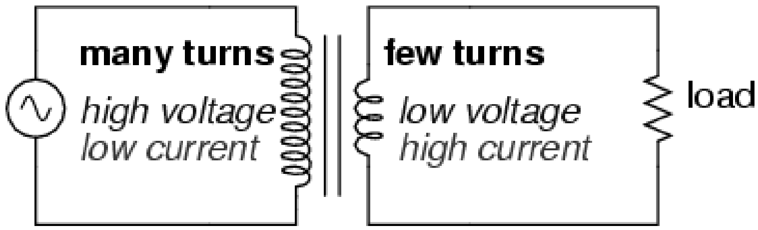


Figure 2.4 - Step-Down Transformer

2.3 Losses in Transformer

When transformers transfer power, they do so with a minimum of loss. As it was stated earlier, modern power transformer designs typically exceed 95% efficiency. It is good to know where some of this lost power goes, however, and what causes it to be lost.

2.3.1 Copper Loss

There is, of course, power lost due to resistance of the wire windings. Unless superconducting wires are used, there will always be power dissipated in the form of heat through the resistance of current-carrying conductors. Because transformers require such long lengths of wire, this loss can be a significant factor. Increasing the gauge of the winding wire is one way to minimize this loss, but only with substantial increases in cost, size, and weight.

2.3.2 Core Losses:

a. Eddy current losses:

Resistive losses aside, the bulk of transformer power loss is due to magnetic effects in the core. Perhaps the most significant of these "core losses" is *eddy-current loss*, which is resistive power dissipation due to the passage of induced currents through the iron of the core. Because iron is a conductor of electricity as well as being an excellent "conductor" of magnetic flux, there will be currents induced in the iron just as there are currents induced in the secondary windings from the alternating magnetic field. These induced currents, as described by the perpendicularity clause of Faraday's Law, tend to circulate through the cross-section of the core perpendicularly to the primary winding turns. Their circular motion gives them their unusual name: like eddies in a stream of water that circulates rather than move in straight lines. This phenomenon is depicted in figure 2.5.

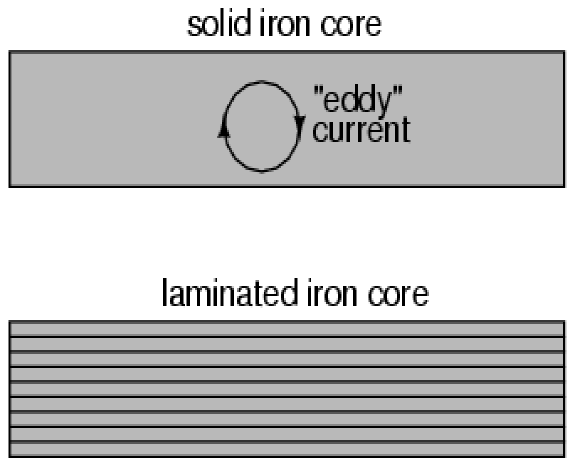


Figure 2.5 – Solid and Laminated Iron Cores

Iron is a fair conductor of electricity, but not as good as the copper or aluminum from which wire windings are typically made. Consequently, these "eddy currents" must overcome significant electrical resistance as they circulate through the core. In overcoming the resistance offered by the iron, they dissipate power in the form of heat. Hence, we have a source of inefficiency in the transformer that is difficult to eliminate.

The main strategy in mitigating these wasteful eddy currents in transformer cores is to form the iron core in sheets, each sheet covered with an insulating varnish so that the core is divided up into thin slices. Such a core is called "Laminated" core and is shown in figure 2.5. The result is very little width in the core for eddy currents to circulate in. Laminated cores are standard in all power system applications.

b. Hysterisis Loss:

Another "core loss" is that of magnetic hysteresis. All ferromagnetic materials tend to retain some degree of magnetization after exposure to an external magnetic field. This tendency to stay magnetized is called "hysteresis," and it takes a certain investment in energy to overcome this opposition to change every time the magnetic field produced by the primary winding changes polarity (twice per AC cycle). This type of loss can be mitigated through good core material selection (choosing a core alloy with low hysteresis, as evidenced by a "thin" B/H hysteresis curve), and designing the core for minimum flux density (large cross-sectional area).

2.4 Core saturation

Transformers are also constrained in their performance by the magnetic flux limitations of the core. For ferromagnetic core transformers, we must be mindful of the saturation limits of the core. Remember that ferromagnetic materials cannot support infinite magnetic flux densities: they tend to "saturate" at a certain level (dictated by the material and core dimensions), meaning that further increases in magnetic field force (mmf) do not result in proportional increases in magnetic field flux (Φ).

When a transformer's primary winding is overloaded from excessive applied voltage, the core flux may reach saturation levels during peak moments of the AC sine wave cycle. If this happens, the voltage induced in the secondary winding will no longer match the wave-shape as the voltage powering the primary coil. In other words, the overloaded transformer will *distort* the waveshape from primary to secondary windings, creating harmonics in the secondary winding's output. Harmonic content in AC power systems causes problems.

For transformers, core saturation is a very undesirable effect, and it is avoided through good design: engineering the windings and core so that magnetic flux densities remain well below the saturation levels. This ensures that the relationship between mmf and Φ is more linear throughout the flux cycle, which is good because it makes for less distortion in the magnetization current waveform. Also, engineering the core for low flux densities provides a safe margin between the normal flux peaks and the core saturation limits.

2.5 Magnetizing Inrush

When a transformer is initially connected to a source of AC voltage, there may be a substantial surge of current through the primary winding called *inrush current*. This is analogous to the inrush current exhibited by an electric motor that is started up by sudden connection to a power source, although transformer inrush is caused by a different phenomenon.

We know that the rate of change of instantaneous flux in a transformer core is proportional to the instantaneous voltage drop across the primary winding. Thus the voltage waveform is the derivative of the flux waveform, and the flux waveform is the integral of the voltage waveform. In a continuously-operating transformer, these two waveforms are phase-shifted by 90^o. Since flux (Φ) is proportional to the magnetomotive force (mmf) in the core, and the mmf is proportional to winding current, the current waveform will be in-phase with the flux waveform, and both will be lagging the voltage waveform by 90^o as shown in figure 2.6.

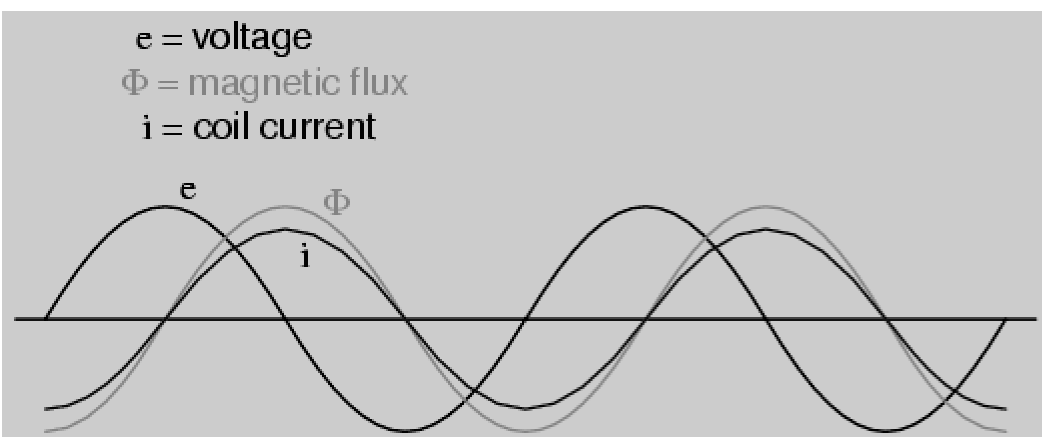


Figure 2.6 Waveform Representation of Flux, Current and Voltage

Let us suppose that the primary winding of a transformer is suddenly connected to an AC voltage source at the exact moment in time when the instantaneous voltage is at its positive peak value as shown in figure 2.7. In order for the transformer to create an opposing voltage drop to balance against this applied source voltage, a magnetic flux of rapidly increasing value must be generated. The result is that winding current increases rapidly, but actually no more rapidly than under normal conditions. Both core flux and coil current start from zero and build up to the same peak values experienced during continuous operation. Thus, there is no "surge" or "inrush" or current in this scenario.

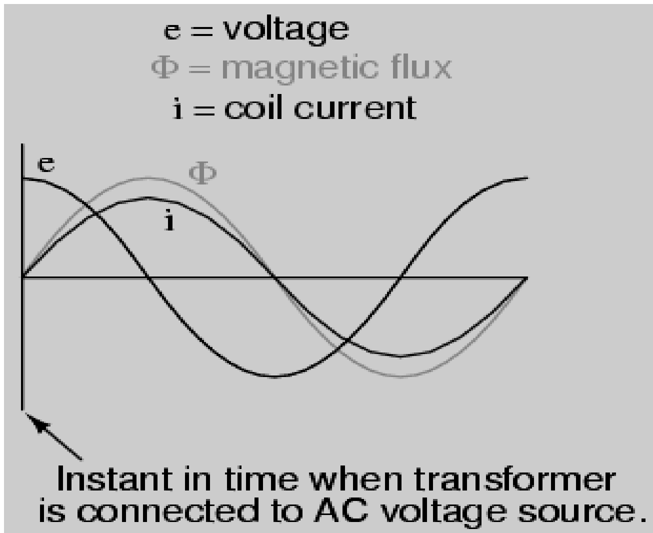


Figure 2.7 – Transformer Energization at the Instant of Positive Peak Voltage

Alternatively, let us consider what happens if the transformer's connection to the AC voltage source occurs at the exact moment in time when the instantaneous voltage is at zero. During continuous operation (when the transformer has been powered for quite some time), this is the point in time where both flux and winding current are at their negative peaks, experiencing zero rate-of-change ($d\Phi/dt = 0$ and $di/dt = 0$). As the voltage builds to its positive peak, the flux and current waveforms build to their maximum positive rates-of-change, and on upward to their positive peaks as the voltage descends to a level of zero.

A significant difference exists, however, between continuous-mode operation and the sudden starting condition assumed in this scenario. During continuous operation, the flux and current levels were at their negative peaks when voltage was at its zero point as shown in figure 2.8. However, in a transformer that has been sitting idle, both magnetic flux and winding current should start at *zero*. As a result, when the magnetic flux increases in response to a rising voltage, it will increase from zero upwards as depicted in figure 2.9 and not from a previously negative (magnetized) condition as we would normally have in a transformer that's been powered for a while. Thus, in a transformer that's just "starting," the flux will reach approximately twice its normal peak magnitude as it "integrates" the area under the voltage waveform's first half-cycle.

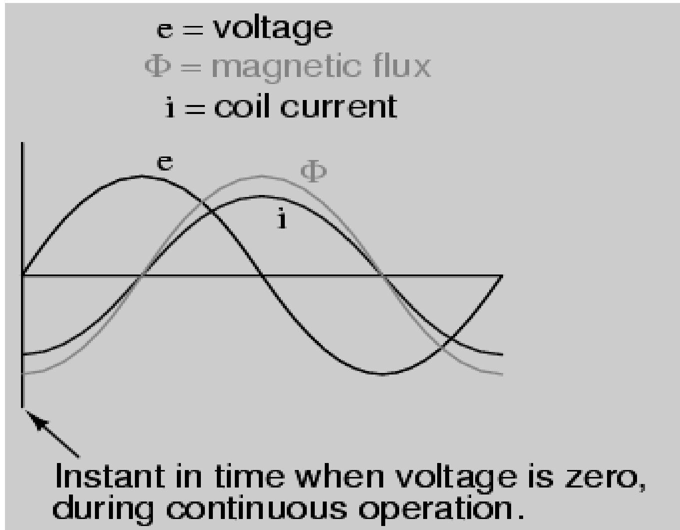


Figure 2.8 – Voltage, Current and Flux Waves at the Instant of Zero Voltage

In an ideal transformer, the magnetizing current would rise to approximately twice its normal peak value as well, generating the necessary mmf to create this higher-than-normal flux. However, most transformers aren't designed with enough of a margin between normal flux peaks and the saturation limits to avoid saturating in a condition like this, and so the core will almost certainly saturate during this first half-cycle of voltage. During saturation, disproportionate amounts of mmf are needed to generate magnetic flux. This means that winding current, which creates the mmf to cause flux in the core, will disproportionately rise to a value far exceeding twice its normal peak. This high starting current is termed inrush current.

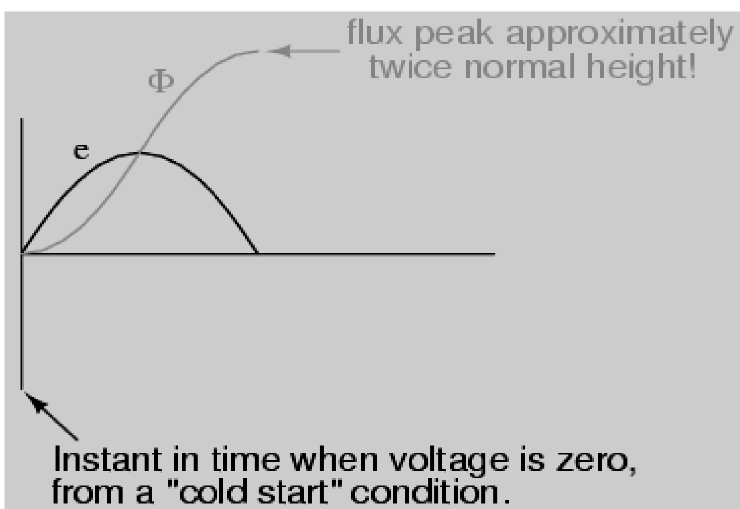


Figure 2.9 - Flux Wave when Transformer is Energized at the instant of Zero Voltage

2.6 Heat and Noise

In addition to unwanted electrical effects, transformers may also exhibit undesirable physical effects, the most notable being the production of heat and noise.

2.6.1 Heat

Heat is one of the most common destroyers of transformers. Operation at only 10 °C above the transformer rating will cut transformer life by 50%. Heat is caused by internal losses due to loading, high ambient temperature, and solar radiation. It is important to understand how your particular transformers are cooled and how to detect problems in the cooling systems. On the basis of types of cooling the transformers can be classified into the following categories:

a. Dry Type Transformers

Oil-less, or "dry," transformers are often rated in terms of maximum operating temperature "rise" (temperature increase beyond ambient) according to a letter-class system: A, B, F, or H. These letter codes are arranged in order of lowest heat tolerance to highest:

- **Class A:** No more than 55^o Celsius winding temperature rise, at 40^o Celsius (maximum) ambient air temperature.
- **Class B:** No more than 80^o Celsius winding temperature rise, at 40^o Celsius (maximum) ambient air temperature.
- **Class F:** No more than 115^o Celsius winding temperature rise, at 40^o Celsius (maximum) ambient air temperature.
- **Class H:** No more than 150^o Celsius winding temperature rise, at 40^o Celsius (maximum) ambient air temperature.

b. Oil Immersed Transformers

Large power transformers have their core and windings submerged in an oil bath to transfer heat and muffle noise, and also to displace moisture which would otherwise compromise the integrity of the winding insulation. Heat-dissipating "radiator" tubes on the outside of the transformer case provide a convective oil flow path to transfer heat from the transformer's core to ambient air:

1. Class ONAN: Transformer windings and core are immersed in some type of oil and are self-cooled by natural circulation of air around the outside enclosure and by oil flow as per the natural principle of convection. Fins or radiators are attached to the enclosure to aid in cooling.

2. Class ON/AF: Cooling method of this group is the same as ONAN above, with the addition of fans. Fans are usually mounted on radiators. The transformer typically has two load ratings, one with the fans off (AN) and a larger rating with fans operating (AF). Fans may be wired to start automatically at a pre-set temperature.

3. Class OF/AF: This transformer typically has radiators attached to the enclosure. The transformer has self-cooling through natural ventilation (AN) and natural cooling by oil flow (ON). In addition to this forced air-cooling (AF) is provide by fans, and forced oil-cooling is provided by oil pumps. The transformer has three load ratings corresponding to each cooling step. Fans and pumps may be wired to start automatically at pre-set levels as temperature increases.

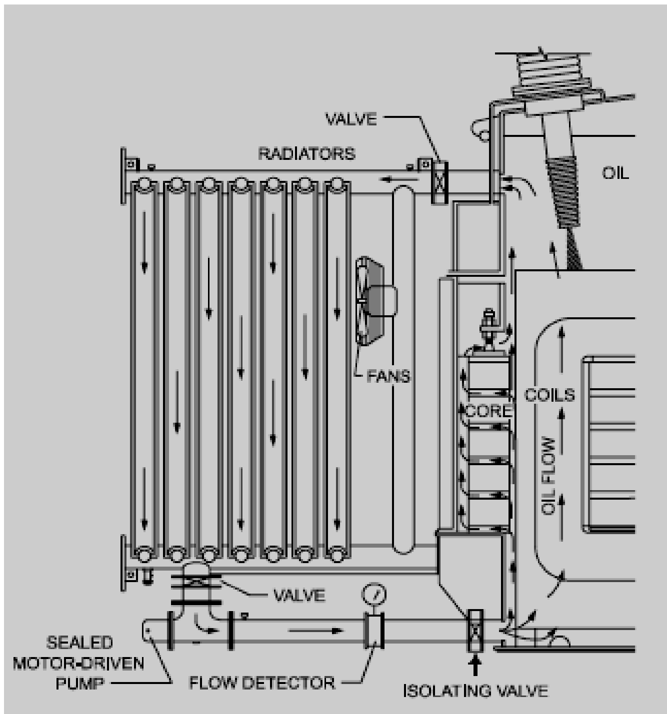


Figure 2.10 - Typical Oil Flow

2.6.2 Noise

Audible noise is an effect primarily originating from the phenomenon of magnetostriction - the slight change of length exhibited by a ferromagnetic object when magnetized. The familiar "hum" heard around large power transformers is the sound of the iron core expanding and contracting at 100 Hz (twice the system frequency, which is 50 Hz in India) - one cycle of core contraction and expansion for every peak of the magnetic flux waveform plus noise created by mechanical forces between primary and secondary windings. Again, maintaining low magnetic flux levels in the core is the key to minimizing this effect, which explains why Ferro-resonant transformers which must operate in saturation for a large portion of the current waveform -- operate both hot and noisy.

Another noise-producing phenomenon in power transformers is the physical reaction force between primary and secondary windings when heavily loaded. If the secondary winding is open-circuited, there will be no current through it, and consequently no magneto-motive force (mmf) produced by it. However, when the secondary is "loaded" (current supplied to a load), the winding generates an mmf, which becomes counteracted by a "reflected" mmf in the primary winding to prevent core flux levels from changing. These opposing mmfs generated between primary and secondary windings as a result of secondary (load) current produce a repulsive, physical force between the windings which will tend to make them vibrate. Transformer designers have to consider these physical forces in the construction of the winding coils, to ensure there is adequate mechanical support to handle the stresses. Under heavy load conditions, though, these stresses may be great enough to cause audible noise to emanate from the transformer.

2.7 Autotransformers

Although the examples illustrated up to this point have used two separate windings to transform the voltage and current, this transformation can be accomplished by dividing one winding into sections. The desired ratio can be obtained by "tapping" the winding at a prescribed point to yield the proper ratio between the two sections. This arrangement is called an "Autotransformer."

Even though the winding is continuous, the desired voltages and currents can be obtained. Although an autotransformer is made up of one continuous winding, the relationship of the two sections can be more readily understood lf they are thought of as two separate windings connected in series. Figure 2.11 shows the voltages and current distribution in the HV and LV windings of an autotransformer.

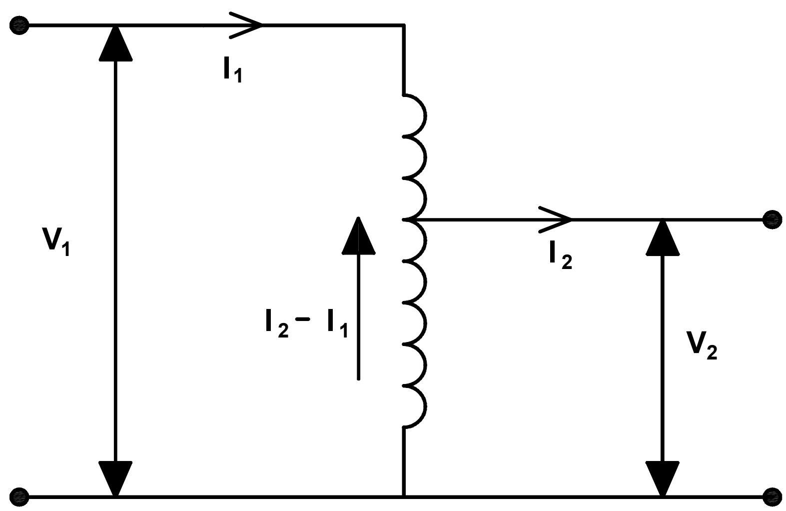


Figure 2.11 - Autotransformer

Autotransformers are inherently smaller than normal two-winding transformers. They are especially suited for applications where there is not too much difference between the primary and secondary voltages (transformer ratios usually less than 3:l). An autotransformer will have lower losses, impedance, and excitation current values than a two-winding transformer of the same KVA rating because less material is used in its construction.

The major drawback of autotransformers is that they do not provide separation between the primary and secondary. This non-insulating feature of the autotransformer should always be remembered; even though a low voltage may be tapped from an autotransformer, the low voltage circuit must be insulated to the same degree as the high voltage side of the transformer. Another drawback is that the autotransformer's impedance is extremely low, and it provides almost no opposition to fault current. Autotransformers are used in power applications where the difference between the primary and secondary voltages is not too great.

2.8 Three Phase Transformers

Since three-phase is used so often for power distribution systems, it makes sense that we would need three-phase transformers to be able to step voltages up or down. This is only partially true, as regular single-phase transformers can be ganged together to transform power between two three-phase systems in a variety of configurations, eliminating the requirement for a special three-phase transformer.

A three-phase transformer is made of three sets of primary and secondary windings, each set wound around one leg of an iron core assembly. Essentially it looks like three single-phase transformers sharing a joined core as shown in figure 2.12.

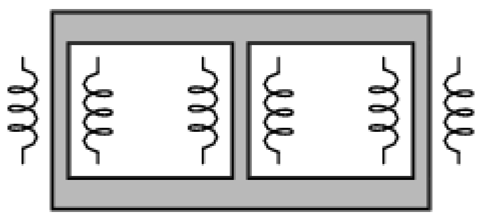


Figure 2.12 – Basic Structure of Three Phase Transformer

These sets of primary and secondary windings can be connected either in Δ, Y or zigzag configurations to form a complete unit. The various combinations of ways that these windings can be connected together in will be the focus of this section.

2.8.1 Three Phase Transformer Winding Configurations

There are 4 basic winding configurations for the typical large 3 phase power transformers: Delta, Wye, Auto, and Zigzag. Zig zag connections are not used in distribution systems. Hence they will not be discussed in detail. Within the delta and wye, there are multiple means of creating the winding configuration. Whether the winding sets share a common core assembly or each winding pair is a separate transformer (single phase transformers connected as a three phase bank), the winding connection options are the same.

Before we discuss the winding configurations of three phase transformer we should be familiar with the Vector Group terminology which marks the connection of windings and their phase position with respect to each other. Vector Group consists of a capital and small letters plus a code number.

Capital letter in vector group designation is used to represent the connection type of **High Voltage** winding.
Delta - D
Star - Y
Interconnected star - Z
Neutral brought out- N

Small letter in vector group designation is used to represent the connection type of **Low Voltage** winding.
Delta - d
Star - y
Interconnected star - z
Neutral brought out - n

Code number in the vector group designation represents phase rotation of primary winding with respect to secondary winding. It is always measured in anti-clockwise direction. (International convention). The hour indicator is used as the indicating phase displacement angle. Because there are 12 hours on a clock, and a circle consists out of 360°, each hour represents 30°. Thus 1 = 30°, 2 = 60°, 3 = 90°, 5 = 150°, 6 = 180°, 7 = 210°, 11 = -30° and 12 = 0° or 360°. The minute hand is set on 12 o'clock and replaces the line to neutral voltage (sometimes imaginary) of the HV winding. This position is always the reference point. Because rotation is anti-clockwise, 1 = 30° lagging (LV lags HV with 30°) and 11 = 330° lagging or 30° leading (LV leads HV with 30°). A few vector group designations are analyzed below for reference:

Dd0 : Delta connected HV winding, delta connected LV winding, no phase shift between HV and LV.
Dyn11 : Delta connected HV winding, star connected LV winding with neutral brought out, LV is leading HV with 30°.
YNd5 : Star connected HV winding with neutral brought out, delta connected LV winding, LV lags HV with 150°.

a. Wye Winding Configurations

Given three windings, named W1, W2, and W3, and three transformer phase bushings named **U**, **V**, **W**, and a neutral bushing **N**, and assuming a positive sequence rotation is to be maintained, there are 6 different ways the windings and bushings can be interconnected, as shown in Figure 2.13. Of the 6 variations of wye connections listed, in actual practice almost all connections can be seen in terms of Y0 or Y6. As previously mentioned, which winding is given the number W1, W2, or W3 will not matter initially, but we need to keep track of which winding is connected to which bushing so that when we connect the second set of windings we will know the positive sequence phase shift across the transformer.

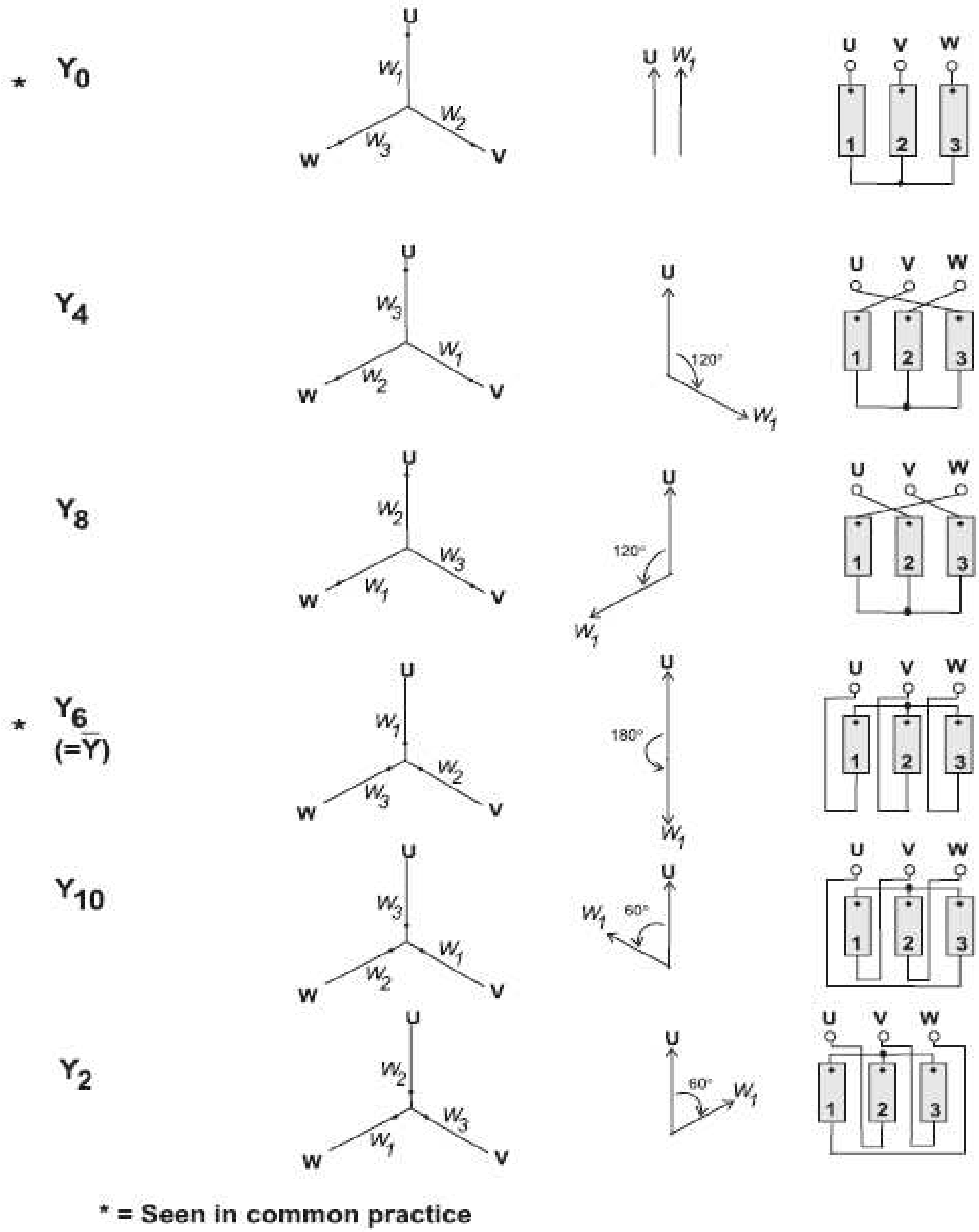


Figure 2.13 - Six Ways to Wire a Y-Winding

Note the use of Y# for naming each of the configurations. The # refers to the phase angle, as viewed on a 12 hour clock, of winding W1 relative to the voltage applied to the **U** bushing with a balanced 3 phase positive sequence voltage (**UVW** or **RYB** sequence).

b. Delta Windings Configurations

Given a set of 3 windings W1, W2, and W3, and three transformer phase bushings **U**, **V**, **W**, and again assuming that positive sequence rotation is to be maintained, there are 6 ways the windings and bushings can be interconnected, as shown in figure 2.14. Again, some of the methods would not be seen in normal practice. The most common ones would be **D1** and **D11**. The **D5** and **D7** configurations are seen in some documentation of transformer connections in the international market.

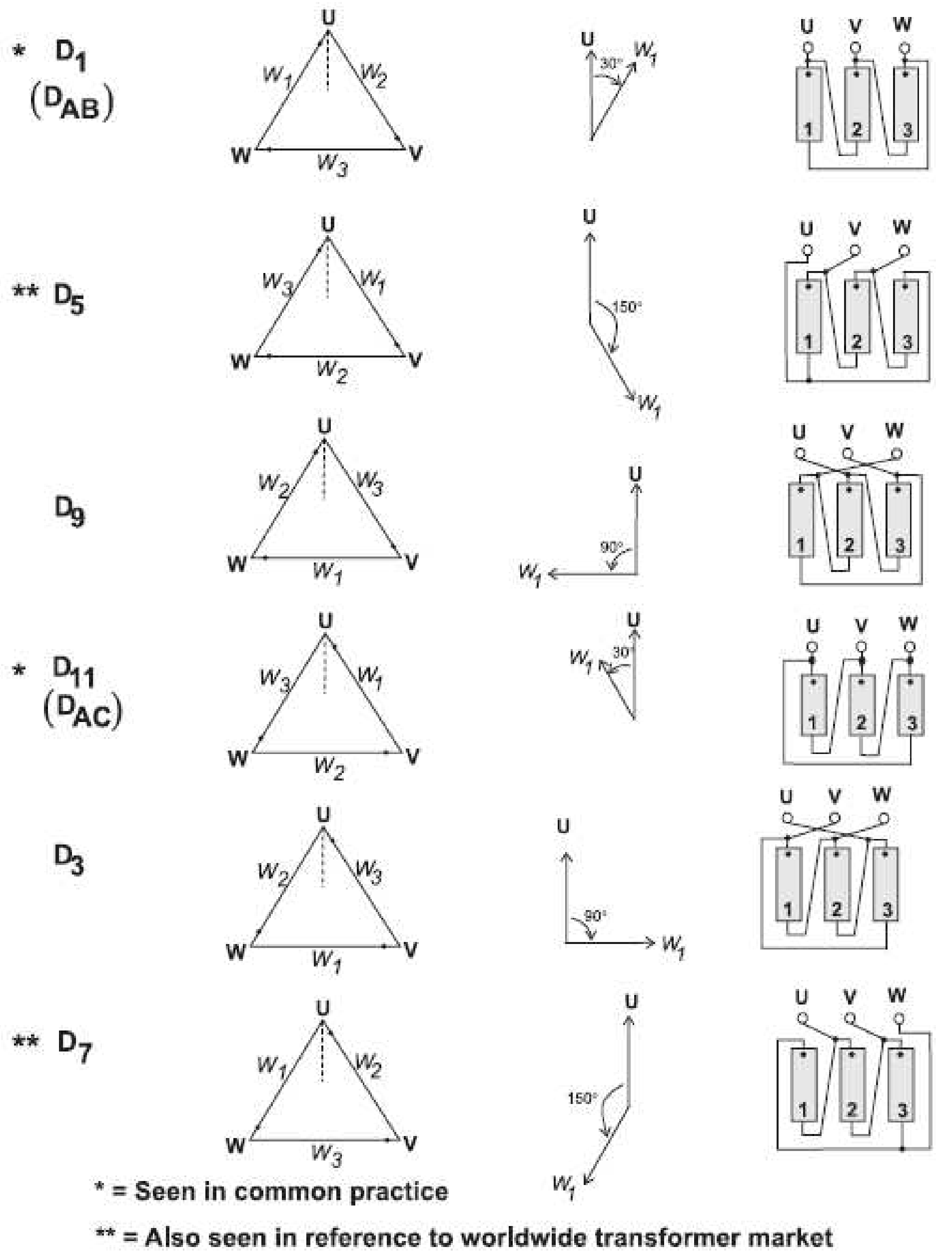


Figure 2.14 - Six Ways to wire A Delta Winding

c. Auto-Transformer Winding Configurations

There is no flexibility in how an auto-transformer is wired. The only way to obtain a phase shift is to rename the phases from one side to another, but this is quite uncommon. Connection diagram of autotransformer windings is depicted in figure 2.15.

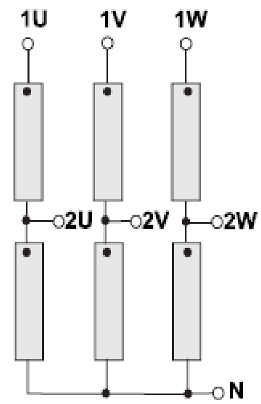


Figure 2.15 - An Autotransformer Winding

The auto-transformer can be treated as a simple wye-wye transformer for current differential calculations. Phase shift in any delta tertiary connection would be treated as a separate delta/wye connection.

d. Combining the Various Winding Configurations

An exhaustive listing of all the possible permutations of transformer winding configurations is not worth presenting. Only a small percentage of all the possible winding configurations is commonly found in practice, and many are effectively redundant views of the same configuration. More complete wiring and phasor diagrams of some of the common configurations are given in figures 2.16 to 2.23. The winding diagram is intended to show most clearly how the windings would be interconnected, using bushing names. The figures show common international method of showing the winding connections, except the method has been modified by the addition of polarity marks and winding numbers. To determine the phase relationship of positive sequence voltage and current between primary and secondary, use the W1 phasor as the common reference for each winding and compare the resultant angle between the **U** phasor on each winding. The angular relationship will be the primary angle minus the secondary angle, on a 12 hour clock as already discussed in Vector Group designations.

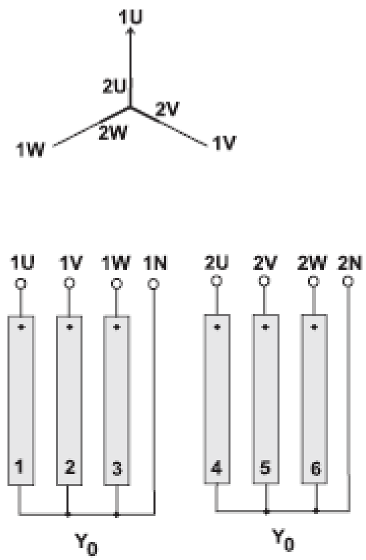


Figure 2.16 - Yy0 Connection

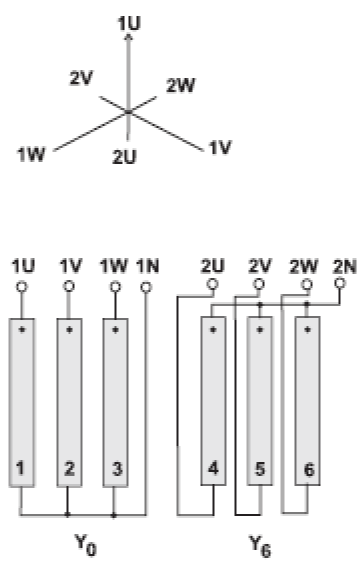


Figure 2.17 - Yy6 Connection

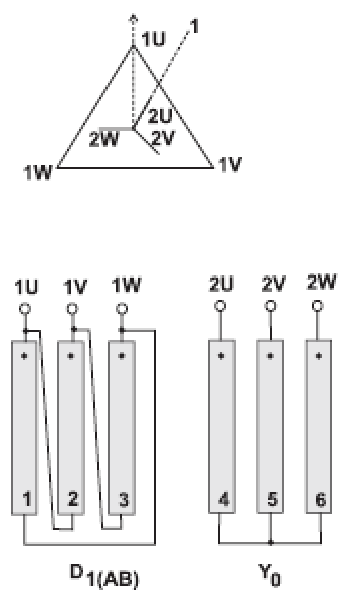


Figure 2.18 - Dy1 Connection

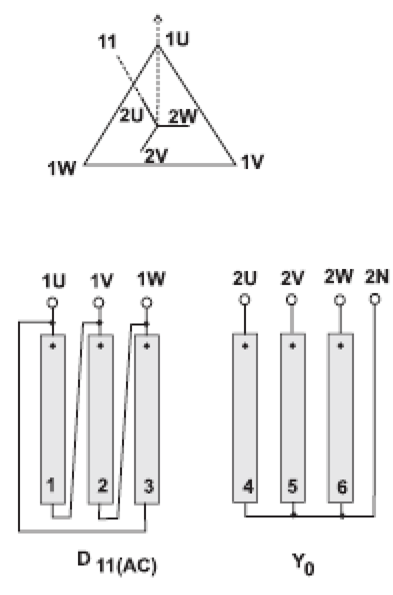


Figure 2.19 - Dyn11 Connection

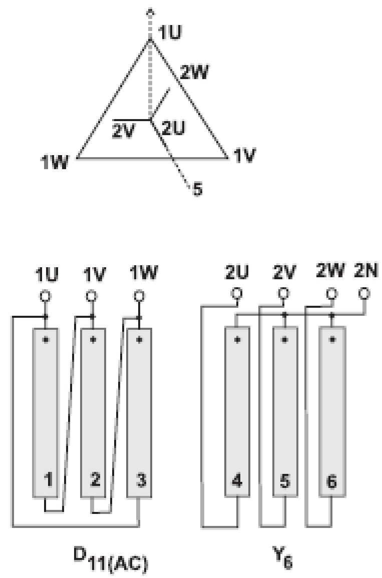


Figure 2.20 - Dyn5 Connection

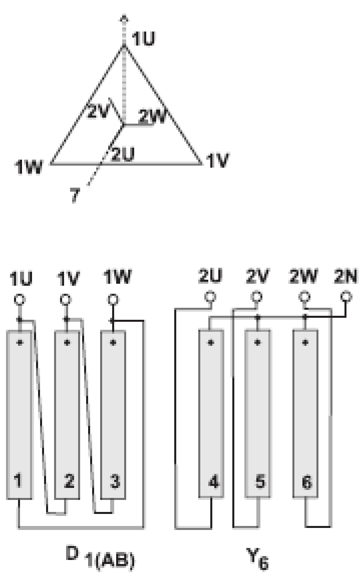


Figure 2.21 - Dyn7 Connection

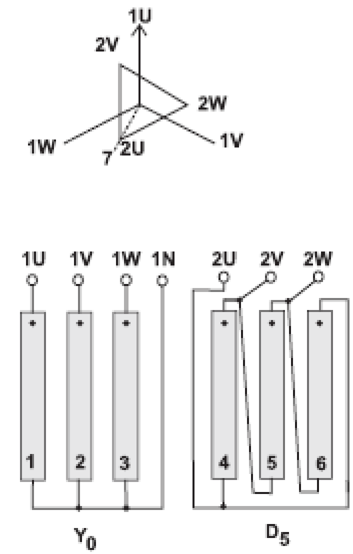


Figure 2.22 - Yd7 Connection

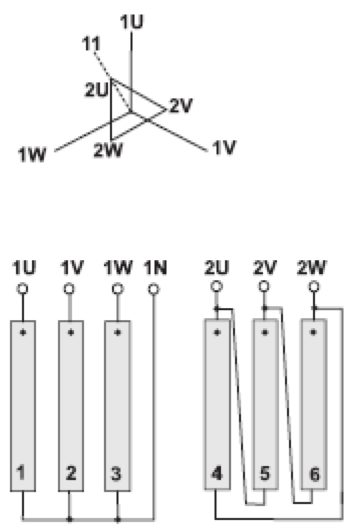


Figure 2.23 - Ynd11 connection

2.9 Power Transformers

2.9.1 Construction Details of Power Transformers

a. Transformer Core:

For core material, high-grade, grain oriented silicon steel strip is used. The core is so constructed that the actual silicon strip is held in a sturdy frame consisting of clamps and tie plates, which resists both mechanical force during hoisting the core-and-coil assembly and short circuits, keeping the silicon steel strip protected from such force.

Silicon steel strips are stacked in a circle-section. Each core leg is fitted with tie plates on its front and rear side, with resin-impregnated glass tape wound around the outer circumference. Sturdy clamps applied to front and rear side of the upper and lower yokes are bound together with glass tape.

In large-capacity Transformers, which are likely to invite increased leakage flux, nonmagnetic steel is used or slits are provided in steel members to reduce the width for preventing stray loss from increasing on metal parts used to clamp the core and for preventing local overheat.

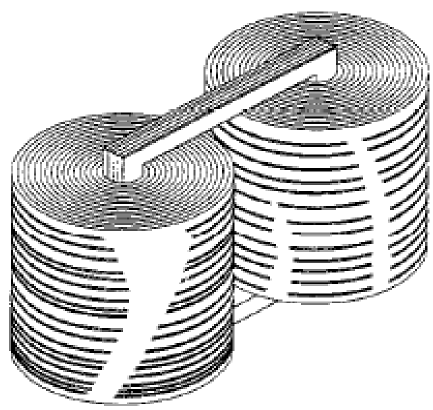


Figure 2.24 - Core form construction

There are two basic types of core assembly, core form and shell form. In the core form, the windings are wrapped around the core, and the only return path for the flux is through the centre of the core. Since the core is located entirely inside the windings, it adds a little to the structural integrity of the transformer's frame. Core construction is desirable when compactness is a major requirement. Figure 2.24 illustrates a core type configuration.

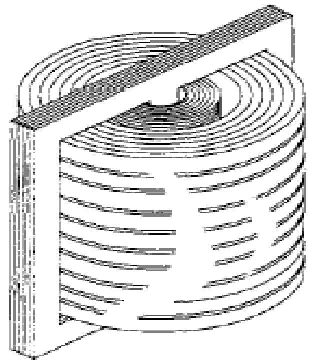


Figure 2.25 - Shell Form construction

Shell form transformers completely enclose the windings inside the core assembly. Shell construction is used for larger transformers, although some core-type units are built for medium and high capacity use. The core of a shell type transformer completely surrounds the windings, providing a return path for the flux lines both through the centre and around the outside of the windings (see figure 2.25). Shell construction is also more flexible, because it allows a wide choice of winding arrangements and coil groupings. The core can also act as a structural member, reducing the amount of external clamping and bracing required. This is especially important in larger application where large forces are created by the flux.

b. Tank

The tank is manufactured by forming and welding steel plate to be used as a container for holding the core and coil assembly together with insulating oil - The base and the shroud over which a cover is sometimes bolted. These parts are manufactured in steel plates assembled together via weld beads. The tank is provided internally with devices usually made of wood for fixing the magnetic circuit and the windings. The tank is designed to withstand the application of the internal overpressure specified, without permanent deformation.

c. Conservator

The tank is equipped with an expansion reservoir called conservator which allows for the expansion of the oil during operation. The conservator is designed to hold a total vacuum and may be equipped with a rubber membrane preventing direct contact between the oil and the air.

d. Transformer Oil:

Mineral oil is the most common fluid used in transformers. Oil plays a dual function in the transformer. The oil helps to draw the heat away from the core, keeping temperatures low and extending the life of the insulation. It also acts as a dielectric material, and intensifies the insulation strength between the windings. To keep the transformer operating properly, both of these qualities of oil must be maintained.

e. Bushing:

The leads from the primary and secondary windings must be safely brought through the tank to form a terminal connection point for the line and load connections. The bushing insulator is constructed to minimize the stresses at these points, and to provide a convenient connection point. The bushing is designed to insulate a conductor from a barrier, such as a transformer lid, and to safely conduct current from one side of the barrier to the other. Not only must the bushing insulate the live lead from the tank surfaces, but it must also preserve the integrity of the tank's seal and not allow any water, air, or other outside contaminants to enter the tank.

There are several types of bushing construction; they are usually distinguished by their voltage ratings, although the classifications do overlap:

1. Solid (high alumina) ceramic-(up to 5kV)
2. Porcelain-oil filled (5kV to 69kV)
3. Porcelain-compound (epoxy) filled (25 to 69kV)
4. Porcelain--synthetic resin bonded paper-filled (34.5 to 115kV)
5. Porcelain-oil-impregnated paper-filled (above 69kV, but especially above 275kv)

For outdoor applications, the distance over the outside surface of the bushing is increased by adding "petticoats" or "watersheds" to increase the creepage distance between the line terminal and the tank. Contaminants will collect on the surfaces of the bushing and form a conductive path. When this creepage distance is bridged by contaminants, the voltage will flashover between the tank and the conductor. This is the reason why bushings must be kept clean and free of contaminants.

Transformer bushings have traditionally been externally clad in porcelain because of its excellent electrical and mechanical qualities. Porcelain insulators are generally oil-filled beyond 35 kV to take advantage of the oil's high dielectric strength. There are a number of newer materials being used for bushings, including: fibreglass, epoxy, synthetic rubbers, Teflon, and silica compounds. These materials have been in use for a relatively short time, and the manufacturer's instructional literature should be consulted when working with these bushings.

f. Valves

The Transformers are provided with sealed valves, sealing joints, locking devices and position indicators.
The Transformers usually include:

1. Two isolating valves for the "Buchholz" relay.
2. One drainage and filtering valve located below the tank.
3. One isolating valve per radiator or per cooler.
4. One conservator drainage and filtering valve.
5. Two isolating valves for the protection relay.
6. One refilling valve for the on-load tap-changer.
7. One drain plug for the tap-changer compartment.

g. The Breather

The dehydrating breather is provided at the conservator of Transformers. The conservator governs the breathing action of the oil system conforming to the temperature change of the equipment, and the dehydrating breather removes the moisture and dust in the air inhaled and prevents the deterioration of the Transformer oil due to moisture absorption. The dehydrating breather uses silica - gel as the desiccating agent and is provided with an oil pot at the bottom to filter the inhaled air.

h. Tap Changer

Transformers are often required to operate under changing primary voltages, or to provide a number of different secondary voltages. Most transformers are equipped with a tap changer and any number of taps can be brought off from windings to accomplish this voltage change.

On Load tap changers are used to regulate the changing voltages found in large substations. As on load tap changers are required to open and close the circuit while it is hot, they incorporate a number of devices to minimize the switching time and the amount of energy (the arc) released. Some tap changers use vacuum bottle type breakers to interrupt the current flow, while others use a conventional main/arcing contact mechanism, much like that found in a circuit breaker. Other tap changers use resistor or reactor circuitry in the mechanism to limit the current flow at the time the switching occurs. Load tap changers can be either automatic or manual, and can be used to vary the voltage and current by as much as 2 or 3 percent, depending on application.

Most load tap changers are immersed in oil and are contained in a separate compartment from the primary and secondary windings. Because of the large amounts of energy (switching arcs) produced, the oil in the tap changing compartment deteriorates at a much faster rate than the oil in the main compartment.

i. Oil Level Indicators

These are float operated devices, with the float mechanism magnetically coupled through the tank wall to the dial indicator as shown in figure 2.26. As level increases, the float rotates a magnet inside the tank. Outside the tank, another magnet follows (rotates), which moves the pointer. The centre of the dial is normally marked with a temperature 25 °C (77 °F). High and low level points are also marked to follow level changes as the oil expands and contracts with temperature changes. The proper way to determine accurate oil level is to first look at the top oil temperature indicator. After determining the temperature, look at the level gauge. The pointer should be at a reasonable level corresponding to the top oil temperature. If the transformer is fully loaded, the top oil temperature will be high, and the level indicator should be near the high mark. If the transformer is de-energized and the top oil temperature is near 25 °C, the oil level pointer should be at or near 25 °C.

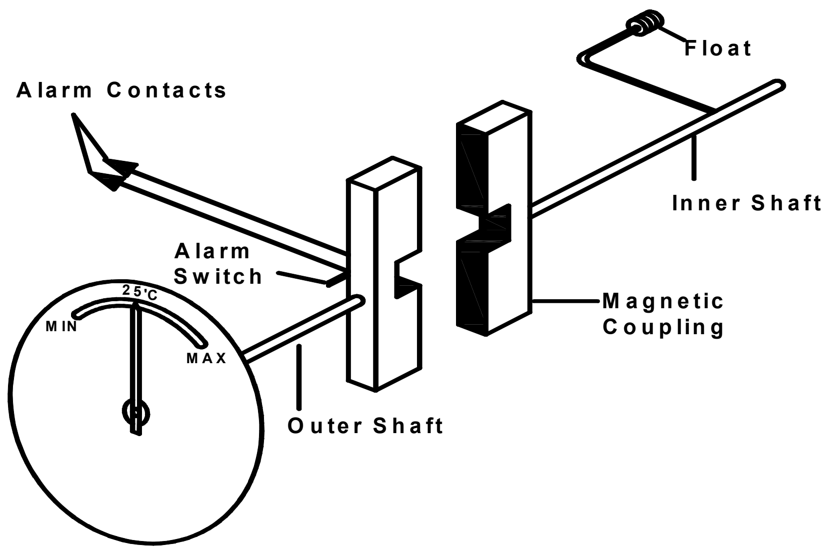


Figure 2.26 - Oil Level Indicator

j. Pressure Relief Devices

These devices are transformers last line of defence against excessive internal pressure. In case of fault or short circuit, the resultant arc instantly vaporises surrounding oil, causing a rapid build-up of gaseous pressure. Pressure relief devices operate within a few milliseconds to avoid a catastrophic rupture of transformer tank.

Pressure Relief devices are spring loaded valves that automatically reclose following a pressure release. A typical pressure relief relay is shown in figure 2.27. The springs are held in compression by the cover and press on a disc which seals an opening in tank top. If pressure in tank exceeds operating pressure, the disc moves upwards and relieves the pressure. As pressure decreases, the springs reclose the valve. After operating, this device leaves a brightly coloured rod exposed above the top. This rod is easily seen upon inspection, although it is not always visible from floor level. The rod may be reset by pressing on top until it is again recessed into the device. The switch must also be manually reset.

k. Sudden Pressure Relay

Internal arcing in oil filled power transformer can instantly vaporize surrounding oil, generating gas pressures that can cause catastrophic failure rupture, rupture the tank, and spread flaming oil over a large area. This can damage or destroy other test equipment in addition to the transformer and presents extreme hazards to workers. Figure 2.28 shows construction details of a typical sudden pressure relay. The relay is designed to detect a sudden pressure increase caused by arcing. It is set to operate before pressure relief device. The control circuit should de-energize the transformer and provide an alarm. The relay will ignore normal pressure changes such as oil-pump surges, temperature changes etc.

Modern sudden pressure relays consist of three bellows with silicone sealed inside. Changes in pressure in the transformer deflect the main sensing bellows. Silicone inside acts on two control bellows arranged like a balance beam, one on each side. One bellow senses pressure changes through small orifice. The opening is automatically changed by bimetallic strip to adjust for normal temperature changes of the coil. The orifice delays pressure changes in this bellow. The other bellow responds to immediate pressure changes and is affected much more quickly. Pressure difference tilts the balance beam and activates the switch. This type relay automatically resets when the two bellows again reach pressure equilibrium.

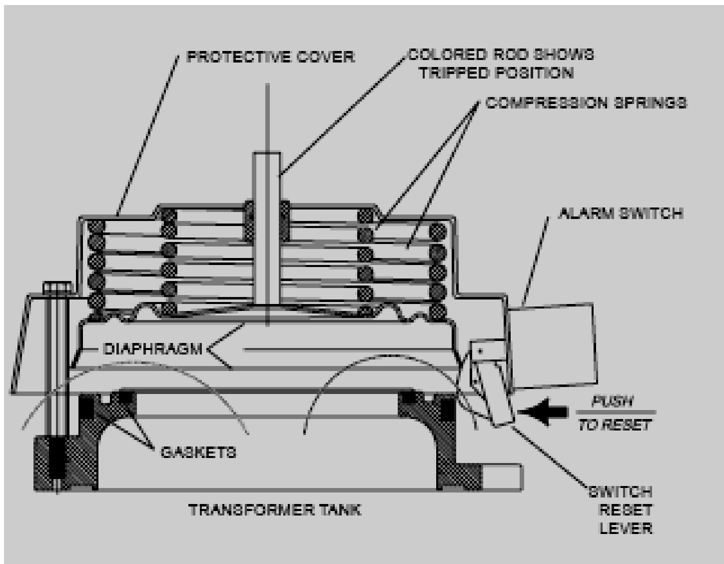


Figure 2.27 - Pressure Relief Device

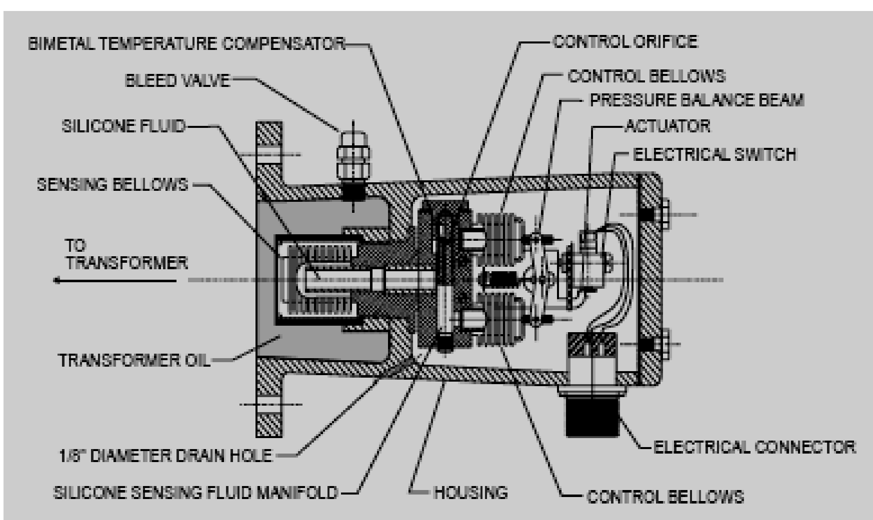


Figure 2.28 - Sudden Pressure relay

l. Buchholz Relay

The Buchholz relay has two oil-filled chambers with floats and relays arranged vertically one over the other as shown in figure 2.29. If high eddy currents, local overheating, or partial discharges occur within the tank, bubbles of resultant gas rise to the top of the tank. These rise through the pipe between the tank and the conservator. As gas bubbles migrate along the pipe, they enter the Buchholz relay and rise into the top chamber. As gas builds up inside the chamber, it displaces the oil, decreasing the level. The top float descends with oil level until it activates a switch which activates an alarm.

The bottom float and relay cannot be activated by additional gas build-up. This float is located slightly below the top of the pipe so that once the top chamber is filled, additional gas goes into the pipe and on up to the conservator. Typically, inspection windows are provided so that the amount of gas and relay operation may be viewed during testing. If the oil level falls low enough (conservator empty), switch contacts in the bottom chamber are activated by the bottom float. These contacts are typically connected to cause the transformer to trip.

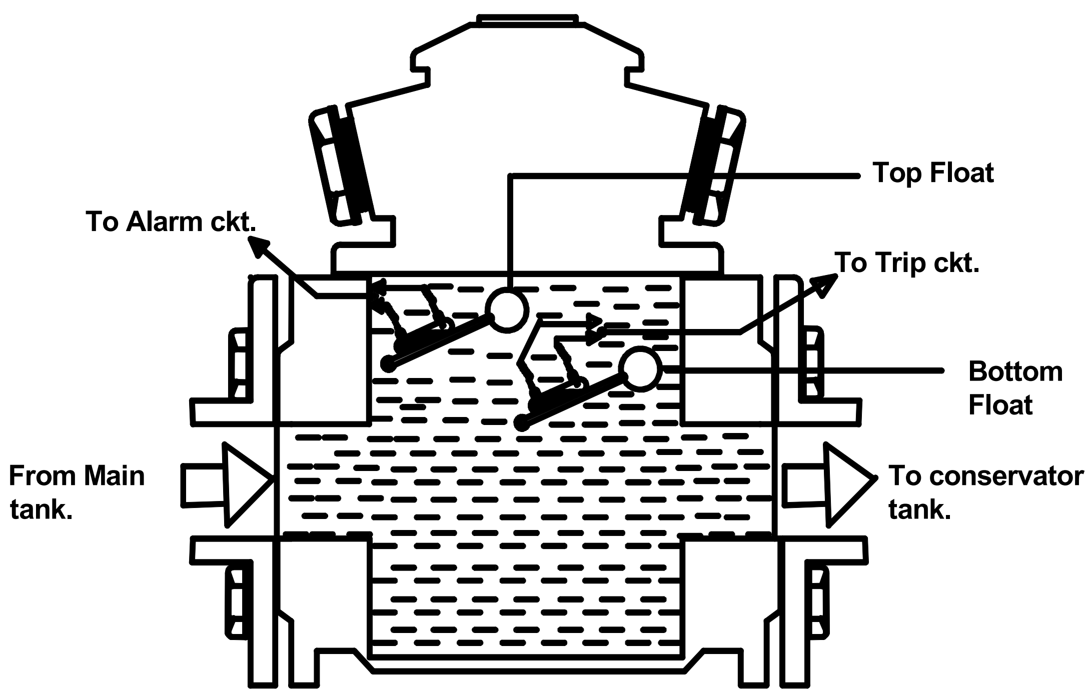


Figure 2.29 - Buchholz Relay

m. Oil Temperature Indicators

These are typically sealed spiral-bourdon-tube dial indicators with liquid-filled bulb sensors. The bulb is normally inside a thermometer well, which penetrates the tank wall into oil near the top of the tank. As oil temperature increases in the bulb, liquid expands, which expands the spiral tube. The tube is attached to a pointer that indicates temperature. These pointers may also have electrical contacts to trigger alarms and start cooling fans as temperature increases. An extra pointer, normally red, indicates maximum temperature since the last time the indicator was reset. This red pointer rises with the main pointer but will not decrease unless manually reset; thus, it always indicates the highest temperature reached since being set. Instruction manual of a specific transformer can be referred for details.

n. Winding Temperature Indicators

These devices are supposed to indicate hottest spot in the winding based on the manufacturer's heat run tests. At best, this device is only accurate at top nameplate rated load and that to only if it is not out of calibration. They are not what their name implies and can be misleading. They are only winding hottest-spot simulators and not very accurate. There is no temperature sensor imbedded in the winding hot spot. At best, they provide only a rough approximation of hot spot winding temperature and should not be relied on for accuracy. They can be used to turn on additional cooling or activate alarms as the top oil thermometers do.
Winding temperature thermometers work the same as the top oil thermometer, except that the bulb is in a separate thermometer well near the top of the tank. A wire-type heater coil is either inserted into or wrapped around the thermometer well which surrounds the temperature sensitive bulb. In some transformers, a current transformer (CT) is around one of the three winding leads and provides current directly to the heater coil in proportion to winding current. In other transformers, the CT supplies current to an auto-transformer that supplies current to the heater coil. The heater warms the bulb and the dial indicates a temperature, but it is not the true hottest-spot temperature. These devices are calibrated at the factory by changing taps either on the CT or on the autotransformer, or by adjusting the calibration resistors in the control cabinet. They normally cannot be field calibrated or tested, other than testing the thermometer. The calibration resistors can be adjusted in the field if the manufacturer provides calibration curves for the transformer.

o. Gaskets

Gaskets have several important jobs in sealing systems. A gasket must create a seal and hold it over a long period of time. It must be impervious and not contaminate the insulating fluid or gas above the fluid. It should be easily removed and replaced. It must be elastic enough to flow into imperfections on the sealing surfaces. It must withstand high and low temperatures and remain resilient enough to hold the seal even with joint movement from expansion, contraction, and vibration. It must be resilient enough to not take a "set" even though exposed for a long time to pressure applied with bolt torque and temperature changes. It must have sufficient strength to resist crushing under applied load and resist blow out under system pressure or vacuum. It must maintain its integrity while being handled or installed. If a gasket fails to meet any of these criteria, a leak will result. Gasket leaks result from improper torque, choosing the wrong type gasket material, or the wrong size gasket. Improper sealing surface preparation or the gasket taking a "set" (becoming hard and losing its resilience and elasticity) will also cause a leak. Usually, gaskets take a set as a result of temperature extremes and age.

2.9.2 Nameplate Details of Transformer:

The transformer nameplate contains most of the important information that will be needed in the field. The nameplate should never be removed from the transformer and should always be kept clean and legible. Although other information can be provided, industry standards require that the following information be displayed on the nameplate of all power transformers:

a. Serial number: The serial number is required any time the manufacturer must be contacted for information or parts. It should be recorded on all transformer inspections and tests.
b. Class. The class indicates the transformer's cooling requirements and increased load capability.
c. The kVA rating. The kVA rating, as opposed to the power output, is a true indication of the current carrying capacity of the transformer. kVA ratings for the various cooling classes should be displayed.
d. Voltage rating. The voltage rating should be given for the primary and secondary, and for all tap positions.
e. Temperature rise. The temperature rise is the allowable temperature change from ambient that the transformer can undergo without incurring damage.
f. Phasor diagrams. Phasor diagrams will be provided for both the primary and the secondary coils. Phasor diagrams indicate the order in which the three phases will reach their peak voltages, and also the angular displacement (rotation) between the primary and secondary.
g. Connection diagram. The connection diagram will indicate the connections of the various windings, and the winding connections necessary for the various tap voltages.
h. Percent impedance. The impedance percent is the vector sum of the transformer's resistance and reactance expressed in percent. It is the ratio of the voltage required to circulate rated current in the corresponding winding, to the rated voltage of that winding. With the secondary terminals shorted, a very small voltage is required on the primary to circulate rated current on the secondary. The impedance is defined by the ratio of the applied voltage to the rated voltage of the winding. If, with the secondary terminals shorted, 138 volts are required on the primary to produce rated current flow in the secondary, and if the primary is rated at 13,800 volts, then the impedance is 1 percent. The impedance affects the amount of current flowing through the transformer during short circuit or fault conditions.
i. Impulse level (BIL). The impulse level is the crest value of the impulse voltage the transformer is required to withstand without failure. The impulse level is designed to simulate a lightning strike or voltage surge condition. The impulse level is a withstand rating for extremely short duration surge voltages. Liquid-filled transformers have an inherently higher BIL rating than dry-type transformers of the same kVA rating.
j. Weight. The weight should be expressed for the various parts and the total. Knowledge of the weight is important when moving or untanking the transformer.
k. Insulating fluid. The type of insulating fluid is important when additional fluid must be added or when unserviceable fluid must be disposed of. Different insulating fluids should never be mixed. The number of gallons, both for the main tank, and for the various compartments should also be noted.

l. Instruction reference. This reference will indicate the manufacturer's publication number for the transformer instruction manual.

2.9.3 Testing and Maintenance of Power Transformers

Of all the equipment involved in a facility's electrical distribution system, the transformer is probably the most neglected. A transformer has no moving parts. Consequently it is often considered maintenance-free. Because the transformer does not trip or blow when oven-stressed (except under extreme conditions), it is frequently overloaded and allowed to operate well beyond its capacity. Because the transformer is usually the fast piece of equipment on the owner's side of the utility feed, it usually operates at much higher voltages than elsewhere in the facility and personnel are not anxious to work on or around it. The fact that a transformer has continued to operate without the benefit of a preventive maintenance/testing program says much about the ruggedness of its construction. However, a transformer's ruggedness is no excuse not to perform the necessary testing and maintenance.

Any piece of electrical equipment begins to deteriorate as soon as it is installed. The determining factor in the service life of a transformer is the life of its insulation system. A program of scheduled maintenance and testing cannot only extend the life of the transformer, but can also provide indications of when a transformer is near the end of its service life, thus allowing for provisions to be made before an unplanned failure occurs. Also, a transformer checked before a failure actually occurs can usually be reconditioned or refurbished more easily than if it had failed while on line. Benefits to a comprehensive maintenance and testing program are as follows:

1. Safety is increased because deficiencies are noted and corrected before they present a hazard.
2. Equipment efficiency is increased because conditions that ultimately increase the transformer's losses can be corrected.
3. If a problem occurs, it can usually be rectified more quickly because service records and equipment information are centrally located and readily available.
4. As the power requirements of a facility grow, any overloaded or unbalanced circuits will be detected more quickly, allowing for adjustments to be made before any damage is incurred.
5. lf impending failures are discovered, the repair work can be scheduled during off-peak hours, reducing the amount of inconvenience and expense.

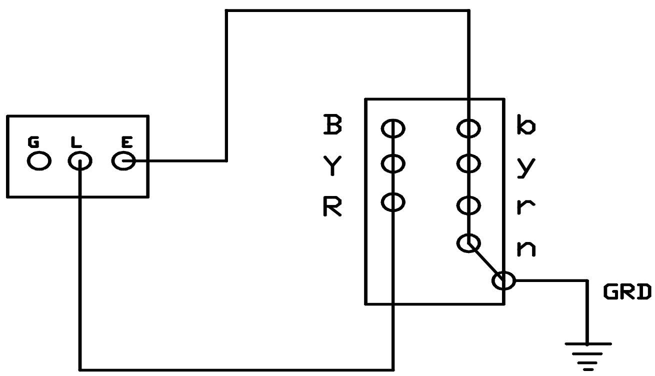
Transformer testing falls into three broad categories:

1. Factory testing when the transformer is new or has been refurbished
2. Acceptance testing upon delivery
3. Field testing for maintenance and diagnostic purposes.

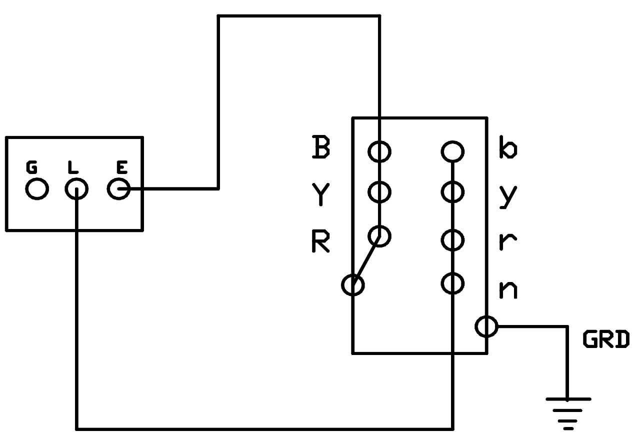
The frequency is usually dependent on the transformer's operating environment. If routine inspections indicate that cleaning is required, periodic tests should be carried out during shutdown for the cleaning operation, after the transformer is thoroughly cleaned. The nominal period between scheduled tests is one year but this may be longer or shorter, depending on the observed accumulation of contamination on the cooling vents. Acceptance and maintenance tests carried out on Power transformers are as follows:

a. IR testing.

The IR of each winding should be measured using a megaohmmeter. The transformer should be de-energized and electrically isolated with all terminals of each winding shorted together. The windings not being tested should be grounded. The megaohmmeter should be applied between each winding and ground (high voltage to ground and low voltage to ground) and between each set of windings (high voltage to low voltage). The megaohm values along with the description of the instrument, voltage level, humidity, and temperature should be recorded for future reference.

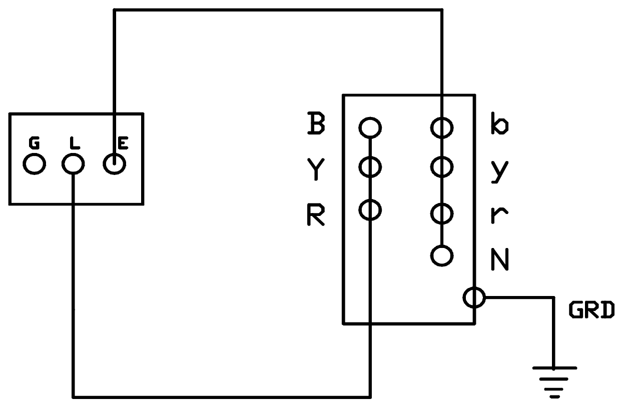


(a) High Winding to Low Winding and Ground



(b) Low Winding to High Winding and Ground

Figure 2.31 IR Testing of Transformer



(c) High Winding to Low Winding

Figure 2.31 IR Testing of Transformer

The minimum mega ohm value for a winding should be 200 times the rated voltage of the winding divided by 1000. For example, a winding rated at 13.2kV would have a minimum acceptable value of 2640 megaohms ([13,200V x 200] / 1000). If previously recorded readings taken under similar conditions are more than 50% higher, you should have the transformer thoroughly inspected, with acceptance tests performed before reenergizing.

b. Turns ratio testing

The transformer turn ratio is the number of turns in the high voltage winding divided by the number of turns in the low voltage winding. This ratio is also equal to the rated phase voltage of the high voltage winding being measured divided by the rated phase voltage of the low voltage winding being measured. Transformer turns ratio measurements are best made with specialized instruments that include detailed connection and operating instructions. The measured turns ratio should be within 0.5% of the calculated turns ratio. Ratios outside this limit may be the result of winding damage, which has shorted or opened some winding turns.

c. Dissipation Factor (Tan Delta) Test

Tan Delta, also called Loss Angle or Dissipation Factor testing, is a diagnostic method of testing to determine the quality of transformer insulation. Any time two conductors are at different potentials, there is a capacitance between them. There is a capacitance between the individual windings, and between each winding and the tank in a transformer. The oil and cellulose insulation that separate the windings from each other and from the tank act as dielectric materials when an alternating current is applied. Uncontaminated oil and winding insulation are excellent dielectric materials and are expected to perform as a capacitor.

In a perfect capacitor, the voltage and current are phase shifted 90 degrees and the current through the insulation is capacitive. If there are impurities in the insulation, the resistance of the insulation decreases, resulting in an increase in resistive current through the insulation. It is no longer a perfect capacitor. The current and voltage will no longer be shifted 90 degrees. It will be something less than 90 degrees. The extent to which the phase shift is less than 90 degrees is indicative of the level of insulation contamination, hence quality/reliability. This "Loss Angle" is measured and analyzed. Figure 2.32 shows a representation of "loss angle". The tangent of the angle is measured. This indicates the level of resistance in the insulation. By measuring I_R/I_C, we can determine the quality of the insulation. In an excellent insulator, the angle would be nearly zero. An increasing angle indicates an increase in the resistive current through the insulation, meaning contamination. The greater the angle, the worse the insulation.

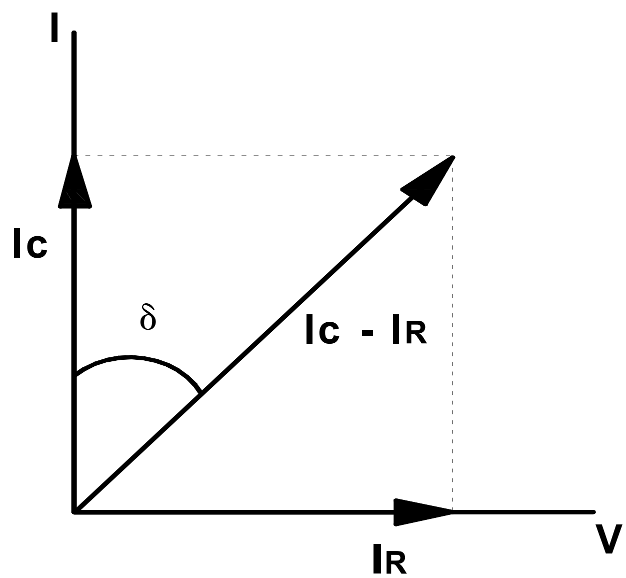


Figure 2.32 Representation of Loss Angle

Dissipation factor tests are performed on transformers, bushings and even on insulating fluid (a special can is used to provide a controlled environment). Specialized instruments are used for this purpose. Bushing dissipation factor measurements are especially useful, and most large bushings have a special voltage tap that provides a standard reference point between the conductor and ground. Bushings without this tap require a "hot collar" test in which the potential is applied to the outer surface of the bushing material and leakage currents are measured through the ceramic or epoxy of the bushings material.

d. Winding Resistance Measurement.

Accurate measurement of the resistance between winding terminals can give you an indication of winding damage, which can cause changes to some or all of the winding conductors. Such damage might result from a transient winding fault that cleared; localized overheating that opened some of the strands of a multistrand winding conductor; or short circuiting of some of the winding conductors. Sometimes, conductor strands will burn open like a fuse, decreasing the conductor cross section and resulting in an increase in resistance. Occasionally, there may be turn-to-turn shorts causing a current bypass in part of the winding; this usually results in a decrease of resistance.

To conduct this test, the transformer should be de-energized and disconnected from all external circuit connections. A micro-ohmmeter or winding resistance meter with suitable range (as per requirement) is used. Winding Resistance values may be compared with original test data corrected for temperature variations between the factory values and the field measurement or they may be compared with prior maintenance measurements. On any single test, the measured values for each phase on a 3-phase transformer should be within 5% of the other phases.

Results are compared to other phases in wye connected transformers or between pairs of terminals on a delta-connected winding to determine if a resistance is too high. Resistances can also be compared to the original factory measurements. Agreement within 5% for any of the above comparisons is considered satisfactory. You may have to convert resistance measurements to the reference temperature used at the factory (usually 75 °C) to compare your resistance measurements to the factory results. To do this use the following formula:

$$Rs = Rm \frac{Ts + Tk}{Tm + Tk}$$

Where,
Rs = Resistance at the factory reference temperature (found in the transformer manual)
Rm = Resistance you actually measured
Ts = Factory reference temperature (usually 75 °C)
Tm = Temperature at which you took the measurements
Tk = a constant for the particular metal the winding is made from 234.5 °C for copper 225 °C for aluminium

e. Magnetic Balance and Magnetizing Current measurement

The magnetization current is the amperage drawn by each primary coil, with a voltage applied to the input terminals of the primary and the secondary or output terminals open-circuited. For this test, you should disconnect the transformer from all external circuit connections. With most transformers, the reduced voltage applied to the primary winding coils may be from a single-phase 230V supply. The voltage should be applied to each phase in succession, with the applied voltage and current measured and recorded. Same process should be repeated for secondary winding.

If there is a defect in the winding, or in the magnetic circuit that is circulating a fault current, there will be a noticeable increase in the excitation current. There is normally a difference between the excitation current in the primary coil on the center leg compared to that in the primary coils on the other legs; thus, it's preferable to have established benchmark readings for comparison. Variation in current versus prior readings should not exceed 5%. On any single test, the current and voltage readings of the primary windings for each of the phases should be within 15% of each other.

f. Vector Group test:

This test is conducted to verify the vector group of the transformer. To understand the basic procedure of performing vector group test, let us undertake the vector group testing of Dyn11 transformer. Vector group representation of Dyn11 transformer is shown in figure 2.33(a). Prefix ‘1’ in the diagram represents primary side and prefix ‘2’ represents secondary side.

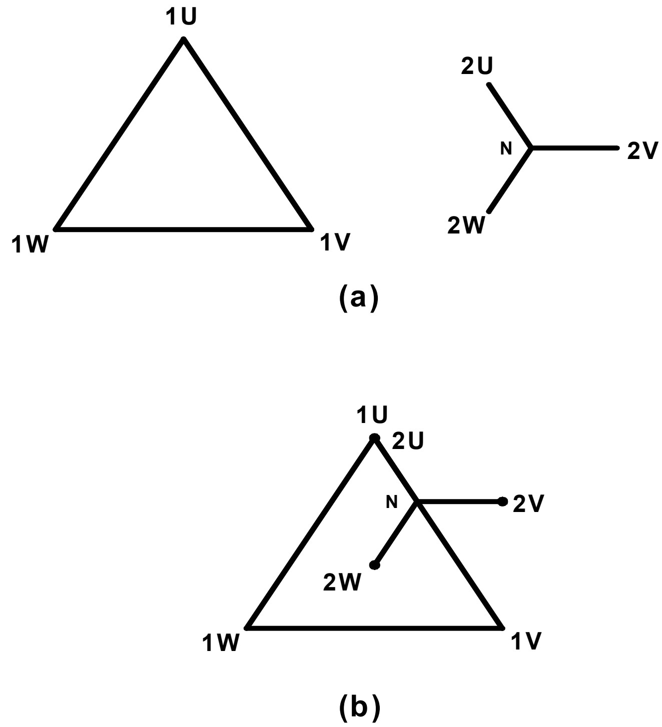


Figure 2.33 Vector Group Test

For the purpose of conducting vector group test, terminals 1U and 2U should be shorted. Vector representation after shorting these terminals is shown in figure 2.33(b). In accordance with this representation it is clear that the following conditions should hold true for the transformer vector group to be Dyn11:

1. **V** (1U,N) + **V**(1V, N) = **V** (1U,1V)
2. **V**(2W,1V) = **V**(2V,1V)
3. **V**(1W,2V) > **V**(1W,2W)

g. Dielectric Strength of Oil

This test measures the voltage at which the oil electrically breaks down. The test gives a good indication of the amount of contaminants (water and oxidation particles) in the oil. The acceptable minimum breakdown voltage is 30 kV for transformers 287.5 kV and above, and 25 kV for high voltage transformers rated under 287.5 kV. Do not base any decision on one test result, or on one type of test; instead, look at all the information over several DGAs and establish trends before making any decision.

h. Dissolved Gas Analysis of Transformer Oil

The primary mechanisms for the breakdown of insulating fluids are heat and contamination. The best way to prevent insulating fluid deterioration is to control overloading (and the resulting temperature increase), and to prevent tank leaks. Careful inspection and documentation of the temperature and pressures level of the tank can detect these problems before they cause damage to the fluid. However, a regular sampling and testing routine is an effective tool for detecting the onset of problems before any damage is incurred. Detection of certain gases in an oil filled transformer is frequently the first indication of a malfunction. Dissolved gas analysis is an effective diagnostic tool for determining the problem in the transformer's operation. Gases are formed in the oil due to the following thermal and electrical, stresses:

1. **Overheating -** Even though the insulation will not char or ignite, temperatures as low as 140 "C will begin to decompose the cellulose and produce carbon dioxide and carbon monoxide. When hot spot temperatures (which can be as high as 400 degree C) occur, portions of the cellulose are actually destroyed (by pyrolysis), and much larger amounts of carbon monoxide are formed.

2. **Corona and sparking**. With voltages greater than 10 kV, sharp edges or bends in the conductors will cause high stress areas, and allow for localized low energy discharges. Corona typically produces large amounts of free hydrogen, and is often difficult to differentiate from water contamination and the resulting rusting and oxidation. When the energy levels are high enough to create a minor spark, quantities of methane, ethane and ethylene will be produced. Sparks are usually defined as discharges with duration of under one microsecond.

3. **Arcing**. Arcing is a prolonged high energy discharge, and produces a bright flame. It also produces a characteristic gas (acetylene), which makes it the easiest fault to identify. Acetylene will occur in a transformer's oil only if there is an arc.

Other conditions that will cause gases to form in the transformer's oil include tank leaks, oil contamination, sludging and residual contaminants from the manufacturing and shipping processes. In most cases, the determinations that can be made are "educated guesses," but they do at least provide a direction and starting point for further investigation. Also, many of the gases can be detected long before the transformer's condition deteriorates to the point of a fault or unacceptable test results.

In general, combinations of elements that occur naturally in pairs, such as hydrogen (H2), oxygen (O2), and nitrogen (N2) reflect the physical condition of the transformer. Higher levels of these gases can indicate the presence of water, rust, leaky bushings, or poor seals. Carbon oxides such as CO and CO2 reflect the demand on the transformer. High levels of each can show whether the transformer is experiencing minor overload conditions, or if it, is actually overheating. The concentrations of hydrocarbon gases, such as Acetylene, ethylene, methane and ethane indicate the integrity of the transformer's internal functions. Acetylene will be produced only by a high energy arc, and the relative concentrations of the others can indicate cellulose breakdown, corona discharge or other faults.

Hydrogen and methane begin to form in small amounts around 150 °C. At about 250°C, production of ethane (C_2H_6) starts. At about 350 °C, production of ethylene (C_2H_4) begins. Acetylene (C_2H_2) starts between 500 °C and 700 °C. In the past, the presence of only trace amounts of acetylene (C_2H_2) was considered to indicate a temperature of at least 700 °C had occurred; however, recent discoveries have led to the conclusion that a thermal fault (hot spot) of 500 °C can produce trace amounts (a few ppm). Larger amounts of acetylene can only be produced above 700 °C by internal arcing. Notice that between 200 °C and 300 °C, the production of methane exceeds hydrogen. Starting about 275 °C and on up, the production of ethane exceeds methane. At about 450°C, hydrogen production exceeds all others until about 750 °C to 800 °C; then more acetylene is produced. Table 2.1 shows the various gases that can be detected, their limits, and the interpretations that can be made from their various concentrations.

Condition 1: Total dissolved combustible gas (TDCG) below this level indicates the transformer is operating satisfactorily. Any individual combustible gas exceeding specified levels in table 2.2 should have additional investigation.

Condition 2: TDCG within this range indicates greater than normal combustible gas level. Any individual combustible gas exceeding specified levels in table 2.2 should have additional investigation. A fault may be present. Take DGA samples at least often enough to calculate the amount of gas generation per day for each gas.

Condition 3: TDCG within this range indicates a high level of decomposition of cellulose insulation and/or oil. Any individual combustible gas exceeding specified levels in table 2.2 should have additional investigation. A fault or faults are probably present. Take DGA samples at least often enough to calculate the amount of gas generation per day for each gas.

Condition 4: TDCG within this range indicates excessive decomposition of cellulose insulation and/or oil. Continued operation could result in failure of the transformer.

Key Gases	Possible Faults	Possible Findings
H_2 possible trace of CH_2 and C_2H_2 Possible CO.	Partial discharges (corona)	Weakened insulation from aging and electrical stress.
H_2, CH_4, (some CO if discharges involve paper insulation). Possible trace amount of C2H2.	Low energy discharges (sparking). (May be static discharges)	Pinhole punctures in paper insulation with carbon and carbon tracking. Possible carbon particles in oil. Possible loose shield, poor grounding of metal objects.
H_2, CH_4, C_2H_6, C_2H_4 and the key gas for arcing C_2H_2 will be present perhaps in large amounts. If C_2H_2 is being generated, arcing is still going on, CO will be present if paper is being heated.	High energy discharges (arcing).	Metal fusion, (Poor contacts in tap changer or lead connections). Weakened insulation, from aging and electrical stress. Carbonized oil, Paper destruction if it is in the arc path or overheated.
H_2, CO_2	Thermal fault less than 300°C in an area close to paper insulation (paper is being heated).	Discoloration of paper insulation. Over loading and/or cooling problem. Bad connection in leads or tap changer. Stray current path and/or stray magnetic flux.
H_2, CO, CH_4, C_2H_6, C_2H_4	Thermal fault between 300°C and 700°C.	Paper insulation destroyed. Oil heavily carbonized.
All the above gases and acetylene in large amounts.	High energy electrical arcing 700° C and above.	Same as above with metal discoloration. Arcing may have caused a thermal fault.

Table 2.1

Status	H_2	CH_4	C_2H_2	C_2H_4	C_2H_6	CO	CO_2	TDCG
Condition 1	100	120	35	50	65	350	2,500	720
Condition 2	101-700	121-400	36-50	51-100	66-100	351-570	2500-4000	721-1920
Condition 3	701-1800	401-1000	51-80	101-200	101-150	571-1400	4001-10000	1921-4630
Condition 4	>1800	>1000	>80	>200	>150	>1400	>10000	>4630

Table 2.2

2.9.4 Maintenance of Transformer Auxiliary Equipment

a. Bushings

Bushings require little maintenance other than an occasional cleaning and checking the connections. Bushings should be inspected for cracks and chips, and if found, should be touched-up with Glyptal paint or a similar type compound. Because bushings are often called on to support a potion of the line cable's weight, it is important to verify that any cracks have not influenced the mechanical strength of the bushing assembly.

There is no "perfect insulator" as a small amount of leakage current always exists. This current "leaks" through and along the bushing surface from the high-voltage conductor to ground. If the bushing is damaged or heavily contaminated, leakage current becomes excessive, and visible evidence may appear as carbon tracking (treeing) on the bushing surface. Flashovers may occur if the bushings are not cleaned periodically.
Look carefully for oil leaks. Check the bushing oil level by viewing the oil-sight glass or the oil level gauge. When the bushing has a gauge with a pointer, look carefully, because the oil level should vary a little with temperature changes. If the pointer never changes, even with wide ambient temperature and load changes, the gauge should be checked at the next outage. A stuck gauge pointer coupled with a small oil leak can cause explosive failure of a bushing, damaging the transformer and other switchyard equipment. A costly extended outage is the result.

If the oil level is low and there is no visible external leak, there may be an internal leak around the lower seal into the transformer tank. If possible, re-fill the bushing with the same oil and carefully monitor the level and the volume it takes to fill the bushing to the proper level.

b. Buchholz Relay

Functionally test the Buchholz relay by pumping a small amount of air into the top chamber with a squeeze bulb hand pump. Watch the float operation through the window. Check to make sure the correct alarm point has been activated. Open the bleed valve and vent air from the chamber. The bottom float and switching cannot be tested with air pressure. On some relays, a rod is provided so that you can test both bottom and top sections by pushing the floats down until the trip points are activated. If possible, verify that the breaker will trip with this operation.

c. Pressure Relief Devices

A mechanical pressure relief device cannot be tested without removing it from the tank. Since removal is impractical, it should be inspected regularly to ensure there are no cracks in the diaphragm and that the diaphragm/spring mechanism is free to operate. The operation of any relay contact and the associated control wiring should also be checked periodically.

d. Sudden Pressure Relay

The sudden pressure relay is usually mounted in the gas space above the oil level, and it is important to ensure that oil does not enter the unit. The operation of the relay is verified by checking that the orifice remains open, and that the bellows is free to move. The control wiring and the contact operation should also be verified.

e. Oil Level Indicators

To check the level indicator, you can remove the outside mechanism for testing without lowering transformer oil. After removing the gauge, hold a magnet on the back of the dial and rotate the magnet; the dial indicator should also rotate. If it fails to respond or if it drags or sticks, replace it. As mentioned above, defective units can be sent to the factory for repair.

There may also be electrical switches for alarms and possibly tripping off the transformer on falling tank level. These should be checked with an ohmmeter for proper operation. The alarm/tripping circuits should also be tested to see if the correct annunciator points and relays respond. See the transformer instruction book for information on your specific indicator.

CHAPTER – 3

CIRCUIT BREAKERS

3.1 Introduction

To effectively, efficiently, and economically deliver energy from the source to the end user, a device is needed that is capable of initiating and interrupting the flow of the current in a power system for normal energizing and de-energizing actions, protecting the system from faults and other disturbances, and for restoring the system following major events. High voltage circuit breakers are the primary means for such switching actions. Circuit breakers are mechanical switching devices capable of making, carrying, and breaking currents under normal circuit conditions and also making, carrying for a specified time, and breaking currents under specified abnormal conditions. Thus, a detailed understanding of the circuit breaker fundamentals and system/equipment impacts is needed to ensure the proper specification and operation of the device. This Chapter addresses the theory and application of high voltage circuit breakers. Important circuit breaker fundamentals are discussed that are necessary for the understanding of the function of circuit breakers, their impacts on the power system, and the needed capabilities of the circuit breakers to withstand the stresses of the power system. In breakers a mechanism operates one or more pairs of contacts to make or break the circuit. The mechanism is powered electromagnetically, pneumatically, or hydraulically. The contacts are located in a part termed the interrupter. When the contacts are parted, opening the metallic conductive circuit, an electric arc is created between the contacts. This arc is a high-temperature ionized gas with an electrical conductivity comparable to graphite. Thus the current continues to flow through the arc. The function of the interrupter is to extinguish the arc, completing circuit-breaking action. High-voltage breakers are broadly classified by the medium used to extinguish the arc.

1. Oil Circuit Breakers
2. Vacuum Circuit Breakers
3. Sulphur Hexafluoride (SF6) Circuit breakers
4. Air Break Circuit Breakers
5. Air Blast Circuit Breakers

3.2 Oil Circuit Breakers

The oil in OCB's serves two purposes. It insulates between the phases and between the phases and the ground, and it provides the medium for the extinguishing of the arc. When electric arc is drawn under oil, the arc vaporizes the oil and creates a large bubble that surrounds the arc. The gas inside the bubble is around 80% hydrogen, which impairs ionization. The decomposition of oil into gas requires energy that comes from the heat generated by the arc. The oil surrounding the bubble conducts the heat away from the arc and thus also contributes to deionization of the arc. Main disadvantage of the oil circuit breakers is the flammability of the oil, and the maintenance necessary to keep the oil in good condition (i.e. changing and purifying the oil).

3.2.1 Bulk Oil Circuit Breakers

Bulk oil circuit breakers are enclosed in metal-grounded weatherproof tanks that are referred to as dead tanks. The original design of bulk OCB’s was very simple and inexpensive. The arc was drawn directly inside of the container tank without any additional arc extinguishing but the one provided by the gas bubble surrounding the arc. Plain break breakers were superseded by arc controlled oil breakers. The arc controlled oil breakers have an arc control device surrounding the breaker contacts. The purpose of the arc control devices is to improve operating capacity, speed up the extinction of arc, and decrease pressure on the tank. The arc control devices can be classified into two groups: cross-blast and axial blast interrupters.

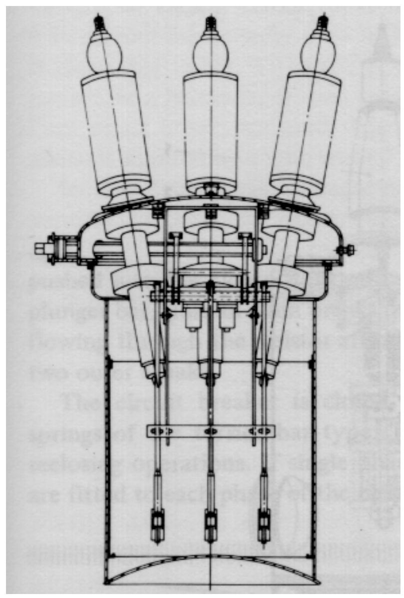


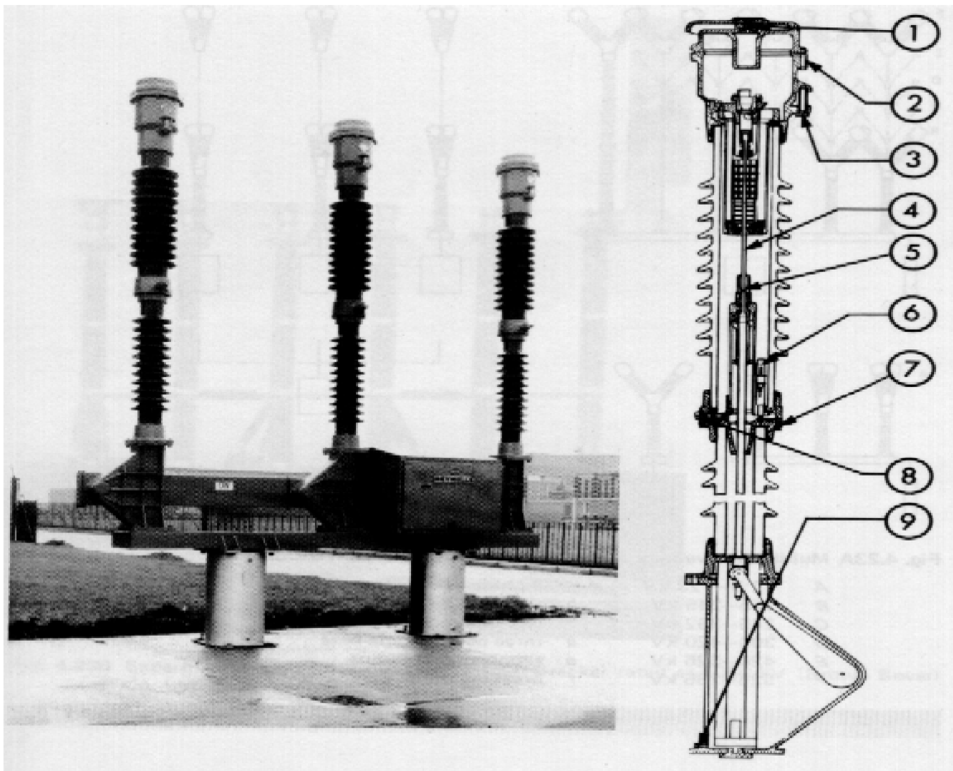
Figure 3.1 - Cross Sectional View of Dead Tank Oil Circuit Breaker

In cross blast interrupters, the arc is drawn in front of several lateral vents. The gas formed by the arc causes high pressure inside the arc control device. The arc is forced to bow into the lateral vents in the pot, which increases the length of the arc and shortens the interruption time. The axial blast interrupters use similar principle as the cross blast interrupters. However, the axial design has a better dispersion of the gas from the interrupter.

Figure 3.1 illustrates a typical 69 kV breaker of 2500 MVA breaking capacity. All three phases are installed in the same tank. The tank is made of steel and is grounded. This type of breaker arrangement is called the dead tank construction. The moving contact of each phase of the circuit breaker is mounted on a lift rod of insulating material. There are two breaks per phase during the breaker opening. The arc control pots are fitted over the fixed contacts. Resistors parallel to the breaker contacts may be installed alongside the arc control pots. It is customary and convenient for this type of breakers to mount current transformers in the breaker bushings.

3.2.2 Minimum Oil Circuit Breakers

In the bulk oil breakers, the oil serves as both arcs extinguishing medium and main insulation. The minimum oil breakers were developed to reduce the oil volume only to amount needed for extinguishing of the arc – about 10% of the bulk- oil amount. A typical MOCB and its sectional view are shown in figure 3.2.



(a) **(b)**

Figure 3.2 Minimum Oil Circuit Breakers
(a) Three phase circuit breaker
(b) Cross-section through a single phase

1. Vent Valve
2. Terminal Pad
3. Oil Level Indicator
4. Moving Contact
5. Lower Fixed Contact
6. Separating Piston
7. Terminal Pad
8. Upper Drain Valve
9. Lower Drain Valve

The arc control for the minimum oil breakers is based on the same principle as the arc control devices of the bulk oil breakers. To improve breaker performance, oil is injected into the arc.

The interrupter containers of the minimum oil breakers are made of insulating material and are insulated from the ground. This is usually referred to as live tank construction. For high voltages (above 132 kV), the interrupters are arranged in series. It is essential to ensure that each interrupter carries its share of the duty. Care must be taken that all breaks occur simultaneously, and that the restriking voltage is divided equally across the breaks during the interrupting process. The natural voltage division depends on stray capacitances between the contacts and to the ground, and therefore is in very uneven. This is corrected by connecting capacitances or resistors in parallel with the interrupting heads.

3.3 Vacuum Circuit Breaker

When two current carrying contacts are separated in a vacuum module, an arc is drawn between them. Intense hot spots or sparks are created at the instant of contact separation from which metal vapour shoot off, constituting plasma. The amount of vapour in the plasma is proportional to the rate of vapour emission from the electrodes and hence to the arc current. With alternating current arc, the current decreases during a portion of wave and tends to zero. Thereby the rate of vapour emission tends to zero and the amount of plasma tends to zero. Soon after natural current zero, the remaining metal vapour condenses and the dielectric strength builds up rapidly, and re-striking of arc is prevented. Let us take example of an ABB make Indoor Vacuum circuit breaker shown in figure 3.3 for detailed understanding of its construction and operation.

Due to the extremely low static interrupter chamber pressure of 10-4 to 10-8 mbar, only a relatively small contact gap is required to achieve a high dielectric strength. The vacuum arc is extinguished on one of the first natural current zeros. Due to the small contact gap ,high conductivity of the metal vapour plasma, and short arcing time, the associated arc energy is extremely low, which has advantageous effects on the life of the contacts and thus on that of the vacuum interrupters.

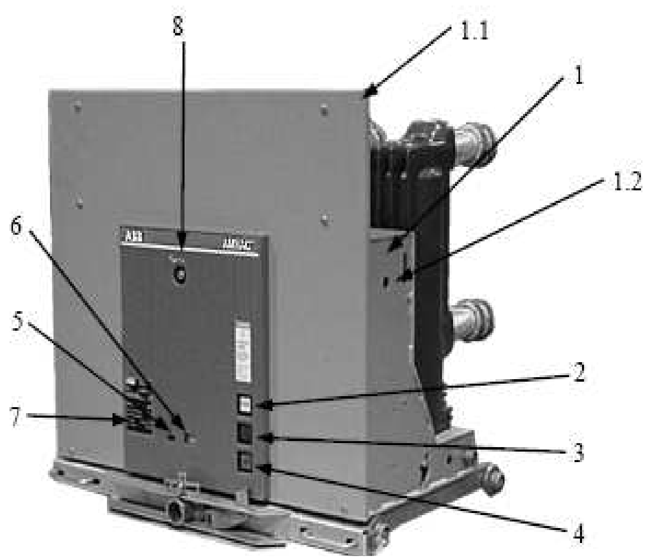


Figure 3.3 - Basic VCB Components

1. Breaker Enclosure
1.1. Front Plate
1.2. Slot for handling both sides
2. “Ready” Indicator
3. CLOSE push-button.
4. OPEN push-button
5. Mechanical operating cycle-counter
6. Mechanical CLOSE/OPEN Indicator.
7. Rating Plate
8. Socket for Emergency Manual Tripping.

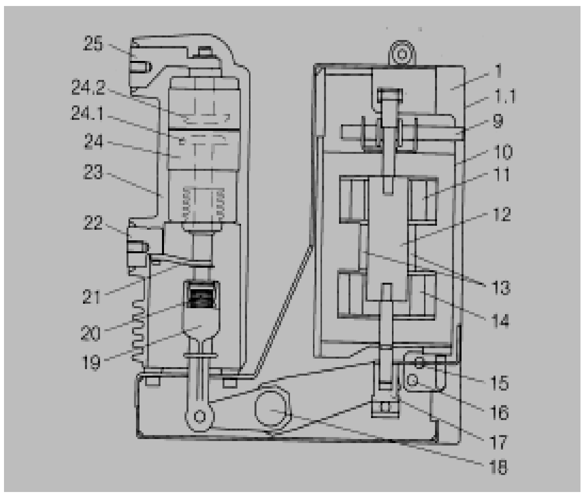


Figure 3.4 Sectional view of an indoor Vacuum circuit breaker

1. Circuit breaker enclosure
1.1. Front panel, removable
9. Emergency manual opening mechanism
10. Magnetic actuator
11. OPEN coil
12. Magnet armature
13. Permanent magnets
14. CLOSE coil
15. Sensor for “Circuit-breaker open” signal
16. Sensor for “Circuit-breaker closed” signal
17. Stroke adjuster
18. Lever shaft
19. Insulated link rod
20. Contact force spring
21. Flexible connector
22. Lower breaker terminal
23. Cast insulation
24. Vacuum interrupter
24.1. Moving Contact
24.2. Fixed Contact
25. Upper breaker terminal

The encapsulated poles are mounted on the rear flat section of the circuit breaker enclosure (1). The live parts of the circuit breaker poles are enclosed in cast resin and protected from impacts and other external influences. With the circuit breaker closed the current path for each pole leads from the upper circuit breaker terminal (25) to the fixed contact (24.2) in the vacuum interrupter (24), then via the moving contact (24.1) and the flexible connector (21) to the lower circuit breaker terminal (22). The change of contact state is delivered by means of the insulated link rod (19) with internal contact force springs (20).

3.4 Sulphur Hexafluoride Circuit Breaker

Sulphur hexafluoride (SF_6) is an inert, heavy gas having good dielectric and arc extinguishing properties. The dielectric strength of the gas increases with pressure and is more than that of dielectric strength of oil at 3 kg/cm^2. SF_6 is now being widely used in electrical equipment like high voltage metal enclosed cables; high voltage metal clad switchgear, capacitors, circuit breakers, current transformers, bushings, etc. The gas is liquefied at certain low temperature, liquefaction temperature increases with pressure. Sulphur hexafluoride gas is prepared by burning coarsely crushed roll sulphur in the fluorine gas, in a steel box, provided with staggered horizontal shelves, each bearing about 4 kg of sulphur. The steel box is made gas tight. The gas thus obtained contains other fluorides such as S_2F_{10}, SF_4 and must be purified further SF_6 gas generally supplier by chemical firms. The cost of gas is low if manufactured in large scale.

The circuit breaker consists of three single poles. Each pole of CB includes interrupter, post insulator, insulating rod. The interrupter adopts the arc quenching principle of auto expansion, which drives the hot gas into thermo-expansion room forming high voltage gas, making use of the energy of arc during interruption high current. The hot gas sprays out quickly from thermo-expansion room as current passes zero and blows the arc out. When small current is interrupted, the pressure from blasting in the compressing room quenches the arc. Absorbent is put in the interrupter of each pole to absorb the moisture. Figure 3.5 depicts the arc extinction process in SF6 circuit breakers. Figure 3.6 shows the extinction of arc by double axial flow principle.

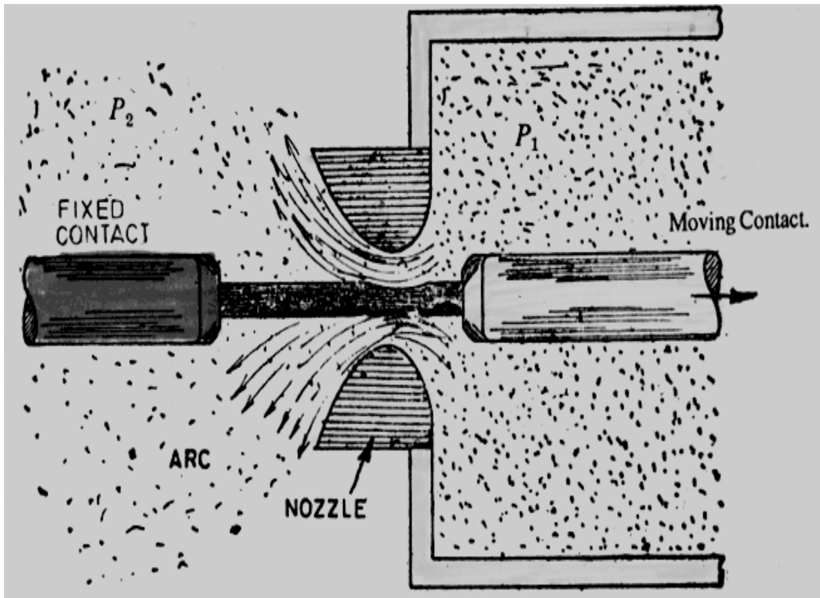


Figure 3.5 - Arc extinction in Gas flow Circuit-Breakers (Gas flow from high pressure P1 to low pressure P2 via an insulating nozzle.)

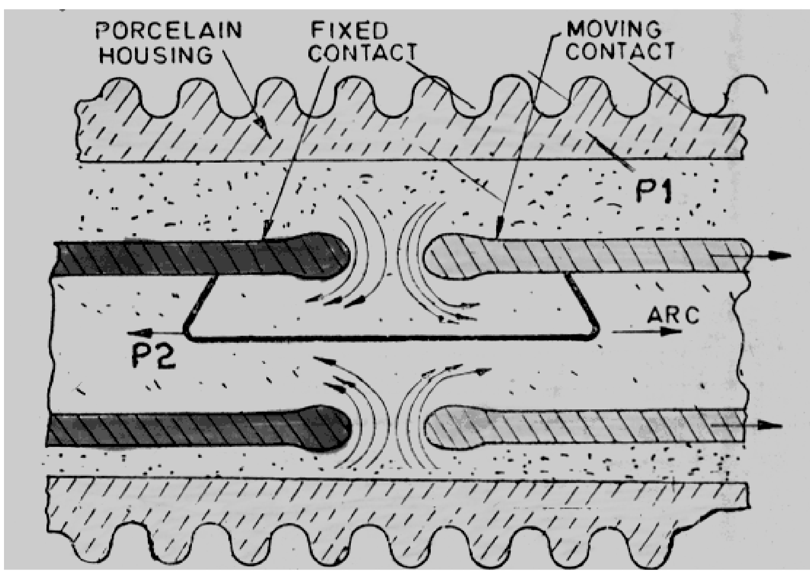


Figure 3.6 - Double Axial flow in SF6 Circuit Breakers

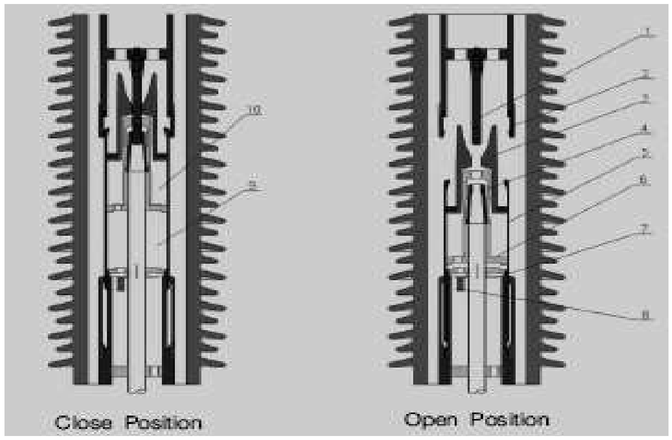


Figure 3.7 Close/Open Position of SF6 Breaker

1. Fixed arcing contact
2. Fixed contact
3. Nozzle
4. Move arcing contact
5. Puffer cylinder
6. Single valve of pressure
7. Decompressing valve
8. Decompressing spring
9. Compressing room
10. Thermo-expansion room

Figure 3.7 shows the sectional view of one limb of SF6 circuit breakers in both close and open positions. The moving parts of cylinder, movable arcing contact and bar etc. move downwards by the force of open spring after CB receives open instruction. The main fixed contact fingers separate from the main moving contact first in the process of motion, the current transfers upon the two arcing contacts being closed. Then the arcing contacts separate and the arc occurs. Gas of high pressure is formed by the hot gas flowing into the thermo expansion rooms from arcing area as breaking short circuit current, because of higher short circuit current making the arcing energy larger. At the moment, the single valve of pressure closes because the pressure in the thermo-expansion room is higher than that in the compressing room. The high pressure gas in the thermo-expansion is blown on the arc in the break and quenches it when current passes zero. In the process of opening, the gas in the compressing room is condensed at the beginning. The elastic pressure releasing valve at the bottom opens when it reaches to a certain value, which compresses and releases at the same time, avoiding the pressure in compressing room being too high. The mechanism needn't overcome more anti-forces from compressing; the operating power is reduced greatly.

The pressure produced from the thermo-expansion room is small as the energy of arc is small in breaking small current (generally below several amperes). The pressure in the compressing room is higher than that of thermo-expansion room at the time. The single valve of pressure opens and the gas being condensed is blown on the break. When current passes zero the gas with pressure is blown on the arc and the arc is quenched.

3.5 Air break circuit breaker

These circuit breakers employ high resistance interruption principle. The arc is rapidly lengthened by means of the arc runners and arc chutes and the resistance of the arc is increased by cooling, lengthening and splitting the arc. The arc resistance increases to such an extent that the voltage drop across the arc becomes more than the supply voltage and the arc is extinguished. Air break circuit breakers are used a.c circuits up to 12 kV. Magnetic field is utilized for lengthening the arc in high voltage air break circuit breaker.

Refer figure 3.8 for understanding the principle of arc extinction in air break circuit breakers. Main contacts conduct the current in closed position of the breaker. They have low contact resistance and are silver plated. The arcing contacts (2) are hard, heat resistant and usually made of copper alloy. While opening the contact, the main contacts dislodge first. The current is shifted to the arcing contacts. The arcing contacts dislodge later and arc is drawn between them (3). This arc is forced upwards by the electromagnetic force and thermal action. The arc ends travel along the Arc Runner (Arcing horns). The arc moves upwards and is split by arc splitter plates (5). The arc is extinguished by lengthening, cooling, splitting etc. In some breakers the arc is drawn in the direction of the splitter by magnetic field.

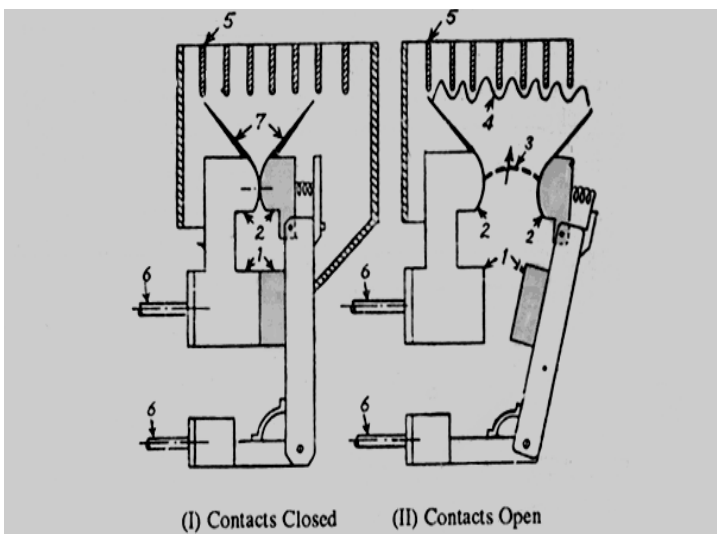


Figure 3.8 - Arc extinction in Air Break Circuit Breaker

1. Main Contacts
2. Arcing Contacts
3. Arc rising in the direction of the arrow.
4. Arc getting Split.
5. Arc Splitter Plates
6. Current carrying terminals
7. Arc Runners.

3.6 Air blast circuit breaker

Fast operations, suitability for repeated operation, auto re-closure, unit type multi break constructions and modest maintenance are some of the main features of air blast circuit breakers. A compressor plant is necessary to maintain high air pressure in the air receiver. Air blast circuit breaker is used for interconnected lines and important lines where rapid operation is desired.

High pressure air at a pressure between 20 to 30 kg / cm2 is stored in the air reservoir. Air is taken from the compressed air system. Three hollow insulator columns are mounted on the reservoir with valves at their basis. The double arc extinguished chambers are mounted on the top of the hollow insulator chambers. The current carrying parts connect the three arc extinction chambers to each other in series and the pole to the neighbouring equipment. Since there exists a very high voltage between the conductor and the air reservoir, the entire arc extinction chambers assembly is mounted on insulators. Since there are three double arc extinction poles in series, there are six breaks per pole. Each arc extinction chamber consists of one twin fixed contact. There are two moving contacts. The moving contacts can move axially so as to open or close. Its position open or close depends on air pressure and spring pressure.

The operating mechanism operates the rod when it gets a pneumatic or electrical signal. The valves open so as to send the high pressure air in the hollow part of the insulator. The high pressure air rapidly enters the double arc extinction chamber. As the air enters into the arc extinction the pressure on the moving contacts becomes more than spring pressure and the contacts open.

The contacts travel through a short distance against the spring pressure. At the end of the contact travel the port for outgoing air is closed by the moving contacts and the entire arc extinction chamber is filled with high pressure air as the air is not allowed to go out. However, during the arcing period the air goes out through the openings and takes away the ionized air of the arc. While closing, the valve is turned so as to close connection between the hollow part of the insulator and the reservoir. The valve lets the air from the hollow insulator to the atmosphere. As a result of the pressure of air in the arc extinction chamber is dropped down to the atmospheric pressure and the moving contacts close over the fixed contacts by virtue of the spring pressure.

The opening is fast because the air takes negligible time to travel from the reservoir to the moving contact. The arc is extinguished within a cycle. Therefore, air blast circuit breaker is very fast in breaking the current. Closing is also fast because the pressure in the arc extinction chamber drops immediately as the valve operates and the contacts close by virtue of the spring pressure. Air Blast Circuit Breaker needs an auxiliary compressed air system which supplies air to the air receiver of the breaker. For opening operation, the air is admitted in the arc extinction chamber. It pushes away the moving contacts. In doing so, the contacts are separated and the air blast takes away the ionized gases along with it and assists in extinction. After a few cycles the arc is extinguished by the air blast and the arc extinction chamber is filled with high pressure air (30 kg/cm2). The high pressure air has higher dielectric strength than that of atmospheric pressure. Hence a small contact gap of few centimetres is enough.

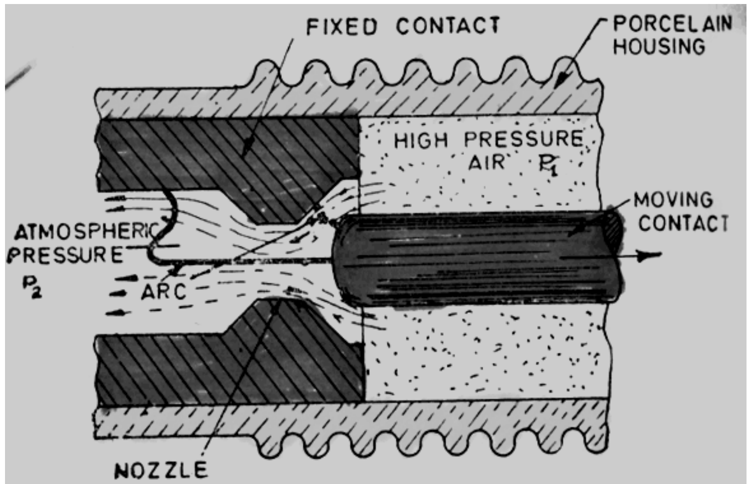


Figure 3.9 - Axial Flow

In axial blast type air flow shown in figure 3.9, the air flows from high pressure reservoir to the atmospheric through a convergent divergent nozzle. The difference is pressure and the design of the nozzle is such that the air expands into the low pressure zone, it attains almost supersonic velocity. The mass flow of air through the nozzle is governed by the parameters like pressure ratio, area of throat, nozzle throat diameter and is influenced by the diameter of the arc itself. The air flowing at a high speed axially along the arc causes the removal of heat from the periphery of the arc and the diameter of the arc reduces to a low value at current zero. At this instant the arc is interrupted and the contact space is flushed with fresh air flowing through the nozzle. The flow of fresh air through the contact space ensures removal of hot gases and rapid building up of dielectric strength.

According to the principle of operation of cross blast flow, the air flows around the arc and the diameter of arc is likely to remain stable for higher values of current. This is depicted in figure 3.10. During the period of arc extinction, the air continues to flow through the nozzle to the atmosphere. The mass flow rate can be increased by increasing the pressure of high pressure system. The increase in the mass flow results in the increased breaking capacity. The air blast circuit breakers come under the class of external extinguishing energy type. The energy supplied for arc extinction is obtained from high pressure air and is independent of current to be interrupted.

After the brief duration of air flow, the interrupter is filled with high pressure air. The dielectric strength of air increases with pressure. Hence the fresh high pressure air in the contact space is capable of withstanding the transient recovery voltage. After the arc extinction the interrupter chamber is filled with high pressure air. For closing operation, the air from this chamber is let out to the atmosphere. Thereby the pressure on the moving contacts from one side is reduced and the moving contacts close rapidly by the spring pressure. The post zero resistance of contact space is high in air blast circuit breakers. This is because the contact clearance space is filled with high pressure air after final current zero and high pressure air has high dielectric strength. The high restriking voltage appears across the contacts does not damp out through the gap because of the high post zero resistance.

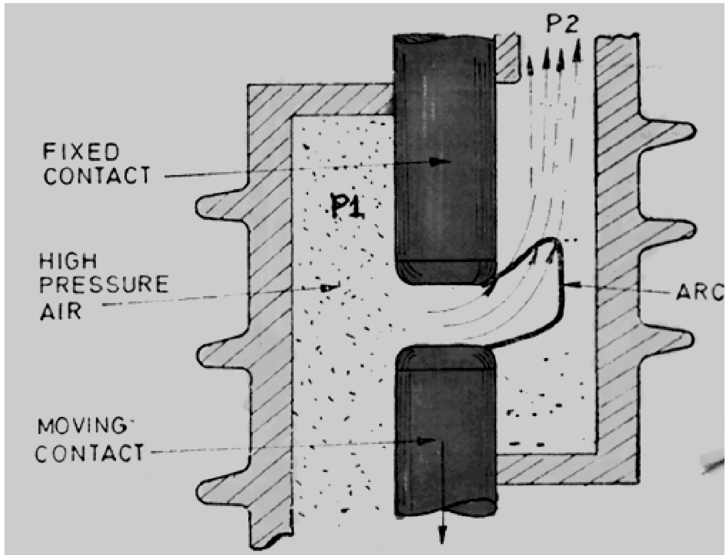


Figure 3.10 - Cross Flow in Air Blast Circuit Breaker

Further, voltages of the order of several times the normal voltage appear across the contacts because of current chopping. If these voltages are not allowed to discharge, they may cause break down of insulation of the circuit breaker or the neighbouring equipment. The overcome this difficulty resistance switching is adopted. The usual procedure is to connect a resistance in shunt with the arc. During the opening operation, air is admitted in the arc extinguishing chamber. It separates the main contacts and pushes the auxiliary contacts. The auxiliary contacts close; thereby the resistors are connected across the arc for a short time of arcing. The auxiliary contacts are located in the inclined V shaped insulators while the resistors are located in the vertical insulators. Immediately after the arc extinction the pressure on either side of the piston of auxiliary contacts gets so adjusted that the auxiliary contacts open and resistor circuit is interrupted. Ceramic resistances of non linear characteristics, similar to those used in the lightning arresters are used for resistance switching.

3.7 Maintenance and Testing of Circuit Breakers

3.7.1 Importance of Maintenance

The maintenance of circuit breakers deserves special consideration because of their importance for routine switching and for protection of other equipment. Electric transmission system break ups and equipment destruction can occur if a circuit breaker fails to operate because of a lack of preventive maintenance. The need for maintenance of circuit breakers is often not obvious as circuit breakers may remain idle, either open or closed, for long periods of time. Breakers that remain idle for 6 months or more should be made to open and close several times in succession to verify proper operation and remove any accumulation of dust or foreign material on moving parts and contacts.

3.7.2 Frequency of Inspections

Most manufacturers recommend complete inspections, external and internal, at intervals of from 6 to 12 months. Experience has shown that a considerable expense is involved, some of which may be unnecessary, in adhering to the manufacturer's recommendations of internal inspections at 6- to 12-month intervals. With proper external checks, part of the expense, delay, and labour of internal inspections may be avoided without sacrifice of dependability.

3.7.3 Inspection Schedule for New Breakers

A temporary schedule of frequent inspections is necessary after the erection of new equipment, the modification or modernization of old equipment, or the replication of old equipment under different conditions. The temporary schedule is required to correct internal defects which ordinarily appear in the first year of service and to correlate external check procedures with internal conditions as a basis for more conservative maintenance program thereafter.

3.7.4 Inspection Schedule for Existing Breakers

The inspection schedule should be based by the interrupting duty imposed on the breaker. It is advisable to make a complete internal inspection after the first severe fault interruption. If internal conditions are satisfactory, progressively more fault interruptions may be allowed before an internal inspection is made. Average experience indicates that up to five fault interruptions are allowable between inspections on 230 kV and above circuit breakers, and up to 10 fault interruptions are allowable on circuit breakers rated less than 230 kV. Normally, no more than 2 years should elapse between external inspections or 4 years between internal inspections.

3.7.5 External Inspection Guidelines

The following items should be included in an external inspection of a high-voltage breaker.

a. Visual Inspection

Visually inspect the operating mechanism. The tripping latches should be examined with special care since small errors in adjustments and clearances and roughness of the latching surfaces may cause the breaker to fail to latch properly or increase the force necessary to trip the breaker to such an extent that electrical tripping will not always be successful, especially if the tripping voltage is low. Excessive "opening" spring pressure can cause excessive friction at the tripping latch and should be avoided. Also, some extra pressure against the tripping latch may be caused by the electromagnetic forces due to flow of heavy short-circuit currents through the breaker. Lubrication of the bearing surfaces of the operating mechanism should be made as recommended in the manufacturer's instruction book, but excessive lubrication should be avoided as oily surfaces collect dust and grit and get stiff in cold weather, resulting in excessive friction.

b. Dielectric Strength of oil (For OCBs)

Check oil dielectric strength and colour for oil breakers. The dielectric strength must be maintained to prevent internal breakdown under voltage surges and to enable the interrupter to function properly since its action depends upon changing the internal arc path from a fair conductor to a good insulator in the short interval while the current is passing through zero. Manufacturer's instructions state the lowest allowable dielectric strength for the various circuit breakers. It is advisable to maintain the dielectric strength above 20 kV even though some manufacturer's instructions allow 16 kV. Detailed instructions for oil testing are found in FIST Volume 3-5. If the oil is carbonized, filtering may remove the suspended particles, but the interrupters, bushings, etc., must be wiped clean. If the dielectric strength is lowered by moisture, an inspection of the fibre and wood parts is advisable and the source of the moisture should be corrected. For these reasons, it is rarely worthwhile to filter the oil in a circuit breaker while it is in service.

c. Breaker Operation

Operate breaker manually and electrically and observe for malfunction. Tripping of breaker from protective relays should also be checked. The presence of excessive friction in the tripping mechanism and the margin of safety in the tripping function should be determined by making a test of the minimum voltage required to trip the breaker. This can be accomplished by connecting a switch and rheostat in series in the trip-coil circuit at the breaker (across the terminals to the remote control switch) and a voltmeter across the trip coil. Staring with not over 50 percent of rated trip-coil voltage, gradually increase the voltage until the trip-coil plunger picks up and successfully trips the breaker and record the minimum tripping voltage. Most breakers should trip at about 56 percent of rated trip-coil voltage. The trip-coil resistance should be measured and compared with the factor test value to disclose shorted turns. Most modern breakers have trip coils which will overheat or burn out if left energized for more than a short period. An auxiliary switch is used in series with the coil to open the circuit as soon as the breaker has closed. The auxiliary switch must be properly adjusted and successfully break the arc without damage to the contacts. Tests should also be made to determine the minimum voltage which will close the breaker and the closing coil resistance.

d. Operating Mechanism Adjustments

Measurements of the mechanical clearances of the operating mechanism associated with the tank or pole should be made. Appreciable variation between the value found and the setting when erected or after the last maintenance overhaul is erected or after the last maintenance overhaul is usually an indication of mechanical trouble. Temperature and difference of temperature between different parts of the mechanism affect the clearances some. The manufacturers' recommended tolerances usually allow for these effects.

e. Contact Resistance Measurement

With the circuit breaker closed, measure the contact resistance of the primary path from the top of the line side bushings to the top of the load side bushings (cable connections are not included). Using the DC current source with the current not less than 10 A, the contact resistance should be measured and compared with the standard results provided by manufacturer. Consistent unacceptable test results may indicate a loose connection, or that the interrupter is at the end of its life and needs to be replaced. Any abnormal increase in the resistance of this circuit may be an indication of foreign material in contacts, contact loose in support, loose jumper, or loose bushing connection. Any one of these may cause localized heating and deterioration. The amount of heat above normal may be readily calculated from the increase in resistance and the current.

f. Hi-Pot (Dielectric) Test

Hi-pot (high potential) tests need to be performed as part of a series of pre-operational tests, regular maintenance, and as a method of determining adequacy against breakdown of insulating materials and spacing under normal conditions.
When performing the hi-pot (dielectric) test:

1. Do not exceed the voltages specified on the Specification plate of the circuit breaker.
2. Keep all persons at least 6 ft (1.8 m) away from the circuit breaker being tested.
3. Discharge the bushings to ground after each test. They can retain a static charge after a hi-pot test.

The procedure to be followed for performing the hi-pot (dielectric) test is as follows:

1. With the circuit breaker in the open position, perform a hi-pot test across each pole.
2. With the circuit breaker in the closed position, perform a phase-to-ground and phase-to-phase hi-pot test for each pole.
3. Gradually increase the voltage to the levels at which the testing is to be carried out.
4. Verify that the circuit breaker sustains the specified voltage without flashover for one minute. If it does not, inspect the insulators for leakage paths. If necessary, clean the surface of each insulator and repeat steps 1–3. If test results continue to differ from target values, DO NOT place the equipment into service.
5. After each hi-pot test, discharge the bushings to ground.

g. Insulation Resistance Measurement

As in hi-pot test, insulation resistance of breakers should be tested across each pole in open position. With breaker in closed position the IR value should be checked across phase to ground and phase to phase. A 5kV megger should be used for this purpose.

h. Closing and Opening Time Measurement

This test is conducted to measure the closing and opening time of breakers. A breaker timing instrument is used for this purpose.

3.7.6 Internal Inspection Guidelines

An internal inspection should include all items listed for an external inspection, plus the breaker tanks or contact heads should be opened and the contacts and interrupting parts should be inspected. These guidelines are not intended to be a complete list of breaker maintenance but are intended to provide an idea of the scope of each inspection. A specific checklist should be developed in the field for each type of inspection for each circuit breaker maintained. The following difficulties should be looked for during internal breaker inspections:

a. Tendency for keys, bolts (especially fibre), cotter pins, etc, to come loose.
b. Tendency for wood operating rods, supports, or guides to come loose from clamps or mountings.
c. Tendency for carbon or sludge to form and accumulate in interrupter or on bushings.
d. Tendency for interrupter to flashover and rupture static shield or resistor.
e. Tendency for interrupter parts or barriers to burn or erode.
f. Tendency for bushing gaskets to leak moisture into breaker insulating material.

Fortunately, these difficulties are most likely to appear early in the use of a breaker and would be disclosed by the early internal inspections. As unsatisfactory internal conditions are corrected and after one or two inspections show the internal conditions to be satisfactory, the frequency of internal inspections may safely be decreased.

3.7.7 Precautions While Working on Breakers

DO NOT work on an energized circuit breaker.

DO NOT work on a circuit breaker unless all components are disconnected by means of a visible break and securely grounded.

DO NOT work on a circuit breaker with power supplied to the secondary control circuit.

DO NOT defeat safety interlocks. This may result in bodily injury, death and/or equipment damage.

DO NOT work on a closed circuit breaker.

DO NOT work on a circuit breaker with charged energy. (Springs, capacitors, etc.)

DO NOT use a circuit breaker by itself as the sole means of isolating a high voltage circuit.

DO NOT leave a circuit breaker in an intermediate position in a cell. Always place the circuit breaker in the Disconnect, Test or Connect position.

CHAPTER – 4

INSTRUMENT TRANSFORMERS

4.1 Introduction

The main tasks of instrument transformers are:

a. To transform currents or voltages from a usually high value to a value easy to handle for relays and instruments.
b. To insulate the metering circuit from the primary high voltage system.
c. To provide possibilities of standardizing the instruments and relays to a few rated currents and voltages.

Instrument transformers are special types of transformers intended to measure currents and voltages. The common laws for transformers are valid.

4.2 Voltage transformers

The standards define a voltage transformer as one in which "the secondary voltage is substantially proportional to the primary voltage and differs in phase from it by an angle which is approximately zero for an appropriate direction of the connections.
Voltage transformers can be split up into two groups, namely inductive voltage transformers and capacitor voltage transformers (CVT). Inductive voltage transformers are most economical up to a system voltage of approximately 145 kV and capacitor voltage transformers above 145 kV. There are two types of capacitor voltage transformers on the market: high and low capacitance types. With requirements on accuracy at different operation conditions, such as pollution, disturbances, variations of the frequency temperature and transient response, the high capacitance type is the best choice. A capacitor voltage transformer can also be combined with PLC-equipment for communication over the high-voltage transmission line, also for voltages lower than 145 kV.

4.2.1 Inductive Voltage Transformers

a. Equivalent Circuit of a Voltage Transformer

The voltage transformer has to be as close as possible to the "ideal" transformer. In an "ideal" transformer, the secondary voltage vector is exactly equal and opposite to the primary voltage vector, when multiplied by the turns ratio as already discussed in chapter-2. In order to achieve this, VTs are designed in such a way that the voltage drops in the windings are small and the flux density in the core is well below the saturation value so that the magnetization current is small; in this way magnetization impedance is obtained which is practically constant over the required voltage range. The equivalent circuit of voltage transformer is shown in Figure 4.1. The magnetization branch can be ignored as the magnetizing current is low.

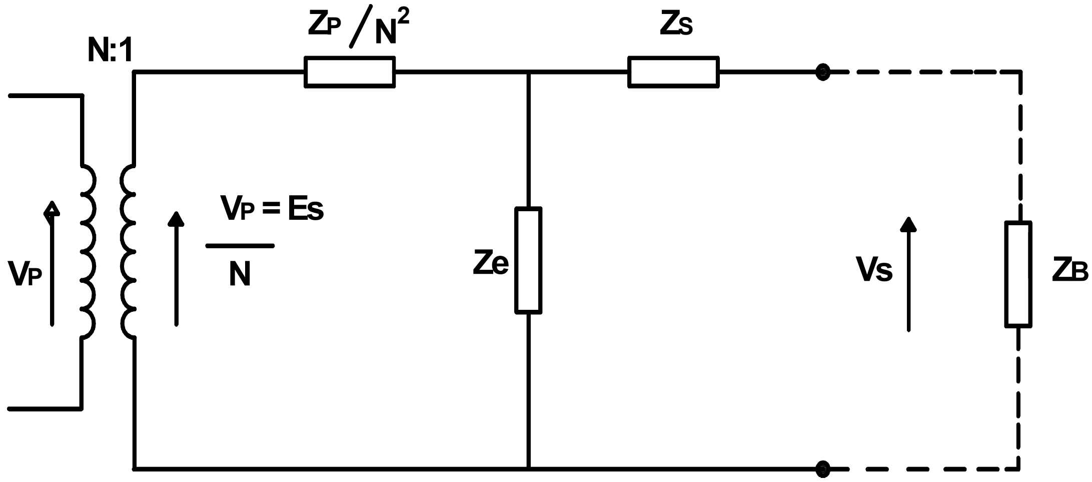


Figure 4.1 Voltage Transformer Equivalent Circuit

Where, Ip is primary current in rms amperes;
Vp is primary voltage
N is ratio of secondary to primary turns
Zp is primary-winding impedance
Ie is secondary-excitation current
Ze is secondary-excitation impedance
Es is secondary-excitation voltage
Zs is secondary-winding impedance
Is is secondary current
Vs is the secondary voltage
Z_B is burden impedance in ohms.

The secondary voltage of a VT is usually 110V phase to phase with corresponding line-to-neutral values. The majority of protection relays have nominal voltages of 110 or 63.5 V, depending on whether their connection is line-to-line or line-to-neutral. VTs have an excellent transient behaviour and accurately reproduce abrupt changes in the primary voltage.

b. Constructional Details

Core and windings are situated in the bottom tank and the porcelain insulator is mounted on the top of the tank. For higher voltage levels (> 245 kV) a cascade type is usual, but a modern capacitor voltage transformer will be more economical. The cascade type consists of two inductive voltage transformers with different potential integrated in the same enclosure. Figure 4.2 shows the structural details of inductive voltage transformer. A voltage transformer is subject to mechanical stresses due to forces in the primary terminal, wind forces and earth-quakes. The load on the primary terminal is normally lower than on a current transformer. The connection lead weighs less because of the very low current in the voltage transformer which can be transferred by a thinner wire. Typical requirements for static and dynamic loads are 1000 N with a safety factor of 2.

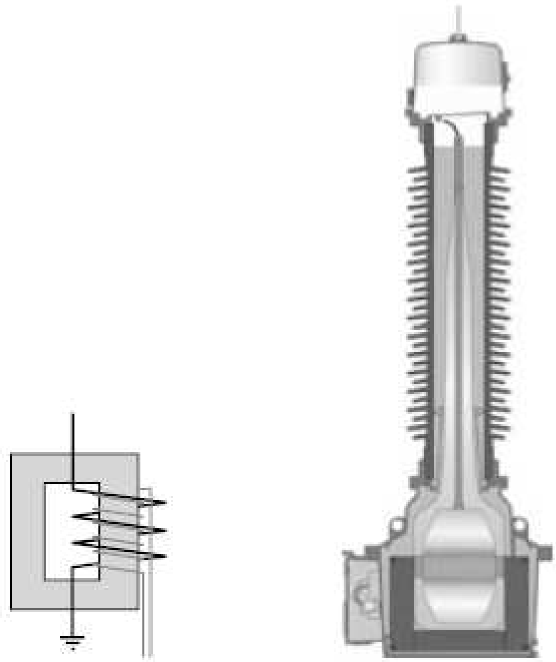


Figure 4.2 Inductive Voltage Transformer

4.2.2 Capacitive Voltage Transformers:

In general, the size of an inductive Voltage Transformer is proportional to its nominal voltage and, for this reason, the cost increases in a similar manner to that of a high voltage transformer. One alternative, and a more economic solution, is to use a capacitive voltage transformer.

A CVT (Figure 4.3) consists of the following components:

1. Coupling capacitors (C1 and C2)
2. Compensating reactor (L)
3. Step-down transformer
4. Ferroresonance-suppression circuit

The coupling capacitors of the CVT function as a voltage divider to step down the line voltage to an intermediate-level voltage, typically 5 to 15 kV. The compensating reactor cancels the coupling capacitor reactance at the system frequency. This reactance cancellation prevents any phase shift between the primary and secondary voltages at the system frequency. The step-down transformer further reduces the intermediate-level voltage to the nominal relaying voltage, typically 110 volts (phase to phase).

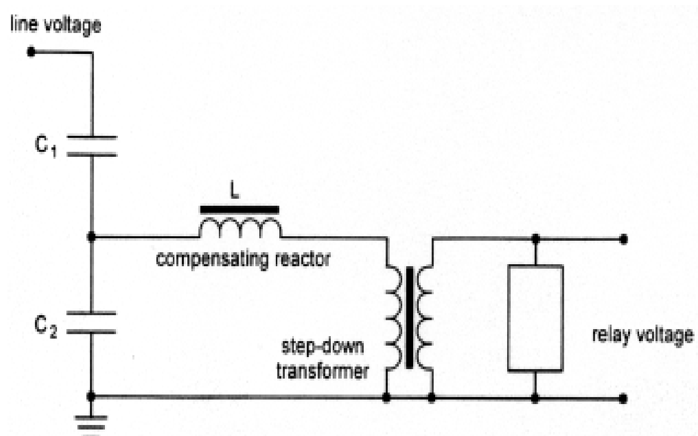


Figure 4.3 - Generic CVT Structure

The compensating reactor and step-down transformer have iron cores. Besides introducing copper and core losses, the compensating reactor and step-down transformer also produce ferroresonance due to the nonlinearity of the iron cores. CVTs include a ferroresonance suppression circuit. This circuit is normally used on the secondary of the step-down transformer. While this circuit is required to avoid dangerous and destructive overvoltages caused by ferroresonance, it can aggravate the CVT transients which will be dealt with later in section 4.2.6.

a. Constructional details of CVT

The CVT consists of two main parts: an inductive circuit housed in the base tank and one or more insulators containing series connected capacitor elements mounted on top of the base tank. Figure 4.4 shows a detailed view of the CVT.

Constructional details of various parts of CVT are explained below in brief.

1. **Capacitor elements** (inner insulation)

   Capacitor elements are wound from alternate layers of aluminium foil, polypropylene film, and kraft paper. The capacitor elements are impregnated with synthetic oil distinguished for its gas absorbing qualities. Precisely controlled vacuum and temperature treatments removes gas and moisture from the paper and oil resulting in an insulation structure of the highest integrity.

2. **Inductive element**

   The inductive element steps down the intermediate voltage provided by the capacitor elements to values suitable for relaying and metering purposes. The inductive element is housed in a die cast aluminium base tank with a die cast aluminium cover eliminating the need for painting.

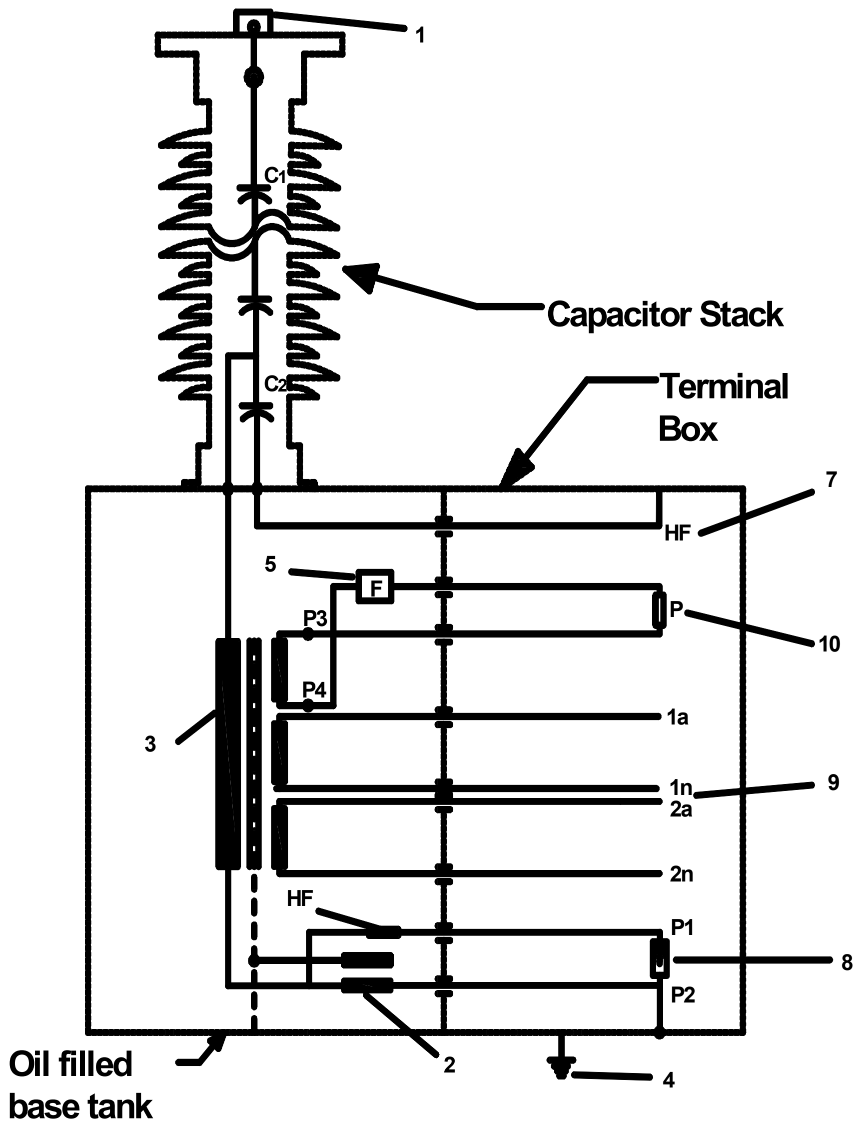


Figure 4.4 - Principle Circuit Diagram of CVT

1. High-voltage terminal
2. Compensation reactor
3. MV voltage transformer
4. Ground terminal
5. Ferroresonance suppression device
6. Damping resistor
7. Carrier (HF) terminal at CCVTs (optional)
8. Overvoltage protective device
9. Secondary terminals
10. Link, to be opened for test purposes

3. Insulator (outer insulation)

The outer insulation consists of high-quality aluminium oxide porcelain in brown or grey. Standard creepage distances are available according to the dimension tables. Connecting flanges made of hot-dip galvanized grey cast iron are bonded to the insulator by means of Portland cement. A composite insulator consisting of a fibre glass reinforced tube and silicone rubber sheds can be provided as an alternative to porcelain.

4. Housing

Capacitor units are mechanically coupled together by means of stainless steel hardware passing through the corrosion proof cast aluminium expansion housing. The mechanical connection also establishes the electrical connection between capacitor units. This facilitates field assembly of the CVT.

5. Seals

The capacitor elements have oil-resistant silicone rubber double gaskets. Single piece moulded O-ring type gaskets are used for all other sealing points.

6. Hermetic sealing system

Each capacitor unit is hermetically sealed. A stainless steel diaphragm (expansion bellows) is installed to preserve the integrity of the oil by maintaining the hermetic seal while allowing for thermal expansion and contracting of the oil. The capacitor units operate in a practically pressure-free mode over a very wide ambient temperature range. The base tank is filled with degassed purified mineral oil and hermetically sealed from the environment and from the synthetic oil in the capacitor units. A sight glass at the rear of the tank provides for easy monitoring of the oil level. No oil maintenance is necessary throughout the service life of the unit. An oil sampling valve is provided on the base tank.

7. Primary Terminal

Several variations are available to meet customer requirements: a vertical palm of aluminium alloy with the specified hole pattern, a line trap mounting adapter with removable HV terminal, or vertical stems of aluminium alloy of the specified diameter. Any of the terminals may be nickel or tin plated solid copper.

8. Secondary Terminal Box

The terminal box is very spacious to accommodate all required connections. The secondaries of the inductive circuit (EMU: electro magnetic unit) are brought out of the base tank through an oil/air seal block assembly. Secondary terminals are housed in a secondary terminal box accessible by a large lockable door. The secondary terminal box area is warmed by heat transfer from the oil filled box. This prevents condensation in the terminal box and removes the need for a space heater. An aluminium gland plate is provided to accommodate conduit hubs.

9. Secondary windings

To meet the requirements for measuring and protection, generally two secondary windings are provided with an option of up to four windings, including the earth fault winding.

10. Carrier Accessories for Coupling Capacitor Voltage Transformer (CCVT)

The CCVT is equipped with carrier accessories for PLC service. An external carrier grounding switch (CGS) and carrier entrance bushing are provided in the terminal box. The carrier accessories include a carrier drain coil with protective spark gap. When a potential ground switch (PGS) is provided, the drain coil and a protective spark gap are installed in the base tank to prevent the loss of the carrier signal when the PGS is in closed position.

11. Corrosion protection

The CVT is maintenance free and does not require painting. All metallic parts are corrosion-proof: housings are of sea water-resistant aluminium alloy and porcelain fittings of hot-dip galvanized iron. All hardware is hot dip galvanized or stainless steel.

12. Grounding

Each transformer is provided with two grounding terminals with two or four 14mm diameter holes. One grounding pad is located at each side of the unit.

4.2.3 Errors in Voltage Transformers

If the voltage drops could be neglected, the transformer should reproduce the primary voltage without errors and the following equation should apply to the primary and secondary voltages:

$$Us = (Ns/Np).Up$$

Where Ns is number of turns of secondary winding
Np is the number of turns of primary winding
Us is the secondary voltage
Up is the primary voltage

In reality, however, it is not possible to neglect the voltage drops in the winding resistances and the leakage reactances. The primary voltage is therefore not reproduced exactly. The equation between the voltages will in this case be:

$$Us = (Ns/ Np).Up - \Delta U$$

Where ΔU is the voltage drop.

Phasor diagram representation of the voltages in the above equation will be helpful in understanding the nature of errors in voltage transformers. The phasor diagram is drawn in figure 4.5.

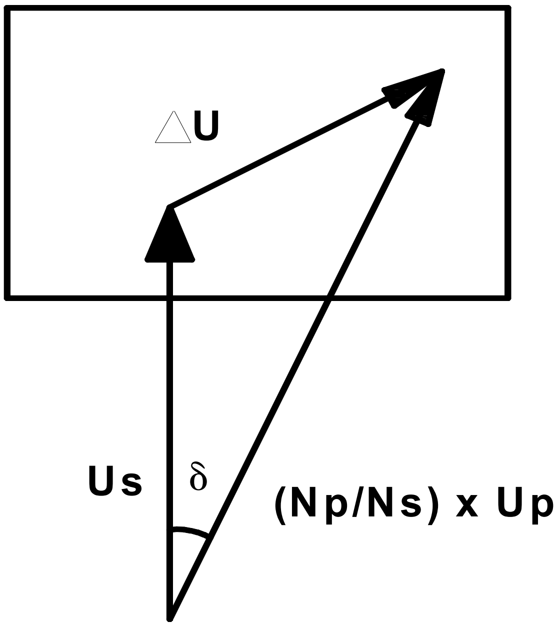


Figure 4.5 Phasor Representation of VT Errors

It is clear from the phasor diagram in figure 4.5 that the error in the reproduction of voltage will appear both in amplitude and phase. The error in amplitude of voltage is called the ratio error and is represented by 'ε' and the error in phase is called phase error or phase displacement and is represented by 'δ'. According to the definition, the ratio error is positive if the secondary voltage is too high, and the phase error is positive if the secondary voltage is leading the primary.

The errors vary if the voltage is changed. This variation depends on the non-linear characteristic of the exciting curve which means that the variation will appear in the no-load errors. The error contribution from the load current will not be affected at all by a voltage change. The variation of errors is small even if the voltage varies with wide limits. Typical error curves are shown in figure 4.6.

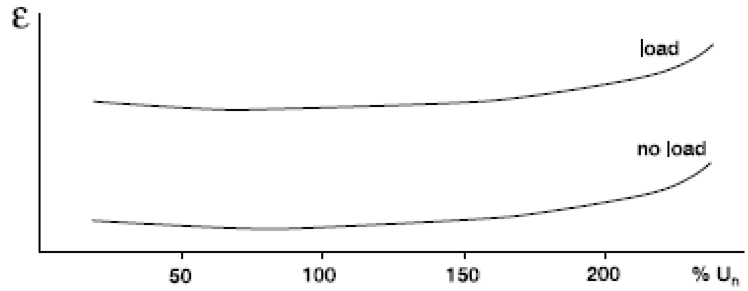


Figure 4.6 – Typical Error Curves

4.2.4 Testing of Voltage transformers

A number of routine and pre-commissioning tests have to be conducted on VT s before they can be put to service. The tests can be classified as:

1. **Ratio test**

Ratio test is conducted to check the transformation ratio of the VT. In this test single phase voltage is applied across the primary terminals and the voltage across the secondary terminals of VT is measured.

2. **Dielectric Insulation test**

Insulation resistance of VT primary with respect to earth is checked with a insulation tester (Megger) at 5kV for a period of one minute. Similarly the insulation resistance between VT primary and VT secondary is checked by using 5kV megger. Insulation resistance of VT secondary with respect to earth is checked by applying 500V or 1kV.

3. **Verification of terminal markings and polarity**

Polarity check is indispensable for making proper connections of the VTs of three phases. For example if we need to connect three single phase VTs in star connection, we should be sure that the VT secondary terminals being starred have the same polarity. In polarity test a 1.5 V cell is connected across the VT secondary terminals momentarily as shown in figure 4.7 by dotted line. It should be noted that positive terminal of cell is connected to terminal 'a' of VT. This convention should be followed for testing the VT of all three phases i.e the polarity of DC voltage applied to VTs should be kept unchanged while conducting polarity test for a set of VTs installed on phases R, Y and B. Momentary application of DC voltage across the VT terminals results in development of magnetic flux which causes the flow of current in the primary side. The direction of this current is checked by a null deflection galvanometer or analog ammeter (with range in mA) connected across the primary winding as shown in figure 3.7. This process is repeated for the VTs of all the three phases. If the direction of Galvanometer deflection for all the VTs is same, their polarity is also same.

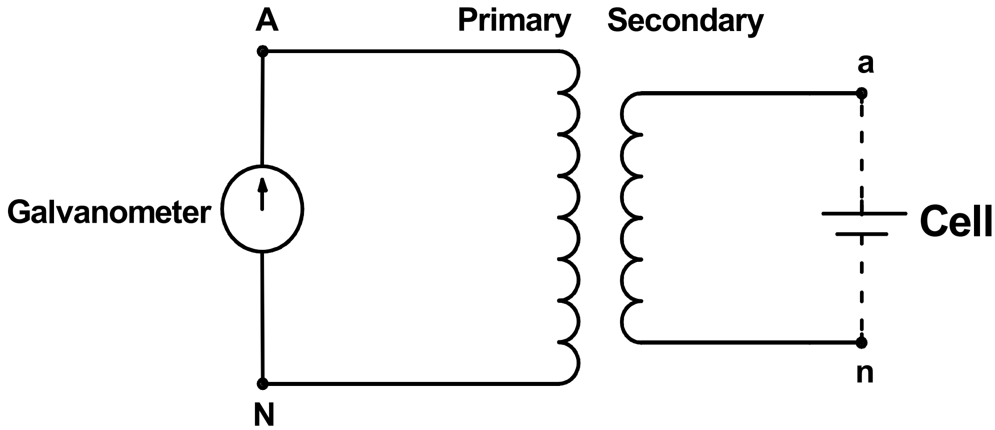


Figure 4.7 - Connections for Polarity Test of VTs

4.2.5 How to Specify Voltage Transformers

Important factors when selecting voltage transformers:

1. Standard (IEC, IEEE or national)
2. Inductive or capacitor voltage transformers
3. Insulation level (service voltage)
4. Rated primary voltage
5. Rated secondary voltage
6. Ratio
7. Rated voltage factor
8. Burdens (outputs) and accuracy for each winding
9. Pollution levels (creepage distance)

1. Rated insulation level

The voltage transformer must withstand the operational voltage and overvoltages in the network. Test voltages are specified in the standards in relation to the system voltage.

2. Rated primary and secondary voltage

The performance of the transformer is based on its rated primary and secondary voltage. Voltage transformers for outdoor applications are normally connected between phase and ground. The standard values of rated primary voltage are $1/\sqrt{3}$ times of the value of the rated system voltage. The rated secondary voltage is chosen according to local practice; in India often $110/\sqrt{3}$ V.

The transformers supply a secondary voltage at good accuracy even when the primary voltage varies considerably from the rated voltage. A check must, however, be made for the connected metering and relaying equipment, to ensure that they operate satisfactorily at the different voltages. The normal measuring range of a voltage transformer for the metering winding is 80-120% of the rated voltage. The relay winding has a voltage range from 0.05 to 1.5 or 1.9 of the rated voltage.

3. Rated voltage factor

Voltage transformers, both inductive and capacitor types are usually connected phase to earth. In the event of a disturbance in a three-phase network, the voltage across the voltage transformer may sometimes be increased even up to the voltage factor, Vf times the nominal rated performance voltage. IEC specifies the voltage factors as follows:

- 1.9 for systems not being solidly earthed
- 1.5 for systems with solidly earthed neutral.

The duration is specified to be 30 seconds if automatic fault tripping is used during earth faults, in other cases 8 hours. Because of the above-mentioned requirement the voltage transformers operate with low flux density at rated voltage. The voltage transformer core must not be saturated at the voltage factor.

4. Burdens and accuracy classes

The accuracy is divided into classes for measuring and classes for protection purposes. For revenue metering, it is important that the transformer is measuring correctly at different temperatures. An inductive voltage transformer has negligible deviations at different temperatures, while capacitor voltage transformers with a dielectric consisting only of paper or polypropylene film show large variations due to changes in capacitance. In a modern capacitor voltage transformer the dielectric consists of two different types of material, paper and polypropylene, which have opposite temperature characteristics and thus combined give a minimum of deviation. The deviation is about the same magnitude as that of an inductive voltage transformer.

On a voltage transformer provided with more than one secondary winding, these windings are not independent of each other, as in the case of a current transformer with several secondary windings each on their own core. The voltage drop in the primary winding of a voltage transformer is proportional to the total load current in all secondary windings. Measuring and protective circuits can therefore not be selected independently of each other. The accuracy class and rated burden are normally selected as follows:

- When the burden consists of metering and relaying components, the higher accuracy class required for metering must be selected.
- The burden requirements must be equivalent to the total burden of all the equipment connected to the voltage transformer.

For Example:

Metering Equipment	25VA
Accuracy Class	0.5
Relays	100VA
Accuracy Class	5P

- The voltage transformer selected should then be able to supply 100 VA at an accuracy corresponding to class 0.5.
- The above is valid provided that the relays consume the 70 VA connected continuously in regular service. If the relay circuits are loaded only under emergency conditions, their influence on the metering circuits can be neglected.

The metering classes of IEC are valid for 80-120% of rated voltage and 25-100% of rated burden. The protective classes are valid from 5% to Vf times rated voltage and for 25-100% of rated burden (Vf = voltage factor). It shall be noted that a voltage transformer winding can be given a combined class, i.e. 0.5/5P, which means that metering accuracy is fulfilled for 80-120% of rated voltage, and, additionally, the accuracy and transient response requirements for the protection class are fulfilled between 5% - 80% and 120% - Vf times rated voltage.

When more than one secondary winding is required, it must be clearly specified how the burdens and classes shall apply.

- For one winding, with the other windings unloaded, or
- With all windings loaded simultaneously.

As different secondary windings of a voltage transformer are dependent on each other, the thermal burden of a voltage transformer is equivalent to the total power the transformer can supply without exceeding the specified temperature rise, taking into consideration the voltage factor.

According to IEC standards and some other standards, the accuracy class shall be fulfilled from 25% to 100% of the rated burden. Modern meters and instruments have low power consumption and the total burden can be lower than 25% of the rated burden. Due to correction of turns the error will increase at lower burden. Minimum error is typically at 75% of the rated burden. The best way is specify a rated burden of 1.5 times the actual connected burden. The voltage transformer will be designed with regard to this requirement.

4.2.6 Transient Response of Capacitive Voltage Transformers:

When a fault suddenly reduces the line voltage, the CVT secondary output does not instantaneously represent the primary voltage. This is because the energy storage elements, such as coupling capacitors and the compensating reactor, cannot instantaneously change their charge or flux. These energy storage elements cause the CVT transient. CVT transients differ depending on the fault point-on-wave (POW) initiation. The CVT transients for faults occurring at voltage peaks and voltage zeros are quite distinctive and different. Figure 4.8 and Figure 4.9 show two CVT transients for zero-crossing and peak POW fault initiations. For comparison, the ideal CVT voltage output (ratio voltage) is shown in each figure.

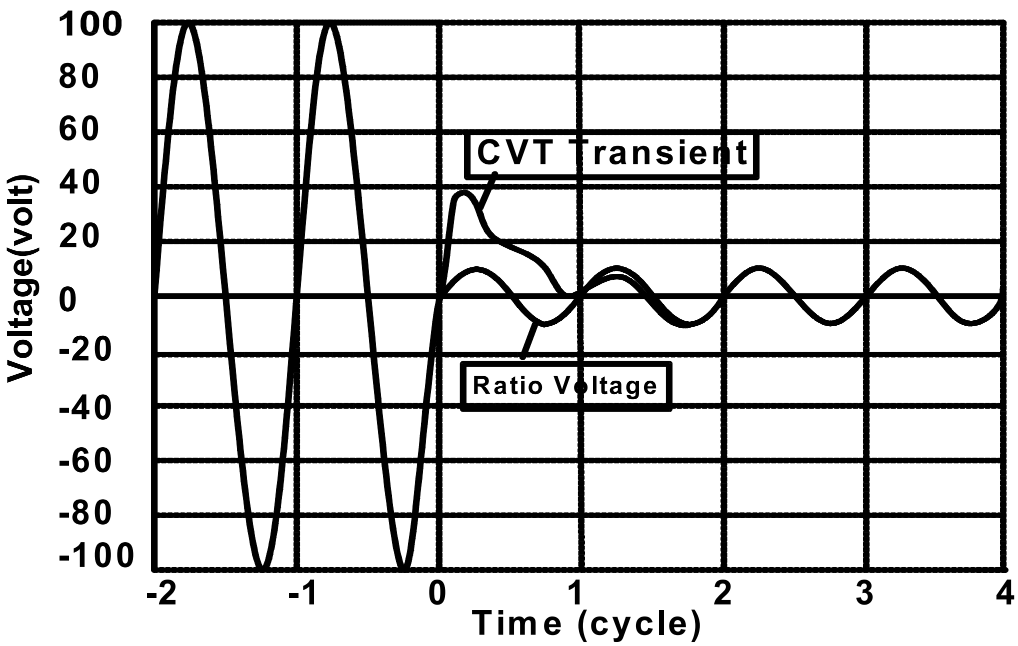


Figure 4.8 CVT Transient with Fault at Zero Voltage

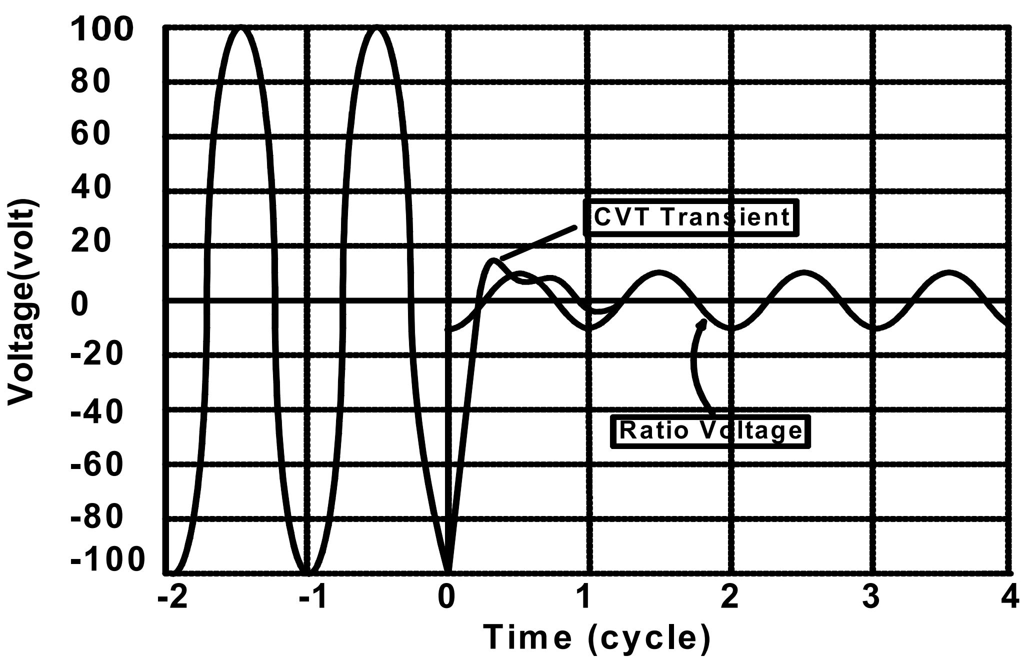


Figure 4.9 CVT Transient with Fault at Voltage Peak

Figure 4.8 shows a CVT transient with a fault occurring at a voltage zero. Also, notice that the CVT output does not follow the ideal output until 1.75 cycles after fault inception. Figure 4.9 shows the CVT response to the same fault occurring at a voltage peak. Again, the CVT output does not follow the ideal output. The CVT transient for this case lasts about 1.25 cycles. The

CVT transient response to a fault occurring at points other than a voltage peak or voltage zero take a wave shape in between those shown in Figure 4.8 and Figure 4.9. Each CVT component contributes to the CVT transient response. For example, the turns ratio of the step-down transformer dictates how well a CVT isolates its burden from the dividing capacitors C1 and C2. The higher the transformer ratio, the less effect the CVT burden has on these capacitors. The different loading on the CVT coupling capacitors due to different transformer ratios changes the shape and duration of CVT transients.

4.2.7 Secondary grounding of voltage transformers

To prevent secondary circuits from reaching dangerous potential, the circuits shall be grounded. Grounding shall be made at only one point on a voltage transformer secondary circuit or galvanically interconnected circuits. A voltage transformer, which on the primary is connected phase to ground, shall have the secondary grounding at terminal n. This is depicted in figure 4.10. A voltage transformer, with the primary winding connected between two phases, shall have the secondary circuit, which has a voltage lagging the other terminal by 120 degrees, grounded. Windings not in use shall be grounded.

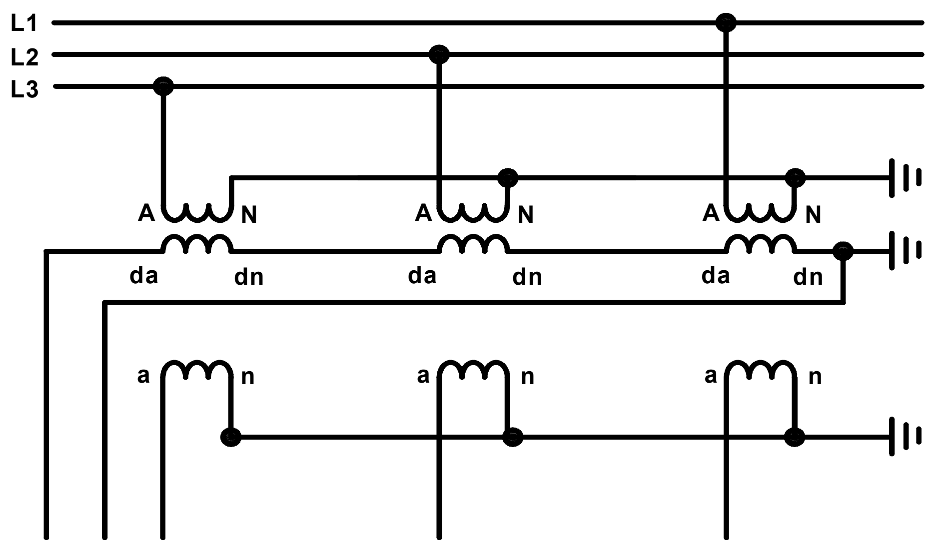


Figure 4.10 - A set of voltage transformers with one Y-connected and one broken delta secondary circuit

4.2.8 Fusing of voltage transformer secondary circuits

Fuses should be provided at the first box where the three phases are brought together. The circuit from the terminal box to the first box is constructed to minimize the risk of faults in the circuit. It is preferable not to use fuses in the voltage transformer terminal box, as this will make the supervision of the voltage transformers more difficult. The fuses in the three-phase box enable a differentiated fusing of the circuits to different loads like protection and metering circuits. The fuses must be selected to give a fast and reliable fault clearance, even for a fault at the end of the cabling.

4.3 Current transformers

A current transformer is defined as "as an instrument transformer in which the secondary current is substantially proportional to the primary current (under normal conditions of operation) and differs in phase from it by an angle which is approximately zero for an appropriate direction of the connections." This highlights the accuracy requirement of the current transformer.
A current transformer is, in many respects, different from other transformers. The primary is connected in series with the network, which means that the primary and secondary currents are stiff and completely unaffected by the secondary burden. The currents are the prime quantities and the voltage drops are only of interest regarding exciting current and measuring cores.

4.3.1 Equivalent Circuit

Like any other transformer the current transformer also works on the principle of variable flux. In the "ideal" current transformer, secondary current would be exactly equal (when multiplied by the turns ratio) and opposite to the primary current. But, as in the voltage transformer, some of the primary current or the primary ampere-turns is utilized for magnetizing the core, thus leaving less than the actual primary ampere turns to be "transformed" into the secondary ampere-turns. The basic principles associated with CTs can be explained with the help of a simplified equivalent circuit shown in figure 4.11.

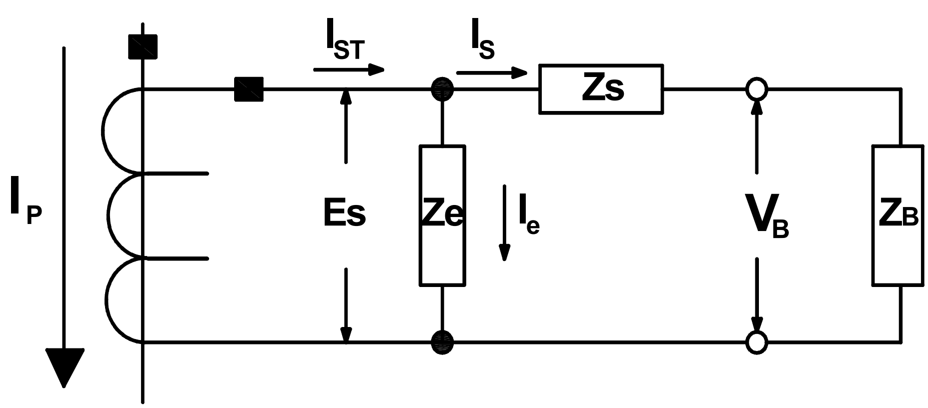


Figure 4.11 Equivalent Circuit of a Current Transformer

Where, I_P is primary current
N is ratio of secondary to primary turns
Zp is primary winding impedance
Ie is excitation current
Ze is secondary excitation impedance
Es is secondary excitation voltage

Zs is secondary winding impedance
I_{ST} is secondary current
Z_B is burden impedance

In this model, the conventional CT symbol is assumed to be an ideal CT where the relationship between the primary (Ip) and secondary current (I_{ST}) is a function of the turns ratio only. The impedance across the secondary terminals is called excitation or magnetizing impedance (Ze). This is nonlinear impedance and its magnitude depends on the voltage across it. The relationship between the secondary excitation voltage (Es) and the excitation current (Ie) is defined by the CT excitation curve, the most important CT characteristic. Typical CT excitation curve is shown in figure 4.12. There is a maximum value of Es the CT can support as defined by the following expression:

$$Es = 4.44 \times f \times A \times N \times Bmax$$

where f is the system frequency, A is the cross sectional area of the core in square cms, N is the number of secondary turns, and Bmax is the maximum flux density of the core in lines per square cms. The other elements of the model are the secondary winding impedance (Zs) and the burden impedance (Z_B), which includes the input impedance of the relay and associated lead resistance.

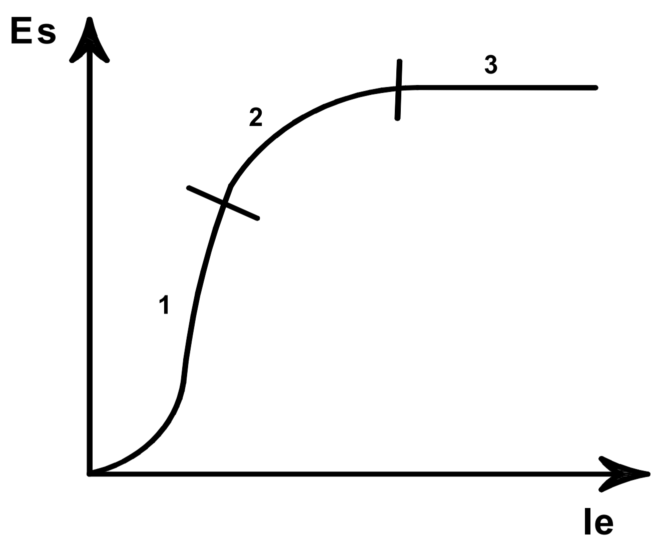


Figure 4.12 Excitation Curve of CTs

The CT magnetisation curve represents the magnetising current as a function of voltage Vs developed at the CT secondary. It can be divided into 3 zones (see figure 4.12):

1. Non-saturated zone
2. Intermediate zone
3. Saturated zone.

In zone 1, current Ie is low and voltage Es increases almost proportionally to the primary current. Zone 2 is a vague zone between the non-saturated zone and the saturated zone. There is no real break in the magnetisation curve. It is hard to locate a precise point on the curve corresponding to the saturation voltage. In zone 3, the curve (Es versus Ie) becomes almost horizontal. The error is considerable on the ratio and the secondary current distorted by the saturation. A certain number of characteristic voltages are highlighted for a CT. They correspond to zone 2 and knowledge of these voltages is necessary when definition is given to a particular CT.

4.3.2 Errors in Current Transformers

If the exciting current could be neglected, the transformer should reproduce the primary current without errors and the following equation should apply to the primary and secondary currents:

$$Is = (Ns/Np).Ip$$

Where Ns is number of turns of secondary winding
Np is the number of turns of primary winding
Is is the secondary current
Ip is the primary current

In reality, however, it is not possible to neglect the exciting current. Figure 4.11 shows that not all the primary current passes through the secondary circuit. Part of it is consumed by the core, which means that the primary current is not reproduced exactly. The relation between the currents will in this case be:

$$Is = (Ns/Np).\ Ip - Ie$$

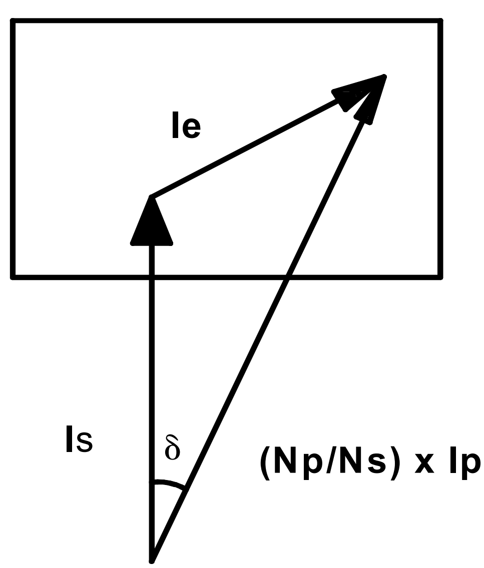


Figure 4.13 - Vector Representation of CT Errors

Figure 4.13 shows a vector representation of the three currents in the equivalent diagram. The error in the reproduction will appear both in amplitude and phase. The error in amplitude is called current or ratio error and is represented by 'ε'. The error in phase is called phase error or phase displacement and is represented by 'δ'.

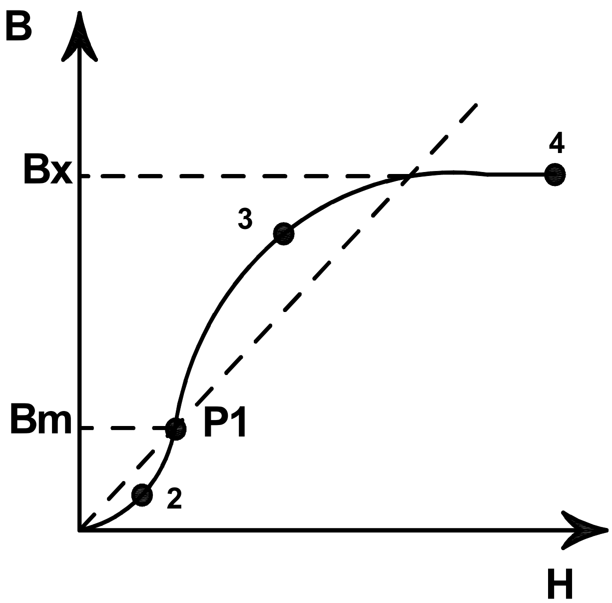


Figure 4.14 – Variation of Errors with Current

If the errors are calculated at two different currents and with the same burden it will appear that the errors are different for the two currents. The reason for this is the non-linear characteristic of the exciting curve. If a linear characteristic had been supposed, the errors would have remained constant. This is illustrated in figure 4.14 and Figure 4.15. The dashed lines apply to the linear case.

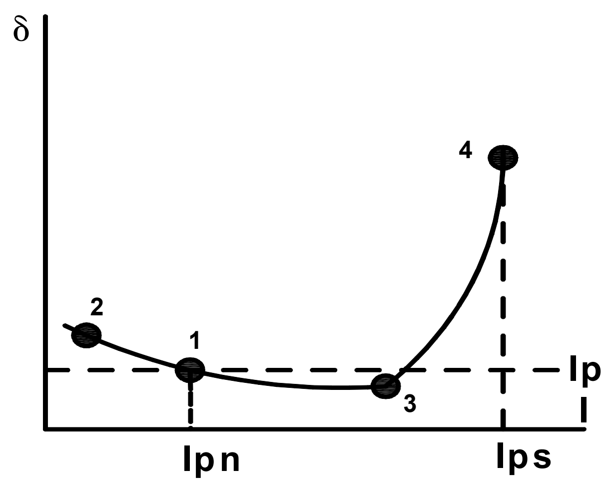


Figure 4.15 - Variation of Errors with Current

Figure 4.15 shows that the error decreases when the current increases. This goes on until the current and the flux have reached a value (point 3) where the core starts to saturate. A further increase of current will result in a rapid increase of the error. At a certain current Ips (4) the error reaches a limit stated in the current transformer standards.

4.3.3 CT Core Material and Types

The core on which the secondary wire is wound plays a significant part in the performance of a CT. Core types include silicon steel, nickel alloy, or ferrite. The type of core determines price and accuracy. Accuracy is comprised by the actual input to output transfer ratio, as well as linearity and phase shift. While phase shift is of little significance for current measurements, in the measurement of power, an uncompensated phase shift will lead to large errors in measurement of real power and power factor.

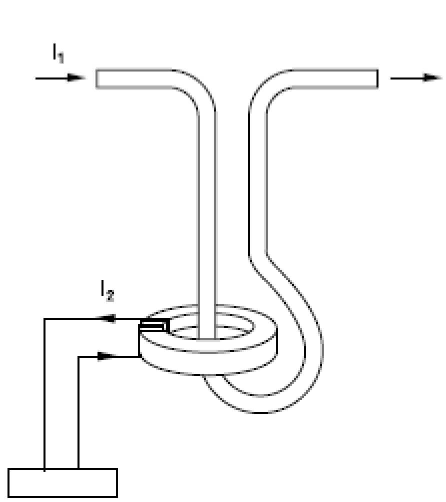
CT cores can be of a solid (closed) or split (open) type. The solid/split core defines how the CT core is designed, and how it can be installed. Solid core CTs feature a closed loop, which the primary conductor must be passed through. Split core CTs can be temporarily opened to facilitate easier installation. When using a split core CT, the primary conductor need not be disconnected to install the CT, and in most cases, the conductor can continue to carry current while the CT is being installed. Split core CTs have a large advantage in installations where shutdowns are not practical or economical. However, because of the added manufacturing complexity, split core CTs carry a large price premium. Likewise, because of the inherent "gap" associated with the CT opening mechanism, split core CTs tend to have lower accuracy and worse phase shift performance compared to their solid counterparts.

4.3.4 Types of Current Transformers

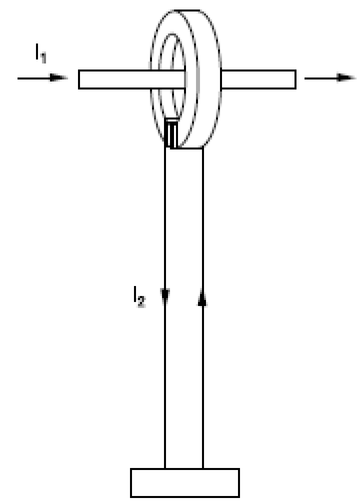
a. Oil-immersed current transformers

Most of the high voltage current transformers sold and installed today are immersed in oil. There are two main types:

1. Tank type with the cores situated in a tank close to the ground. The primary conductor is U-shaped (hair-pin) or coil-shaped (eye-bolt).
2. Inverted type (top-core) with the cores situated at the top of the transformer. The primary conductor is usually in the shape of a bar. The primary winding can also be coil-shaped.



(a) Hair Pin Type CT



(b) Top Core Type CT

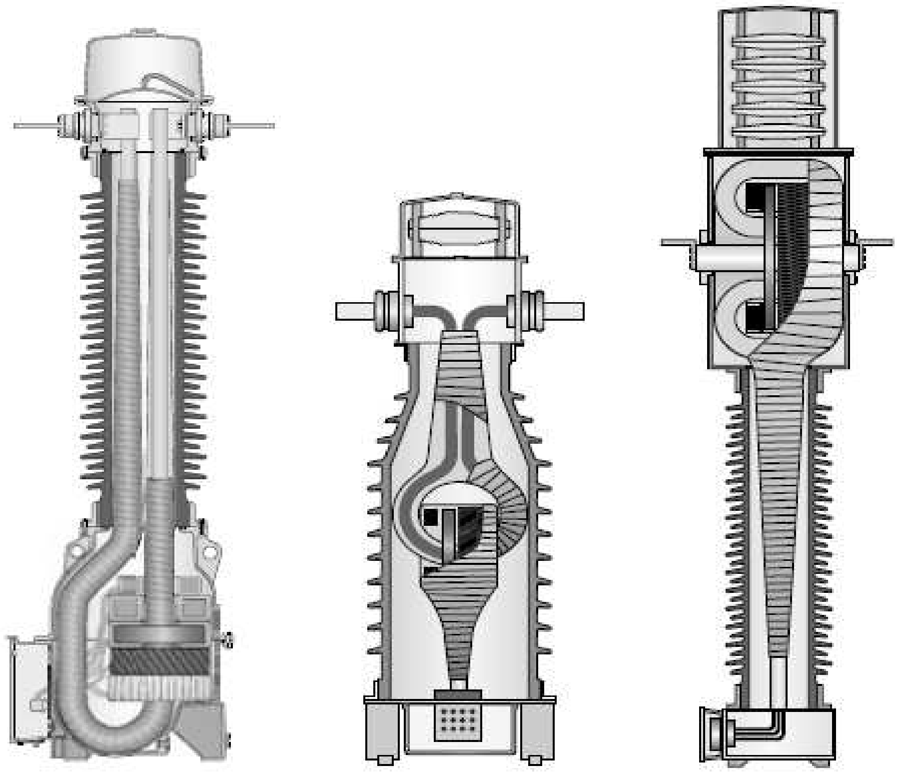
Figure 4.16 - Oil Immersed CT Designs

b. Epoxy-moulded current transformers

Other types of current transformers are epoxy-moulded. The operating principle is the same as that of oil-immersed current transformers. Epoxy-insulated current transformers have the primary winding and the secondary cores embedded in a mixture of epoxy and quartz flour. This gives a well-stabilized design with good fixture of the windings and the cores. For outdoor erection the epoxy has to withstand climatic stress on the creepage surfaces. A common type of epoxy that can withstand the outdoor climate is cycloalipatic epoxy. However, porcelain and silicone rubber are more resistant to atmospheric corrosion. Epoxy-insulated current transformers with creepage surfaces made of porcelain may be a viable option in aggressive environments. Epoxy-insulated current transformers up to 110 kV level are available on the market, but lower voltage levels are more common.

c. SF6 gas insulated current transformers

For the SF6 gas insulated current transformers the oil and paper insulation have been replaced by Sulphur hexafluoride (SF6) gas. The gas is not flammable and has good dielectric and thermal capabilities. The design is typical top-core type. The gas is solely for insulating purposes, although it will not improve the insulation of the current transformer. The high overpressure (4-5 bars) of the gas requires high performance of the insulators, vessel and gaskets.



Hair-pin / Tank type **Eye-bolt** **Top-core**

Figure 4.17 - Typical Designs of CTs

d. Advantages and Disadvantages of Various CT Designs

Advantages of Hair-pin type (Tank type)

1. Low centre of gravity.
2. High earthquake resistance.
3. Using heavy cores without stressing the porcelain insulator.
4. Easy to adapt the core volume to different requirements.
5. High quality with the use of machines when insulating the primary conductor.
6. The tank is part of the support.
7. Oil circulation in the primary conductor (tube) ensures an even temperature and no hot spots.

Disadvantage of Hair-pin type (Tank type)

1. Long primary conductor means higher thermal losses. Limitation of the short-circuit currents.

Advantages of Eye-bolt type

1. Low centre of gravity
2. High earthquake withstand

Disadvantage of Eye-bolt type

1. Long primary conductor means thermal losses and the current transformer will not be very competitive compared to top-core transformers at currents above 2000 A.
2. Difficult in cooling the primary conductor.
3. Limitation of the short-circuit currents.
4. Difficult to have large core volumes. While being insulated the core must be assembled on the primary conductor.

Advantages of Top-core type

1. Short primary conductor with low thermal losses
2. High rated current and short-time current.

Disadvantage of Top-core type

1. High centre of gravity
2. Large core volume stresses the porcelain insulator
3. Limited core volume
4. Difficult to cool the secondary windings, which are embedded in paper insulation.

4.3.5 Other Types of CTs

1. Summation CT

When the currents in a number of feeders need not be individually metered but summated to a single meter or instrument, a summation current transformer can be used. The summation CT consists of two or more primary windings which are connected to the feeders to be summated, and a single secondary winding, which feeds a current proportional to the summated primary current. A typical ratio would be (5+5+5)/5A, which means that three primary feeders of 5 are to be summated to a single 5A meter.

2. Core balance CT (CBCT)

The CBCT, also known as a zero sequence CT, is used for earth leakage and earth fault protection. In the CBCT, the three core cable or three single cores of a three phase system pass through the inner diameter of the CT as shown in figure 4.18. When the system is fault free, no current flows in the secondary of the CBCT. When there is an earth fault, the residual current (zero phase sequence current) of the system flows through the secondary of the CBCT and this operates the relay. In order to design the CBCT, the inner diameter of the CT, the relay type, the relay setting and the primary operating current need to be furnished. Detailed analysis of CBCT based protection scheme shown in figure 4.18 will be presented in chapter- 9.

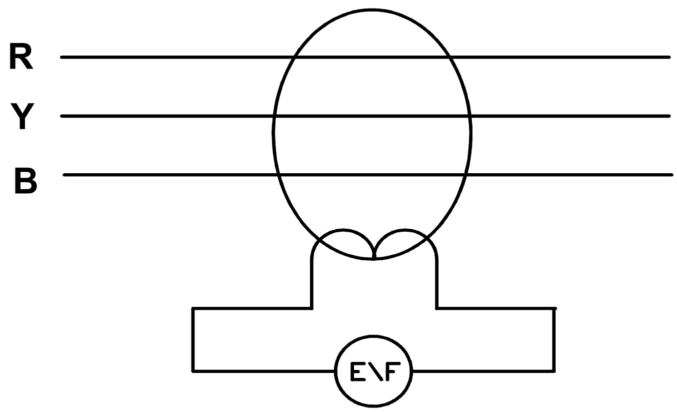


Figure 4.18 Core Balance Current Transformer

3. **Interposing Current Transformers (ICTs)**

Interposing CTs are used to transform the secondary current output of main CTs connected in power circuits. For example, consider line CTs with a ratio of 1000/5A. Suppose the relays of 1A rating are to be used for overcurrent protection of lines. In this case an ICT of ratio 5/1A can be used to change the current output of main CT in accordance with the current rating of the protective relay.

4.3.6 Testing of CTs

A number of routine and pre-commissioning tests have to be conducted on CTs. The tests can be classified as:

a. Ratio Test

Ratio is the most important piece of information relating to CTs. In ratio test primary injection set is used to inject current in the primary side of the CT. Corresponding current on the secondary side is measured using a clamp meter.

b. Dielectric insulation test

Insulation resistance of CT primary with respect to earth is checked with a 5kV insulation tester (Megger) by applying the voltage to CT primary for one minute. Similarly the insulation resistance between CT primary and CT secondary is checked by applying 5kV to CT primary. Insulation resistance of CT secondary with respect to earth is checked by applying 500V to the secondary terminals of CT.

c. Verification of terminal markings and polarity test

Purpose of conducting the polarity test has already been given in testing of VTs (section 3.2.4). Figure depicting the connections for polarity test of CTs is shown in figure 4.19. A 1.5 V cell is connected across the CT primary terminals. Dotted line has been used to indicate that the application of DC voltage should be momentary. The polarity of application of DC voltage should be kept same for testing the CTs of all three phases. Momentary application of DC voltage across the CT terminals results in development of magnetic flux which causes the flow of current in the secondary side. The direction of this current is checked by null deflection galvanometer (or analog ammeter with range in mA) connected across the secondary winding as shown in figure 4.19. This process is repeated for the CTs of all the three phases. For the polarity of CT secondaries to be same, deflection of galvanometer should be in same direction.

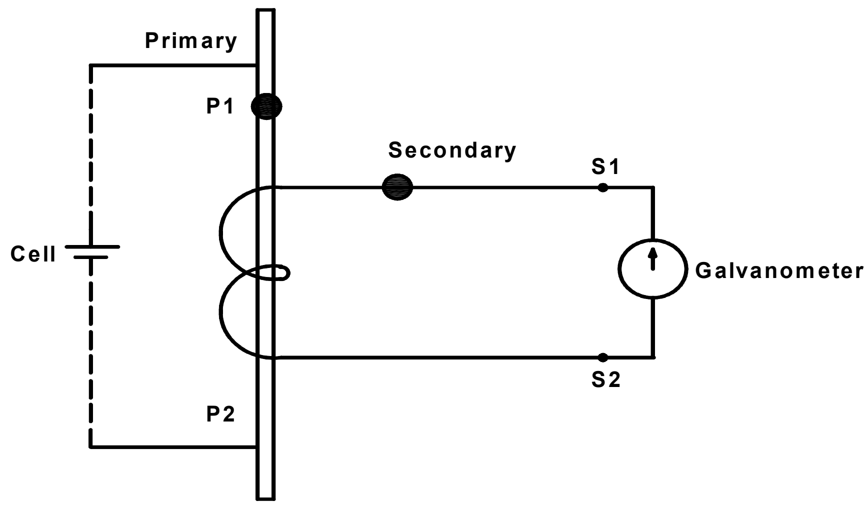


Figure 4.19 - Connections for Polarity Test of CTs

d. Knee Point test

This test is conducted on PS class cores of CTs to determine the voltage level above which the CT core enters into the saturation zone. Knee point is an important parameter for PS class cores so as to ensure stability of unit protection schemes during through faults. In Knee point test, voltage is applied across the secondary of the CT using a variable voltage source (Variac). Voltage across the secondary terminals is increased gradually and the current drawn by the CT is measured using a clamp meter. Knee point is said to be reached when a 10% increase in voltage gives rise to a 50% increase in current.

4.3.7 How to Specify Current Transformers

Following parameters are required to specify a CT:

1. Standard (IEC, IEEE or national)
2. Rated insulation level (service voltage)
3. Ambient temperature (daily temperature or average over 24 hours)
4. Rated primary current
5. Rating factor (maximum continuous current)
6. Rated secondary current.
7. Short-time current
8. Dynamic current
9. Number of cores
10. Burdens (outputs) and accuracies for each core
11. Pollution level (creepage distance)

1. Rated insulation level

The current transformer must withstand the operational voltage and overvoltages in the network. Test voltages are specified in the standards in relation to the system voltage. These tests shall show the ability of a current transformer to withstand the overvoltages that can occur in the network.

2. Rated primary current

It is the value of current which is to be transformed to a lower value. The primary rated current should be selected to be approximately 10% - 40% higher than the estimated operating current. This gives a high resolution on the metering equipment and instruments.

3. Rated continuous thermal current

The continuous rated thermal current is the current which can be permitted to flow continuously in the primary winding without the temperature rise exceeding the values stipulated in the standards. Unless otherwise specified it is equal to the rated primary current, i.e. the rating factor is 1.0.

4. Rated secondary current

The current in the secondary circuit and on which the performance of the CT is based. Typical values of secondary current are 1 A or 5 A. In the case of transformer differential protection, secondary current of 0.578 A is also specified.

5. Short-time thermal current (Ith)

This is the maximum current, which the transformer can withstand for a period of one second, without reaching a temperature that would be disastrous to the insulation, e.g. 250ºC for oil immersed transformers.

6. Burden and accuracy

Rated burden is defined as the apparent power of the secondary circuit in Volt-amperes expressed at the rated secondary current and at a specific power factor (0.8 for almost all standards). In practice all current transformer cores should be specially adapted for their application for each station. Do not specify higher requirements than necessary. The output required from a current transformer depends on the application and the type of load connected to it:

1. Metering equipment or instruments, like kW, kVar, A instruments or kWh or kVArh meters, are measuring under normal load conditions. These metering cores require high accuracy, a low burden (output) and a low saturation voltage. They operate in the range of 5-120% of rated current according to accuracy classes 0.2 or 0.5 (IEC) or 0.3 or 0.6 (IEEE).
2. For protection relays and disturbance recorders information about a primary disturbance must be transferred to the secondary side. Measurement at fault conditions in the overcurrent range requires lower accuracy, but a high capability to transform high fault currents to allow protection relays to measure and disconnect the fault. Typical relay classes are 5P, 10P and PS.

In each current transformer a number of different cores can be combined. Normally one or two cores are specified for metering purposes and two to four cores for protection purposes.

a. Metering cores

To protect the instruments and meters from being damaged by high currents during fault conditions, a metering core must be saturated typically between 5 and 20 times the rated current. Normally energy meters have the lowest withstand capability, typically 5 to 20 times rated current.

The rated Instrument Security Factor (FS) indicates the overcurrent as a multiple of the rated current at which the metering core will saturate. It is thus limiting the secondary current to FS times the rated current. The safety of the metering equipment is greatest when the value of FS is small. Typical FS factors are 5 or 10. It is a maximum value and only valid at rated burden. To fulfil high accuracy classes (e.g. class 0.2, IEC) the magnetizing current in the core must be kept at a low value. The consequence is a low flux density in the core. High accuracy and a low number of ampere-turns result in a high saturation factor. To fulfil high accuracy with low saturation factor the core is usually made of nickel alloyed steel.

With modern meters and instruments with low consumption the total burden can be lower than 25% of the rated burden. Due to turns correction and core material the error may increase at lower burdens. To fulfill accuracy requirements the rated burden of the metering core shall thus be relatively well matched to the actual burden connected. The minimum error is typically at 75% of the rated burden. The best way to optimize the core regarding accuracy is consequently to specify a rated burden of 1.5 times the actual burden.

It is also possible to connect an additional burden, a “dummy burden”, and in this way adapt the connected burden to the rated burden. However, this method is rather inconvenient. A higher output from a core will also result in a bigger and more expensive core, especially for cores with high accuracy (class 0.2).

b. Relay cores

Protective current transformers operate in the current range above rated currents. The standard classes for protective current transformers are typical 5P and 10P and PS.

The main characteristics of these current transformers are:

- Low accuracy (larger errors permitted than for measuring transformers)
- High saturation voltage
- Little or no turn correction

The saturation voltage is given by the Accuracy Limit Factor (ALF). It indicates the overcurrent as a multiple of the rated primary current up to which the rated accuracy is fulfilled with the rated burden connected. It is given as a minimum value. It can also be defined as the ratio between the saturation voltage and the voltage at rated current. Also the burden on the secondary side influences the ALF. In the same way as for the metering cores, the overcurrent factor changes for relay cores when the burden is changed. In 5P and 10P classes the numbers 5 and 10 respectively represent the composite error. Composite error is the rms value of the difference between the instantaneous primary current and the instantaneous secondary current multiplied by the turns ratio, under steady state conditions.

Class PS cores are used in balance systems of protection as CTs with a high degree of similarity in their characteristics are required. These requirements are met by Class PS. Their performance is defined in terms of a knee-point voltage (KPV), the magnetizing current (Imag) at the knee point voltage or 1/2 or 1/4 the knee-point voltage, and the resistance of the CT secondary winding. Accuracy is defined in terms of the turns ratio.

7. Rated knee point e.m.f. (Ek)

The minimum sinusoidal e.m.f. (r.m.s.) at rated power frequency applied to the secondary terminals of the transformer, all other terminals being open-circuited, which when increased by 10% causes the r.m.s. exciting current to increase by no more than 50%. Note : The actual knee point e.m.f. will be ≥ the rated knee point e.m.f.

8. Short time rating

The value of primary current (in kA) that the CT should be able to withstand both thermally and dynamically without damage to the windings, with the secondary circuit being short-circuited. The time specified is usually 1 or 3 seconds.

4.3.9 Typical Specification for a 11 kV CT

System voltage:11 kV
Ratio: 1200/1-1-1A
Core 1: 1A, metering, 15 VA/class 1, ISF<10
Core 2: 1 A, protection, 15 VA/5P10
Core 3: 0.577 A, Class PS, KPV>= 150 V, Imag at Vk/2 <=30 mA, RCT at 75 C<=2 ohms
Short time rating:20 kA for 1 second

4.3.10 Terminal designations for current transformers

According to IEC standards, the terminals of CTs should be designated as shown in the following diagrams. All terminals that are marked P1, S1 and C1 are to have the same polarity.

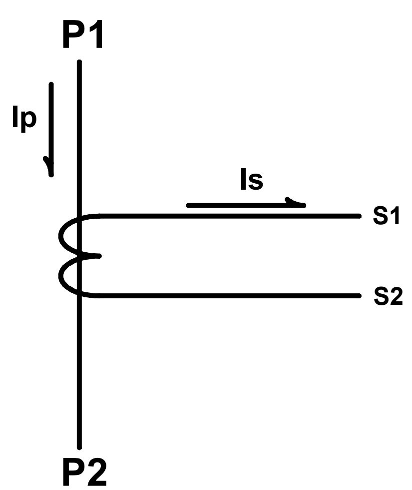


Figure 4.20 - CT with One Secondary

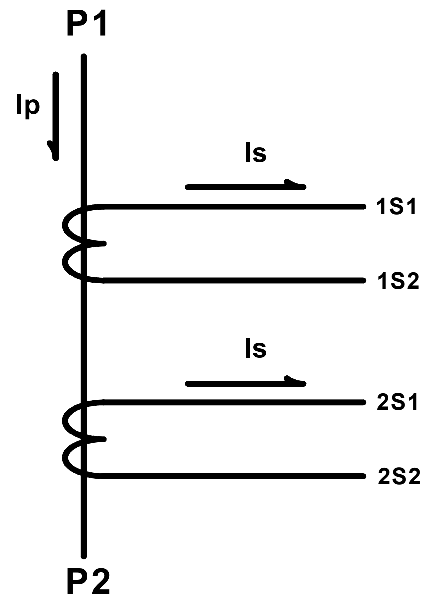


Figure 4.21 - CT with Two Secondaries

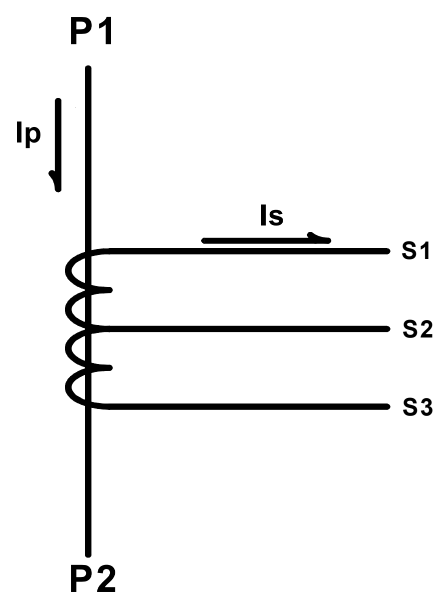


Figure 4.22 - CT with one secondary winding which has an extra tapping

4.3.11 Secondary grounding of current transformers

To prevent the secondary circuits from attaining dangerously high potential to ground, these circuits have to be grounded. Connect either the S1 terminal or the S2 terminal to ground. For protective relays, ground the terminal that is nearest to the protected objects. For meters and instruments, ground the terminal that is nearest to the consumer. When metering instruments and protective relays are on the same winding, the protective relay determines the point to be grounded. If there are unused taps on the secondary winding, they must be left open. If there is a galvanic connection between more than one current transformer, these shall be grounded at one point only (e.g. differential protection). If the cores are not used in a current transformer they must be short-circuited between the highest ratio taps and shall be grounded.

4.3.12 Warning - Never Keep CT Secondary Open

A current transformer secondary should never be kept open circuited while its primary winding is energized. Failure to observe this precaution may cause serious consequences both to the operating personnel and to the current transformer.

Primary winding of current transformer is in series with the line whose current is to be measured and this current is in no way controlled or determined by the conditions of the secondary winding. Under normal operating conditions both primary and secondary windings carry currents. The secondary current produces mmf which neutralizes the mmf produced by the primary current.

If the secondary winding is kept open circuited when the primary winding is carrying current, the primary mmf is not neutralized due to the absence of secondary current. This large primary mmf produces a large flux in the CT core. Large flux linking the secondary winding turns induces a very high voltage across the secondary winding which could be dangerous to the CT insulation (although modern CTs are designed to withstand this voltage) and to the person who has opened the circuit.

Most current transformers are provided with a shorting link at the secondary winding terminals. It should always be closed before any change is made in the secondary winding circuit with primary winding excited.

CHAPTER – 5

PROTECTIVE RELAYING FUNDAMENTALS

5.1 Introduction to Protective Relays

One of the most important equipments employed in the protection of power systems are protective relays. These are one of the most flexible, economic and well-known devices that provide reliable, fast and inexpensive protection. Relay is defined as "an electric device that is designed to interpret input conditions in a prescribed manner, and; after specified conditions are met, to respond to cause contact operation or similar abrupt changes in associated electric control circuits". Relays acquire signals from the power system (electrical, magnetic, heat, pressure, etc.) and process them with a designed process or algorithm. A protective relay is defined as "a relay whose function is to detect defective lines or apparatus or other power conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action". Protective relays have provided protection since the beginning of the electric industry, and have encountered great transformations with time as power systems have grown in size and complexity. Early protective relays were constructed using solenoids and electromagnetic actuators. Those relays were bulky and heavy devices that needed lot of space to be mounted. Because of their development and use over several decades, electromechanical relays evolved to become standard accepted devices. Even modern relays use most of the principles of operation of electromechanical relays. Solid-state relays replaced electromechanical actuators by analog electronic elements. Even when the protection systems based on electromechanical relays had proved to be reliable, solid-state relays gained confidence of protection engineers because of their advantages of lower costs, reduced space and weight, and ease to set, maintain and operate.

The developments in digital technology led to the incorporation of microprocessors in the construction of relays. Digital and numerical relays are sophisticated, multipurpose equipment with the capacity to record signals during faults, monitor themselves and communicate with their peers. Numerical relays employ microprocessors especially constructed to process digital signals, which make them faster and more powerful, while preserving their economic advantages.

5.2 Fundamentals of Protective Relaying

Protection of costly electrical equipment against short circuits is one of the key concerns of protection engineers. Equipments used for protection against short circuits can be classified into two categories

1. Primary Protection
2. Backup Protection

5.2.1 Primary Protection

Figure 5.1 illustrates primary relaying. The first observation is that circuit breakers are located in the connections to each power element. This provision makes it possible to disconnect only a faulty element. Occasionally, a breaker between two adjacent elements may be omitted, in which event both elements must be disconnected for a failure in either one. The second observation is that, without at this time knowing how it is accomplished, a separate zone of protection is established around each system element. The significance of this is that any failure occurring within a given zone will cause the tripping (i.e., opening) of all circuit breakers within that zone, and only those breakers. It will become evident that, for failures within the region where two adjacent protective zones overlap, more breakers will be tripped than the minimum necessary to disconnect the faulty element. But, if there were no overlap, a failure in a region between zones would not lie in either zone, and therefore no breakers would be tripped. The overlap is the lesser of the two evils. The extent of the overlap is relatively small, and the probability of failure in this region is low; consequently, the tripping of too many breakers will be quite infrequent.

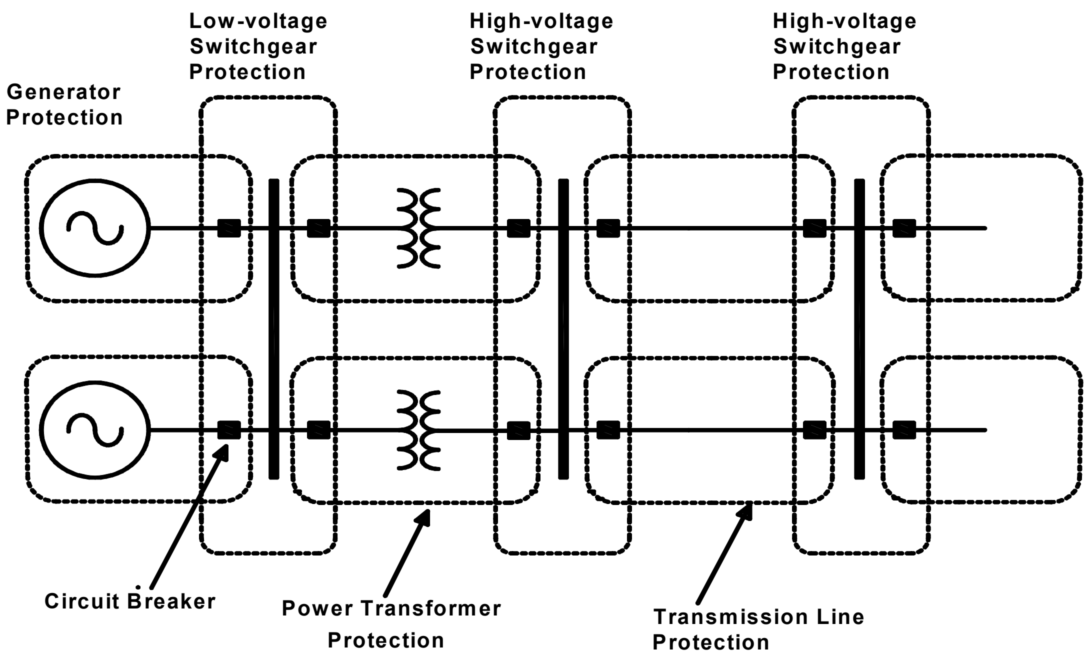


Figure 5.1 - Relay Protection Zones

Finally, it will be observed that adjacent protective zones of figure 5.1 overlap around a circuit breaker. This is the preferred practice because, for failures anywhere except in the overlap region, the minimum number of circuit breakers need to be tripped. When it becomes desirable for economic or space-saving reasons to overlap on one side of a breaker, as is frequently true in metal-clad switchgear the relaying equipment of the zone that overlaps the breaker must be arranged to trip not only the breakers within its zone but also one or more breakers of the adjacent zone, in order to completely disconnect certain faults. This is illustrated in figure 5.2, where it can be seen that, for a short circuit at X, the circuit breakers of zone B, including breaker C, will be tripped; but, since the short circuit is outside zone A, the relaying equipment of zone B must also trip certain breakers in zone A if that is necessary to interrupt the flow of short circuit current from zone A to the fault. This is not a disadvantage for a fault at X, but the same breakers in zone A will be tripped unnecessarily for other faults in zone B to the right of breaker C. Whether this unnecessary tripping is objectionable will depend on the particular application.

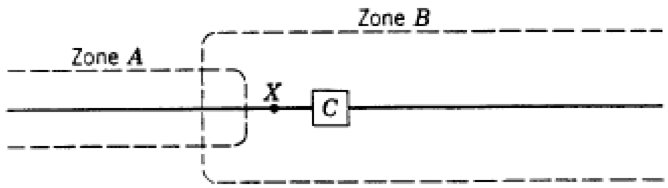


Figure 5.2 - Overlapping Adjacent Protective Zones

5.2.2 Back-Up Protection

Back-up protection is provided to ensure that the faulted element of the system is disconnected even if the primary protection fails to isolate the faulted element. Back-up protection can be provided locally or from a remote location. Local back-up protection is provided by equipment that is in addition to the equipment provided for primary protection whereas remote back-up protection is provided by equipment that is physically located at substations away from the location where equipment for primary protection is located. Primary relaying may fail because of failure in any of the following:

A. Current or voltage supply to the relays.
B. D.C. tripping-voltage supply.
C. Protective relays.
D. Tripping circuit or breaker mechanism.
E. Circuit breaker.

It is highly desirable that back-up relaying be arranged so that anything that might cause primary relaying to fail will not also cause failure of back-up relaying. It will be evident that this requirement is completely satisfied only if the back-up relays are located so that they do not employ or control anything in common with the primary relays that are to be backed up. So far as possible, the practice is to locate the back-up relays at a different station. Consider, for example, the back-up relaying for the transmission line section EF of figure 5.3. The back-up relays for this line section are normally arranged to trip breakers A, B, I, and J. Should breaker E fail to trip for a fault on the line section EF, breakers A and B are tripped; breakers A and B and their associated back-up equipment, being physically apart from the equipment that has failed, are not likely to be simultaneously affected as might be the case if breakers C and D were chosen instead.

The back-up relays at locations A, B, and F provide back-up protection if bus faults occur at station K. Also, the back-up relays at A and F provide back-up protection for faults in the line DB. In other words, the zone of protection of back-up relaying extends in one direction from the location of any back-up relay and at least overlaps each adjacent system element. Where adjacent line sections are of different length, the back-up relays must overreach some line sections more than others in order to provide back-up protection for the longest line. A given set of back-up relays will provide incidental back-up protection of sorts for faults in the circuit whose breaker the back-up relays control. For example, the back-up relays that trip breaker A of figure 5.3 may also act as back-up for faults in the line section AC. However, this duplication of protection is only an incidental benefit and is not to be relied on to the exclusion of a conventional back-up arrangement when such arrangement is possible; to differentiate between the two, this type might be called duplicate primary relaying.

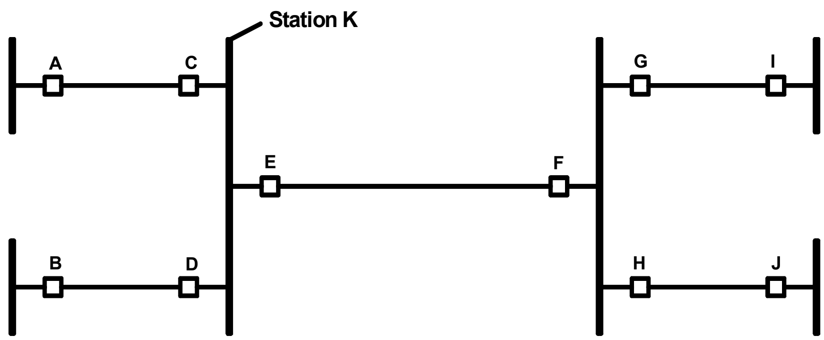


Figure 5.3 - Illustration for Backup Protection of Transmission Line EF

A second function of back-up relaying is often to provide primary protection when the primary-relaying equipment is out of service for maintenance or repair. It is perhaps evident that, when back-up relaying functions, a larger part of the system is disconnected than when primary relaying operates correctly. This is inevitable if back-up relaying is to be made independent of those factors that might cause primary relaying to fail. However, it emphasizes the importance of the second requirement of back-up relaying, that it must operate with sufficient time delay so that primary relaying will be given enough time to function if it is able to. In other words, when a short circuit occurs, both primary relaying and back-up relaying will normally start to operate, but primary relaying is expected to trip the necessary breakers to remove the short-circuited element from the system, and back-up relaying will then reset without having had time to complete its function. When a given set of relays provides back-up protection for several adjacent system elements, the slowest primary relaying of any of those adjacent elements will determine the necessary time delay of the given back-up relays. For many applications, it is impossible to abide by the principle of complete segregation of the back-up relays. Then one tries to supply the back-up relays from sources other than those that supply the primary relays of the system element in question, and to trip other breakers. This can usually be accomplished; however, the same tripping battery may be employed in common, to save money and because it is considered only a minor risk. In extreme cases, it may even be impossible to provide any back-up protection; in such cases, greater emphasis is placed on the need for better maintenance. In fact, even with complete back-up relaying, there is still much to be gained by proper maintenance. When primary relaying fails, even though back-up relaying functions properly, the service will generally suffer more or less. Consequently, back-up relaying is not a proper substitute for good maintenance.

5.3 Protection Against Other Abnormal Conditions

Protective relaying for other than short circuits is included in the category of primary relaying. However, since the abnormal conditions requiring protection are different for each system element, no universal overlapping arrangement of relaying is used as in short protection. Instead, each system element is independently provided with whatever relaying is required, and this relaying is arranged to trip the necessary circuit breakers which may in some cases be different from those tripped by the short-circuit relaying. As previously mentioned, back-up relaying is not employed because experience has not shown it to be economically justifiable. Frequently, however, back-up relaying for short circuits will function when other abnormal conditions occur that produce abnormal currents or voltages, and back-up protection of sorts is thereby incidentally provided.

5.4 Characteristics of Protective Relays

A number of different characteristics for operation may be established, but the three most common ones are speed, reliability/security and selectivity. All the characteristics need to be combined in a sound engineering solution to produce the desirable performance, but for the sake of clarity, each of the characteristic is now discussed separately.

5.4.1 Speed

The speed of operation is the most critical protective relay operating criterion. The relays have to be fast enough to allow clearing of a fault in the minimum time needed to ensure reliable and safe power system operation. The minimum operating time of a relay is achieved when the relay operates without any intentional time delay settings. Such an example is the time of operation of a distance relay in a direct (instantaneous) trip in zone1. The operating time may vary from the theoretical minimum possible to the time that a practical solution of a relaying algorithm and technology used to implement the relay design. Because the relays respond to the fault transients, the relay operating time may vary slightly for the same relay if subjected to the transients coming from different types of faults. The minimum acceptable operating time is often established to make sure that the relay will operate fast enough to meet other time critical criteria. The overall time budget for clearing faults in a system is expressed based on the number of cycles of the fundamental frequency voltage and current signals. This time is computed from the worst case fault type persisting and potentially causing instability in the overall power system. To prevent the instability from occurring, the fault needs to be cleared well before this critical time is reached, hence the definition of the minimum fault clearance time. The relay operating time is only a portion of this time budget allocation. The rest is related to the operation of circuit breakers and a possible multiple reclosing action that needs to be taken. The consideration also includes the breaker failure action taken in the case a breaker fails to open and other breakers get involved in clearing the fault. The relay operating time is a critical criterion even through it is allocated a very small portion of the mentioned fault clearing time budget criteria.

5.4.2 Reliability/ Security

An important operating criterion for protective relays is dependability/security. It is often mentioned as a pair since dependability and security are selected in a trade-off mode. Dependability is defined as the relay ability to respond to a fault by recognizing it each time it occurs. Security is defined as an ability of a relay not to act if a disturbance is not a fault. In almost all the relay approaches used today, the relays are selected with a bias toward dependability or security in such a way that one affects the other. A more dependable approach will cause the relays to over trip. The term used to designate that the relay will operate whenever there is a fault but at the expense of possibly tripping even for non fault events. The security emphasis will cause relays not to trip for no fault conditions but at a risk of not operating correctly when the fault occurs. The mentioned trade off when selecting the relaying approach is made by choosing different types of relaying schemes and related settings to support one or the other aspect of the relay operation.

5.4.3 Selectivity and Discrimination

The relaying system shall be such that the faulty equipment alone is isolated from the system, leaving the remaining healthy portion intact, In case of failure of protection of an equipment, the back up relay operates, in which case, certain amount of selectivity is lost as equipment which are not involved in the abnormal conditions, may also have to be isolated. The relays shall be designed to discriminate the fault from normal conditions, which may appear as an abnormal condition when seen by the relay. Typical examples are charging in rush current of transformer, starting current of direct on line starting of induction motor, which will be seen by the relay as an overload. So also, power swings may be seen by an impedance measuring relay as a fault. The relay should be suitably designed to differentiate such conditions from the fault conditions without losing selectivity or speed of operation.

Successful operation of protection systems depends not only on relays but also on other factors like reliability of control supply, healthiness of trip coil and its circuit and mechanical and electrical operation of the switchgear. Since the ultimate aim of the relay operation is isolation of the equipment, proper operation of the switchgear should also be ensured. Thus the healthiness of control supply and other factors become as important as the reliability of the relay itself.

5.5 Electromechanical relays

There are only two fundamentally different operating principles of electromechanical relays:

1. Electromagnetic attraction
2. Electromagnetic induction

Electromagnetic attraction relays operate by virtue of a plunger being drawn into a solenoid, or an armature being attracted to the poles of an electromagnet. Such relays may be actuated by d-c or by a-c quantities. Electromagnetic-induction relays use the principle of the induction motor whereby torque is developed by induction in a rotor; this operating principle applies only to relays actuated by alternating current, and in dealing with those relays we shall call them simply "induction-type" relays.

5.5.1 Electromagnetic Attraction Relays

a. Operating Principle

The electromagnetic force exerted on the moving element is proportional to the square of the flux in the air gap. If we neglect the effect of saturation, the total actuating force may be expressed:

$$F = K_1 I^2 - K_2$$

Where F = net force.
K_1 = a force-conversion constant.
I = the rms magnitude of the current in the actuating coil.
K_2 = the restraining force (including friction).

b. Ratio of Reset to Pickup

One characteristic that affects the application of some of these relays is the relatively large difference between their pickup and reset values. As such a relay picks up, it shortens its air gap, which permits a smaller magnitude of coil current to keep the relay picked up than was required to pick it up. This effect is less pronounced in a-c than in d-c relays. By special design, the reset can be made as high as 90% to 95% of pickup for a-c relays, and 60% to 90% of pickup for d-c relays. Where the pickup is adjusted by adjusting the initial air gap, a higher pickup calibration will have a lower ratio of reset to pickup. For overcurrent applications where such relays are often used, the relay trips a circuit breaker which reduces the current to zero, and hence the reset value is of no consequence. However, if a low-reset relay is used in conjuction with other relays in such a way that a breaker is not always tripped when the low-reset relay operates, the application should be carefully examined. When the reset value is a low percentage of the pickup value, there is the possibility that an abnormal condition might cause the relay to pick up (or to reset), but that a return to normal conditions might not return the relay to its normal operating position, and undesired operation might result.

c. Tendency towards Vibration

Unless the pole pieces of such relays have "shading rings" to split the air-gap flux into two out-of-phase components, such relays are not suitable for continuous operation on alternating current in the picked-up position. This is because there would be excessive vibration that would produce objectionable noise and would cause excessive wear. This tendency to vibrate is related to the fact that a-c relays have higher reset than d-c relays; an a-c relay without shading rings has a tendency to reset every half cycle when the flux passes through zero.

d. Directional Control

Relays of this group are used mostly when "directional" operation is not required. More will be said later about "directional control" of relays; suffice it to say here that plunger or attracted-armature relays do not lend themselves to directional control nearly as well as induction-type relays, which will be considered later.

e. Effect of Transients

Because these relays operate so quickly and with almost equal current facility on either alternating current or direct current, they are affected by transients, and particularly by d-c offset in a-c waves. This tendency must be taken into consideration when the proper adjustment for any application is being determined. Even though the steady-state value of an offset wave is less than the relay's pickup value, the relay may pick up during such a transient, depending on the amount of offset, its time constant, and the operating speed of the relay. This tendency is called "overreach" for reasons that will be given later.

f. Time Characteristics

This type of relay is inherently fast and is used generally where time delay is not required. Time delay can be obtained, as previously stated, by delaying mechanisms such as bellows, dash pots, or escapements. Very short time delays are obtainable in d-c relays by encircling the magnetic circuit with a low-resistance ring, or "slug" as it is sometimes called. This ring delays changes in flux, and it can be positioned either to have more effect on air increase if time-delay pickup is desired, or to have more effect on air-gap-flux decrease if time-delay reset is required.

g. Directional Relays of Electromagnetic Attraction Type

Figure 5.4 illustrates schematically the operating principle of this type of relay. A movable armature is shown magnetized by current flowing in an actuating coil encircling the armature, and with such polarity as to close the contacts. A reversal of the polarity of the actuating quantity will reverse the magnetic polarities of the ends of the armature and cause the contacts to stay open. Although a "polarizing," or "field," coil is shown for magnetizing the polarizing magnet, this coil may be replaced by a permanent magnet in the section between x and y. There are many physical variations possible in carrying out this principle, one of them being a construction similar to that of a d-c motor.

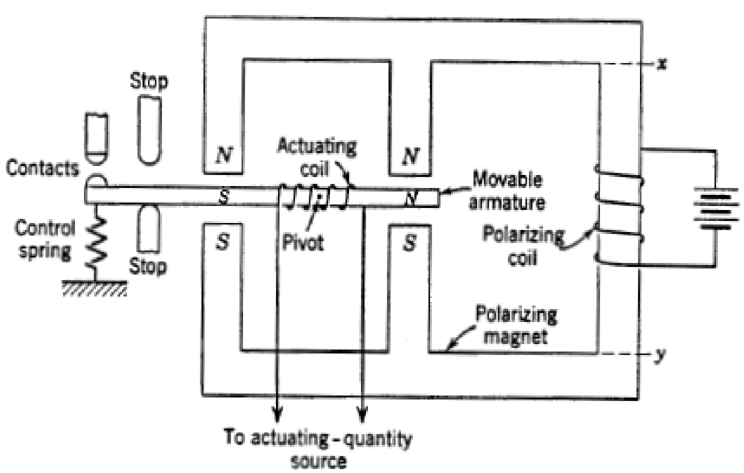


Figure 5.4 - Directional Relay of the Electromagnetic Armature Type

The force tending to move the armature may be expressed as follows, if we neglect saturation:

$$F = K_1 I_p I_a - K_2,$$

Where F is the net force
K_1 is a force-conversion constant.
Ip is the magnitude of the current in the polarizing coil.
Ia is the magnitude of the current in the armature coil.
K_2 is the restraining force (including friction).

At the balance point when F = 0, the relay is on the verge of operating, and the operating characteristic is:

$$I_p . I_a = K_1/K_2 = \text{constant}$$

Ip and Ia, are assumed to flow through the coils in such directions that a pickup force is produced, as in figure 5.4. It will be evident that, if the direction of either Ip or Ia (but not of both) is reversed, the direction of the force will be reversed. Therefore, this relay gets its name from its ability to distinguish between opposite directions of actuating-coil current flow, or opposite polarities. If the relative directions are correct for operation, the relay will pick up at a constant magnitude of the product of the two currents. If permanent-magnet polarization is used, or if the polarizing coil is connected to a source that will cause a constant magnitude of current to flow, the operating characteristic becomes:

$$I_a = K_2/(K_1 I_p)$$

Ia still must have the correct polarity, as well as the correct magnitude, for the relay to pick up. This type of relay in much more efficient than hinged-armature or plunger relays, from the standpoint of the energy required from the actuating-coil circuit. For this reason, such directional relays are used when a d-c shunt is the actuating source, whether directional action is required or not. Occasionally, such a relay may be actuated from an a-c quantity through a full-wave rectifier when a low-energy a-c relay is required.

5.5.2 Induction Type Relays

Induction-type relays are the most widely used for protective-relaying purposes involving ac quantities. They are not usable with d-c quantities, owing to the principle of operation. An induction-type relay is a split-phase induction motor with contacts. Actuating force is developed in a movable element, which may be a disc or other form of rotor of non magnetic current-conducting material, by the interaction of electromagnetic fluxes with eddy currents that are induced in the rotor by these fluxes.

a. Operating Principle

Figure 5.5 shows how force is produced in a section of a rotor that is pierced by two adjacent a-c fluxes. Various quantities are shown at an instant when both fluxes are directed downward and are increasing in magnitude. Each flux induces voltage around itself in the rotor, and currents flow in the rotor under the influence of the two voltages. The current produced by one flux reacts with the other flux, and vice versa, to produce forces that act on the rotor.

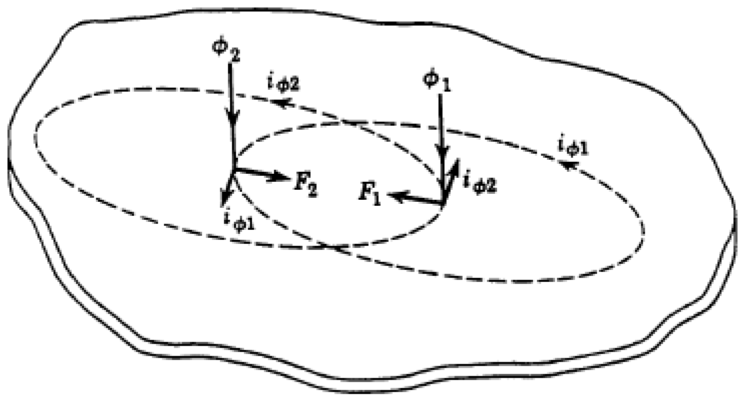


Figure 5.5 - Torque Production in Induction Relay

The quantities involved in Fig. 5.5 may be expressed as follows:

$$\phi_1 = \Phi_1 \sin \omega t$$
$$\phi_2 = \Phi_2 \sin (\omega t + \theta),$$

where θ is the phase angle by which ϕ_1 leads ϕ_2. It may be assumed with negligible error that the paths in which the rotor currents flow have negligible self-inductance, and hence that the rotor currents are in phase with their voltages:

$$i\phi_1 \;\alpha\; d\phi_1/dt \;\alpha\; \Phi_1 \cos \omega t$$

$$i\phi_2 \;\alpha\; d\phi_2/dt \;\alpha\; \Phi_2 \cos (\omega t + \theta)$$

We note that figure 5.5 shows the two forces in opposition, and consequently we may write the equation for the net force (F) as follows:

$$F = (F_2 - F_1)\; \alpha\; (\phi_2 i\phi_1 - \phi_1 i\phi_2) \qquad (1)$$

Substituting the values of the quantities into equation 1, we get:

$$F \;\alpha\; \Phi_1\Phi_2 [\sin (\omega t + \theta) \cos \omega t - \sin \omega t \cos (\omega t + \theta)] \qquad (2)$$

which reduces to:

$$F \;\alpha\; \Phi_1\Phi_2 \sin \theta \qquad (3)$$

Since sinusoidal flux waves were assumed, we may substitute the rms values of the fluxes for the crest values in equation 3. Apart from the fundamental relation expressed by equation 3, it is most significant that the net force is the same at every instant. This fact does not depend on the simplifying assumptions that were made in arriving at equation 3. The action of a relay under the influence of such a force is positive and free from vibration. Also, although it may not be immediately apparent, the net force is directed from the point where the leading flux pierces the rotor toward the point where the lagging flux pierces the rotor. It is as though the flux moved across the rotor, dragging the rotor along. In other words, actuating force is produced in the presence of out-of-phase fluxes. One flux alone would produce no net force. There must be at least two out-of-phase fluxes to produce any net force, and the maximum force is produced when the two fluxes are 90° out of phase. Also, the direction of the force-and hence the direction of motion of the relays movable member-depends on which flux is leading the other. A better insight into the production of actuating force in the induction relay can be obtained by plotting the two components of the expression inside the brackets of equation 2, which we may call the "per-unit net force." Figure 5.6 shows such a plot when θ is assumed to be 90°. It will be observed that each expression is a double-frequency sinusoidal wave completely offset from the zero-force axis.

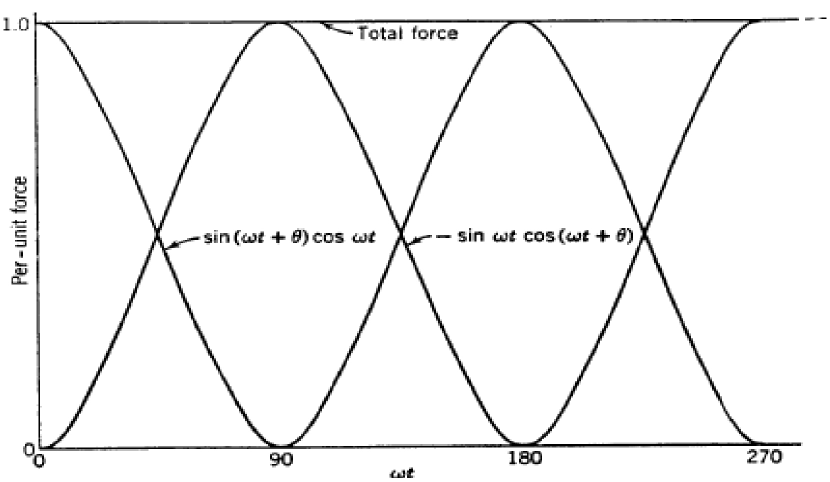


Figure 5.6 - Per Unit Net Force

The two waves are displaced from one another by 90° in terms of fundamental frequency, or by 180° in terms of double frequency. The sum of the instantaneous values of the two waves is 1.0 at every instant. If θ were assumed to be less than 90°, the effect on figure 5.6 would be to raise the zero-force axis, and a smaller per-unit net force would result. When θ is zero, the two waves are symmetrical about the zero-force axis, and no net force is produced. If we let θ be negative, which is to say that Φ2 is lagging Φ1, the zero-force axis is raised still higher and net force in the opposite direction is produced. However, for a given value of q, the net force is the same at each instant.

In some induction-type relays one of the two fluxes does not react with rotor currents produced by the other flux. The force expression for such a relay has only one of the components inside the brackets of equation 2. The average force of such a relay may still be expressed by equation 3, but the instantaneous force is variable, as shown by omitting one of the waves of figure 5.6. Except when θ is 90° lead or lag, the instantaneous force will actually reverse during parts of the cycle; and, when θ = 0, the average negative force equals the average positive force. Such a relay has a tendency to vibrate, particularly at values of θ close to zero.

b. Types of Actuating Structure

The different types of structure that have been used are commonly called:

1. The "shaded pole" structure;
2. The "watthour-meter" structure;
3. The "induction-cup" and the "double-induction-loop" structures;
4. The "single-induction-loop" structure.

1. Shaded Pole Structure.

The shaded-pole structure, illustrated in figure 5.7, is generally actuated by current flowing in a single coil on a magnetic structure containing an air gap. The airgap flux produced by this current is split into two out-of-phase components by a so-called "shading ring," generally of copper, that encircles part of the pole face of each pole at the air gap. The rotor, shown edgewise in figure 5.7, is a copper or aluminum disc, pivoted so as to rotate in the air gap between the poles. The phase angle between the fluxes piercing the disc is fixed by design, and consequently it does not enter into application considerations.

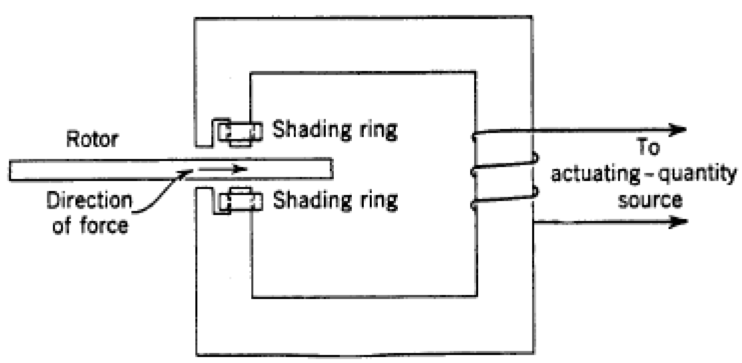


Figure 5.7 Shaded Pole Structure

The shading rings may be replaced by coils if control of the operation of a shaded-pole relay is desired. If the shading coils are short-circuited by a contact of some other relay, torque will be produced; but, if the coils are open-circuited, no torque will be produced because there will be no phase splitting of the flux. Such torque control is employed where "directional control" is desired, which will be described later.

2. Watt-hour Meter Structure

This structure gets its name from the fact that it is used for watthour meters. As shown in figure 5.8, this structure contains two separate coils on two different magnetic circuits, each of which produces one of the two necessary fluxes for driving the rotor, which is also a disc.

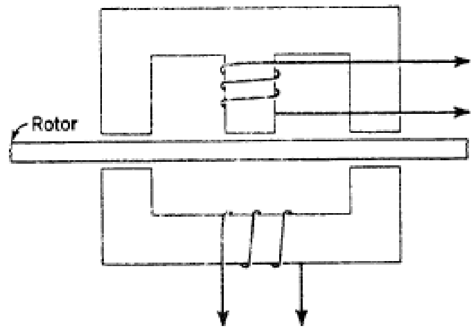


Figure 5.8 - Watt-hour Meter Structure

3. Induction Cup and Double Induction Loop Structures

These two structures are shown in figures 5.9 and 5.10. They most closely resemble an induction motor, except that the rotor iron is stationary, only the rotor-conductor portion being free to rotate. The cup structure employs a hollow cylindrical rotor, whereas the double-loop structure employs two loops at right angles to one another. The cup structure may have additional poles between those shown in figure 5.9. Functionally, both structures are practically identical.

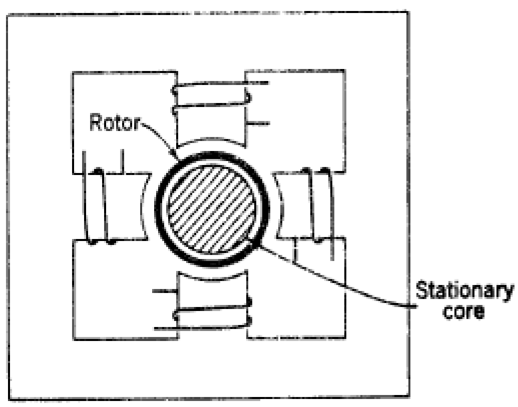


Figure 5.9 - Induction Cup Structure

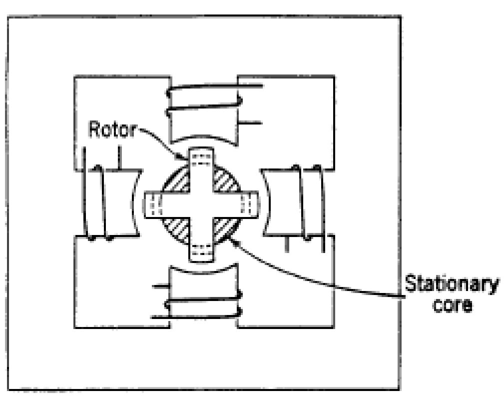


Figure 5.10 - Double Induction Loop Structure

These structures are more efficient torque producers than either the shaded-pole or the Watt-hour meter structures and they are the type used in high-speed relays.

4. Single Induction Loop Structure

This structure, shown in figure 5.11, is the most efficient torque producing structure of all the induction types that have been described. However, it has the rather serious disadvantage that its rotor tends to vibrate as previously described for a relay in which the actuating force is expressed by only one component inside the brackets of equation 2. Also, the torque varies somewhat with the rotor position.

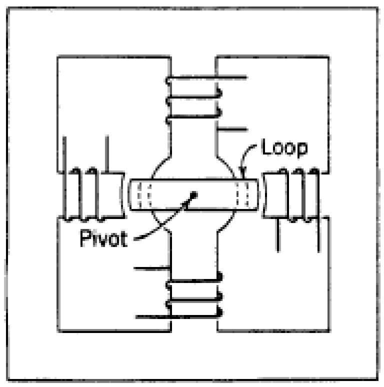


Figure 5.11 - Single Induction Loop Structure

c. Accuracy

The accuracy of an induction relay recommends it for protective-relaying purposes. Such relays are comparable in accuracy to meters used for billing purposes. This accuracy is not a consequence of the induction principle, but because such relays invariably employ jewel bearings and precision parts that minimize friction.

d. Single Quantity Induction Relays

A single-quantity relay is actuated from a single current or voltage source. Any of the induction relay actuating structures may be used. The shaded-pole structure is used only for single-quantity relays. When any of the other structures is used, its two actuating circuits are connected in series or in parallel; and the required phase angle between the two fluxes is obtained by arranging the two circuits to have different X/R (reactance-to-resistance) ratios by the use of auxiliary resistance and/or capacitance in combination with one of the circuits. Neglecting the effect of saturation, the torque of all such relays may be expressed as:

$$T = K_1 I^2 - K_2$$

where I is the rms magnitude of the total current of the two circuits. The phase angle between the individual currents is a design constant, and it does not enter into the application of these relays. If the relay is actuated from a voltage source, its torque may be expressed as:

$$T = K_1V^2 - K_2$$

Where V is the rms magnitude of the voltage applied to the relay.

e. Ratio of Reset to Pickup

The ratio of reset to pickup is inherently high in induction relays; because their operation does not involve any change in the air gap of the magnetic circuit. This ratio is between 95% and 100% friction and imperfect compensation of the control-spring torque being the only things that keep the ratio from being 100%. Moreover, this ratio is unaffected by the pickup adjustment where tapped current coils provide the pickup adjustment.

f. Reset Time

Where fast automatic reclosing of circuit breakers is involved, the reset time of an inverse time relay may be a critical characteristic in obtaining selectivity. If all relays involved do not have time to reset completely after a circuit breaker has been tripped and before the breaker recloses, and if the short circuit that caused tripping is re-established when the breaker recloses, certain relays may operate too quickly and trip unnecessarily. Sometimes the drop-out time may also be important with high-speed reclosing.

g. Time Characteristics

Inverse-time curves are obtained with relays whose rotor is a disc and whose actuating structure is either the shaded-pole type or the watthour-meter type. High-speed operation is obtained with the induction-cup or the induction-loop structures.

h. Directional Induction Relays

Contrasted with single-quantity relays, directional relays are actuated from two different independent sources, and hence the angle of equation 3 is subject to change and must be considered in the application of these relays. Such relays use the actuating structures of figures 5.8, 5.9, 5.10 or 5.11.

1. Torque Relations for Current-Voltage Relays

A current-voltage relay receives one actuating quantity from a current-transformer source and the other actuating quantity from a voltage-transformer source. The torque is given by the equation:

$$T = K1VI \cos(\theta - \tau) - K2 \qquad (4)$$

Where, V = the rms magnitude of the voltage applied to the voltage coil circuit.
I = the rms magnitude of the current-coil current.
θ = the angle between I and V.
τ = the angle of maximum torque.
For whatever relation between I and V that we call θ positive, we should also call τ positive for that same relation. These quantities are shown in figure 5.12 together with the voltage-coil current I_V and the approximate angle ϕ by which I_V lags V.

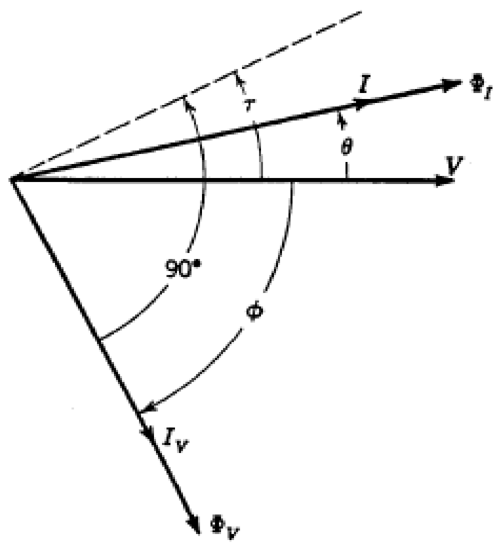


Figure 5.12 Vector diagram for maximum torque in a current-voltage induction type directional relay.

The value of ϕ is of the order of 60° to 70° lagging for most voltage coils, and therefore τ will be of the order of 30° to 20° leading if there is no impedance in series with the voltage coil. By inserting a combination of resistance and capacitance in series with the voltage coil, we can change the angle between the applied voltage and I_V to almost any value either lagging or leading V without changing the magnitude of I_V. A limited change in ϕ can be made with resistance alone, but the magnitude of I_V will be decreased, and hence the pickup will be increased. Hence, the angle of maximum torque can be made almost any desired value. By other supplementary means, which we shall not discuss here, the angle of maximum torque can be made any desired value.

2. Significance of the Term Directional

AC directional relays are used most extensively to recognize the difference between current being supplied in one direction or the other in an a-c circuit, and the term "directional" is derived from this usage. Basically, an a-c directional relay can recognize certain differences in phase angle between two quantities, just as a d-c directional relay recognizes differences in polarity. This recognition, as reflected in the contact action, is limited to differences in phase angle exceeding 90° from the phase angle at which maximum torque is developed, as already described.

3. The Polarizing Quantity of Directional Relay

The quantity that produces one of the fluxes is called the "polarizing" quantity. It is the reference against which the phase angle of the other quantity is compared. Consequently, the phase angle of the polarizing quantity must remain more or less fixed when the other quantity suffers wide changes in phase angle. The choice of a suitable polarizing quantity will be discussed later, since it does not affect our present considerations.

4. The Operating Characteristic of a Directional Relay

Consider, for example, the torque relation expressed by equation (4) for a current-voltage directional relay. At the balance point when the relay is on the verge of operating, the net torque is zero, and we have

$$VI \cos (\theta - \tau) = K_2/K_1 = \text{Constant}$$

This operating characteristic can be shown on a polar-coordinate diagram, as in figure 5.13. The polarizing quantity, which is the voltage for this type of relay, is the reference; and its magnitude is assumed to be constant. The operating characteristic is seen to be a straight line offset from the origin and perpendicular to the maximum positive-torque position of the current. This line is the plot of the relation:

$$I \cos (\theta - \tau) = \text{Constant}$$

which is obtained when the magnitude of V is assumed to be constant, and it is the dividing line between the development of net positive and negative torque in the relay. Any current vector whose head lies in the positive-torque area will cause pickup; the relay will not pick up, or it will reset, for any current vector whose head lies in the negative-torque area.

For a different magnitude of the reference voltage, the operating characteristic will be another straight line parallel to the one shown and related to it by the expression:

$$VImin = \text{constant}$$

Where Imin, as shown in figure 5.13, is the smallest magnitude of all current vectors whose heads terminate on the operating characteristic. Imin, is called "the minimum pickup current," although strictly speaking the current must be slightly larger to cause pickup.

Thus, there are an infinite possible number of such operating characteristics, one for each possible magnitude of the reference voltage. The operating characteristic will depart from a straight line as the phase angle of the current approaches 90° from the maximum-torque phase angle. For such large angular departures, the pickup current becomes very large, and magnetic saturation of the current element requires a different magnitude of current to cause pickup from the one that the straight-line relation would indicate.

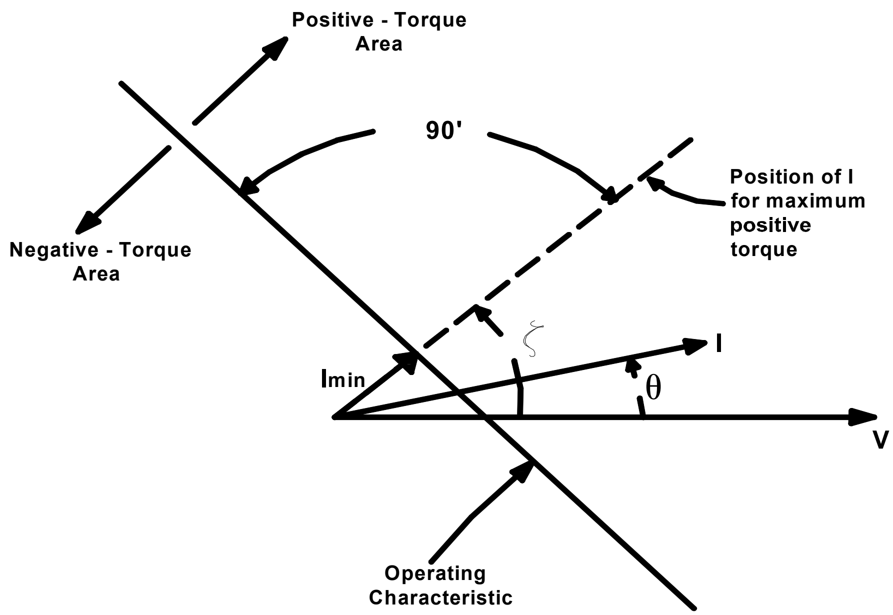


Figure 5.13 - Operating characteristic of a directional relay on polar coordinates.

5.6 Static Relays

A static relay can be defined as a protective relay in which the designated response is developed by electronic, magnetic or other components without mechanical motion. Electrical signals from current transformers and potential transformers are processed for desired functional output. Processing circuits comprise of amplifiers, comparators, phase shifting networks and filters etc. Settings of operating value, operating time and characteristic curves in Static relays is accomplished with potentiometers or fixed resistor selected by dip switches or thumb wheel switches. Settings are obtained by having taps on the built in instrument transformers causing relay burdens to vary.

5.7 Numerical Relays

In these relays the input signals from CTs and PTs are converted to digital signals by the device called Microprocessor or Microcontroller. The principle of these relays comprises of storing the digital signals in a circuit block called register and carrying out the signal processing by a series of instructions (Logic and Arithmetic). This technique of processing of signals is popularly referred to as “Software”.

Numerical relays provide superior performance and flexibility. Settings of relays are obtained without taps on instrument transformers which makes burden constant at all settings. Settings of numerical relays can be done by push buttons and can be read directly on a LCD display provided on the relay. Numerical relays also have memory feature which helps in recording of fault data and retrieval of the data for further analysis. Stored data can be uploaded on PC using the communication ports (RS232) provided on the relay.

5.7.1 Advantages of Numerical Relays over Electromechanical Relays

1. Numerical relays provide a very wide setting ranges with much better resolution (steps) as compared to eletromechanical and static relays.
2. Different charcteristics can be programmed in one relay enabling selection of the required charcteristic at site.
3. Numerical Relays have very high performance accuracy (operating errors can generally be Limited to 1 or 2%).
4. Numerical relays have extremely low burdens.
5. Numerical Relays are maintenance free and are much smaller in size as compared to electromechanical & static relays.
6. Numerical relays have memory and hence can store fault records. These records are very useful for fault analysis.

CHAPTER – 6

TYPES
OF
PROTECTIVE RELAYS

6.1 Introduction

Every important component of power system such as a power transformer or a transmission line needs to be protected against faults in order to minimize the damage caused by the fault. Nature of faults on various power system components vary. As a result different types of protective relays have been developed to provide efficient and reliable protection against various power system faults. Protective relays can be broadly classified into five basic classes

1. Magnitude relays
2. Directional relays
3. Distance (impedance) relays
4. Differential relays
5. Pilot relays

6.2 Magnitude Relays

These relays operate based on the magnitude of input quantities. Overcurrent relays, Overvoltage relays and Undervoltage relays are examples of this category of relays.

6.2.1 Overcurrent Relays

Over current protection is based on a very simple premise that in most instances of a fault, the level of fault current dramatically increases from the pre-fault value. If one establishes a threshold well above the nominal load current, as soon as the current exceeds the threshold, it may be assumed that a fault has occurred and a trip signal may be issued. The relay based on this principle is called an instantaneous over current relay, and it is widely used for protection of radial low voltage distributing lines, ground protection of high voltage transmission lines, and protection of machines (motors and generators). The main issue in applying this relaying principle is to understand the behaviour of the fault current well, in particular when compared to the variation in the load current caused by significant changes in the connected load. A typical example where it may become difficult to distinguish the fault levels from the normal operating levels is the over current protection of distribution lines with heavy fluctuations of the load. To accommodate the mentioned difficulty, a variety of over current protection applications are developed using the basic principle as described previously combined with a time delay. One approach is to provide a fixed time delay, and in some instances, the time delay is proportional to the current level. One possible relationship is an inverse one where the time delay is small for high currents and long for smaller ones. Relays with such characteristics are called Inverse Definite Minimum Time (IDMT) relays. The standard characteristic curve of such a relay is usually represented on a logarithmic scale and gives the operating time at different multiples (Plug Setting Multiplier) of setting current (Is), for the maximum “Time Multiplier Setting” (TMS). The TMS is continuously adjustable giving a range of time/current characteristic. Characteristic curves of IDMT relay and DMT relay are given below in figure 6.1 for reference.

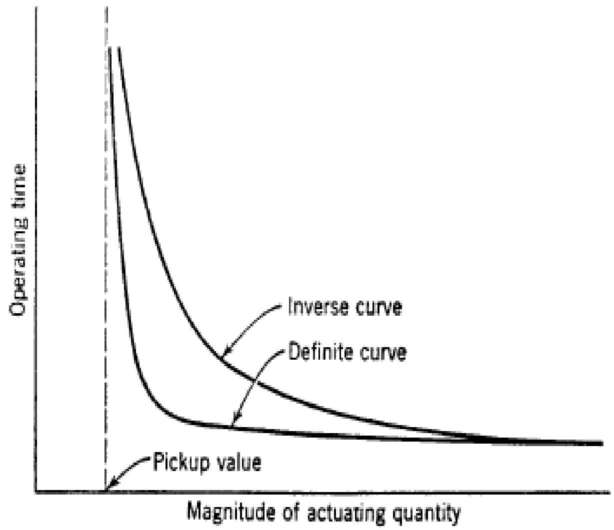


Figure 6.1 Characteristic of IDMT and DMT relays

6.2.2 Overvoltage and Undervoltage Relays

Overvoltage relays are used for protection against overvoltages. These relays operate if the system voltage exceeds a preset value. Overvoltage relays are used for tripping shunt capacitor banks when the system voltage improves to a desired level. On the other hand Undervoltage relays operate when the system voltage decreases below the set value.

6.3 Directional relays

When fault current can flow in both directions through the relay location, it may be necessary to make the response of the relay directional by the introduction of a directional control facility. The facility is provided by use of additional voltage inputs or polarizing voltage inputs to the relay. Relays that must respond to power are generally used for protecting against conditions other than short circuits. Such relays are connected to be polarized by a voltage of a circuit, and the current connections and the relay characteristics are chosen so that maximum torque in the relay occurs when unity-power-factor load is carried by the circuit. The relay will then pick up for power flowing in one direction through the circuit and will reset for the opposite direction of power flow. If a single-phase circuit is involved, a directional relay is used having maximum torque when the relay current is in phase with the relay voltage. The same relay can be used on a three-phase circuit if the load is sufficiently well balanced; in that event, the polarizing voltage must be in phase with the current in one of the three phases at unity-power-factor load (For simplicity, the term “phase” will be used frequently where the term “phase conductor” would be more strictly correct). Directional Element of Overcurrent relay checks the phase angle between current & voltage and threshold magnitude of current. If the phase angle is reverse & fault magnitude crosses its threshold then it allows the operation of relay.

6.3.1 Phase directional protection

The conventions and nomenclature used in dealing with three phase voltage and current vector diagrams for connections of directional relays is shown in figure 6.2. The voltages of figure 6.2 are defined as follows:

$$V_{ab} = V_a - V_b$$
$$V_{bc} = V_b - V_c$$
$$V_{ca} = V_c - V_a$$

From these definitions, it follows that:

$$V_{ba} = -V_{ab} = V_b - V_a$$
$$V_{cb} = -V_{bc} = V_c - V_b$$
$$V_{ac} = -V_{ca} = V_a - V_c$$

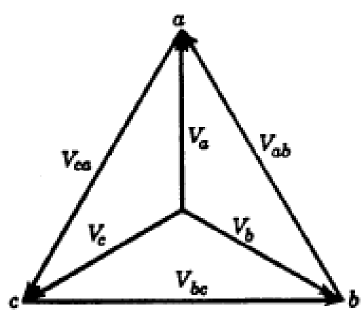


Figure 6.2 - Conventions and Nomenclature for Three Phase Voltage Vector Diagrams

More often than not, this type of protection equipment is two phase comprising two independent, single phase elements. Sometimes three-phase protection equipment may be used. For each monitored phase, the relay measures its current magnitude, and then uses a phase to phase voltage as the polarisation variable. The phase to neutral voltage is not used since it varies greatly when a fault occurs to earth, due to the displacement effect of the neutral point (residual voltage).

The characteristic angle of a directional phase relay defines the position of the angular tripping zone. It is the angle between the normal to the tripping plane and the polarisation variable. In order to be able to measure the fault direction, the polarisation variable (the voltage) must have a sufficiently high value. In particular, a three-phase fault very close to a directional relay is not detected because all of the phase to phase voltages are zero. To obtain the direction of this type of fault, the protection system must use a memory voltage.

There are mainly three possibilities for connections of voltage and current inputs for phase fault overcurrent elements and these connections are dependent on the phase angle, at unity system power factor, by which the current and voltage applied to the relay are displaced.

1. 90° Relay Quadrature Connection

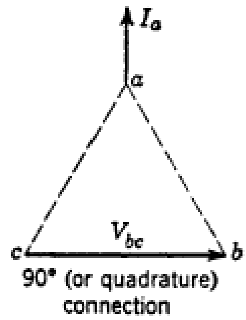


Figure 6.3 - 90° (Quadrature) Connection of Directional Relays

In this connection A-phase relay element is supplied with current Ia. Voltage Vbc is used as the polarizing quantity.

2. 30° Relay Adjacent Connection

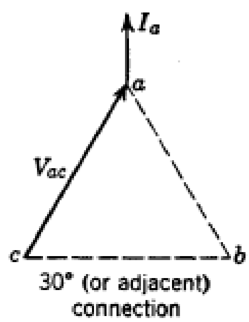


Figure 6.4 - 30° (Adjacent) Connection of Directional Relays

In this connection A-phase relay element is supplied with current Ia. Voltage Vac is used as the polarizing quantity.

3. 60° Relay Connection

In this connection A-phase relay element is supplied with current Ia. Voltage Vbc + Vac is used as the polarizing quantity.

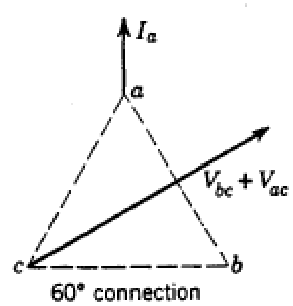


Figure 6.5 - 60° Connection of Directional Relays

Depending on the angle by which the applied voltage is shifted to produce maximum relay sensitivity (the Relay Characteristic Angle, or RCA for numerical relays & MTA for Electromechanical & static relays) two types are available.

1. 30° Maximum Torque Angle (MTA) Lead

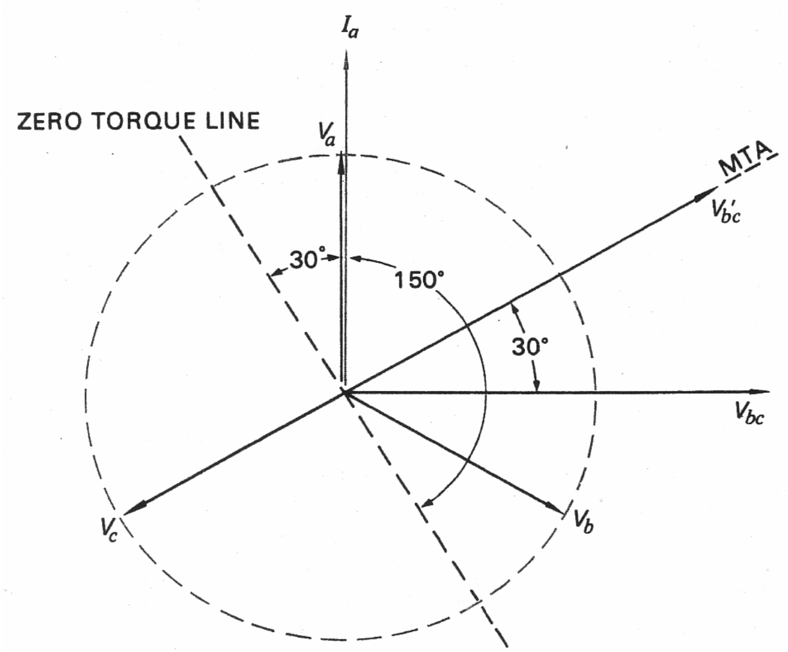


Figure 6.6 - 30° Maximum Torque Angle Lead

The *A* phase relay element is supplied with Ia current and Vbc voltage displaced by 30° in an anti-clockwise direction. In this case, the relay maximum sensitivity is produced when the current lags the system phase to neutral voltage by 60°. This connection gives a correct directional tripping zone over the current range of 30° leading to 150° lagging; see figure 6.6. The relay sensitivity at unity power factor is 50% of the relay maximum sensitivity and 86.6% at zero power factor lagging. This characteristic is recommended when the relay is used for the protection of plain feeders with the zero sequence source behind the relaying point.

2. 45° Maximum Torque Angle (MTA) Lead

The *A* phase relay element is supplied with current Ia and voltage Vbc displaced by 45° in an anti-clockwise direction. The relay maximum sensitivity is produced when the current lags the system phase to neutral voltage by 45°. This connection gives a correct directional tripping zone over the current range of 45° leading to 135° lagging. The relay sensitivity at unity power factor is 70.7% of the maximum torque and the same at zero power factor lagging; see figure 6.7. This connection is recommended for the protection of transformer feeders or feeders that have a zero sequence source in front of the relay. It is essential in the case of parallel transformers or transformer feeders, in order to ensure correct relay operation for faults beyond the star/delta transformer.

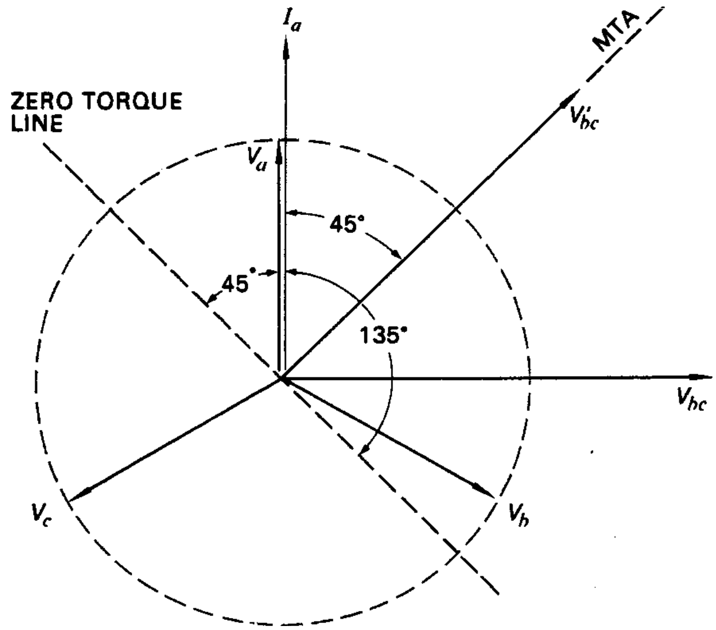


Figure 6.7 - 45° Maximum Torque Angle Lead

6.3.2 Earth fault directional protection

The directional earth-fault unit measures the neutral current "I0", the residual voltage "U0" from open delta PT and the phase angle between residual voltage(U0) and neutral current(I0). An earth-fault stage starts if all of the three criteria mentioned below are fulfilled at the same time:

1. The residual voltage U0 exceeds the threshold or set level
2. The neutral current I0 exceeds the set value
3. If the phase angle between residual voltage and neutral current falls within the operation area

The residual current can be derived easily by summating the CT currents of all three phases as shown in figure 6.9. Residual voltage is used as polarizing quantity for the relay. The latter should not be confused with the zero sequence voltage. It is the vector sum of the individual phase voltages. If the secondary windings of a three-phase, five limb voltage transformer or three single-phase units are connected in open delta, the voltage developed across its terminals will be the vector sum of the phase to ground voltages and hence the residual voltage of the system. The primary star point of the VT must be earthed. However, a three-phase, three limbs VT is not suitable, as there is no path for the residual magnetic flux.

Often VT's with two secondary windings as shown in figure 6.8(a) are used: one is star connected and enables both phase to neutral and phase to phase voltages to be measured; the other is open delta connected enabling the residual voltage to be measured. If the main VT's only have one secondary winding which is star connected, and grounded, a set of auxiliary

VT's can be used to measure the residual voltage as shown in figure 6.8(b). This situation is often encountered when the protection plan for existing installations is upgraded. It should be noted that certain protection equipments like numerical relays do not require auxiliary VT's, they themselves calculate the residual voltage value from the three phase to earth or phase to phase voltages.

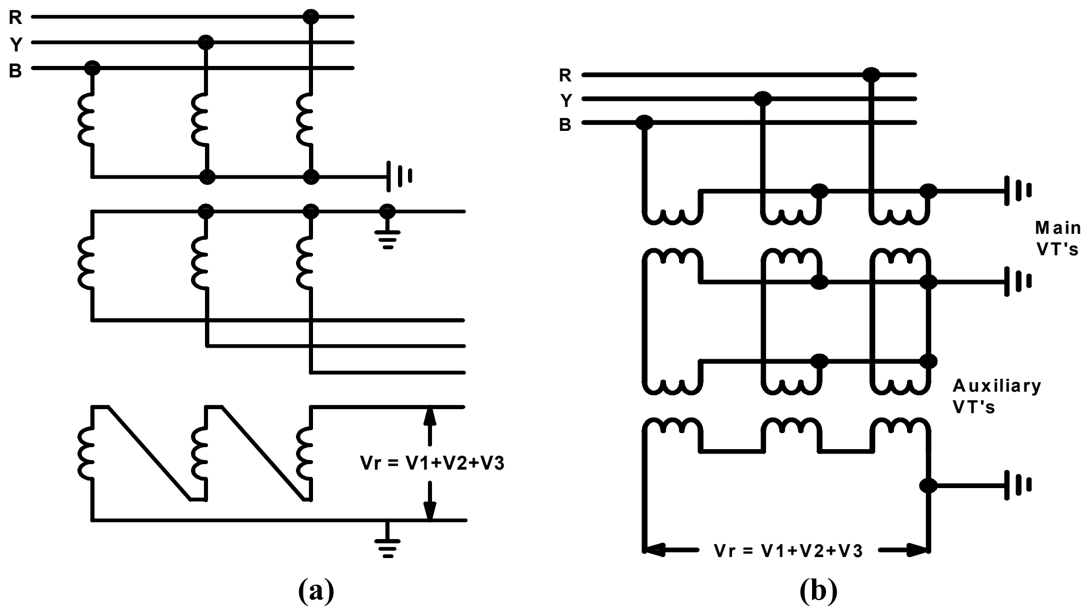


Figure 6.8 (a) Measuring the residual voltage using 3 VT's.
(b) Measuring the residual voltage using auxiliary VT's.

Complete connection diagram of earthfault directional relay is given in figure 6.9. Figure 6.10 shows the vector representation of residual voltage under balanced and earthfault conditions. It is clear that the residual voltage is zero under balanced conditions whereas it has a specific value given by vector 3Vo when a earthfault occurs on phase A.

6.3.3 Applications of Directional Relays

Directional protection equipment is useful for all network components in which the direction of flow of power is likely to change, notably in the instance of a short circuit between phases or of an earthing fault (single phase fault). Phase directional protection is installed to protect two connections operated in parallel, a loop or a network component connected to two power sources. Earth fault directional protection is sensitive to the direction of flow of the current to earth. It is necessary to install this type of protection equipment whenever the phase to earth fault current is divided between several earthing systems.

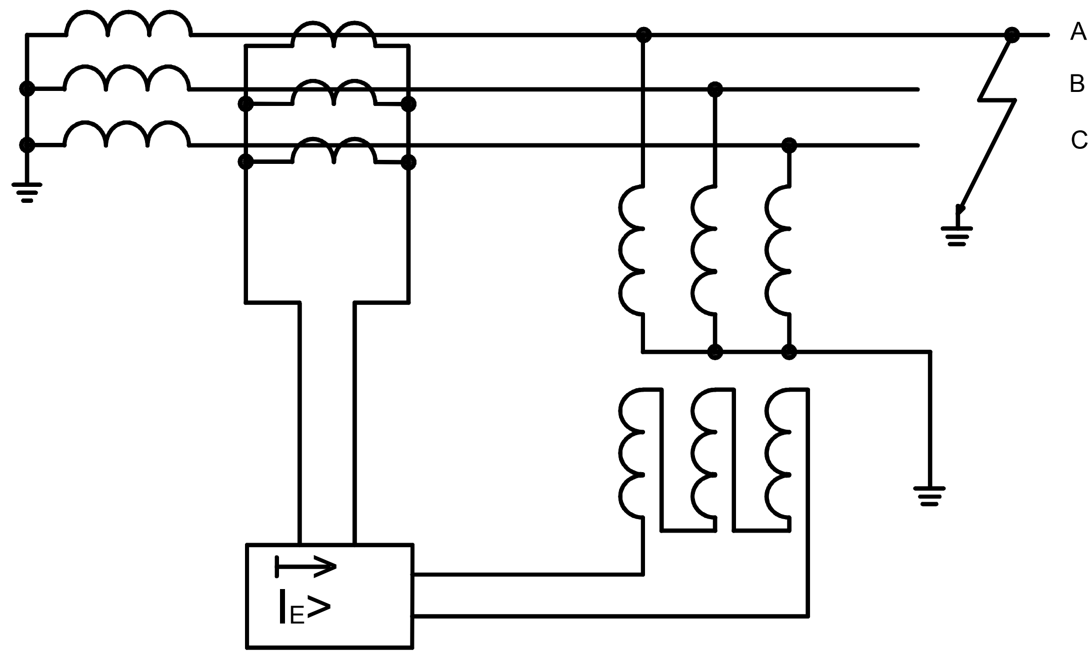
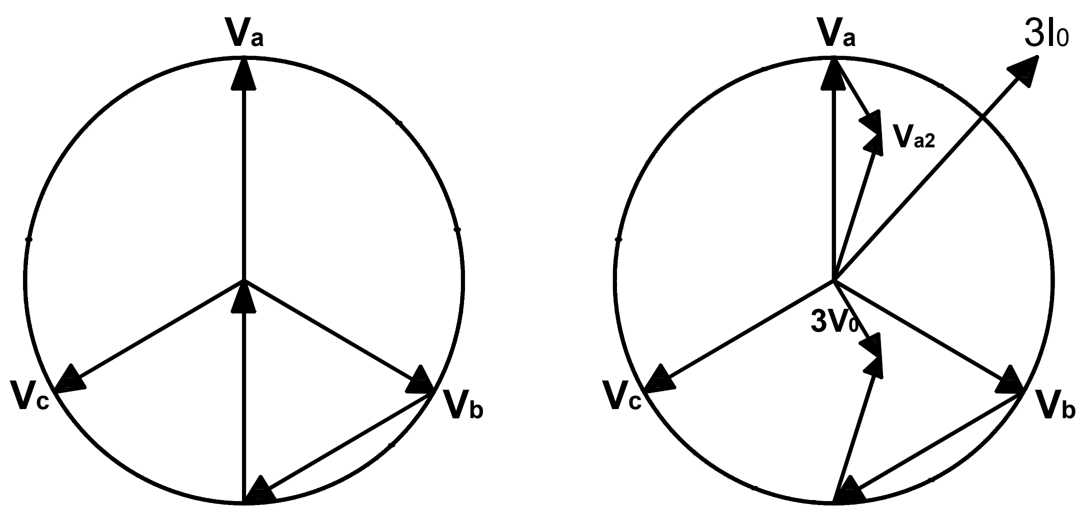


Figure 6.9 - Connections of Directional Earthfault relay



(a) **(b)**

Figure 6.10 - (a) Residual Voltage under Balanced Conditions
(b) Residual Voltage with Phase A Faulted

6.4 Differential Relaying

Differential protection is one of the most reliable and popular techniques in power system protection. Differential protection compares the currents that enter with the currents that leave a zone. If the net sum of the currents that enter and the currents that leave a protection zone is essentially zero, it is concluded that there is no fault in the protection zone. However, if the net sum is not zero, the differential protection concludes that a fault exists in the zone and takes steps to isolate the zone from the rest of the system.

In 1904, British engineers Charles H. Merz and Bernard Price developed the first approach for differential protection. Figure 6.11 shows one phase of a three-phase differential protection system for maintaining the simplicity. Also, it can be observed from Figure 6.11 that the protection zone is delimited by a couple of current transformers. Due to its very nature, differential protection does not provide backup protection to other system components. For this reason, differential protection is categorized as unit protective scheme. The conductors bringing the current from the current transformers to the differential relay are in some situations called pilot wires.

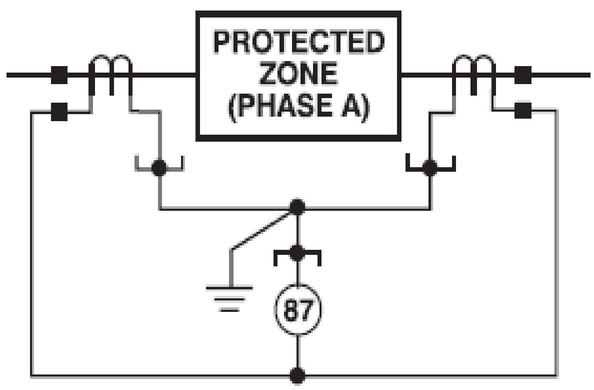


Figure 6.11 - Simplified Representation of Differential Protection

The advantages of the scheme proposed by Merz and Price were soon recognized and the technique has been extensively applied since then. However, it soon became apparent that differential protection operated incorrectly due to mismatch of current transformers provided at the two ends of the zone, differences in the relay circuitry and due to inrush currents or excessive currents caused by system over-voltages at the transformer terminals. Over the years, various methods have been developed to ensure correct operation of differential relays. Percentage differential protection is one such scheme. It is widely used for protection of power transformers. Its operating principle is discussed in the following section.

6.4.1 Percentage Differential Relaying

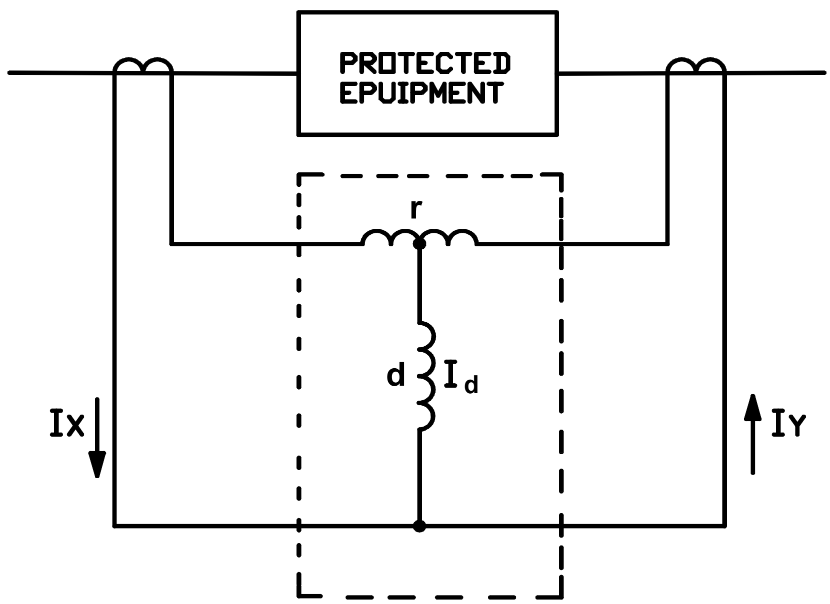
Figure 6.10 shows a single phase schematic diagram of percentage differential relaying principle. Differential elements compare an operating current with a restraining current. The operating current (also called differential current), Id, can be obtained as the phasor sum of the currents entering the protected element. The expression for differential relay can be expressed as:

$$Id = Ix - Iy$$

Relay operates if, Ix - Iy > "Id setting" (setting of differential relay). The expression for restraining (bias) currents can be expressed as:

$$Ir = K(Ix + Iy)$$

where K is the compensation factor usually taken as 1 or 0.5.



r: restraint circuitry
d: differential circuitry
Figure 6.12 - Percentage Differential Relaying

Restraint current "**Ir"**, together with the operating current "**Id"** define the relay operation on a coordinate plane, as shown in figure 6.13. A line divides the coordinate plane in two parts. The upper part is the operating region while the lower part is the restraining region. This dividing line is called the characteristic of the differential relay. Typical characteristic of differential relays present a small slope for low currents to allow sensitivity to light internal faults. At higher currents, the slope of the characteristic is much higher, which requires that the operating current, Id, be higher in order to cause operation of the differential relay.

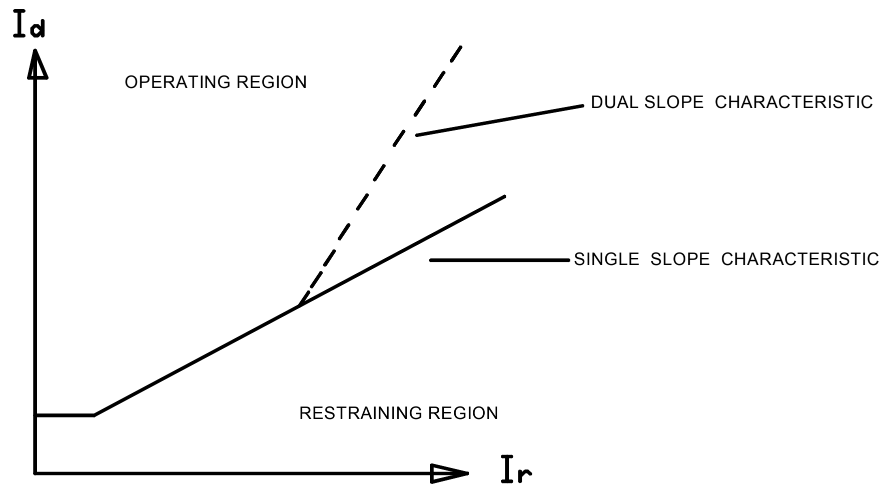


Figure 6.13 - Characteristic of Percentage Differential Relay

The operation of a percentage-differential relay can be expressed by the following equation.

$$Id > S.Ir$$

Where S is the slope of the differential relay characteristic.
Differential relays perform well for external faults, as long as the CTs reproduce the primary currents correctly. When one of the CTs saturates, or if both CTs saturate at different levels, false operating current appears in the differential relay and can cause relay mal-operation. Some differential relays use the harmonics caused by CT saturation for added restraint and to avoid mal-operations. In addition, the slope characteristic of the percentage differential relay provides further security for external faults with CT saturation. A variable-percentage or dual slope characteristic further increases relay security for heavy CT saturation. Figure 6.13 shows this characteristic as a dotted line.

6.5 Distance Relays

Distance relaying belongs to the principle of ratio comparison. The ratio is between the voltage and current, which in turn produces impedance. The impedance is proportional to the distance in transmission on line, hence the “distance relaying” designation for the principle. The principle is primarily used for protection of high voltage transmission lines. Computing the impedance in a three phase system is a bit involved because each type of fault produces a different impedance expression. Because of these differences the settings of a distance relay need to be selected to distinguish between the ground and phase faults. In addition, fault resistance may create problems for distance measurements because the value of the fault resistance may be difficult to predict. It is particularly challenging for distance relays to measure correct fault impedance when a current in feed from the other end of the line creates an unknown voltage drop on the fault resistance. This may contribute to erroneous computation of the impedance, called apparent impedance, “seen” by the relay located at one end of the line and using the current and voltage measurement just from that end. Once the impedance is

computed, it is compared to the settings that define the operating characteristic of a relay. Based on the comparison, a decision is made if a fault has occurred or not.
Due to variety of application reasons, the operating characteristics of a distance relay may have different shapes, the quadrilateral and mho being the most common. The different operating characteristic shapes will be discussed in the following sections. The characteristics dictate relay performance for specific application conditions, such as the changes in the loading levels, different values of fault resistance, effects of power swings, presence of mutual coupling, and reversals of fault direction.
In an attempt to better comprehend, visualize, and diagnose the operation of impedance based relays, the R-X diagram is used. This diagram permits the use of only two quantities R and X (or Z and in polar form) instead of the confusing combination of V, I, and phase angle. Further, we are able to represent the relay characteristics as well as the system characteristics on the same diagram and quickly determine at a glance what conditions will lead to relay operation

6.5.1 Impedance Type Distance Relay

Since this type of relay involves impedance-type units, let us first become acquainted with them. Generally speaking, the term impedance can be applied to resistance alone, reactance alone, or a combination of the two. In protective-relaying terminology, however, an impedance relay has a characteristic that is different from that of a relay responding to any component of impedance. And hence, the term impedance relay is very specific.

In an impedance relay, the torque produced by a current element is balanced against the torque of a voltage element. The current element produces positive (pickup) torque, whereas the voltage element produces negative (reset) torque. In other words, an impedance relay is a voltage-restrained overcurrent relay. If we let the control-spring effect be -K3, the torque equation is:

$$T = K_1 I^2 - K_2 V^2 - K_3$$

Where I and V are rms magnitudes of the current and voltage supplied to the relay, respectively. At the balance point, when the relay is on the verge of operating, the net torque is zero, and

$$K_2 V^2 = K_1 I^2 - K_3$$

Dividing by $K_2 I^2$, we get:

$$V^2 / I^2 = K_1/K_2 - K_3 / K_2 I^2$$
$$V/I = Z = (K_1/K_2 - K_3 / K_2 I^2)^{1/2}$$

It is customary to neglect the effect of the control spring, since its effect is noticeable only at current magnitudes well below those normally encountered. Consequently, if we let K3 be zero, the preceding equation becomes:

$$Z = (K_1/K_2)^{1/2} = \text{Constant}$$

In other words, an impedance relay is on the verge of operating at a given constant value of the ratio of V to I, which may be expressed as impedance. The operating characteristic in terms of voltage and current is shown in figure 6.14, where the effect of the control spring is shown as causing a noticeable bend in the characteristic only at the low-current end. For all practical purposes, the dashed line, which represents a constant value of Z, may be considered the operating characteristic. The relay will pick up for any combination of V and I represented by a point above the characteristic in the positive-torque region, or, in other words, for any value of Z less than the constant value represented by the operating characteristic. By adjustment, the slope of the operating characteristic can be changed so that the relay will respond to all values of impedance less than any desired upper limit.

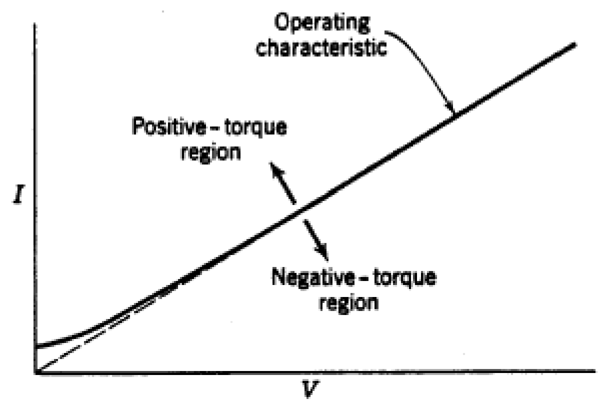


Figure 6.14 - Operating Characteristic of Impedance Relay

A much more useful way of showing the operating characteristic of distance relays is by means of the so-called impedance diagram or R-X diagram. The operating characteristic of the impedance relay, neglecting the control-spring effect, is shown in figure 6.15 on R-X diagram. The numerical value of the ratio of V to I is shown as the length of a radius vector, such as Z, and the phase angle q between V and I determines the position of the vector, as shown. If I is in phase with V, the vector lies along the +R axis; but, if I is 180 degrees out of phase with V, the vector lies along the -R axis. If I lags V, the vector has a +X component; and, if I leads V, the vector has a -X component. Since the operation of the impedance relay is practically or actually independent of the phase angle between V and I, the operating characteristic is a circle with its center at the origin. Any value of Z less than the radius of the circle will result in the production of positive torque, and any value of Z greater than this radius will result in negative torque, regardless of the phase angle between V and I.

At very low currents where the operating characteristic of figure 6.14 departs from a straight line because of the control spring, the effect on figure 6.15 is to make the radius of the circle smaller. This does not have any practical significance, however, since the proper application of such relays rarely if ever depends on operation at such low currents.

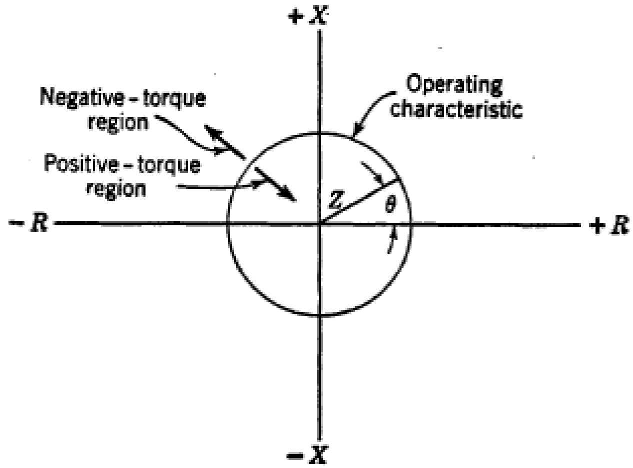


Figure 6.15 - Operating Characteristic of Impedance Relay on R-X diagram

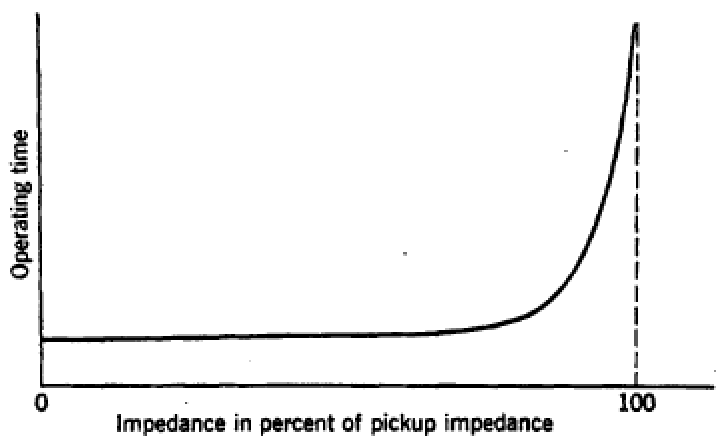


Figure 6.16 - Operating-time-versus-impedance characteristic of a high-speed relay for one value of current.

Although impedance relays with inherent time delay are encountered occasionally, we shall consider only the high-speed type. The operating-time characteristic of a high-speed impedance relay is shown qualitatively in figure 6.16. The curve shown is for a particular value of current magnitude. Curves for higher currents will lie under this curve, and curves for lower currents will lie above it. In general, however, the operating times for the currents usually encountered in normal applications of distance relays are so short as to be within the definition of high speed, and the variations with current are neglected. In fact, even the increase in time as the impedance approaches the pickup value is often neglected, and the time curve is shown simply as in figure 6.17.

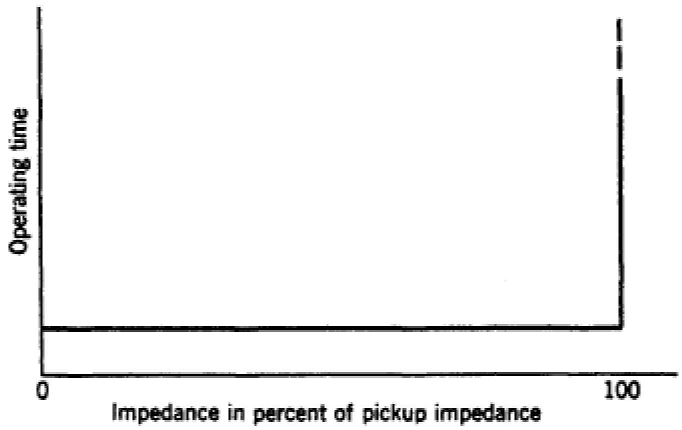


Figure 6.17 - Simplified representation of figure 6.14

An inspection of figure 6.15 makes it clear that the impedance type distance relays operate both for positive and negative values of specified impedance settings. Hence impedance type relays are non directional relays. However its characteristic can be modified by a directional unit so as to obtain a distance relay that is directional in nature. Characteristic of such a impedance relay modified by directional characteristic is shown in figure 6.18

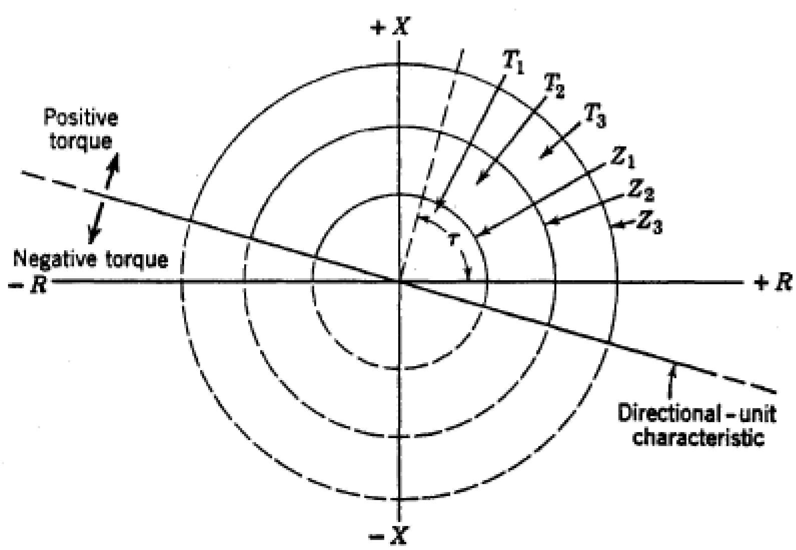


Figure 6.18 - Operating and time-delay characteristics of an impedance-type distance relay

Since the directional unit permits tripping only in its positive-torque region, the inactive portions of the impedance unit characteristics are shown dashed. The net result is that tripping will occur only for points that are both within the circles and above the directional-unit characteristic. Three characteristics Z_1, Z_2, Z_3 shown in the figure 6.19 define the zones of operation of impedance relay. T_1, T_2, T_3 correspond to the respective operating times of the three zones.

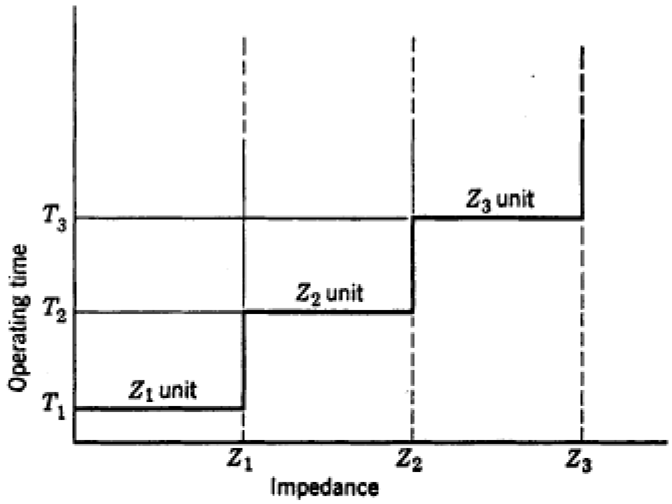


Figure 6.19 -Operating time versus impedance for an impedance-type distance relay

Looking somewhat ahead to the application of distance relays for transmission-line protection, we can show the operating-time-versus-impedance characteristic as in figure 6.19. This characteristic is generally called a stepped time-impedance characteristic and will be analyzed in detail latter in the chapter on Line protection. It will also be shown later that the Z1 and Z2 units provide the primary protection for a given transmission-line section, whereas Z2 and Z3 provide back-up protection for adjoining busses and line sections.

6.5.2 The Reactance Type Distance Relays

The reactance-relay unit of a reactance-type distance relay has, in effect, an overcurrent element developing positive torque, and a current-voltage directional element that either opposes or aids the overcurrent element, depending on the phase angle between the current and the voltage. In other words, a reactance relay is an overcurrent relay with directional restraint. The directional element is arranged to develop maximum negative torque when its current lags its voltage by 90°. The induction-cup or double-induction-loop structures are best suited for actuating high-speed relays of this type. If we let the control-spring effect be -K3, the torque equation is:

$$T = K_1 I^2 - K_2 VI \sin\theta - K_3$$

where θ is defined as positive when I lags V. At the balance point, the net torque is zero, and hence;

$$K_1 I_2 = K_2 VI \sin\theta + K_3$$

Dividing both sides of the equation by I_2, and neglecting the effect of control spring we get:

$$Z \sin\theta = X = K_1/K_2 = \text{Constant}$$

In other words, this relay has an operating characteristic such that all impedance radius vectors whose heads lie on this characteristic have a constant X component. This describes the straight line of figure 6.20. The significant thing about this characteristic is that the resistance component of the impedance has no effect on the operation of the relay; the relay responds solely to the reactance component. Any point below the operating characteristic whether above or below the R axis will lie in the positive-torque region.

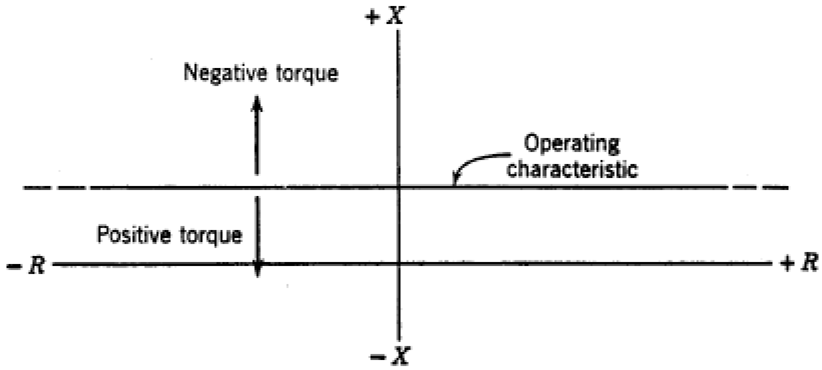


Figure 6.20 - Operating Characteristic of a Reactance Relay

Taking into account the effect of the control spring would lower the operating characteristic toward the R axis and beyond at very low values of current. This effect can be neglected in the normal application of reactance relays. It is clear from figure 6.20 that reactance relays, like impedance relays, are non-directional in nature. However a reactance-type distance relay for transmission-line protection could not use a simple directional unit as in the impedance-type relay, because the reactance relay would trip under normal load conditions at or near unity power factor, as will be seen later when we consider what different system-operating conditions look like on the R-X diagram. The reactance-type distance relay requires a directional unit that is inoperative under normal load conditions. The type of unit used for this purpose has a voltage-restraining element.

6.5.3 Mho Type Distance Relay

Reactance relay suffers from the drawback of being a non-directional relay. A reactance-type distance relay for transmission-line protection could not use a simple directional unit as in the impedance-type relay, because the reactance relay would trip under normal load conditions at or near unity power factor. The reactance-type distance relay requires a directional unit that is inoperative under normal load conditions. The type of unit used for this purpose has a voltage-restraining element that opposes a directional element, and it is called an admittance or mho unit or relay. In other words, this is a voltage-restrained directional relay. When used with a reactance type distance relay, this unit has also been called a starting unit. If we let the control-spring effect be – K3, the torque of such a unit is:

$$T = K_1 VI \cos(\theta - \tau) - K_2 V_2 K_3$$

where θ and τ are defined as positive when I lags V. At the balance point, the net torque is zero, and hence:

$$K_2 V_2 = K_1 VI \cos(\theta - \tau) - K_3$$

If we neglect the control-spring effect,

$$Z = K_1/K_2 \cos(\theta - \tau)$$

It will be noted that this equation is like that of the directional relay when the control spring effect is included, but that here there is no voltage term, and hence the relay has but one circular characteristic. The operating characteristic described by this equation is shown in figure 6.21. The diameter of this circle is practically independent of voltage or current, except at very low magnitudes of current or voltage when the control-spring effect is taken into account, which causes the diameter to decrease.

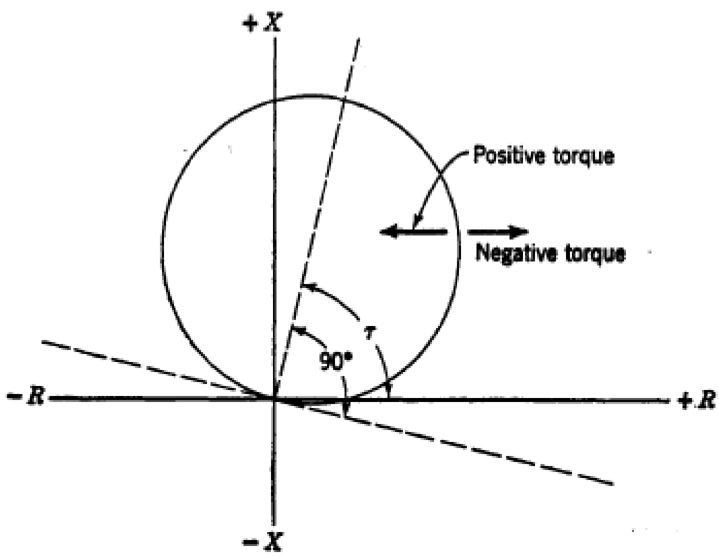


Figure 6.21 - Operating Characteristic of Mho Type Distance Relay

6.5.4 General Considerations Applicable to All Distance Relays

1. Overreach

When a short circuit occurs, the current wave is apt to be offset initially. Under such conditions, distance relays tend to overreach, i.e., to operate for a larger value of impedance than that for which they are adjusted to operate under steady-state conditions. This tendency is greater, the more inductive the impedance is. Also, the tendency is greater in electromagnetic-attraction-type relays than in induction-type relays. The tendency to overreach is minimized in the design of the relay-circuit elements, but it is still necessary to compensate for some tendency to overreach in the adjustment of the relays. Compensation for overreach as well as for inaccuracies in the current and voltage sources is obtained by adjusting the relays to operate at 10% to 20% lower impedance than that for which they would otherwise be adjusted. This will be further discussed when we consider the application of these relays.

2. Memory Action

Relays in which voltage is required to develop pickup torque, such as mho-type relays or directional units of other relays, may be provided with memory action. Memory action is a feature that can be obtained by design in which the current flow in a voltage-polarizing coil does not cease immediately when the voltage on the high-voltage side of the supply voltage transformer is instantly reduced to zero. Instead, the stored energy in the voltage circuit causes sinusoidal current to flow in the voltage coil for a short time. The frequency of this current and its phase angle are for all practical purposes the same as before the high-tension voltage dropped to zero, and therefore the relay is properly polarized since, in effect, it remembers the voltage that had been impressed on it. It will be evident that memory action is usable only with high-speed relays that are capable of operating within the short time that the transient polarizing current flows. It will also be evident that a relay must have voltage applied to it initially for memory action to be effective; in other words, memory action is ineffective if a distance relays voltage is obtained from the line side of a line circuit breaker and the breaker is closed when there is a short circuit on the line. Actually, it is a most rare circumstance when a short circuit reduces the relay supply voltage to zero. The short circuit must be exactly at the high-voltage terminals of the voltage transformer, and there must be no arcing in the short circuit. About the only time that this can happen in practice is when maintenance men have forgotten to remove protective grounding devices before the line breaker is closed. The voltage across an arcing short circuit is seldom less than about 4% of normal voltage, and this is sufficient to assure correct distance-relay operation even without the help of memory action.

3. The Versatility of Distance Relays

It is probably evident from the foregoing that on the R-X diagram we can construct any desired distance-relay operating characteristic composed of straight lines or circles. The characteristics shown here have been those of distance relays for transmission-line protection. But, by using these same characteristics or modifications of them, we can encompass any desired area on the R-X diagram, or we can divide the diagram into various areas, such that relay operation can be obtained only for certain relations between V, I, and q. That this is a most powerful tool will be seen later when we learn what various types of abnormal system conditions look like on the R-X diagram.

4. The Significance of Z

Since we are accustomed to associating impedance with some element such as a coil or a circuit of some sort, one might well ask what the significance is of the impedance expressed by the ratio of the voltage to the current supplied to a distance relay. To answer this question completely at this time would involve getting too far ahead of the story. It depends, among other things, on how the voltage and current supplied to the relay are obtained. For the protection of transmission lines against short circuits, which is the largest field of application of distance relays, this impedance is proportional, within certain limits, to the physical distance from the relay to the short circuit. However, the relay will still be energized by voltage and current under other than short-circuit conditions, such as when a system is carrying normal load, or when one part of a system loses synchronism with another, etc. Under any such condition, the impedance has a different significance from that during a short circuit. This is a most fascinating part of the story, but it must wait until we consider the application of distance relays. At this point, one may wonder why there are different types of distance relays for transmission-line protection such as those described. The answer to this question is largely that each type has its particular field of application wherein it is generally more suitable than any other type. This will be discussed when we examine the application of these relays. These fields of application overlap more or less, and, in the overlap areas, which relay is chosen is a matter of personal preference for certain features of one particular type over another.

CHAPTER – 7

RELAY TESTING PROCEDURES

7.1 Why Test Protective Relays

The goal of protective relay testing is to maximize the availability of protection and minimize the risk of relay malfunction. With this in mind, we must define adequate testing methods and intervals for various types of protective relays.

When a traditional relay fails, the failure can cause the relay to false trip, prevent operation for fault, or alter the relay operation characteristics. Electromechanical relays do not provide self-tests or status monitoring. Therefore, routine testing is required to verify proper relay operation. If a problem exists in a electromechanical relay, the problem may go undetected until routine maintenance is performed or the relay fails to operate for a fault. The reliability of electromechanical relays is, therefore, largely dependent on the frequency of routine testing and maintenance.

Digital relay failures can also cause relay malfunctions and prevent operation for faults. However, relay characteristics are typically not affected by failures. Failures tend to be significant enough to either generate a self test failure indication or cause the user to recognize the problem during normal use of relay.

7.2 New Installations

Before placing a new installation into operation, polarity of instrument transformers and the wiring to the relays should be checked. In some cases, the manufacturer's polarity marking has been found to be incorrect. New relays should be inspected carefully and all blocking put in by the manufacturer removed. The test man should read instruction books furnished by the manufacturer to become familiar with construction and operating principle of the relays. A sufficient number of initial operations should be made by manually operating relay contacts to make sure that all devices which should be operated by the relay, including auxiliary contacts and targets within the relay, function freely and properly. Breaker trip coils and other devices operated by the relay should be checked to see that proper operation is obtained at voltages considerably below normal (approximately 56 percent of normal voltage for breaker trip coils). The voltage drop in trip circuits and tripping current required should be checked. Factory adjustments on relays, other than taps, or other adjusting devices intended for customary adjustment should not be changed unless tests show that factory adjustments have been disturbed, in which case the manufacturers' instruction books should be followed.

7.3 Testing Equipment Required

A good set of testing equipment and relay tools are important. Several manufacturers now produce portable relay test sets that will provide excellent results. Relay testing kits available with BSES Delhi are as follows

1. Omicron 256-6 (Make- Omicron)
2. Freja 300 (Make- Programma)
3. Secondary Injection System PTE-100-C (Make – SMC)
4. Relay test system (Make - Tinsley)

7.4 Testing Precautions

Before starting to test any relay or equipment in service, the person testing should become familiar with the relays and the circuits involved. Where test blocks are used, the person testing must make sure that in removing or inserting plugs that a current transformer circuit will not be opened, resulting in a voltage being built up which may be dangerous to personnel, property, or equipment, or cause an important circuit to trip out. In old installations where test blocks are not available, current transformer circuits must be short circuited by jumpers having reliable clamping devices which will not come loose, before the relay current circuit is opened.

7.5 Frequency of Testing

It is recommended that protective and auxiliary relays be given a complete calibration test and inspection at least once a year. This schedule, however, sometimes cannot be met due to existing workloads and available manpower with the result that routine calibration tests intervals of many relays are longer than a year. Factors to be considered if changes to the test schedule are needed, are shown in table 1.

7.6 Annual Inspection

All relays shall be given an annual inspection. This inspection should include the following:

a. A visual inspection should be made of all relays on a terminal including the tripping auxiliaries and accessories. Any draw-out type relay should be withdrawn from its case for a close-up examination. All other, including auxiliaries, should at least have covers removed. Included in this visual inspection should be a check for loose connections, broken studs, burned insulation, and dirty contacts. Each relay should be checked to be in agreement with its setting sheet. On some distance relays it may have been necessary to set the taps on something other than specified values in order to get proper calibration. Because of this, it may also be necessary to check the taps against the last calibration test report.

b. A test trip should be made of all relay systems. All relay elements which initiate some protective function should be checked. After proving that tripping relays will successfully trip the circuit breaker and that all schemes work, continuity checks should be used, where applicable, to complete the checkout of the circuit breaker trip circuits.

Relay System Variables	Factor Reducing Test Interval	Factors lengthening Test Interval
Type of Relays	Complex (distance, differential),	Simple (hinged armature plunger).
Age of Relays	New installations with little operating history. Systems 20 years or older where insulation aging, etc., can be a problem	5-10 years old with a good operating history
Environment	Dusty area, contaminated atmosphere, temperature extremes.	Clean and/or air conditioned area.
History and Experience	Subjected to severe or frequent faults. Often required adjustments when tested.	Subjected to moderate or few faults.
Current Rating	Relays rated 5 amperes which are called upon to carry 7 or 8 amperes due to load requirements.	Relays operated at or below their 5 ampere rating
Control Voltage	Relays operated in battery circuit more than 5 percent above nominal relay rated voltage of nominal relay rated voltage	Relays operated in battery circuit within _+ 5 percent
Station Service	Station service voltage supplied is more than 5 percent above nominal relay rated voltage.	Station service Voltage supply operated within + 5 percent of

Table 7.1 – Factors Affecting the Test Schedule of Relays

7.7 Testing of Electromechanical Relays

7.7.1 General tests

The following tests should be included for all electromechanical relays:

a. A visual inspection of the relay cover can reveal valuable information. Any excessive dust, dirt, or metallic material deposited on the cover should be noted and removed, thus preventing such material from entering the relay when the cover is removed. A cover glass which is fogged should be cleaned. Fogging is in most cases a normal condition due to volatile materials being driven out of coils and insulating materials, and is not an indication of a problem. However if fogging appears excessive, since most relays are designed to operate in ambient temperatures not exceeding 40ºC (104ºF), a further check of the ambient temperature would be in order. Voltage and current supplied to the relay should be checked and compared with the name plate or instruction book ratings. Should evidence of overheating be found, the insulation should be checked for embrittlement and, where necessary, replaced. Removal of the connection plug in draw-out relays may reveal evidence of severe fault currents or contaminated atmospheres, either of which may indicate the advisability of a change in maintenance schedule. The condition of the relay contacts can be equally revealing.

b. Mechanical adjustments and inspection should be made according to the following instructions:

1. Check to see that all connections are tight. Several loose connections could indicate excessive vibration which should be corrected.
2. All gaps should be checked that they are free of foreign material. If foreign material is found in the relay, the case gasket should be checked and replaced if necessary.
3. All contact or armature gaps should be measured and values compared with previous measurements. Large variations in these measurements may indicate excessive wear, and worn parts should be replaced. Also an adjusting screw could have worked loose and must be tightened. All of this information should be noted on the test record.
4. All contacts except those not recommended for maintenance should be measured for alignment.
5. Since checking bearings or pivots usually involves dismantling the relay, it is recommended that such a test be made only when the relay appears to be extremely dirty, or when subsequent electrical tests indicate undue friction.

c. Electrical tests and adjustments should be made according to the following instructions:

1. Contact function.-Manually close or open the contacts, and observe that they perform their required function; such as trip, reclose, or block.
2. Pickup.-Gradually apply current or voltage to see that pickup is within limits. The current or voltage should be applied gradually in order to yield data which can be compared with previous or future tests and not be clouded by such effects as transient overreach.
3. Dropout or reset.-To test for excess friction, reduce current until the relay drops out or resets. Should the relay be sluggish in resetting or fail to reset, then the jewel bearing and pivot should be examined. A four power magnification is adequate for examining the pivot, and the jewel bearing can be examined with the aid of a needle which will reveal any cracks in it. If dirt is the problem, the jewel can be cleaned with a stick and the pivot can be wiped clean with a soft, lint free cloth. No lubricant should be used on either the jewel or pivot.

Other tests to be performed on relays depend on the function of the relay. The additional tests to be performed on various types of relays are given below.

7.7.2 Auxiliary Relays

In addition to tests described in section 7.7.1, auxiliary relays employing devices for time delay (for example, capacitors) should have an operating time test performed (either pickup or dropout, whichever is applicable).

7.7.3 Time Overcurrent and Time Overvoltage relays

All tests described in section 7.7.1 should be performed for time-overcurrent and time-overvoltage relays where applicable. These types of relays should always be tested in the case in order to duplicate "in-service" conditions or to match published curves since the relay case normally acts as a shunt for flux that the electromagnetic iron circuit cannot handle due to saturation. Testing the relay out of the case will also produce results that would not check previous tests or future tests since changes in test conditions, such as being near a steel cabinet, will change results obtained if the relay is tested out of the case. The first electrical test made on the relay should be a pickup test. Allowing for such things as meter differences and interpretations of readings, this value should be within ± 5 percent of previous data. One or two points on the time-current curve are generally sufficient for maintenance purposes. Reset the relay to the original time-dial setting and check at two points such as 2 and 5 times pickup. Always use the same points for comparison with previous tests. The instantaneous unit should be checked for pickup using gradually applied current.

7.7.4 Directional Overcurrent Relays

In addition to tests recommended for the overcurrent relay, the directional unit of the directional overcurrent relay should be tested for minimum pickup, directional feature, phase angle range for operation and contact gap.

7.7.5 Distance Relays

When testing distance relays, tests should be made of pickup, resistive and reactive reach for individual zone settings and contact gap in addition to the tests described in section 7.7.1.

7.7.6 Differential Relays

A test of minimum pickup should be performed for differential relays. The differential characteristic (slope) should be checked, and where applicable, the harmonic restraint should be tested. Differential relays using ultra sensitive polarized units as sensing devices are slightly affected by previous history, such as heavy internal or external fault currents. It is therefore recommended that for this type of relay two pickup readings be taken and the second reading be the one that is used for comparison with previous and future tests.

7.8 Static Relays

The procedure for testing of pickup, operating time, directional feature etc of static relays is similar to the one described for testing of their electromechanical counterparts. As there are no moving parts in static relays, there is no physical wear due to usage and no need for lubricants. Prime causes of failure in electronic components are heat, vibration, and moisture. Overheating can be caused by voltage transients, current surges, excessive power, or high ambient temperature. Vibration can loosen or break leads and connections and can crack component casings or insulation resulting in equipment failure. Moisture can result in corrosion of metallic elements which can result in circuit discontinuities, poor contact, or shorts. Preventive maintenance of static relays should be directed toward removing causes of failure listed above by doing the following:

a. Keep equipment clean by periodic vacuuming or blowing out of dirt, dust, and other surface contaminants.
b. Keep the equipment dry and protected against moisture and corrosion.
c. Inspect to see that all connections, leads, and contacts are tight and free as possible from effects of vibration.
d. Check to see that there is adequate ventilation to conduct heat away efficiently.

Preventive measures should not be applied unnecessarily as this may contribute to failures. For example, printed circuit cards should not be pulled from their racks to be inspected if there is no real need. Operating test switches unnecessarily may introduce damaging voltage transients.

7.9 Testing of Numerical Relays

Testing of numerical relays is intricate when compared to testing of static or electromechanical relays. Pickup, operating time at various current values, directional element etc. of numerical relays can be tested in a manner similar to that described in sections 7.7.2, 7.7.3, 7.7.4 and 7.7.5 for testing of electromechanical relays. However in addition to these tests various other characteristics of numerical relays need to be checked. This section focuses on describing the additional tests to be carried out on numerical relays.

Numerical relays are generally multifunctional relays. Testing multifunction relays may require that certain elements be disabled to accommodate steady state testing. For example, if our simple 50/51 relay has both time and instantaneous elements programmed to the same output contact, it may be necessary to disable the 51 element to get an accurate pickup value on the 50 element. This is not a difficult job in most relays, but it does require making a change to the relay from the in-service setting to make a test. The preferred method of testing any circuit or relay is to test it exactly as it will be when it is in service. Making changes to the in-service settings after they are loaded into the relay requires that the setting be changed back. This may be risky because there may be dozens of settings that need to be changed and human error is a possibility.

One alternative is to begin by loading a copy of the in-service settings in the relay and disable elements for testing as the need arises. When the testing is complete, instead of trying to reverse all the changes, load the original copy of the in-service settings back to the relay. Now we know we are back where we started. File corruption between downloads is a remote possibility.

In applications where the same scheme will be used over and over it may be more convenient to create a setting group used only for testing. In this setting group the relay set points can be the same as the in-service group but with elements programmed to individual output contacts that are needed for testing.

7.9.1 Testing Setting Group Change

This may be one of the most powerful features of numerical relays, the ability to have several groups of relay setting that can be switched on manually or automatically to match the needs of the system. When system conditions change, the relay is notified and the settings can be changed instantly. There is no need to compromise a setting to fit two different system conditions.

However, in most applications we only need one or two setting groups so the others can stay empty having no settings at all. If the relay should inadvertently switch to an unused setting group, the relay would essentially be out of service. This is another instance where making the "negative" test is very important. Making checks to see the design works right is called a "positive" test. Making checks to see that the design doesn't work incorrectly is called a "negative" test. Just because my settings and schematics show no setting group change, I should make the negative test to ensure that it will not cause an unintended consequence by switching to an unused group. If setting groups are not used, copy the in-service group settings to all other unused setting groups. If the relay switches to one of those groups, it will still be in service with the proper settings. When more than one setting group is used, copy the default setting to all of the unused groups.

We should also identify any automatic or dynamic functions during the setting and commissioning process so they may be set and tested to work when needed and not work when not needed. It's the lack of a negative test that can cause us trouble on an automatic feature. If the setting group was accidentally programmed to change groups five minutes after the 51 element was at 70% of pickup, we might never encounter this during testing. After installation, when the load gets high, the relay will switch to another setting group and perhaps have no settings.

Using our 50/51 overcurrent relay example, let's say we don't need setting groups for our application. The setting sheet should list the setting group change and whatever set points or commands are needed to program it for "no setting group change". This way the setting engineer and the commissioning engineer have both identified the function so it can be a part of the testing and commissioning. Leaving it off the setting sheet because the function is not needed may mean it will not be checked at all. In this case a setting of zero is important.

7.9.2 Testing Programmable Logic

Multifunction relays have, in one device, the equivalent of several single function relays that would be found on the traditional relay panel. The functional schematic of the traditional relay is determined by the wiring from one device to the next. In the numerical relay the programmable logic takes the place of the wiring. Therefore, we should treat the programmable logic the same way we would switchboard wiring. Logic diagrams should be drawn out and documented on blueprints. Those prints should be part of the construction package or settings file. When it is time for the functional testing part of commissioning, testing of the programmable logic should be taken as seriously as functional testing traditional schemes.

Programmable logic is saved and transmitted to the relay electronically, sometimes in the same file as the settings. Saving the programmable logic to a file in advance of commissioning is a time saver, but it should not replace the need to generate a hard copy of the logic diagram to be used during commissioning and a permanent copy in the substation prints for troubleshooting.

The logic should be tested just as we described functional testing for traditional relays. That means we confirm that all inputs, outputs, relay function blocks, controls, alarms, and switches perform as intended and do not operate with unintended consequences (all positive and negative tests). The sequence of events feature of numerical relays can be used to help sort out the results of logic testing to confirm that the proper elements are asserted, logic has functioned correctly, and timing is proper.

7.9.3 Testing External Inputs

Most numerical relays use optical isolators to condition the input circuits. These optical isolators have some DC voltage that defines their threshold of operation. The optical isolator should have a threshold higher than half the battery voltage but below the minimum expected DC bus voltage. If battery system is ungrounded you should confirm that the optical isolator will not operate with a full positive or negative battery ground. On a 220 volt DC system full battery ground would give half battery voltage or 110 volts to the optical isolator. After you test the input for proper operation at normal battery voltage, you should repeat the test at half battery voltage to confirm the optical isolator will not operate.

Some relays have internal jumpers used to set the optical isolator threshold. Set at greater than half the battery voltage, but less than the minimum expected voltage. If settable jumpers are not available, test the inputs for their threshold level and record this information on setting sheets and blueprints. This will remind others that the inputs may be falsely triggered for battery grounds.

7.9.4 Testing Targets and Output Contacts

Electromechanical relays commonly used trip and seal-in units in conjunction with the main relay contacts. The main contacts were normally not rated for tripping duty and the combination trip and seal-in took care of tripping duty, and reporting a mechanical target. The seal-in unit will stay picked up as long as trip current is flowing to the trip coil.

The output contacts of a numerical relay are usually individually sealed relays rated for 30A tripping duty. However, they will break less than 1 amp and will be damaged if opened while trip current is flowing. The output contacts are initiated by the internal trip logic of the relay and, therefore, are independent of trip current. To avoid damaging output contacts used for trip and close duty, the manufacturer should supply a hold-up circuit that will allow output contacts to remain closed for 10-12 cycles regardless of what the logic is doing. Once a trip or close has been initiated the contact should remain closed long enough to complete the breaker operation. This type of setting is easily overlooked and may not be discovered until the relay is in service. This is another item that should be added to the setting sheet document so that it can be properly programmed and checked during commissioning.

In some cases, the targets of numerical relays have programmable features such as report last target, report all targets, report initial fault targets, ignore certain targets and so on. Electromechanical targets are cumulative. If we have five faults since last reset we won't know which targets went with which fault. Numerical relays normally report only the targets for the last fault. Previous target data can be retrieved from event data. Because there may be settings or logic associated with targets they also should become a part of the setting and commissioning procedure.

7.9.5 Making Changes to Existing Settings

After the numerical relay is in service and a setting change must be made, how much testing should be done? First of all, the field engineer should be armed with the existing settings and the new settings in case there is any question about the as found settings. This will also permit returning to the old settings if there is a problem installing the new ones. This should be in electronic format and hard copy printout.
The next step is to download the existing settings from the relay and check them against the existing setting file we brought with us. Discrepancies should be documented; after all, the reason for the setting change might be a mis-operation caused by a wrong setting in the first place.
If the two existing setting files match, we can load in the new settings. This is usually done electronically but some manufacturers have keypads that allow inputting of relay settings from the front panel. When the settings are loaded we should test all those items that have been changed. If the change is a relay setpoint, then secondary injection testing is indicated. If the change is in the relay's programmable logic, then a functional test should be performed. If the instrument transformer inputs have been disturbed, then in-service tests should be done.

7.9.6 In-Service Readings of Numerical Relays

Most numeric relays display the measured values of current and voltage that are used by the relay for protection. Sometimes these values can be compared to other values in the relay in terms of phase angle. Fundamentally there is nothing wrong with using these displays to perform your in-service readings so long as you leave knowing that the relay is, in fact, connected correctly. Using these displays is no different than picking up a new phase angle meter. At some point you must confirm the meter display is correct. When you test the relay you will be able to check the display by inputting known current, voltage and phase angle from a test set. If the display is correct with a known source, there is no reason to break out another instrument for in-service tests.

With the test set connected, pay particular attention to the lead-lag convention of the relay and what quantity the relay is using as a reference. For example, if R phase current is used as a reference for the phase angle readings, then the angle for A phase will be 0 degrees. If Y phase is 240 degrees, is that lead or lag? There is no standard; you must make note of it before commissioning the relay.

Knowing the lead-lag convention used in the relay will help us determine the phase sequence of the quantities applied to the relay. Most numerical relays can calculate sequence components for use in metering and protective elements. This may not seem important if the negative sequence element is not being used, but that doesn't mean it won't be in the future. Also, proper sequence will make negative sequence metering correct. Others may depend on the metering or may become alarmed at high readings. Most relays have the capability of setting the normal phase sequence inside the relay either RYB or RBY. This is another setting that should be identified on the setting sheets so it can be confirmed in the testing and commissioning. You should be able to confirm this setting during commissioning by reading the metered value of the negative sequence current. It should be low for balanced load conditions. If not, check the phase sequence setting and CT wiring. If they do not match, relay targets may be incorrect. Correct CT wiring if necessary.

Numerical transformer differential relays have the capability of internally adjusting for the phase shift of a delta-wye connected bank. Keep in mind when using internal compensation that the currents going into the relay will not be 180 degrees out of phase as we expect with traditional relays. With numerical relays there is no physical operate winding, only a calculated value. So external in-service readings can only be taken on the restraint windings. Operating current calculated values are usually displayed by metering or software.

7.9.7 CT Polarity Change Option

Some relays have a setting for CT polarity so the user can reverse the polarity if it is incorrect without re-wiring the CT circuit. Making the correction in the relay normally means the external wiring is incorrect. Changing polarity in the relay will make the relay work correctly but would mean the AC elementary is incorrect in the way the CT is wired to polarity of the relay. Either the AC schematic and setting sheet should be corrected, or the CT wiring should be corrected.

7.10 Temperature Relays

Temperature relays used on bearings and for other important purposes should be checked for correct operation by placing the bulb in a pail of water with a thermometer, and gradually heating to the temperature at which the relay is set to operate. A mercury or alcohol thermometer should be used to read the temperature while the water is being stirred. Record temperature at which the relay operates on increasing temperature and at which it resets on falling temperature. Temperature relays operating from RTD's (resistance temperature detectors) should be checked by heating the detectors slowly in an enclosed air space since they should not be immersed in water or other liquid.

7.11 Pressure Relays

Pressure relays can be checked for correct operation by comparing with an accurate pressure gauge. Pressure should be increased and decreased to determine the pressure at which the relay operates and resets. The above does not apply to sudden pressure relays, which should be maintained in accordance with the manufacturer's recommendations.

7.12 Grounding CT and PT Circuits

The CT and PT circuits should be grounded at only one point. Relay malfunction can be caused by grounding the neutral at two points, such as one ground at the switchyard and another at the relay panel. At least once every 3 years with the primary deenergized, the known ground should be removed and the overall circuits should be checked for additional grounds and insulation breakdowns.

CHAPTER – 8

FAULT CALCULATIONS AND RELAY COORDINATION

8.1 Introduction

Successful Operation of a power system depends largely on the engineer's ability to provide reliable and uninterrupted service to loads. The reliability of the power supply implies much more than merely being available. Ideally, the loads must be fed at constant voltage and frequency at all times. In practical terms this means that consumer's equipment may operate satisfactorily. For example, a drop in voltage of 10-15% or a reduction of the system frequency of only a few hertz may lead to stalling of the motor loads on the system. As electrical utilities have grown in size, and the number of interconnections has increased, planning for future expansion has become increasingly complex. The increasing cost of additions and modifications has made it imperative that utilities consider a range of design options, and perform detailed studies of the effects on the system of each option, based on the number of assumptions: like normal and abnormal operating conditions, peak and off-peak loadings, and present and future years. Future transmission and distribution systems will be far more complex than those of today. This means that the power system planner's task will be more complex. If the systems being planned are to be optional with respect to construction cost, performance, and operating efficiency, better planning tools are required.

8.2 Parameter Conversion

Power transmission lines are operated at voltage levels where kilovolt is the most convenient unit to express voltage. The amount of power transmitted is in terms of kilowatts or megawatts and kilo amperes or mega amperes. However the quantities, current and Ohms are often expressed as a percent or per unit of base value. The per unit value of any quantity is defined as the ratio of the quantity to its base value expressed as a decimal. Both the per unit (p.u.) and percent methods of calculation are simpler than the use of actual amperes, Ohms, and voltage values. The per unit method has an advantage over the percent method because the product of two quantities expressed in per unit is expressed in per unit itself, but the product of two quantities expressed in percent must be divided by 100 to obtain the result in percent. The per unit value of a line to neutral voltage on the line to neutral voltage base is equal to the per unit value of the line to line voltage at the same point on the line to line voltage base if the system is balanced. Similarly, the three-phase kVA is three times the kVA/phase and the three-phase kVA base is three times the base kVA per phase. Therefore the per unit value of the three-phase kVA on the three-phase kVA base is identical to the per unit value of the kVA per phase on the kVA per phase base. Base impedance and base current value can be computed directly from three phase values of base kilovolts and base kilo-amperes.

Base Current = {Base kVA (3-ph) / 1.7325 x Base kV}
Where, Base kV is the line-to-line voltage.

Base Z = { (Base kV / 1.7325)^2 x 1000 / (Base kVA) / 1.7325 }

Base Z = { (Base kV)^2 / (Base MVA) }

Sometimes the per unit impedance of a component of a system is expressed on a base other than the one selected as base for the part of the system in which the component is located. Since all impedances in any one part of a system must be expressed on the same impedance base when making computations, it is necessary to have a means of converting per unit impedances from one base to another. The per unit impedance is given by following equation;

Per unit Z = { (Actual Z in Ohms x Base MVA) / (Base kV)^2 }

Which shows that per unit impedance is directly proportional to "base MVA" and inversely proportional to the square of the base voltage. Therefore, to change from per unit impedance on a given base to per unit impedance on a new base, the following equation is used,

Per unit Z_{new} = (Per unit Z_{given}) x (Base kV_{given} / Base kV_{new})^2 x (Base MVA_{new} / Base MVA_{given})

The Ohmic values of resistance and leakage reactance of a transformer depends on whether they are measured from the LT side or HT side of a transformer. If they are expressed in "p.u.", the base MVA rating of the transformer which is same as referred from HT side or LT side. The base kV is selected as the voltage of LT winding, if the ohmic values are referring to LT side, else it is selected as voltage of HT winding, if the ohmic values are referring to HT side of transformer. Whereas the "PU" values remains same regardless of whether they are determined from HT side or LT side. Relation between per unit and percentage values is as follows:

Per Unit Quantity = Percentage Quantity / 100

The advantages of the "PU" method are:

1. The "PU" impedance of machines of same type and widely different ratings usually lie within a narrow range, although the ohmic values differ for machines of different ratings. For this reason, when the impedance is not known definitely, it is generally possible to select from the tabulated values"PU" impedance which will be reasonably correct.
2. When impedance in ohms is specified in an equivalent circuit, each impedance must be referred to the same circuit by multiplying it by the square of the ratio of rated voltages of the two sides of a transformer. The "PU" impedance, once expressed in proper base, remains same either referring from HT side or LT side.
3. The way in which transformers are connected in three phase circuits does not affect the "PU" impedances of the equivalent circuit, although the transformer connection does determine the relation between the voltage bases on the two sides of the transformer.

8.2.1 Two winding Transformer Parameter Conversions:

Manufacturers usually specify the impedance of a piece of apparatus in percent or per on the base of the nameplate rating. It is converted to common base using MVA rating and the voltage rating of transformer. Sometimes the voltage ratings of the transformer do not match exactly with the base voltage on their respective sides, in case the transformer parameters are converted to the base values of voltage and MVA. To begin with, assuming that transformer tap is on primary side (HV side), the given impedance is converted to common base as;

$$Z_{new\ pu} = \{ (Z_{old\ pu}) \times (MVA_{new} / MVA_{old}) \times (\text{Rated kV}_{sec} / \text{Base kV}_{sec})^2 \}$$

If the transformer parameters are given in actual units (ohms). Then the values are converted to common base as;

$$Z_{pu} = (Z_{ohms}) \times (\text{Base MVA} / \text{Base kV}^2)$$

Base kV is the voltage referred to the side at which measurements are made. The transformer R/X ratio is used to separate the transformer resistance and reactance values from the impedance. If number of units are in parallel then the effective equivalent impedance is computed by dividing the impedance by units.

$$X = [\{\sqrt{Z^2} / \{ 1 + (R / X)^2 \}\} / \text{Units}]$$
$$R = (X)*(R / X)$$

The zero sequence impedances differ greatly depending on the type of connection and the construction of the transformers. Conductors connected to transformer windings with delta connection or with star with an insulated neutral point cannot carry a zero sequence current. The zero sequence impedance is therefore infinite. When the neutral point of star winding is earthed or connected, zero sequence can flow in the associated system. If the transformer is star connected on primary side and delta connected on secondary side, then shunt impedance will exists from primary node to ground and vice-versa. The neutral impedance given in ohms, converted to common base as;

$$\text{Base } Z_{pri} = (\text{Base kV}_{pri}^2 / \text{Base MVA}) \text{ in Ohm}$$
$$\text{Base } Z_{sec} = (\text{Base kV}_{sec}^2 / \text{Base MVA}) \text{ in Ohm}$$
$$R_{pu\ neutral\ pri} = (R_{ohm\ neutral\ pri} / \text{Base } Z_{pri})$$
$$R_{pu\ neutral\ sec} = (R_{ohms\ neutral\ sec} / \text{Base } Z_{sec})$$

EXAMPLE:
Rated MVA = 315
Primary Voltage = 420 kV
Secondary Voltage = 240 kV
Positive sequence impedance = 0.125PU or 12.5%
Zero sequence impedance = 0.100PU or 10%
Neutral $R_{pri} = R_{sec}$ = 2.0 Ohm.
Connection = YnYn0

The transformer is connected to a bus on HT side with voltage 400 kV and on LT side is connected to a bus with voltage 220 kV. Hence primary base voltage = 400 kV and the secondary base voltage is 220 kV. The common base MVA = 100

$Z_{\text{positive seq.}}$ in PU = (%Z / 100) x (Base MVA / Rated MVA)*(Rated kV / Base kV)^2
= (12.5 / 100) x (100 / 315) x (240/220)^2
= 0.047225 PU

$X_{\text{positive seq.}}$ in PU = [{√Z^2 / { 1 + (R / X)2 }} / Units]
= [{√(0.047225)^2 } / { 1 + (0.05)^2 }]
= 0.047166 PU

$R_{\text{positive seq.}}$ in PU = (0.04766 x 0.05)
= 0.002358 PU

$Z_{\text{zero seq.}}$ in PU = (%Z / 100) x (Base MVA / Rated MVA)*(Rated kV / Base kV)^2
= (10 / 100) x (100 / 315) x (240/220)^2

$X_{\text{zero seq.}}$ in PU = [{√Z^2 / {1 + (R / X)^2 }} / Units]
= [{√ (0.0377804)^2} / {1 + (0.05)^2}]
= 0.0377332 PU

$R_{\text{zero seq.}}$ in PU = (0.0377332 x 0.05)
= 0.00188666 PU

The neutral impedance values are computed as;
Base Z_{pri} = (Base $kV_{pri}{}^2$ / Base MVA) in Ohm
= (400)^2 / 100
= 1600 Ohm.

Base Z_{sec} = (Base $kV_{sec}{}^2$ / Base MVA) in Ohm
= (220)^2 / 100
= 484 Ohm.

$R_{\text{pu neutral pri}}$ = ($R_{\text{ohm neutral pri}}$ / Base Z_{pri})
= (2 / 1600)
= 0.00125 PU

$R_{\text{pu neutral sec}}$ = ($R_{\text{ohms neutral sec}}$ / Base Z_{sec})
= (2 / 484)
= 0.004132 PU

8.2.2 Transmission Line Parameter Conversions:

For a transmission line, line resistance, reactance and the susceptance of the line are given in actual units (Ohms) per km length of the line per circuit. Zero sequence impedance denotes the impedance of zero sequence system of a three phase line per phase in which equal and in-phase currents are flowing through the three phase conductors of the system. The operative zero sequence impedance is affected by, among other things, the electrical conductivity of the earth and the presence of earth wires. The same formulae are used for both positive and zero sequence parameter conversion. The line positive sequence parameters are converted to per unit on common base values as;

Base Z = (Base kV)^2 / Base MVA
R_{1pu} = (R_{1ohm} / Base Z) x (Length / Circuits)
X_{1pu} = (X_{1ohm} / Base Z) x (Length / Circuits)
B_{1pu} = (B_{1mho} x Base Z) x (Length x Circuits)

EXAMPLE:

Number of Circuits = 1.0
Length of Line = 181km.
Positive sequence R = 0.0288864 Ohm/km.
Zero sequence R = 0.072216 Ohm/km.
Positive sequence X = 0.32704 Ohm/km.
Zero sequence X = 0.8176 Ohm/km.
Positive sequence B = 1.78087E-06 mho/km.
Zero sequence B = 1.52374E-06 mho/km.
Common base MVA = 100 and Base voltage = 400.0 kV.

Base Z = (Base kV)^2 / Base MVA
= (400)^2 / 100
= 1600 Ohm.

$R_{1pos.}$ pu = (R_{1ohm} / Base Z) x (Length / Circuits)
= (0.0288864 / 1600) x (181 / 1)
= 0.003267 PU

$X_{1pos.}$pu = (X_{1ohm} / Base Z) x (Length / Circuits)
= (0.32704 / 1600) x (181 / 1)
= 0.03699 PU

$B_{1pos.}$pu = (B_{1mho} x Base Z) x (Length x Circuits)
= (1.78087E-06 x 1600) x (181 x 1)
= 0.51574 PU

$R_{1zero.}$ pu = (R_{0ohm} / Base Z) x (Length / Circuits)
= (0.072216 / 1600) x (181 / 1)

= 0.008169 PU

$X1_{zero.pu}$ = ($X0_{ohm}$ / Base Z) x (Length / Circuits)
= (0.8176 / 1600) x (181 / 1)
= 0.09249 PU

$B1_{zero.pu}$ = ($B0_{mho}$ x Base Z) x (Length x Circuits)
= (1.52374E-06 x 1600) x (181x 1)
= 0.44127 PU

8.2.3 Shunt Capacitor Parameter Conversions:

The shunt capacitor banks are used extensively to correct power factors and as results, improve voltage regulation at the point of connection. The shunt capacitor conductance and susceptance values are given in PU on its own rating. The values are converted to common base as:

$$G_{new} = (G_{old}) \times (\text{Base kV}_{new} / \text{Base kV}_{old})^2 \times (\text{MVA}_{old} / \text{MVA}_{new})$$
$$B_{new} = (B_{old}) \times (\text{Base kV}_{new} / \text{Base kV}_{old})^2 \times (\text{MVA}_{old} / \text{MVA}_{new})$$

8.3 Short-Circuit Calculations

8.3.1 Need for Short-Circuit Calculations

Several sections of the National Electrical Code relate to proper over-current protection. Safe and reliable application of over-current protective devices based on these sections mandate that a short circuit study and a selective coordination study be conducted. The protection for an electrical system should not only be safe under all service conditions but, to insure continuity of service, it should be selectively coordinated as well. A coordinated system is one where only the faulted circuit is isolated without disturbing any other part of the system. Over-current protection devices should also provide short-circuit as well as overload protection for system components, such as bus, wire, motor controllers, etc. To obtain reliable, coordinated operation and assure that system components are protected from damage, it is necessary to first calculate the available fault current at various critical points in the electrical system. Once the short-circuit levels are determined, the engineer can specify proper interrupting rating requirements, selectively coordinate the system and provide component protection.

To determine the fault current at any point in the system, first draw a one-line diagram showing all of the sources of short-circuit current feeding into the fault, as well as the impedances of the circuit components. To begin the study, the system components, including those of the utility system, are represented as impedances in the diagram. It must be understood that short circuit calculations are performed without current limiting devices in the system. Calculations are done as though these devices are replaced with copper bars, to determine the maximum “available” short circuit current. This is necessary to project how the system and the current limiting devices will perform. Also, current limiting devices do not operate in series to produce a “compounding” current limiting effect. The downstream, or load side, fuse will operate alone under a short circuit condition if properly coordinated.

8.3.2 Three-phase Short-Circuit Calculation by Per-Unit Method:

The Per-Unit method is generally used for calculating short-circuit currents when the electrical system is more complex. After establishing a one-line diagram of the system, proceed to the following calculations:

Step-1:
First draw an SLD showing equipment ratings and impedances.

Step-2:
Choose base MVA and base voltage

Step-3:
Convert the impedances on common base MVA and base voltage

Step-4:
Draw impedance diagram showing impedances in PU

Step-5:
Determine the total equivalent impedance "Z PU" upto the point of fault.

Step-6:
Determine the total Short Circuit MVA at the point of fault as follows
$MVA_{SC1} = (MVA_{Base}) / (Z_{Total\ PU})$

Step-7:
Determine Short Circuit Current as follows.
$I_{kA} = (MVA_{SC1}) / (1.7325 \times \text{Rated KV})$

8.4 Relay Coordination

8.4.1 Need for Relay Coordination

The objective of protective relay coordination in an interconnected power system is to achieve selectivity without sacrificing sensitivity and fast fault clearance time. It is evident that in spite of all precautions taken in the design & installation of electrical power / distribution systems, there are bound to arise abnormal conditions or faults some of which like short circuits may prove extremely damaging to not only the faulty component but to the neighbouring components & to the power system as a whole. It is of vital importance to limit the damage to a minimum by speedy isolation of the faulty section, without disturbing the working of the rest of the system.

It is obvious that faster the speed of operation of elements of protective system (relay & breaker), less is the damage to the equipment. The time setting of the relays has to be decided based on the short time rating of the equipments to be protected. More over if the faults are not cleared within the time, the generator may go out of step and complete shut down of the generator may occur resulting in to total dark-out. On the same way relay should not be made extremely fast, as otherwise the relays may operate unnecessarily for transient conditions Protective system should be able to discriminate between fault & load condition even when the minimum fault current is less than the maximum load current. The relay should be able to distinguish between over load & over current. Only faulty element of the system should be isolated & healthy section should be left intact. This selectivity can be obtained by grading of protections of several zones.

8.4.2 Principles of Overcurrent Relay Coordination

Protective relay coordination can be achieved by utilising one of the following techniques:

a. Discrimination by Time

In this method an appropriate time interval is given by each of the relays controlling the circuit breakers in a power system to ensure that the breaker nearest to the fault opens first. A simple radial distribution system is shown in figure 8.1 to illustrate the principle.

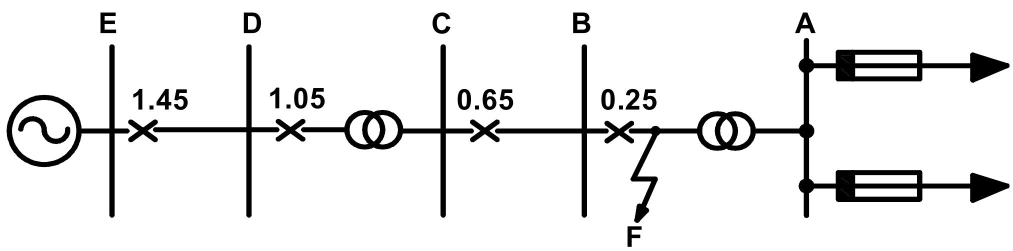


Figure 8.1 - Radial System with Time Discrimination

Circuit breaker protection is provided at *B, C, D* and E, that is, at the infeed end of each section of the power system. Each protection unit comprises a definite time delay over current relay in which the operation of the current sensitive element simply initiates the time delay element. Provided the setting of the current element is below the fault current value this element plays no part in the achievement of discrimination. For this reason, the relay is sometimes described as an 'independent definite time delay relay' since its operating time is for practical purposes independent of the level of over current.

It is the time delay element, therefore, which provides the means of discrimination. The relay at B is set at the shortest time delay permissible to allow a fuse to blow for a fault on the secondary side of transformer A. Typically, a time delay of 0.25s is adequate. If a fault occurs at F, the relay at B will operate in 0.25s, and the subsequent operation of the circuit breaker at B will clear the fault before the relays at C, D and E have time to operate. The main disadvantage of this method of discrimination is that the longest fault clearance time occurs for faults in the section closest to the power source, where the fault level (MVA) is highest.

b. Discrimination by current

Discrimination by current relies on the fact that the fault current varies with the position of the fault, because of the difference in impedance values between the source and the fault. Hence, typically, the relays controlling the various circuit breakers are set to operate at suitably tapered values such that only the relay nearest to the fault trips its breaker. Figure 8.2 illustrates the method.

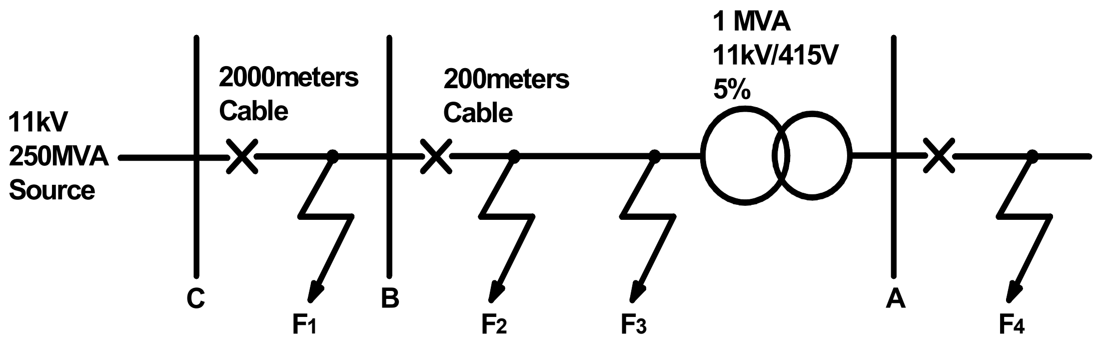


Figure 8.2 Radial System with Current Discrimination

For a fault at F_1, the system short circuit current is given by:

$I = 6350 / (Z_S + Z_{L1})A$

Where, Z_S = source impedance = $11^2 / 250 = 0.485$ ohms
Z_{L1}= cable impedance between C and $B = 0.24$ ohms

Hence I= 6350/0.725 = 8800 A

So a relay controlling the circuit breaker at C and set to operate at a fault current of 8800 A would in simple theory protect the whole of the cable section between C and B. However, there are two important practical points which affect this method of coordination. It is not practical to distinguish between a fault at F_l and a fault at F. Since the distance between these points is only a few meters, the corresponding to a change in fault current is very low i.e. of the order of approximately 0·1%. In practice, there would be variations in the source fault level, typically from 250 MVA to 130 MVA due to changes in system. At this lower fault level the fault current would not exceed 6800 A even for a cable fault close to C, so a relay set at 8800 A would not protect any of the cable section concerned.

Discrimination by current is therefore not a practical proposition for correct grading between the circuit breakers at C and B. However, the problem changes appreciably when there is significant impedance between the two circuit breakers concerned. This can be seen by considering the grading required between the circuit breakers at B and A in figure 8.2. Assuming a fault at F_4, the short-circuit current on HV side of transformer is given by:

$I = 6350 /(Z_S + Z_{L1} + Z_{L2} +Z_T)A$

Where, Z_s = source impedance
Z_{L1} = cable impedance between C and B is 0.24 ohms
Z_{L2} = cable impedance between B and 1 MVA transformer is 0.04 ohms
Z_T = transformer impedance
$=0.05(11^2/1) = 6.05$ ohms
Hence I = 6350/ 6.815 = 931.7 A

For this reason, a relay controlling the circuit breaker at B and set to operate at a current of 931.7 A plus a safety margin would not operate for a fault at F_4 and would thus discriminate with the relay at A. Assuming a safety margin of 20% to allow for relay errors and a further 10% for variations in the system impedance values, it is reasonable to choose a relay setting of 1.3 x 931.7, that is, 1211.2 A for the relay at B. Now, assuming a fault at F_3, that is, at the end of the 11 kV cable feeding the transformers, the short-circuit current is given by:

$I = 6350 /(Zs + Z_{L1} + Z_{L2})$
$I = 6350 /(0.485 + 0.24 + 0.04) = 8300$ A

Alternatively, assuming a source fault level of 130 MVA:

$I = 6350 /(0.93 + 0.24 + 0.004)=5250$ Amp.

In other words, for either value of source level, the relay at B would operate correctly for faults anywhere on the 11 kV cable feeding the transformer.

c. Discrimination by both time and current

Each of the two methods described so far has a fundamental disadvantage. In the case of discrimination by time alone, the disadvantage is due to the fact that the more severe faults are cleared in the longest operating time. Discrimination by current can only be applied where there is appreciable impedance between the two circuit breakers concerned.

It is because of these limitations imposed by the independent use of either time or current co-ordination that the inverse time over current relay characteristic has evolved. With this characteristic, the time of operation is inversely proportional to the fault current level and the actual characteristic is a function of both 'time' and 'current' settings.

This technique has the following advantages:

1. With the same Pickup & Time dial settings, lower Time of operating for near end faults and higher operating times for near end faults inherently achieved.
2. In case of the difference in the fault current magnitude along system, IDMTL relays are superior to the DMT relays.
3. In case of same fault current magnitude along system, desired operating time can be achieved by adjusting pickup & time dial.

8.4.3 Data Required to Perform O/C & E/F Relay Coordination Study

Following data should be collected before carrying out relay coordination study :

1. Power, voltage ratings, impedance, and connection configurations of all transformers included in the system to be analyzed.
2. Normal and emergency switching/steady state conditions.
3. Nameplate data from all protective devices included in study; i.e., manufacturer's Catalogue number, voltage/current, and IEC ratings.
4. Trip device type-range and current setting.
5. Conductor sizes, types, configurations, and temperature ratings.
6. Current transformer ratios.
7. Utility equipment rating and device settings.
8. Existing System one-line diagram.

a. Required Data of Transformer

1. MVA rating
2. Primary and secondary voltage rating
3. Percentage impedance [%Z] on the given MVA rating for positive and zero sequence [%Z1 and %Z0]
4. X/R Ratio for positive and zero sequence
5. Winding connection and Neutral Grounding Reactance / Resistance if any
6. Tap data for both fixed taps and LTC taps, minimum and maximum %tap position and steps size for LTC

b. Required Data of Line/Cable

1. Cable/Conductor type
2. Cable length [more than 100 Mt] and cable size
3. Resistance [ohm], Reactance [ohm] and susceptance [mho] per Km for both positive and zero sequence values.

c. Required Data of Relays

1. Relay type, model and manufacturer's name
2. CT rating/ratio
3. Plug setting range
4. Time dial setting range
5. Relay characteristic curve details
6. Instantaneous setting data or Range.

8.4.4 Criteria for Setting Relays

a. In order to understand the procedures of setting various relays, we should be familiar with some very important terms related to relay settings. These terms are defined below.

1. **Time Multiplier Setting (TMS)**

It refers to adjusting the time taken by relay to trip once the current exceeds the set value

TMS = T/Tm

Where T - is the required time of operation
Tm - is the time obtained from the relay characteristics curve at TMS 1.0 and using the Plug Setting Multiplier (PSM) equivalent to the maximum fault current

2. Pick-up Current (Primary Operating Current)

Pickup is defined as the minimum current that starts an action. Pickup current of an overcurrent relay is the minimum value of current that will cause the relay to close its contacts. For an induction disk overcurrent relay, pickup is the minimum current that will cause the disk to start to move and ultimately close its contacts.

3. Plug Setting Multiplier

It is defined as the ratio between the fault current and the primary operating current

PSM = Fault Current/ Primary operating current

b. Proper selection of Pickup & Time dial setting is the essence of relay coordination. The criteria for selecting time multiplier setting and pickup of relays will be discussed next. The following points may be considered while coordinating the operation of different relays in a radial system.

• Circuit Breaker Interrupting Time
• Relay overshoot
• Relay operating time error
• Final safety margin

The discrimination time between two electro-mechanical relays is given as
T = (0.4 t + 0.2) in second

The discrimination time between two numerical relays is given as
T = (0.4t + 0.15) in second

Where "t" is the operating time of fuse and 0.4*t is the discrimination time between fuse & breaker.

The discrimination time between two electro-mechanical relays is given as
T = (0.25t + 0.2) in second

The discrimination time between two numerical relays is given as
T = (0.25t + 0.15) in second

Where "t" is the operating time of fuse and 0.25*t is the discrimination time between breaker & breaker.

The time interval according to **IEEE** is usually 0.3 seconds. This interval is measured between relays in series either at the instantaneous setting of the load side feeder circuit breaker relay or the maximum short circuit current which can flow through both devices simultaneously, whichever is lowest. The recommended time has the following components:

• Circuit breaker opening time (3 cycles): 0.06 seconds
• Relay over-travel or Overshoot: 0.10 seconds
• Safety factor for CT saturation, setting errors, etc.: 0.2 seconds

An over current Protections are used for the feeder protections because of economical cost and more simplicity. As discussed in chapter 6, an over current relay operates when the magnitude of the current exceeds it's preset value. Various types of over current relay characteristics used for protection have also been given in chapter no.6. Most commonly used characteristics are given in figure 8.3. Formulae to get operation times of IDMT relays for these curves are given below

1. Standard Normal inverse (3.0s at 10times of PS),
   T in second = [0.14 / ((PSM) $^{0.02}$ – 1)]* TMS

2. Standard Very inverse (1.5s at 10times of PS),
   T in second = [13.5 / ((PSM) – 1)]* TMS

3. Standard extremely inverse (0.8s at 10times of PS),
   T in second = [80 / ((PSM) ^{2} - 1)]* TMS

4. Standard long inverse (17s at 10times of PS),
   T in second = [120 / ((PSM) – 1)]* TMS

Earlier in electro-mechanical protection, one relay was used with only one characteristic like CDG-11 has Normal inverse characteristic, CDG-12 has long inverse characteristic, CDG-13 has very inverse characteristic, CDG-14 has extremely inverse characteristic. But, now today modern numerical protection (like SPAJ-140C, 7SJ602, 7SJ61, P122 etc.) have more than one characteristics so today we have better selectivity and ranges which gives us a better relay co-ordination. It is sometimes difficult to find an inverse time relay having characteristics are not suitable to grade with fuses because of characteristic curve is not close with defined fuse characteristic. Extremely inverse characteristic is very close with fuse operating characteristics.

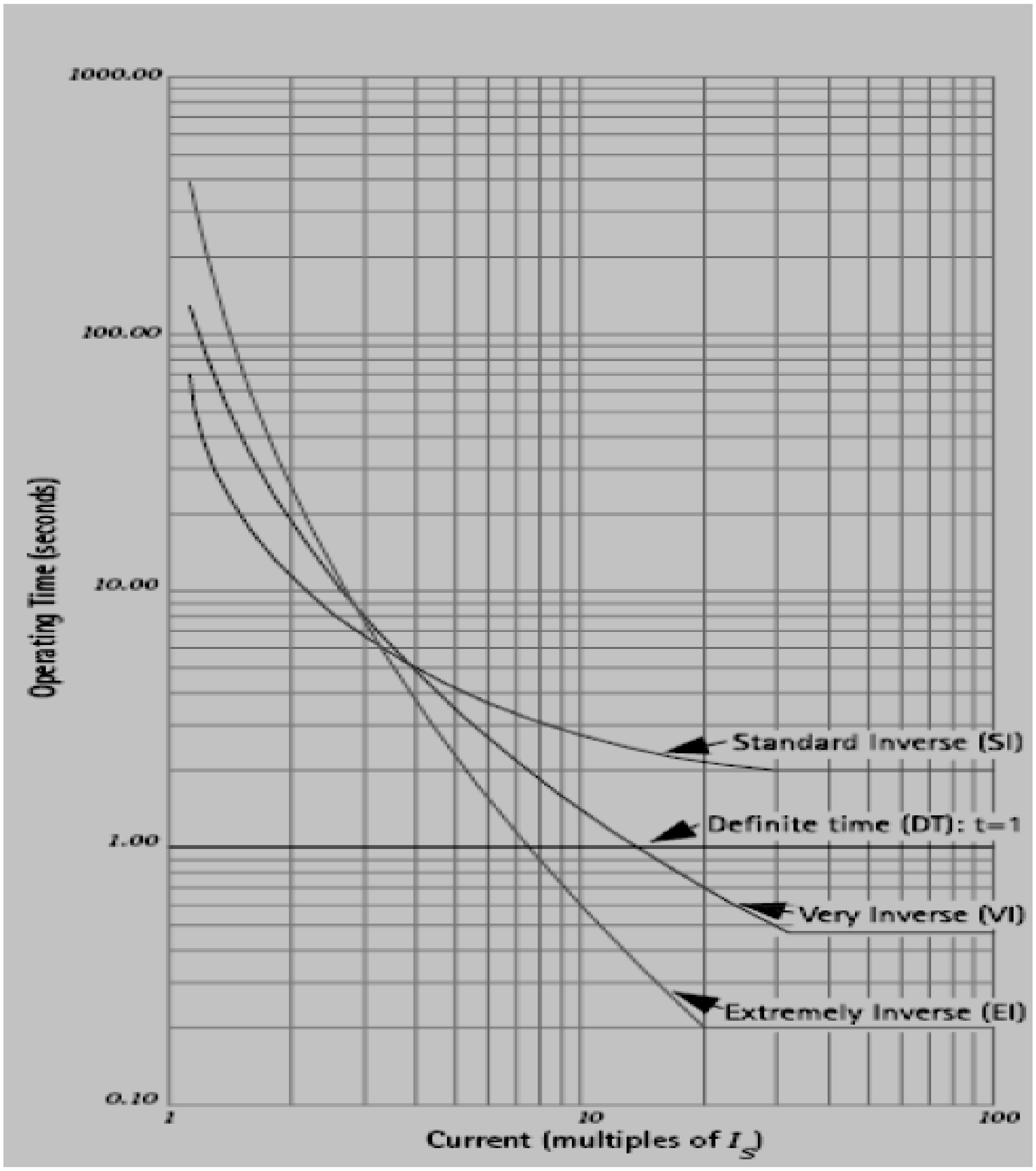


Figure 8.3 - IEC Curves

c. Setting of DMT Relays:

Following points should be kept in mind while selecting the Primary Operating Current:

1. Setting must be above maximum running load current and largest drive starting current by safety margin.
2. Setting must be below the lowest through fault current.
3. Maximum load current includes motor full load current. Hence, it is subtracted.
4. Relevant for generally used DOL Starting.
5. Formula for selecting the POC is as follows:

$$\mathbf{If > P.O.C > (I_{RL} + I_{STM} - I_{FLM})}$$

Where,
P.O.C. = Desired Primary Operating Current of relay
I_{RL} = Maximum running load current
I_{STM} = Highest rating drive starting current
I_{FLM} = Highest rating drive full load current
If = Minimum fault current relay to sense
PSM for DMT Relays is independent of fault current.

d. Setting of IDMT Relays:

For these relays generally the pickup setting is available in steps (not continuously) in electromechanical relays & variable in numerical relays. If it is not possible to get the exact set point value, the next higher available step should be selected.
PSM for IDMT Relays is set greater than 2

Step:-1
Primary operating current:
P.O.C. = ($I_{RL} + I_{STM} - I_{FLM}$)
Where,
P.O.C. = Desired primary operating current
$\mathbf{I_{RL}}$ = Maximum running load current
$\mathbf{I_{STM}}$ = Highest drive starting current
$\mathbf{I_{FLM}}$ = Highest drive full load current

Step:-2
Plug setting (PS) = (P.O.C.) / (C.T.R) = **[($I_{RL} + I_{STM} - I_{FLM}$) / C.T.R]**
Selected Pickup setting: Select the next higher available step.

Step:-3
Actual Primary Operating current (P.O.C.) = Selected Pickup setting * C.T.R.

Step:-4
Plug setting Multiplier (PSM) = Fault current / Actual P.O.C.

Step:-5
Desired relay Operating time **(t) = td + T**
Where, td = Discrimination time & T = Downstream relay/fuse operating time

Step:-6
Based on formula or curves, Calculate the relay operating time at TMS1.0 on PSM

Step:-7
Desired Time Dial Set point (TMS) = {(Desired relay Operating time) / (Relay operating time at TMS1.0)}
Select time dial setting: Nearest higher time dial setting selected

8.5 Case Study

A case study will further help in gaining a stronghold on the concepts of relay coordination. Single line diagram of grid substation is given in figure 8.4. Detailed fault calculations and relay coordination at various voltage levels of grid substation are discussed below.

Data used for cables is given below

SI.No.	Type	Voltage Level	R(Ω)/KM	X(Ω)/KM	Ro(Ω)/KM	Xo(Ω)/KM
1	630 Sq.mm XLPE	66 kV	0.0623	0.119	0.149	0.061
2	3CX400 Sq.mm XLPE	33 kV	0.19285	0.1995	0.627	0.1121
3	3CX300 mm² XLPE	11 kV	0.13	0.13	0.8219	0.8219

Calculations based on fault current provided by ETAP.

First let us undertake the fault calculation study of the Network shown in figure 8.4 using System Study Software “ETAP”. Three Phase and single phase short circuit studies were carried out using the software. The network data and assumptions of the study are mentioned below.

220/66 kV Transformer
Rated output: 100 MVA
Vector Group: YNyn0 (Assumption)
Percentage Impedance: 15%

66/33 kV Transformer
Rated output: 50 MVAV
Vector Group: Dyn11
Percentage Impedance: 9.6%

33/11 kV Transformer
Rated output: 20 MVA
Vector Group: YNyn0 (Auto Transformer)
Percentage Impedance: 13.75%

66kV Park Street Transco to 66kV Shastri Park
Cable Type: 630 Sq.mm XLPE
Cable Length: 5 km

33 kV Shastri Park to 33kV Anand Parwat
Cable Type: 3CX400 Sq.mm XLPE
Cable Length: 5.9 km

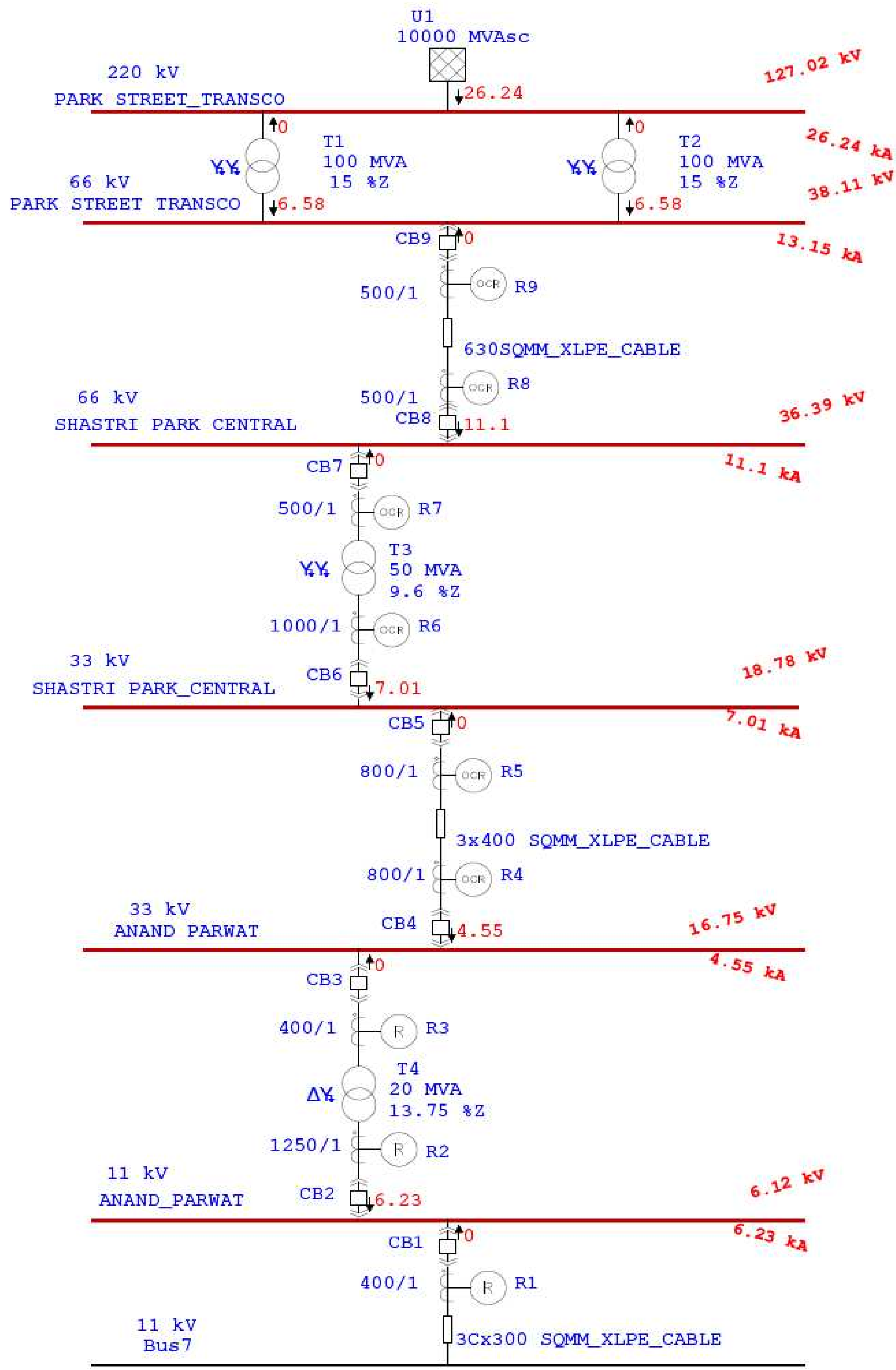


Fig 8.4 Single Phase Fault Currents at Different Buses.

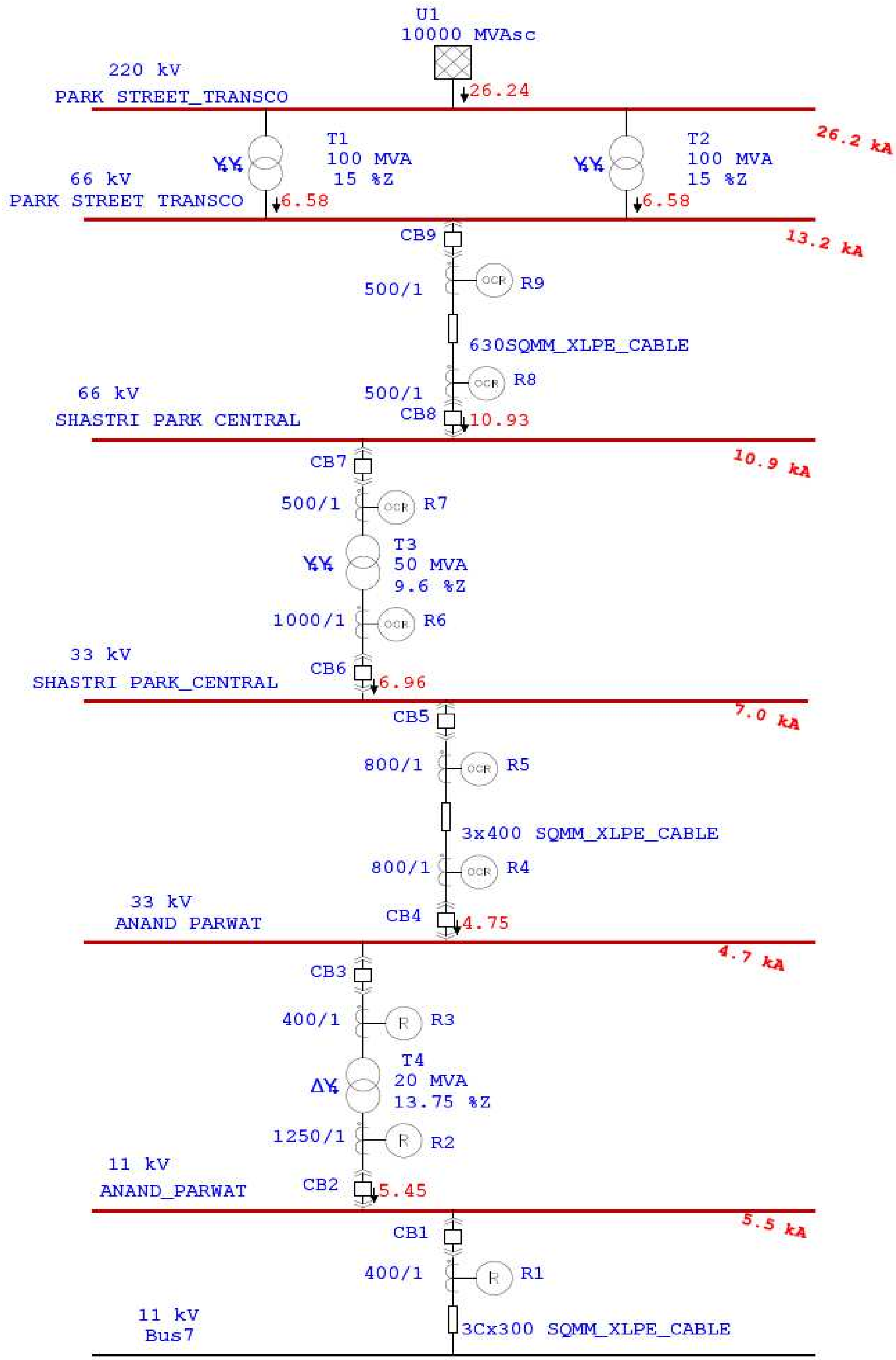


Fig 8.5 Three Phase Fault Currents at Different Buses.

Setting at 11kV O/G feeders:

<u>Phase Fault OC</u>

Three Phase fault current: 5450A
PS: 75%
PSM= 5450/300= 18.17
At K=1
TOO is 2.344sec
At **K=.05**
TOO is 117ms

<u>Earth Fault OC</u>

Single Phase Earth Fault current: 6230A
PS: 20%
PSM= 6230/80= 77.87
At K=1
TOO is 2.2sec
At **K=.05**
TOO is 110ms

Setting at 11kV I/C feeder:
<u>Phase Fault OC</u>

Three Phase fault current: 5450A
PS: 100%
PSM= 5450/1250= 4.36
At K=1
TOO is 4.68sec
Required TOO is 117+200= 317ms
Hence K= 0.07
Actual TOO is 327ms

<u>Earth Fault OC</u>

Single Phase Earth Fault current: 6230A
PS: 20%
PSM= 6230/250= 24.92
At K=1
TOO is 2.2sec
Required TOO is 110+200= 310ms
Hence **K=0.14**
Actual TOO is 308ms

Setting at 33kV Transformer feeder:

<u>Phase Fault OC</u>

Three Phase fault current: 4750A
PS: 100%
PSM= 4750/400= 11.87
At K=1TOO is 2.76sec
Reflected fault current of 11kV is 5450/3=1816.67A
Now PSM= 1816.67/400= 4.54
At K=1 TOO is 4.56sec
Required TOO for fault on 11kV side is 450ms
Hence **K= 0.098≈0.1**
TOO for fault on 33kV side is 276ms

<u>Earth Fault OC</u>

Single Phase Earth Fault current: 4550A
If there is a phase to earth fault at 11kV bus bar it will be reflected as phase fault at 33kV side of Transformer (Dyn11). So the earth fault relay setting can be put at min value.
At K= 0.05 TOO is 110ms
PSM=20%, **TMS =0.05**

Setting at 33kV I/C Anand Parwat:

<u>Phase Fault OC</u>

Three Phase fault current: 4750A
PS: 100%
PSM= 4750/800= 5.937
At K=1TOO is 3.86sec
Required TOO 276+200=476ms
Hence **K= 0.12**
TOO for fault on 33kV side is 463ms

<u>Earth Fault OC</u>

Single Phase Earth Fault current: 4550A
PS: 20%
PSM= 4550/160= 28.43
At K=1 TOO is 2.2sec
Required TOO is 110+200= 310ms
Hence **K=0.14**
Actual TOO is 308ms

Setting at 33kV O/G Shastri Park:

<u>Phase Fault OC</u>

Three Phase fault current: 6960A
PS: 100%
PSM= 6960/800= 8.7
At K=1TOO is 3.17sec
Required TOO 463+200=663ms
Hence **K= 0.2**
TOO for fault on 33kV side is 634ms

<u>Earth Fault OC</u>

Single Phase Earth Fault current: 7010A
PS: 20%
PSM= 7010/160= 43.8
At K=1 TOO is 2.2sec
Required TOO is 310+200= 510ms
Hence **K=0.23**
Actual TOO is 506ms

Setting at 33kV I/C Shastri Park:

<u>Phase Fault OC</u>

Three Phase fault current: 6960A
PS: 100%
PSM= 6960/1000= 6.96
At K=1TOO is 3.54sec
Required TOO 634+200=834ms
Hence **K= 0.23**
TOO for fault on 33kV side is 810ms

<u>Earth Fault OC</u>

Single Phase Earth Fault current: 4550A
PS: 20%
PSM= 7010/200= 35.05
At K=1 TOO is 2.2sec
Required TOO is 506+200= 706ms
Hence **K=0.32**
Actual TOO is 700ms

Setting at 66kV Transformer feeder Shastri Park:

Phase Fault OC

Three Phase fault current: 10930A
PS: 100%
PSM= 10930/500= 21.86
At K=1TOO is 2.2sec
Reflected fault current of 33kV is 6960/2= 3480A
Now PSM= 3480/500= 6.96
At K=1 TOO is 3.54sec
Required TOO for fault on 33kV side is 1000ms
Hence **K= 0.28**
TOO for fault on 66kV side is 616ms

Earth Fault OC
Single Phase Earth Fault current: 11100A
PS: 20%
PSM= 11100/100= 111
At K=1 TOO is 2.2sec
Reflected fault current of 33kV is 7010/2= 3505A
Now PSM= 3505/100= 35.05
At K=1 TOO is 2.2sec
Required TOO for fault on 33kV side is 906ms
Hence **K= 0.41**
TOO for fault on 66kV side is 906ms

Setting at 66kV I/C Shastri Park:

Phase Fault OC
Three Phase fault current: 10930A
PS: 100%
PSM= 10930/500= 21.8
At K=1TOO is 2.2sec
Required TOO 616+200=816ms
Hence **K= 0.37**
TOO for fault on 66kV side is 820ms

Earth Fault OC
Single Phase Earth Fault current: 11100A
PS: 20%
PSM= 11100/100= 111ms
At K=1 TOO is 2.2sec
Required TOO is 770+200= 970ms
Hence **K=0.44**
Actual TOO is 700ms

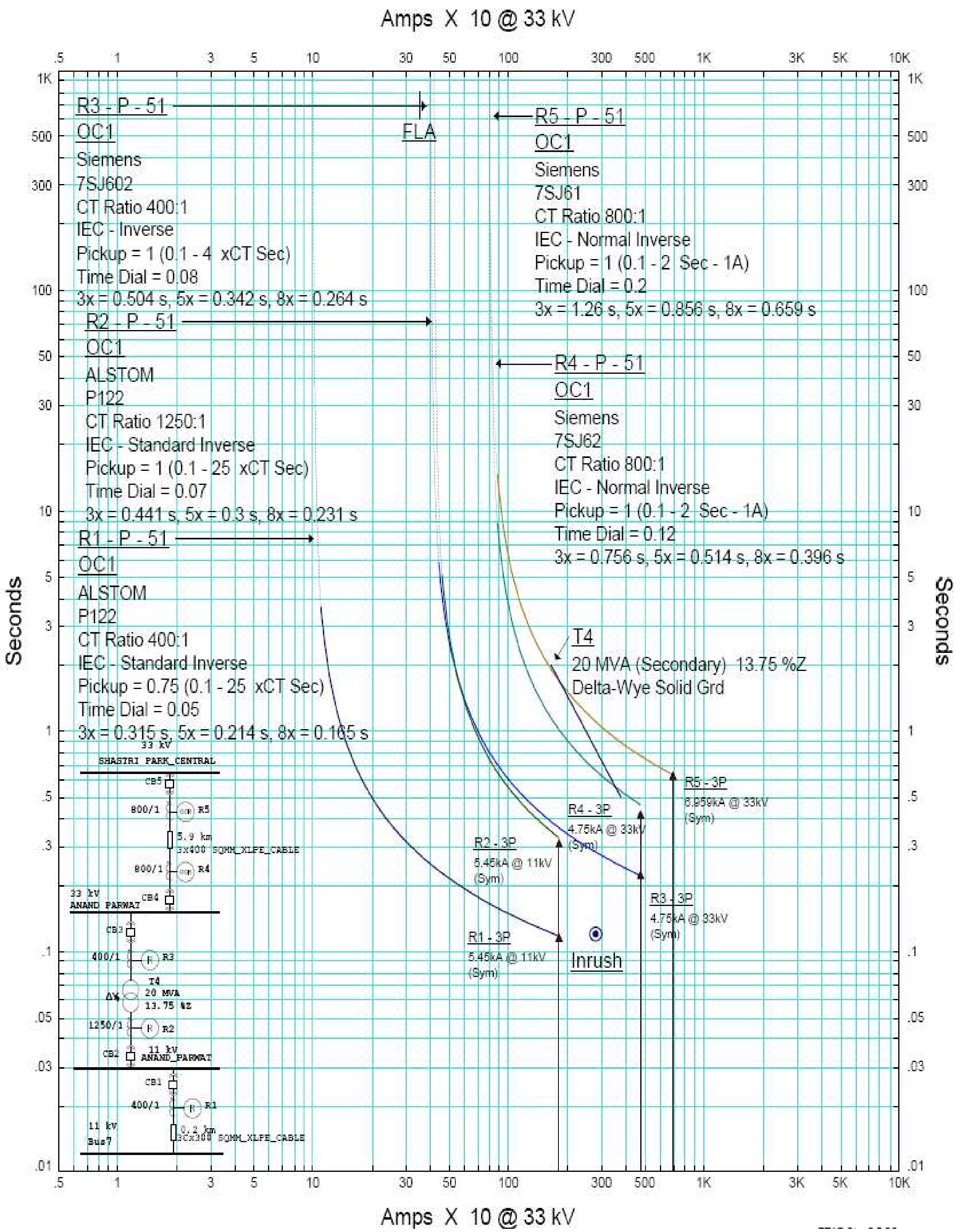


Figure 8.6 - O/C Relay characteristics provided by ETAP

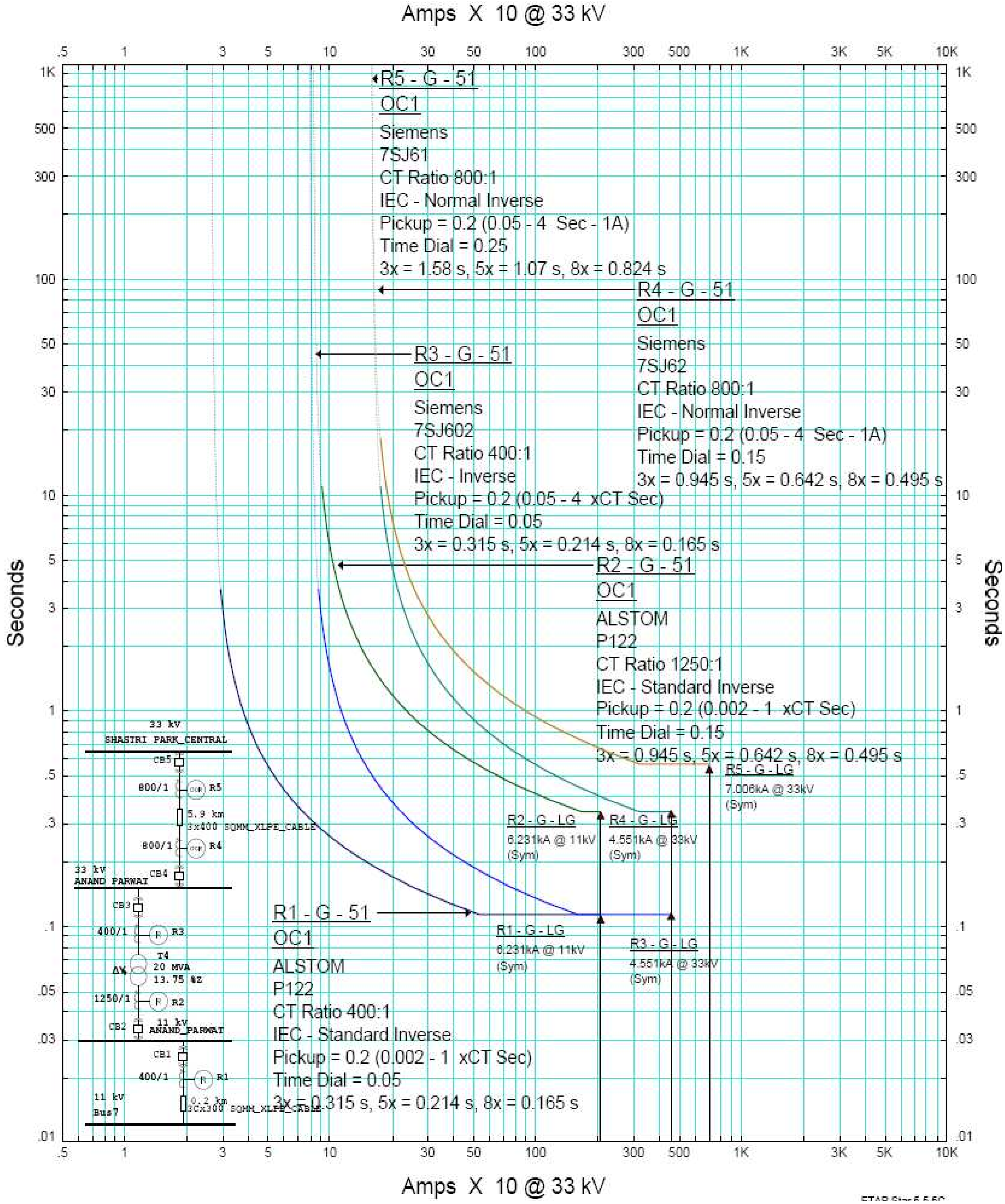


Figure 8.7 - E/F Relay characteristics provided by ETAP.

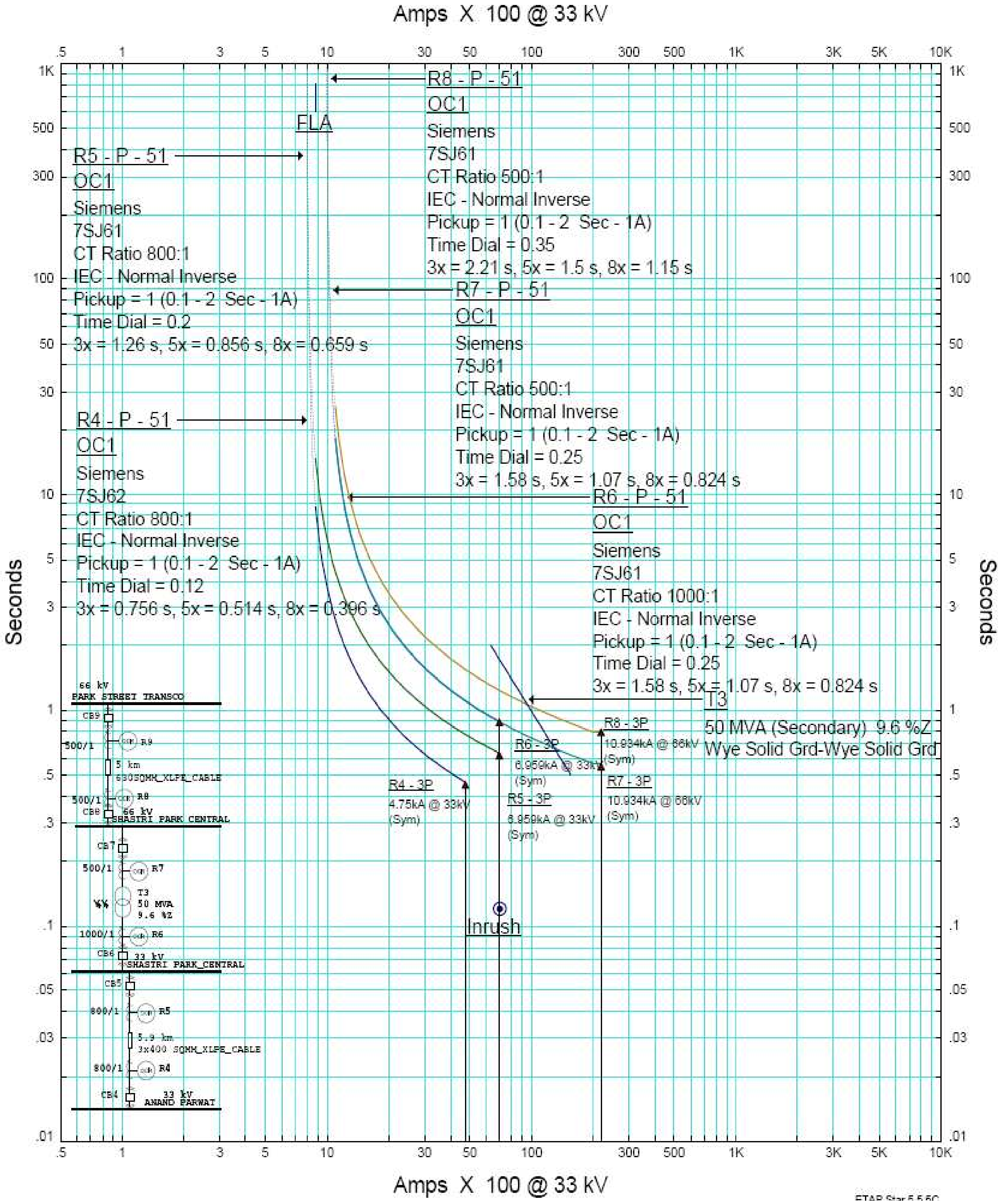


Figure 8.8 - O/C Relay characteristics provided by ETAP.

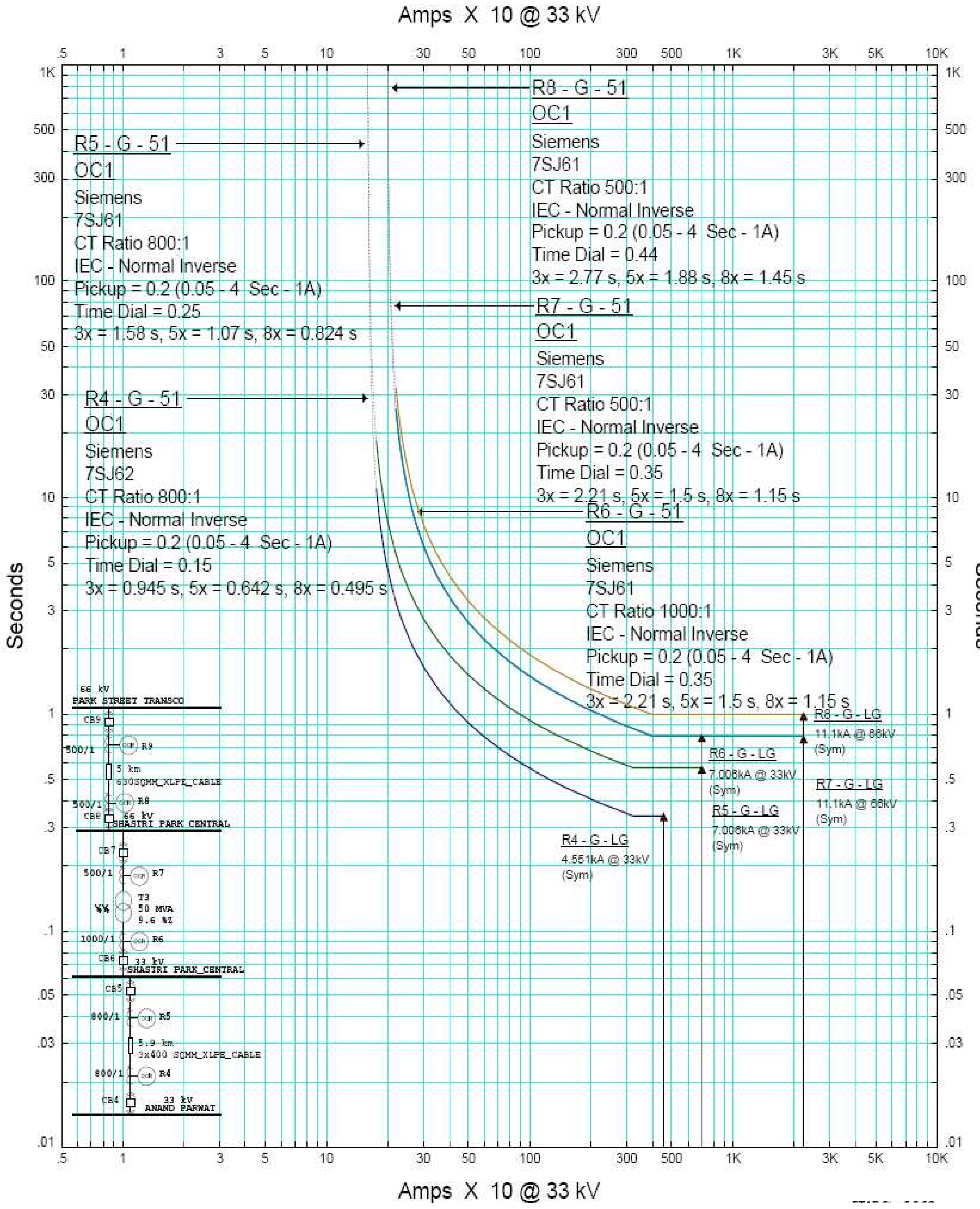


Figure 8.9 - E/F Relay characteristics provided by ETAP.

Fault calculation using per unit method:

630XLPE Cable $Z_1 = 0.134\Omega/km$
630XLPE Cable $Z_0 = 0.161\Omega/km$

Z_{pu} (66kV) = (0.134x100)/ (66x66) = 0.0031
Z_{opu} (66kV) = (0.161x100)/ (66x66) = 0.0037

400XLPE Cable = $0.277\Omega/km$
Z_{pu} (33kV) = (0.277x100)/ (33x33) = 0.0254

Assumptions: Z1=Z2=Z0

Fault Calculations

We take 100MVA Base; we will consider source impedance as 0.01
3Φ Fault MVA at bus **B**= (100/ (0.01+ (0.15/2))) =1176MVA
1Φ Fault= (3*100/ ((0.085+0.085+ (0.075x (0.0185+0.192)/ (0.075+0.0185+0.192)) =1332MVA

Fault MVA at bus C
Total length of conductor =5km
Thus impedance/km= 5x0.0031 = 0.0155pu
3Φ Fault= 100/ (0.01+0.075+ 0.0155) = 995.02MVA
1Φ Fault= (3*100/ (.1005+.1005+(.1*.192/(.1+.192))=1124.86MVA

Fault MVA at bus D
3Φ Fault= (100/ (0.01+0.075+0.0155+0.192)) = 341.88MVA

Fault MVA at bus E
Total length of conductor=5.9km
Thus impedance/km= 5.9x0.0254= 0.1498pu
3Φ Fault= (100/ (0.01+0.075+0.0155+0.192+0.1498)) = 226.06MVA

Fault MVA at bus F
3Φ Fault= (100/ (0.01+0.075+0.0155+0.192+0.1498+0.687)) = 88.55MVA
1Φ Fault= (3*100/ (1.129+1.129+0.687)) = 101.87MVA
(Since Delta offers ‘Neutral’ break for zero sequence ground fault currents.)

Relay Settings

If there is any fault on O/G 11kV feeder (3ph) there we have CT ratio of 400/5. But the cable size is 3x300sq. mm, so maximum current which will be carried by cable is 300A.

O/C Setting at Relay -1
Current setting = **75%**

Fault current = 83.89x10E6/ (√3 x 11000) = 4647.8A
PSM = 4647.8/300 = 15.49
Relay operating at TMS 1 for PSM 15.49 = 2.48s
Required time for breaker operation is 0.12s
TMS required is 0.11/2.48 = 0.048 ≅ 0.05
Therefore **TMS 0.05, P.S. is 75%**

Earth Fault Setting At Relay 1
Earth fault current = 101.87x10E6/ (√3 x 11000) = 5347A
Earth fault setting = 20%
PSM = 5347/80 = 66.84
Relay operating time=2.2s
Time of operation required is 110ms
Therefore TMS = 0.11/2.2 = 0.05
Earth fault setting is **PSM=20%, TMS =0.05**

O/C Setting at Relay -2
CT ratio at 2 = 1250
PS= 100%
So PSM = 4647.8/1250 = 3.72
Time of operation of relay = 5.26
Therefore TSM required for TOO 310ms = 0.31/5.26 = 0.0589 ≅ 0.06
Setting at relay 2 is **PSM 100%, TMS 0.06**

Earth Fault setting at relay 2
CT ratio at 2 = 1250
PS= 20%
PSM= 5347/250 = 21.39
Time of operation required is 0.31s
Relay operating time at K=1 for PSM 21.39 = 2.2s
Therefore TMS =0.31/2.2=0.14
Earth fault setting at relay 2 is **PSM=20%, TMS =0.14**

Earth Fault setting at relay 3
Three Phase and single fault currents at bus E: 226x10E6/(√3 x 33000)= 3954A
PS: 100%
PSM= 3954/400= 9.88
At K=1 TOO is 2.98sec
Reflected fault current of 11kV is 4647.8/3=1549.27A
Now PSM= 1549.27/400= 3.87
At K=1 TOO is 5.1sec
Required TOO for fault on 11kV side is 450ms
Hence **K= 0.09**
TOO for fault on 33kV side is 268ms

If there is any fault at 1 or 2 it will be reflected as phase fault at 3. So the earth fault relay setting can be put at min value.
Earth fault setting at 3
PSM=20%, TMS =0.05

O/C Setting at relay 4
CT ratio is 800
PS= 100%
PSM = 3954/800 = 4.94
Time of operation of relay = 4.31s
Required time of operation 0.470s
TMS= 0.47/4.31 = 0.11
O/C setting: **PSM 100%; TMS 0.11**

E/F/ Setting at relay 4
CT ratio is 800
PSM = 39548/160 = 24.7
Time of operation of relay at K=1 is 2.2s
Required time of operation 310ms
TMS=0.31/2.2 = 0.14
E/F setting: **PSM 20%, TSM 0.14**

Fault at bus D is of 341.88MVA
3Phase fault current at bus D is 341.88x10E6/ (√3x33, 000) = 5981A

O/C Setting at relay 5
CT ratio is 800
PS= 100%
PSM = 5981/800 = 7.47
Time of operation of relay = 3.4s
Required time of operation 0.670s
TMS= 0.67/3.4 = 0.197 ≈.2
O/C setting: **PSM 100%; TMS 0.2**

E/F/ Setting at relay 5
CT ratio is 800
PSM = 5981/160 = 42.25
Time of operation of relay at K=1 is 2.2s
Required time of operation 510ms
TMS=0.51/2.2 = 0.23
E/F setting: **PSM 20%, TSM 0.23**

O/C relay setting at 6
CT ratio is 1000
PSM = 5981/1000 = 5.98

Required time of operation 0.87s
Time of operation of relay at 5.98 = 3.84s
TMS=0.87/3.84 = 0.22
O/C setting: **PSM 100%; TMS 0.22**

E/F/ Setting at relay 6
CT ratio is 1000
PSM = 5981/200 = 29.9
Required time of operation 0.65s
Time of operation of relay = 2.2s
TMS=0.65/2.2 = 0.29≈0.3
E/F setting: PSM 20%, TSM 0.3

Fault Currents at bus C:
3Phase fault current at bus C is 995x10E6/ (√3x66, 000) =8704A

O/C relay setting at 7
CT ratio is 500
PS= 100%
PSM = 8704/500 = 17.41
At K=1 TOO is 2.38s
Reflected fault current of 33kV is 5981/2=2990.5A
Now PSM= 2990.5/500= 5.98
At K=1 TOO is 3.84sec
Required TOO for fault on 33kV side is 1000ms
Hence **K= 0.25**
TOO for fault on 66kV side is 595ms

E/F/ Setting at relay 7
1Phase Fault current at bus C is 1124.86x10E6/ (√3x66, 000) =9840.26A
CT ratio is 500
PS= 20%
PSM = 9840.26/100 = 98.4
At K=1 TOO is 2.2sec
Reflected fault current of 33kV is 6760/2=3380A
Now PSM= 3380/100= 33.8
At K=1 TOO is 2.2sec
Required TOO for fault on 33kV side is 850ms
Hence **K= 0.38**
TOO for fault on 66kV side is 850ms

Fault Currents at bus C:
3Phase fault current at bus C is 995x10E6/ (√3x66, 000) =8704A

O/C relay setting at 8
CT ratio is 500
PSM = 8704/500 = 17.4
Time of operation of relay = 2.38s
Required TOO is 600+200= 800ms
TMS=0.8/2.38 = 0.34
O/C setting: **PSM 100%; TMS 0.5**

E/F/ Setting at relay 8
CT ratio is 500
PSM = 9840/100 = 98.4
Time of operation of relay = 2.2s
Required time of operation 850+200= 1050ms
TMS=1.05/2.2 = 0.47
E/F setting: **PSM 20%, TSM 0.47**

Fault Currents at bus B:

3Phase fault current at bus B is 1176x10E6/ (√3x66, 000) =10, 290A
1Phase Fault current at bus B is 1332x10E6/ (√3x66, 000) =11, 652A

SI.No.	Relays	CT Ratio	Phase O/C NI Curve		Earth fault NI Curve	
			PS (%)	TMS	PS (%)	TMS
1	**R1**	**400/1**	**75**	**0.05**	**20**	**0.05**
2	**R2**	**1250/1**	**100**	**0.06**	**20**	**0.14**
3	**R3**	**400/1**	**100**	**0.09**	**20**	**0.05**
4	**R4**	**800/1**	**100**	**0.11**	**20**	**0.14**
5	**R5**	**800/1**	**100**	**0.2**	**20**	**0.23**
6	**R6**	**1000/1**	**100**	**0.22**	**20**	**0.30**
7	**R7**	**500/1**	**100**	**0.25**	**20**	**0.38**
8	**R8**	**500/1**	**100**	**0.34**	**20**	**0.47**

CHAPTER – 9

TRANSFORMER PROTECTION

9.1 Introduction

Power Transformer is one of the most important equipment in a power transmission and distribution system. Being static equipment, the design and construction is relatively simple. This makes the transformer a highly reliable piece of equipment. The reliability can be further enhanced by providing adequate protections, besides proper maintenance while in service. The Choice of protection is influenced by several factors, the important ones being:

1. Size and rating of the transformer
2. Vector configuration
3. Source and Neutral Earthing
4. Type of transformer (2 winding / 3 winding /Auto Transformer etc.)
5. Infeed condition (radial, parallel, interconnecting).
6. OLTC Range

This chapter mainly focuses on protection of power transformers.

9.2 Types of faults on power transformers

Faults on power transformers can be classified as through faults and internal faults. A through fault is located outside the protection zone of the transformer. The unit protection of the transformer should not operate for through faults. The transformer must be disconnected when such faults occur only when the faults are not cleared by other relays in pre-specified time. Internal faults can be phase-to-phase and phase-to ground faults. Internal faults are dangerous for the integrity of the power transformer. These internal faults can be classified into two groups.

Group I: Electrical faults that cause immediate serious damage but are generally detectable by unbalance of current or voltage. Amongst them are the following:

1. Phase-to-earth fault
2. Phase-to-phase fault
3. Short circuit between turns of high-voltage or low-voltage windings

Group II: These include incipient faults, which are initially minor faults but cause substantial damage if they are not detected and taken care of. These faults cannot be detected by monitoring currents or voltages at terminals of the transformer. Incipient faults include the following:

1. A poor electrical connection between conductors.
2. Core fault which causes arching in oil.
3. Coolant failure, which causes rise of temperature.
4. Bad load sharing between transformers in parallel, which can cause overheating due to circulating currents.

For a Group I fault, the transformer should be isolated as quickly as possible after the occurrence of the fault. The Group II faults, though not serious in the incipient stage, may cause major faults in the course of time. Incipient faults should be cleared soon after they are detected. Protection against Group I faults will be the subject of discussion of the following section.

9.3 Differential Protection of Power Transformers

It is the practice of manufacturers to recommend percentage-differential relaying for short circuit protection of all power-transformer banks whose three-phase rating is 5000 kVA and higher. To apply these recommendations to power autotransformers, the foregoing ratings should be taken as the equivalent physical size of autotransformer banks, where the equivalent physical size equals the rated capacity times $[1 - (V_L/V_H)]$, and where V_L and V_H are the voltage ratings on the low-voltage and high-voltage sides, respectively. The differential relay should operate a hand-reset auxiliary that will trip all transformer breakers. The hand-reset feature is to minimize the likelihood of a transformer breaker being reclosed inadvertently, thereby subjecting the transformer to further damage unnecessarily. Where transmission lines with high-speed distance relaying terminate on the same bus as a transformer bank, the bank should have high speed relaying. Not only is this required for the same reason that the lines require it, but also it permits the second-zone time of the distance relays looking toward the bus to be set lower and still be selective.

9.3.1 Current Transformer Connections for Differential relays

A simple rule of thumb is that the CTs on any wye winding of a power transformer should be connected in delta, and the CTs on any delta winding should be connected in wye. This rule may be broken, but it rarely is; for the moment let us assume that it is inviolate. Later, we shall learn the basis for this rule. The remaining problem is how to make the required interconnection between the CTs and the differential relay. Two basic requirements that the differential-relay connections must satisfy are:

(1) The differential relay must not operate for load or external faults
(2) The relay must operate for severe enough internal faults.

As an example, let us take the delta-wye power transformer of figure 9.1. The first step is arbitrarily to assume currents flowing in the power-transformer windings in whichever directions one wishes, but to observe the requirements imposed by the polarity marks that the currents flow in opposite directions in the windings on the same core, as shown in figure 9.1. We shall also assume that all the windings have the same number of turns so that the current magnitudes are equal, neglecting the very small exciting-current component. (Once the proper connections have been determined, the actual turn ratios can very easily be taken into account.) On the basis of the foregoing, figure 9.2 shows the currents that flow in the power-transformer leads and the CT primaries for the general external-fault case for which the relay must not trip. We are assuming that no current flows into the ground from the neutral of the wye winding; in other words, we are assuming that the three-phase currents add vectorially to zero. The next step is to connect one of the sets of CTs in delta or in wye, according to the rule of thumb already discussed; it does not matter how the connection is made, i.e., whether one way or reversed.

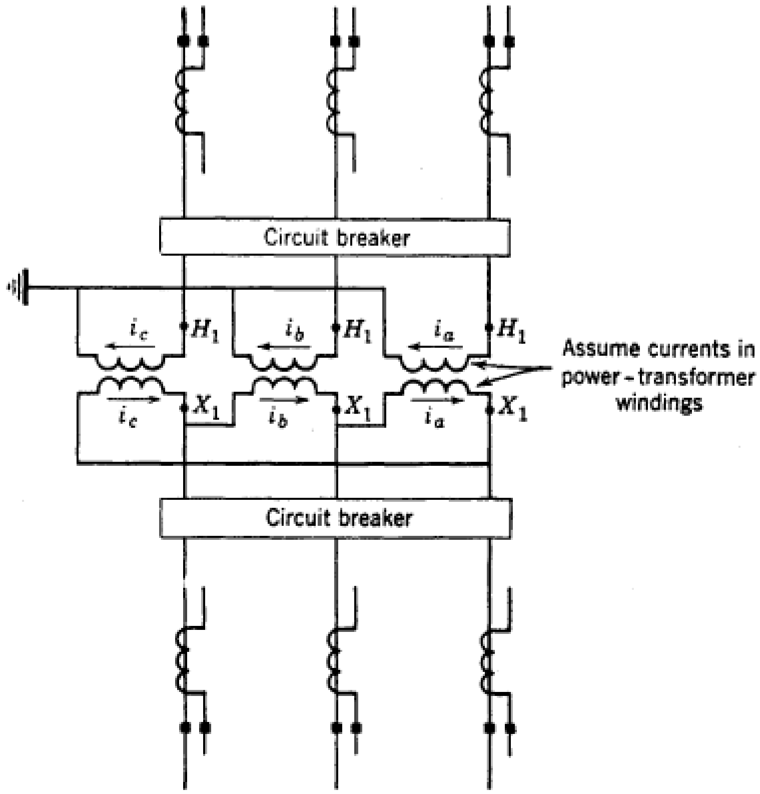


Figure 9.1 First Step in Development of Connections for Transformer Differential Relaying

Then, the other set of CTs must be connected also according to the rule, but, since the connections of the first set of CTs have been chosen, it does matter how the second set is connected; this connection must be made so that the secondary currents will circulate between the CTs as required for the external-fault case. A completed connection diagram that meets the requirements is shown in figure 9.3. The connections would still be correct if the connections of both sets of CTs were reversed. Proof that the relay will tend to operate for internal faults will not be given here, but the reader can easily satisfy himself by drawing current-flow diagrams for assumed faults. It will be found that protection is provided for turn-to-turn faults as well as for faults between phases or to ground if the fault current is high enough.

We shall now examine the rule of thumb that tells us whether to connect the CTs in wye or in delta. Actually, for the assumption made in arriving at figure 9.2, namely, that the three phase currents add vectorially to zero, we could have used wye-connected CTs on the wye side and delta-connected CTs on the delta side. In other words, for all external-fault conditions except ground faults on the wye side of the bank, it would not matter which pair of CT combinations was used. Or, if the neutral of the power transformer was not grounded, it would not matter.

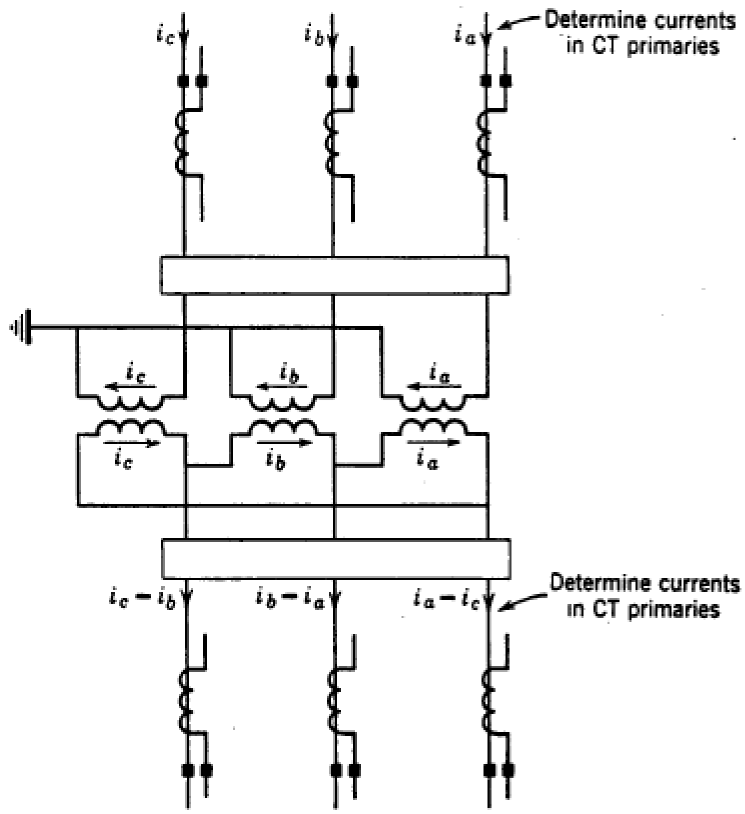


Figure 9.2 Second Step in Development of CT Connections for Transformer Differential Relaying

The significant point is that, when ground current can flow in the wye windings for an external fault, we must use the delta connection (or resort to a zero-phase-sequence-current-shunt that will be discussed later). The delta CT connection circulates the zero-phase-sequence components of the currents inside the delta and thereby keeps them out of the external connections to the relay. This is necessary because there are no zero-phase-sequence components of current on the delta side of the power transformer for a ground fault on the wye side; therefore, there is no possibility of the zero-phase-sequence currents simply circulating between the sets of CTs and, if the CTs on the wye side were not delta connected, the zero-phase-sequence components would flow in the operating coils and cause the relay to operate undesirably for external ground faults.

Incidentally, the fact that the delta CT connection keeps zero-phase-sequence currents out of the external secondary circuit does not mean that the differential relay cannot operate for single-phase-to-ground faults in the power transformer; the relay will not receive zero phase sequence components, but it will receive and operate on the positive- and negative-phase-sequence components of the fault current. The foregoing instructions for making the CT and relay interconnections apply equally well for power transformers with more than two windings per phase; it is only necessary to consider two windings at a time as though they were the only windings. For example, for three-winding transformers consider first the windings H and X.

Then, consider H and Y, using the CT connections already chosen for the H winding, and determine the connections of the Y CTs. If this is done properly, the connections for the X and Y windings will automatically be compatible.

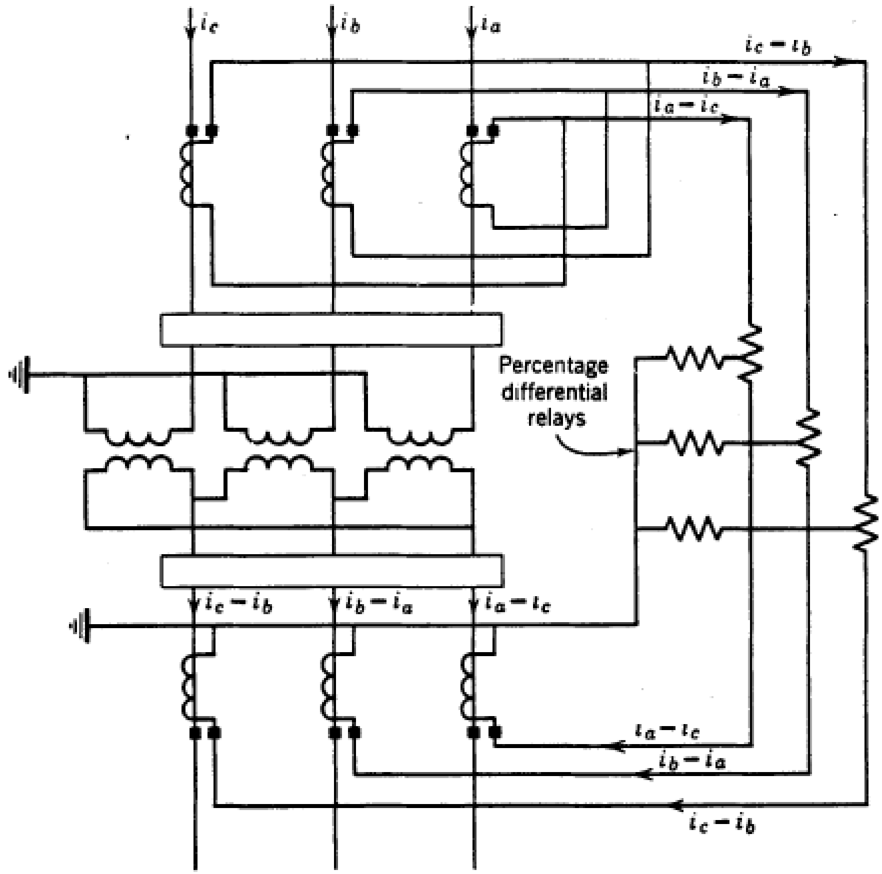


Figure 9.3 Completed connections for percentage-differential relaying for two winding transformer.

9.3.2 Choice of Percentage Slope for Differential Relays

Percentage-differential relays are generally available with different percent slopes; they may have adjustment so that a single relay can have any one of several slopes. The purpose of the percent-slope characteristic is to prevent undesired relay operation because of unbalances between CTs during external faults arising from an accumulation of unbalances for the following reasons:

(1) Tap-changing in the power transformer
(2) Mismatch between CT currents and relay tap ratings
(3) The difference between the errors of the CTs on either side of the power transformer.

Power transformers have taps that will give ±X% change in transformation ratio. It is the practice to choose CT ratios and relay or autotransformer taps to balance the currents at the midpoint of the tap changing range; on that basis, the most unbalance that can occur from this cause is X%. The maximum unavoidable mismatch between CT currents and relay tap ratings is one-half of the difference between two relay tap ratings, expressed in percent. The percent difference between CT errors must be determined for the external fault that produces the greatest error; the best that we can do is to calculate this on a steady-state basis. We should assume that all three unbalances are in the same direction to get the total maximum possible unbalance. Then add at least 5% to this value, and the new total is the minimum percent slope that should be used.

9.3.3 Differential Protection Restraint for Magnetizing Inrush Current

The phenomenon of magnetic inrush in transformers has already been discussed in Chapter 5. While the normal steady state magnetizing current is less than 5% of full load current, the transient core saturation caused due to magnetizing inrush may raise it to several times the normal load current. The situation is even worse if there is remnant flux in the core which happens to be in the direction in which the first peak occurs. Since the Inrush current flows only in the primary winding it appears as an operating current to the differential relay, producing instability and causing the differential relay to trip. As the inrush is not a condition of fault, it is necessary to stabilize the differential relay during the inrush transient. The immunity to inrush current can be obtained either by delaying the protection or by providing a harmonic restraint.

a. Time delay:

Since the magnetizing inrush is a transient phenomena, a small time delay can be provided in the differential relay to override the same and ensure stability Induction disc relays with an adjustable delay provided by the disc movement, is one of the earlier designs of biased differential protection.

b. Harmonic Restraint

Time delay associated with the differential relay, as explained before, would make the protection slower in operation and increase the fault damage. Modern high speed differential relays, therefore, employ a different approach to this problem. The principle of harmonic-current restraint makes a differential relay self-desensitizing during the magnetizing-current-inrush period, but the relay is not desensitized if a short circuit should occur in the transformer during the magnetizing-inrush period. This relay is able to distinguish the difference between magnetizing-inrush current and short-circuit current by the difference in wave shape. Magnetizing-inrush current is characterized by large harmonic components that are not noticeably present in short-circuit current. A harmonic analysis of a typical magnetizing inrush current wave is shown in the accompanying table.

Harmonic Component	Amplitude as % of Fundamental
DC	55
2nd	63
3rd	26.8
4th	5.1
5th	4.1
6th	3.7
7th	2.4

The proportion of 2nd harmonic generally varies between 30-65 **%** of the fundamental and is unique to the inrush current. This component is filtered from the filtering circuit and is used to restrain the protection the same way as through current bias. The harmonic restraint is so proportioned that 15% of 2nd harmonic current will just balance the operating current of 100% of fundamental frequency elimination. While through current bias and 2nd harmonic bias (restraint) is an essential feature of a modern high speed differential protection. Following additional features are an incorporated to enhance stability and maintain operating speed. The magnetizing current of an over excited transformer contains substantial proportion of 5^{th} harmonic. Thus the restraining circuit is designed to prevent the operation of relay during over excitation of transformer. Figure 9.4 shows how the relay is arranged to take advantage of the harmonic content of the current wave to be selective between faults and magnetizing inrush.

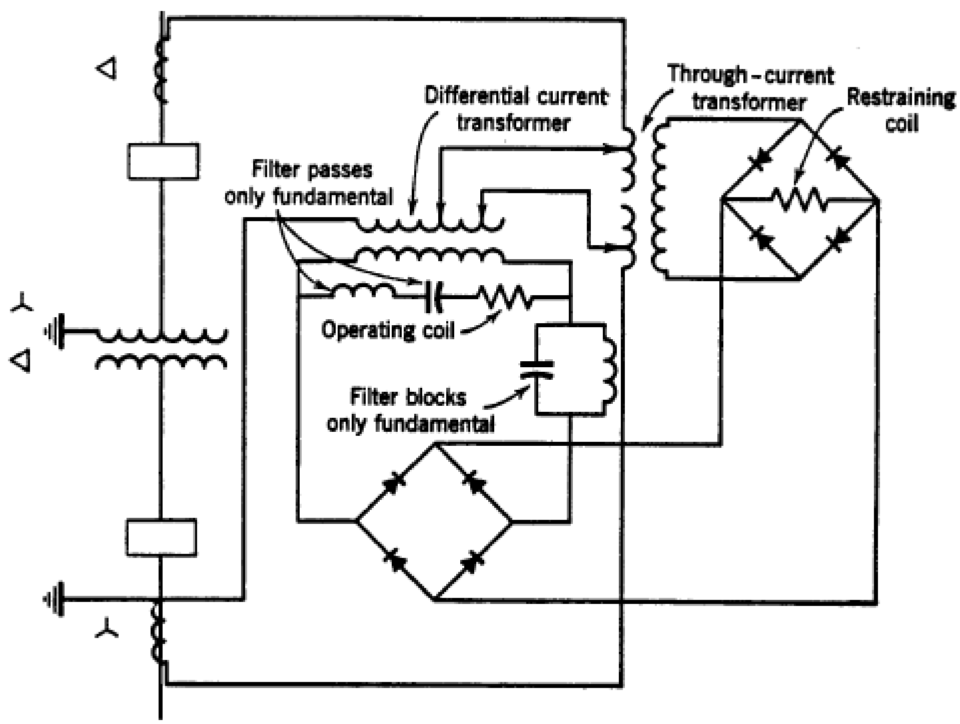


Fig 9.4 - Harmonic-current-restraint percentage-differential relay.

Figure 9.4 shows that the restraining coil will receive from the through-current transformer the rectified sum of the fundamental and harmonic components. The operating coil will receive from the differential-current transformer only the fundamental component of the differential current, the harmonics being separated, rectified, and fed back into the restraining coil. The direct-current component, present in both magnetizing-inrush and offset fault current, is largely blocked by the differential-current and the through-current transformers, and produces only a slight momentary restraining effect.

9.3.4 Unrestrained Differential Highset (Id>>):

The harmonic restraint may slow down the protection, on severe internal fault, if the associated CTs suffer transient saturation and produce a high degree of harmonic distortion. To ensure high speed operation under the above condition an unrestrained differential highest with pick up threshold (usually 8-10 times) is incorporated in the differential relay.

There are alternative designs which do not use harmonic bias (restraint) to achieve immunity against magnetizing inrush or over excited operation of the transformer. One such design, distinguishes between the above conditions and an internal fault, by verifying the zero periods in the differential current waveform over a cycle. The magnetizing current waveform during switching inrush or over excited condition has substantial zero periods (in excess of ¼ cycle over one cycle period), Unlike in the case of an internal fault. This method enables high speed of operation for internal fault in the absence of any harmonic restraint. Numerical versions of differential protections are also now available which use suitable algorithm for measurement. The ratio and phase angle correction is a software function in these relays, which eliminate the need for matched CTs/ ICTs.

9.3.5 Example of Relays for Differential Protection:

Sr.No.	Make	Type
1	ALSTOM	DTH31/32
2	ALSTOM	MBCH12
4	ALSTOM	MICOM P632
5	ABB	RADSB
6	ABB	SPAD-346C
8	EASUN REYROLLE	DUOBIAS
9	SIEMENS	7UT61

9.4 Restricted Earth Fault (REF) Protection

This is a circulating current earth fault differential system, usually applied to the star winding of a transformer, by balancing the residual current of the three line current transformers with the output current of a CT in the neutral earth connection. The protection arrangement is shown in figure 9.5 below. REF protection is highly sensitive to earth faults and can even sense the faults in the winding near to the neutral of the star winding. This is the reason that REF protection is provided in addition to differential protection.

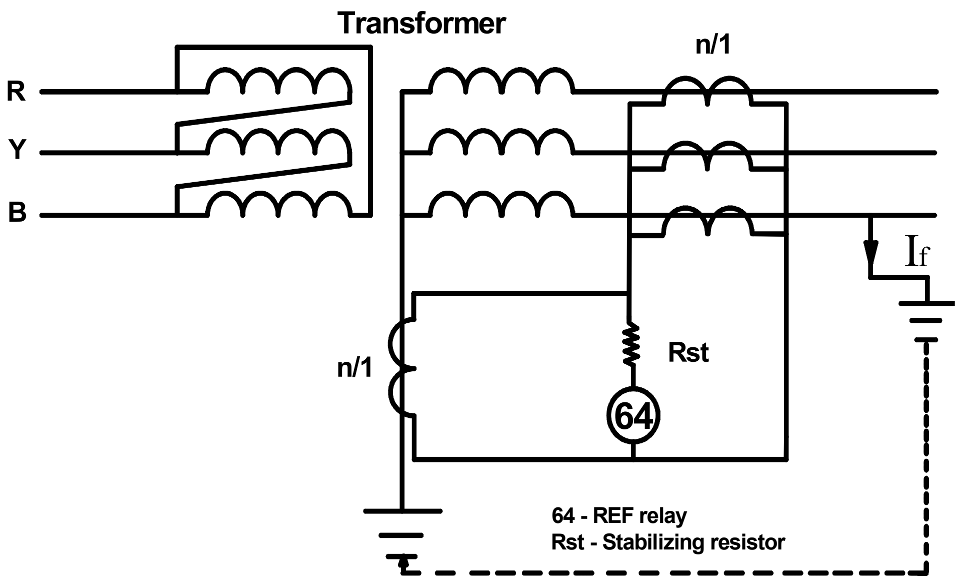


Figure 9.5 - Restricted Earth Fault Protection of Star Winding

It is clear from figure 9.5 that phase and neutral CTs should have the same ratio. For an external earth fault, the associated phase and neutral CT see same fault current **(If)** but of different polarity, while the phase CT sees an outflow of current, the neutral C.T. sees an inflow with respect to the transformer. The phase and neutral CT therefore, form a series connection between them with no differential current through the relay, if the CTs are assumed to be ideal with no errors. For an internal fault, either the neutral CT sees an inflow because of infeed reversal through the latter (in case of parallel transformers). This produces a differential current through the relay corresponding to the summated infeeds at the fault point, thereby causing operation. In practice, however, the associated CTs may experience unequal saturation say due to the remnant flux in the core or dissimilarities in their magnetizing characteristics, particularly when the through fault current has large D.C offsets with slow decay rate. The worst condition would occur when one CT completely saturates while the other remains fully active during a severe external fault as shown in figure 9.6.

The voltage that can be developed across the relay under the condition in figure 9.6 is given by

$$Vs = (I_F/n)*(R_{CT} + 2R_L) \text{ Volts}$$

Where I_F = Maximum through fault current limited by transformer leakage current
N = C.T. Ratio
R_{CT} = C.T. secondary resistance
$2R_L$ = To & fro Lead resistance

The REF protection is invariably high impedance and is calibrated either in terms of voltage or current. In case of voltage relay, a setting voltage above "Vs" can be set. In case of current operated relay, a series stabilizing resistor is added to make the relay branch high impedance such that current through the relay will not exceed its current setting (Is).

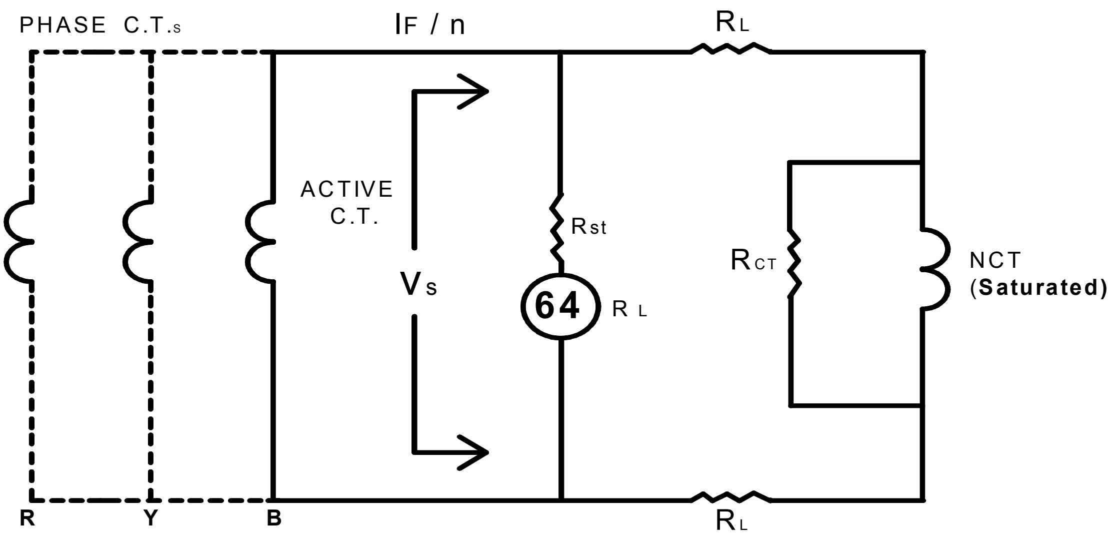


Figure 9.6 Saturation of NCT during External Fault Condition

The external stabilizing resistor value can be worked out as follows:

$$Rst = (Vs/Is) – [(VA_R) / (Is)^2]$$

Where, (VA_R) = VA burden at relay setting (Is)
Rst = Stabilizing resistor
Is = relay setting
The minimum primary operating current (POC) is influenced by the magnetizing current of the associated CTs and is given by:

$$POC = N [Is + N1x\ Im]\ Amps$$

Where, N = CT Ratio
N1 = Number of CTs are connected in parallel
Im = Magnetizing current of each CT at Vs
The relay branch being high impedance may force the CTs in to saturation for a severe internal fault when summated current associated CTs seek its path through the relay. This may cause peak over voltage across the CT secondary / Pilot as also the relay threatening the insulation. The maximum peak voltage across the CT secondary is given by the expression:-

$$Vpeak = (2 \times 1.414)x\ [(Vk \times (Vp – Vk))]^{1/2}$$

Where, Vk is the knee point voltage
Vp is the Prospective voltage assuming unsaturated operation = (IF/N) x (Rst + Rr)
Rr is the Relay resistance or relay ohmic burden
If the peak voltage so worked out exceeds 3000 Volts a non-linear resistor (metrosil) should be provided across the relay branch to limit this voltage within safe limits.

Due to the absence of neutral point in delta connection the REF scheme shown in figure 9.5 cannot be used for protection of delta connected windings. REF scheme is modified as shown in figure 9.7 for earthfault protection of delta windings.

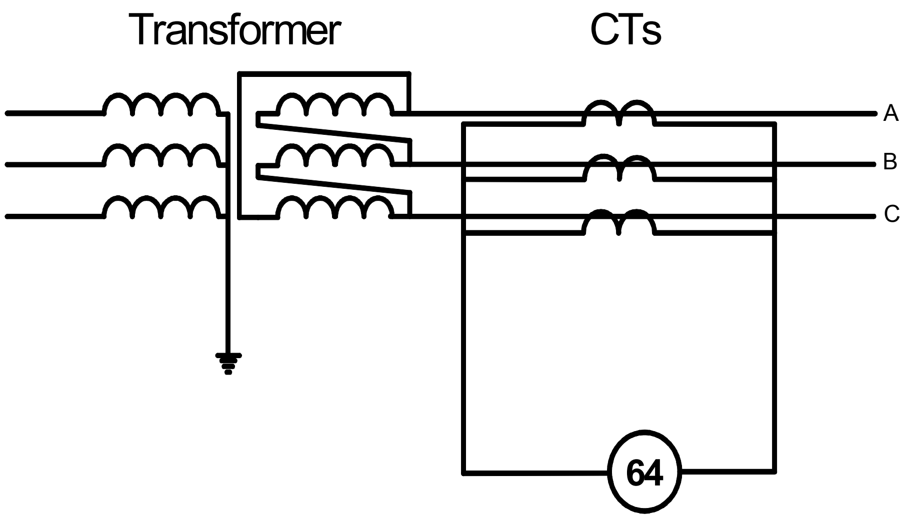


Figure 9.7 - REF Protection of Delta Winding

As already discussed in chapter 2, in autotransformers the LV winding is just a tapping on the HV winding. LV current in the autotransformer is the vector sum of HV current and neutral current. Hence, REF protection of autotransformers is accomplished by summating the currents of HV side CTs, LV side CTs and neutral CT. Figure 9.8 depicts the connection of current transformers for implementation of such a scheme. It should be noted that the CT ratios for all the CTs has been specified as n/1. This is necessary for balancing (making the resultant current zero) the LV, HV and NCT current inputs to the REF relay in case of through faults. If the CT ratios are not same ICTs can be used for balancing the currents.

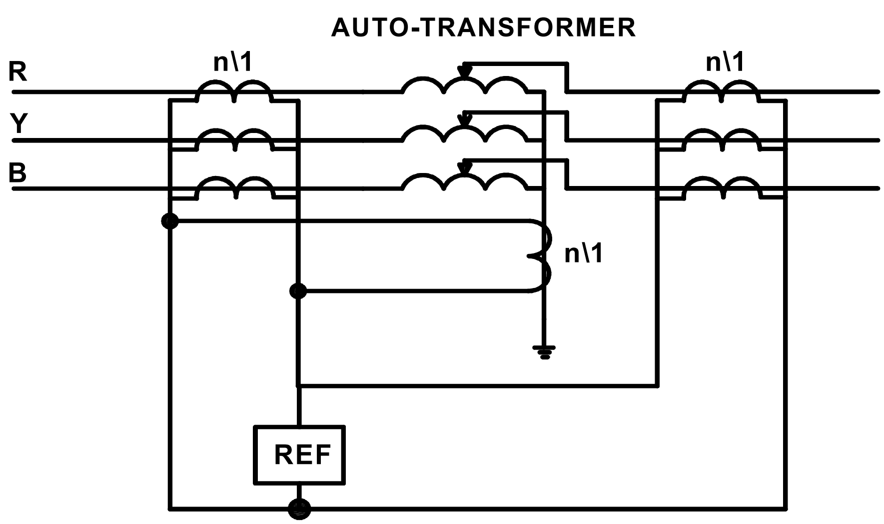


Figure 9.8 - REF Protection of Autotransformers

In case a single PS class core is available on the star side CTs of transformer, differential and REF protections may be implemented in a single scheme. Wiring diagram of such a scheme is depicted below for protection of a Dyn11 transformer.

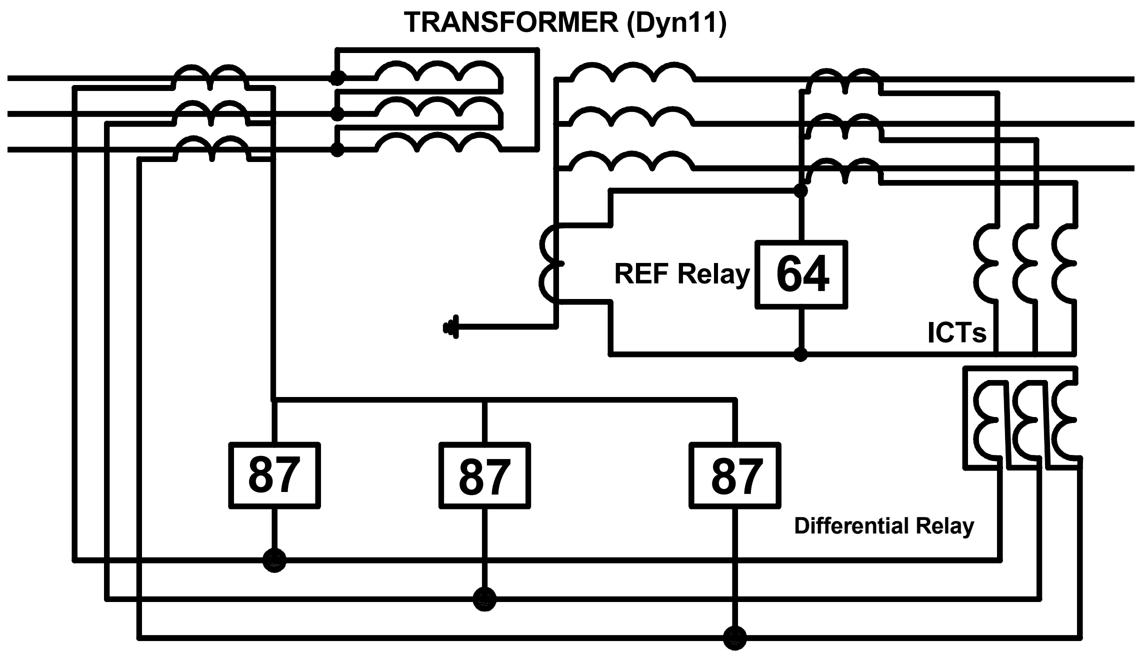


Figure 9.8 - Combined Differential & REF scheme for DYn11 Transformer with one set of ICTs

Examples of Relays for High impedance REF Protection is given below.

Sr.No.	Make	Type
1.	ALSTOM	CAG14
2.	ABB	SPAD346C
3.	ALSTOM	MICOM P120

9.5 Overcurrent Protection of Transformers

Differential and REF protection provide primary protection to the power transformers. Three CTs, one in each phase, and at least two overcurrent phase relays and one overcurrent ground relay should be provided on each side of the transformer bank that is connected through a circuit breaker to a source of short-circuit current. The overcurrent relays should have an inverse-time element whose pickup can be adjusted to somewhat above maximum rated load current, say about 150% of maximum, and with sufficient time delay so as to be selective with the relaying equipment of adjacent system elements during external faults. The relays should also have an instantaneous element whose pickup can be made slightly higher than either the maximum short-circuit current for an external fault or the magnetizing current inrush. When the transformer bank is connected to more than one source of short-circuit current, it may be necessary for at least some of the overcurrent relays to be directional in order to obtain good protection as well as selectivity for external faults. The overcurrent relays for short-circuit protection of transformers also provide external-fault back-up protection. Connection of CTs for overcurrent protection of transformers is shown in figures 9.9 and 9.10.

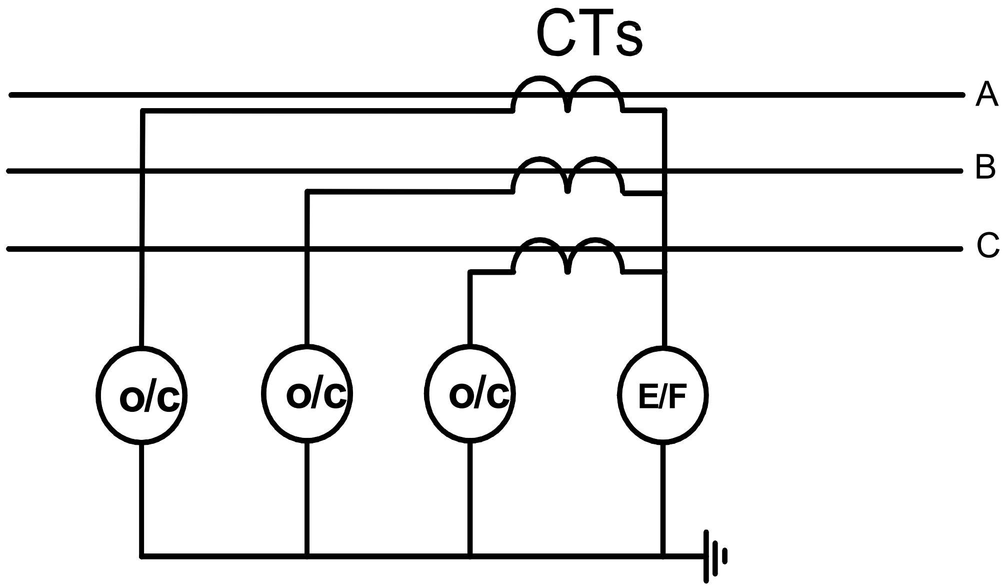


Figure 9.9 - Overcurrent Protection with Three O/C and One E/F relay

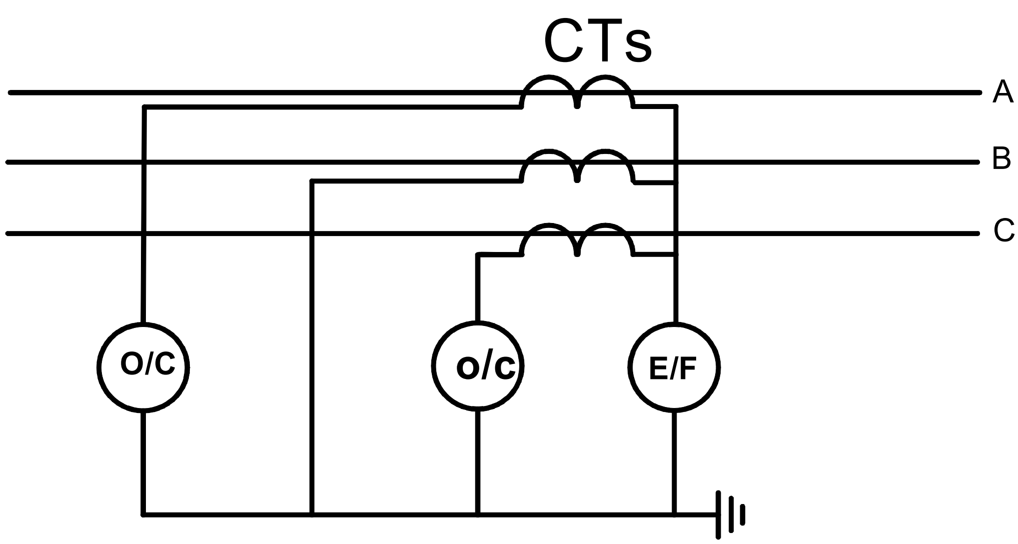


Figure 9.10 - Overcurrent Protection with Two O/C and One E/F relay

9.5.1 Two Overcurrent One Earthfault scheme Vs Three Overcurrent one Earthfault scheme

Let us consider a fault on LV side of Delta Wye transformer. Figure 9.11 shows the distribution of currents on the delta side for a fault between R and Y phases. The magnitude of the current will be I, 2I & I in the R, Y & B lines of primary side respectively. The magnitude of the fault current is maximum in “Y-ph” & in “Y-ph” there is no over current element in this scheme as shown in figure 9.10. The tripping of the circuit breaker will be delayed because of low current (I) flows in “Rph” & “B-ph”. Thus two over current and one earth fault scheme is inadequate protection for this particular case. Hence three overcurrent and one earthfault scheme is recommended for protection in this case.

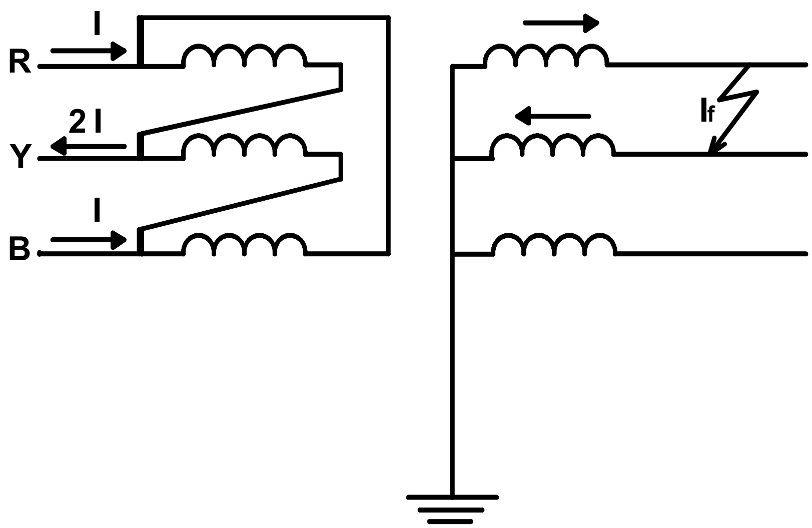


Figure 9.11 - Current Distribution in Delta Star Transformer

Relays utilized for three phase overcurrent and one earthfault protection are as follows:
CDG-61 & CDG-11 Alstom Make Electromechanical Relay
ICM-21 ABB Make Electromechanical Relays
SPAJ-140 ABB Make Numerical Relay
7SJ61X Siemens Make Numerical Relay
P122 Alstom Make Numerical Relay

9.5.2 Sensitive Earth Fault Protection Using CBCT

This scheme is used when high degree of earth fault sensitivity is required. In this type of protection (figure 9.12) a single ring shaped core of magnetic material, encircles the conductors of all the three phases. A secondary coil is connected to a relay unit. The cross-section of ring-core is ample, so that saturation is not a problem. During no-earth-fault condition, the components of fluxes due to the fields of three conductors are balanced and the secondary current is negligible. During earth faults, such a balance is disturbed and current is induced in the secondary. Core-balance protection can be conveniently used for protection of low-voltage and medium voltage systems. The burden of relays and exciting current are deciding factors. Very large cross-section of core is necessary for sensitivity less than 10 A. This form of protection is likely to be more popular with static relays due to the fewer burdens of the latter. Instantaneous relay unit is generally used with core balance schemes.

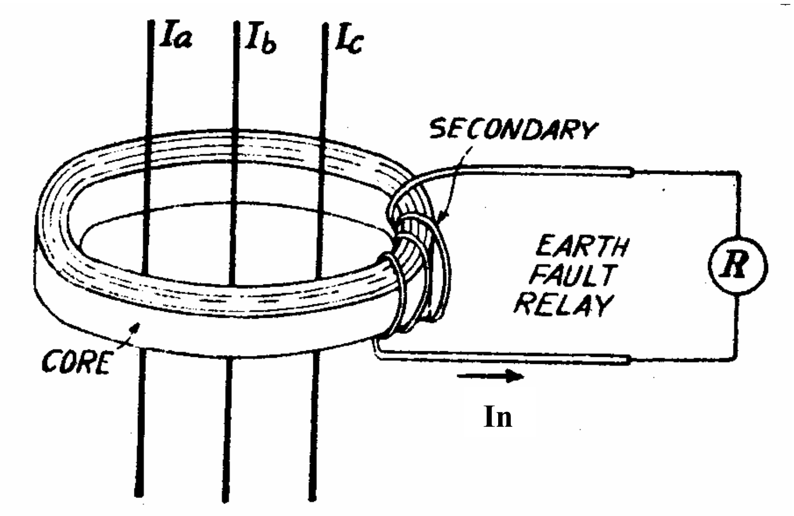


Figure 9.12 Principle of Core-Balance CT for earth fault protection

Let I_a, I_b and I_c, be the three line currents and Φ_a, Φ_b and Φ_c be corresponding components of magnetic flux in the core. Assuming linearity, we get resultant flux Φ as,

$$\Phi = k\,(I_a + I_b + I_c)$$

Where k is a constant $\Phi = K * I_a$. Referring to theory of symmetrical components

$$(I_a + I_b + I_c) = 3\,I_c = I_n$$

Where, I_o is zero sequence current and In, is current in neutral to ground circuit. During normal condition, when earth fault is absent,

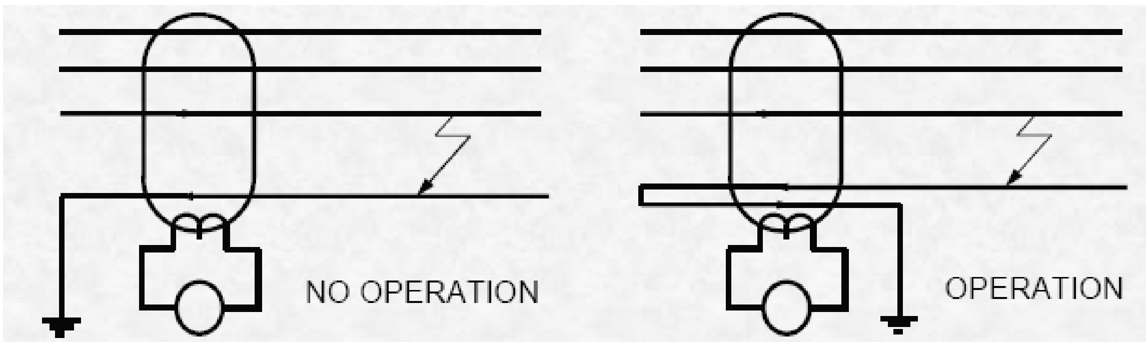
$$(I_a + I_b + I_c) = 0$$

Hence $\Phi r = 0$ and relay does not operate. During earth fault the earth fault current flows through return neutral path. For example for single line ground fault,

$$I_f = 3\,I_{ao} = I_n$$

The zero-sequence component of I_o produces the resultant flux Φr in the core. Hence core balance current transformer is also called as zero sequence current transformers.

Let us undertake an example of installation of CBCT in the cable termination. The termination of a three core cable into three separate lines or bus-bars is through cable terminal box as shown in figure 9.14. The Core Balance Protection is used along with the cable box and should be installed before making the cable joint. The induced current flowing through cable sheath of normal healthy cable needs particular attention with respect to the core balance protection. The sheath currents flow through the sheath to the cover of cable-box and then to earth through the earthing connection of the sheath. This earthfault current through the sheath neutralizes the unbalance flux created by the phase currents as shown in figure 9.13(a). For eliminating the error due to sheath current the earthing lead between the cable-box and the earth should be taken through the core of the core balance protection. In this case as shown in figure 9.13(b) the sheath current first enters and then returns through the CBCT thereby creating a net zero flux.



(a) No Operation During Earthfault **(b) Operation During Earthfault**

Figure 9.13 - Proper Placement of CBCT

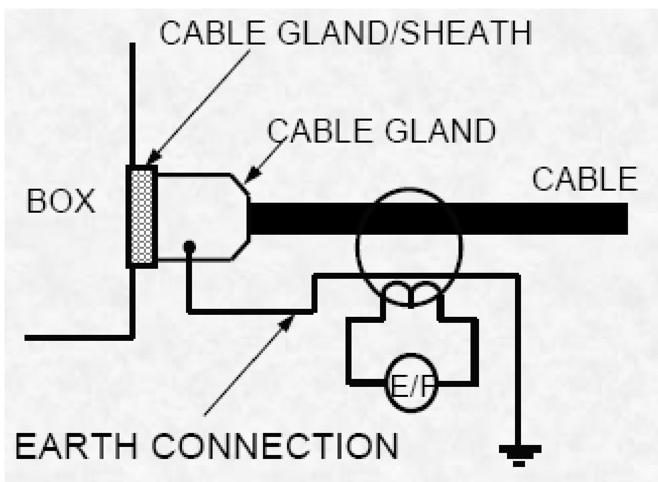


Figure 9.14 - Mounting of Core Balance CT with Cable Terminal Box

9.6 Protection against Incipient Faults:

Following relays are used for protection of transformers against incipient faults:

1. Buchholz relay
2. Pressure Relief Valve
3. Sudden Pressure Release
4. Temperature monitoring devices (Winding Temperature Indicators and Oil Temperature Indicators)

These protection devices have already been discussed in detail in chapter 2. It should be noted that these protections are provided only for faults inside the transformer tank; differential or other types of relaying must be provided for protection in the event of external bushing flashovers or faults in the connections between a transformer and its circuit breakers. Such relays are therefore valuable principally as supplements to other forms of protection.

CHAPTER – 10

LINE AND FEEDER PROTECTION

10.1 Introduction

Lines are protected by overcurrent-, distance-, or pilot-relaying equipment, depending on the requirements. Overcurrent and distance protection schemes will be discussed in detail in this chapter. Overcurrent relaying is the simplest and cheapest, the most difficult to apply, and the quickest to need readjustment or even replacement as a system changes. It is generally used for phase- and ground-fault protection on station-service and distribution circuits in electric utility and in industrial systems, and on some subtransmission lines where the cost of distance relaying cannot be justified. It is used for primary ground-fault protection on most transmission lines where distance relays are used for phase faults, and for ground back-up protection on most lines having pilot relaying for primary protection. However, distance relaying for ground-fault primary and back-up protection of transmission lines is slowly replacing overcurrent relaying. Overcurrent relaying is used extensively also at power-transformer locations for external fault back-up protection, but here, also, there is a trend toward replacing overcurrent with distance relays. It is generally the practice to use a set of two or three overcurrent relays for protection against interphase faults and a separate overcurrent relay for single-phase-to-ground faults. Separate ground relays are generally favored because they can be adjusted to provide faster and more sensitive protection for single-phase-to-ground faults than the phase relays can provide.

10.2 Overcurrent Protection of Lines and Feeders

Overcurrent relaying is well suited to distribution-system protection for several reasons. Not only is overcurrent relaying basically simple and inexpensive but also these advantages are realized in the greatest degree in many distribution circuits. Very often, the relays do not need to be directional, and then no a-c voltage source is required. Also, two phase relays and one ground relay are permissible. And finally, tripping reactor or capacitor tripping (described elsewhere) may be used. In electric-utility distribution-circuit protection, the greatest advantage can be taken of the inverse-time characteristic because the fault-current magnitude depends mostly on the fault location and is practically unaffected by changes in generation or in the high-voltage transmission system. Not only may relays with extremely inverse curves be used for this reason but also such relays provide the best selectivity with fuses and reclosers. Inverse-time relaying is supplemented by instantaneous relaying wherever possible. Speed in clearing faults minimizes damage and thereby makes automatic reclosing more likely to be successful. Connection of CTs for overcurrent and earthfault protection of lines can be done in the manner similar to the one discussed in section 9.5. Connection diagram for two overcurrent one earthfault and three overcurrent one earthfault schemes is repeated below in figures 10.1 and 10.2 for quick reference.

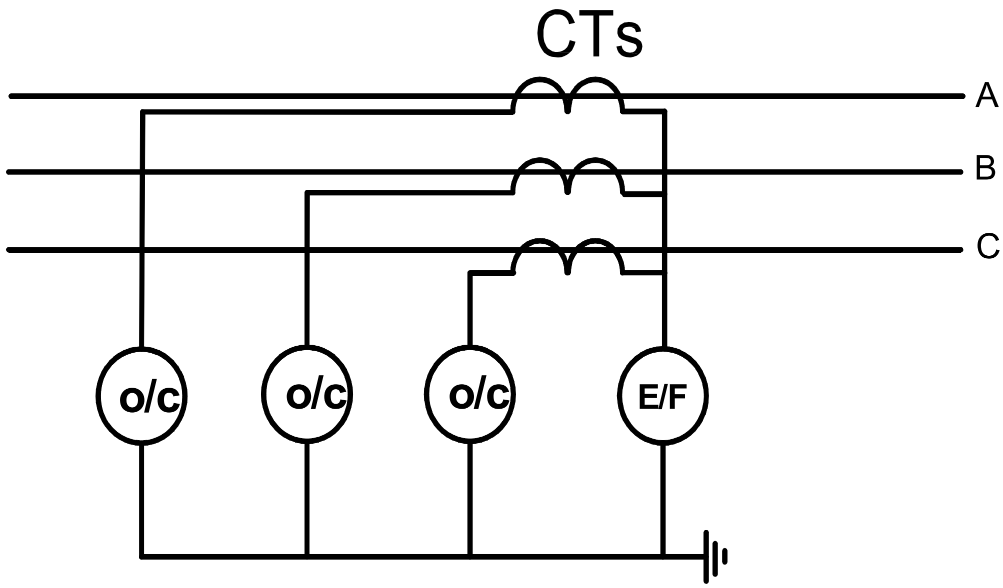


Figure 10.1 - Three Overcurrent and One Earthfault relay scheme

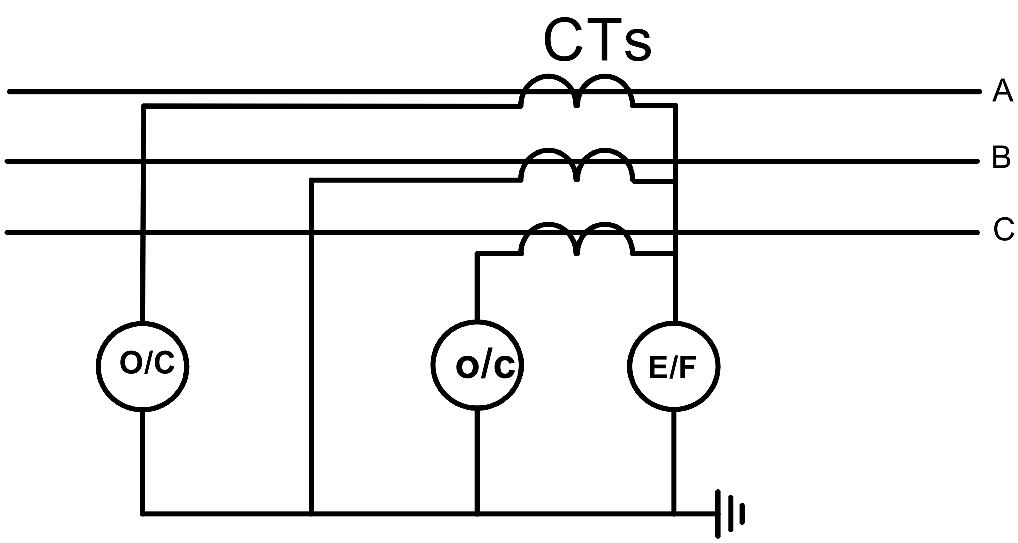


Figure 10.2 - Two Overcurrent and One Earthfault relay scheme

Instantaneous overcurrent relays are applicable if the fault-current magnitude under maximum generating conditions about triples as a fault is moved toward the relay location from the far end of the line. This will become evident by referring to figure 10.3 where the symmetrical fault-current magnitude is plotted as a function of fault location along a line for three-phase faults and for phase-to-phase faults assuming that the fault-current magnitude triples as the fault is moved from the far end of the line to the relay location. The pickup of the instantaneous relay is shown to be 25% higher than the magnitude of the current for a three-phase fault at the end of the line; the relay should not pick up at much less current or else it might overreach the end of the line when the fault-current wave is fully offset. In a distribution circuit, the relay could be adjusted to pick up at somewhat lower current because the tendency to overreach is less.

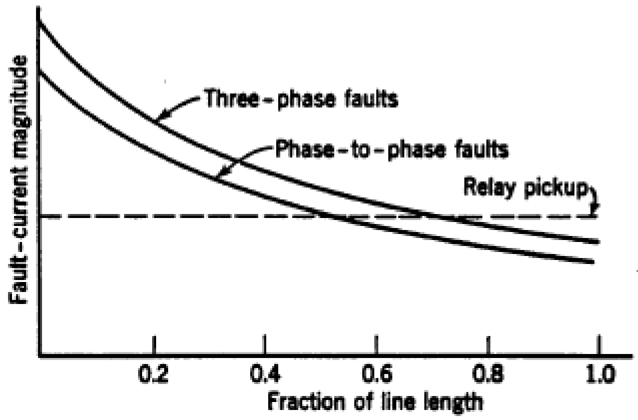


Figure 10.3 Performance of Instantaneous Overcurrent Relays

For the condition of Figure 10.3, it will be noted that the relay will operate for three phase faults out to 70% of the line length and for phase-to-phase faults out to 54%. If the ground-fault current is not limited by neutral impedance, or if the ground resistance is not too high, a similar set of characteristics for ground faults would probably show somewhat more than 70% of the line

10.2.1 Protection of Parallel Lines

If non-directional relays are applied to parallel feeders, any faults that might occur on any one line will, regardless of the relay settings used, isolate both lines and completely disconnect the power supply. With this type of system configuration it is necessary to apply directional relays at the receiving end and to grade them with the non-directional relays at the sending end, to ensure correct discriminative operation of the relays during line faults. This is done by setting the directional relays R'1 and R'_2 as shown in figure 10.4 with their directional elements looking into the protected line, and giving them lower time and current settings than relays R_1 and R_2. Relays R_1 and R_2 are non directional relays as indicated by bi-directional arrows. Now if the fault occurs at point F, relay $R_{1'}$ will trip as the direction of current flowing through this relay will reverse thereby isolating the faulty line. Relay $R_{2'}$ will not trip as the direction of current flow through this relay will remain unchanged even in case of fault. Thus only the faulty line will be isolated.

The usual practice is to set relays R'1 and R'_2 to 50% of the normal full load of the protected circuit and 0·05 TMS, but care must be taken to ensure that their continuous thermal rating of twice rated current is not exceeded. Connections of directional relays have already been discussed in detail in chapter-6

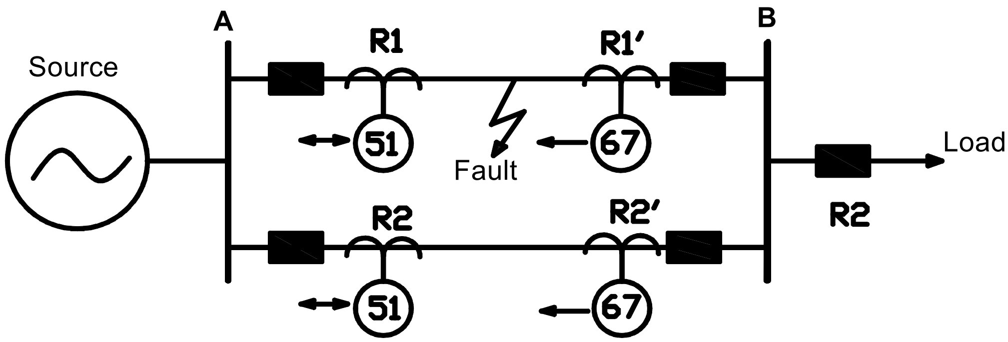


Figure 10.4 Protection of Parallel Lines

10.3 Distance Protection of Lines

One of the most critical issues in power system protection of any kind is the speed with which a fault can be cleared. Distance relaying should be considered when overcurrent relaying is too slow or is not selective. Distance relays are preferred to overcurrent relays because they are not nearly so much affected by changes in short-circuit-current magnitude as overcurrent relays are, and, hence, are much less affected by changes in generating capacity and in system configuration. This is because distance relays achieve selectivity on the basis of impedance rather than current.

During normal operation the apparent impedance as seen by a distance relay is large whereas during a fault condition the apparent impedance is small. To discriminate between normal and fault conditions a zone of operation (fault detector zone, tripping zone) is used. If the apparent impedance as seen by the relay is outside the zone of operation the relay will not trip whereas when the apparent impedance is within the zone of operation the relay operates.

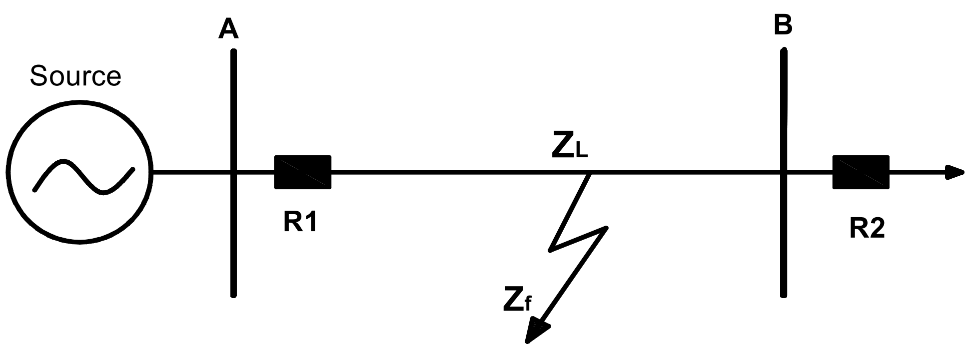


Figure 10.5 - A one line system protected by the distance relays R1 and R2. The total line impedance is Z_L, the load impedance is Z_{load} and the impedance between terminal A and the fault location F is Z_f

In figure 10.5 the generator and the load are connected through a transmission line where the line is protected by the two distance relays R1 and R2. Figure 10.6 shows the operating principle for distance protection. During normal conditions the apparent impedance as seen by R1 is approximately the load impedance Z_{load}. Hence the apparent impedance as seen by R1 is located far outside the zone of operation; this is the case at indication 1. When the short circuit fault occurs at F the apparent impedance 'jumps' into the zone of operation and the relay operates. The new apparent impedance as seen by R1 is the impedance Z_f between terminal A and the fault location F which is less than the pre set impedance value of the zone of operation.

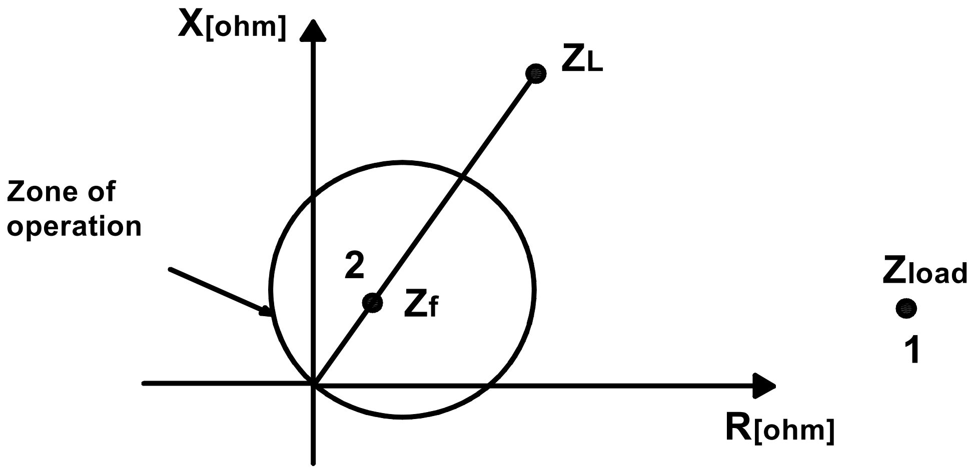


Figure 10.6 - RX- diagram for the distance relay R1 in figure 10.5. Indication 1 refers to normal operation whereas 2 indicates the fault situation.

There is always an uncertainty in the parameters involved in a protection system. For example, the line impedance may vary due to the outside temperature and/or the polarization voltage may be distorted. Due to uncertainty in impedance measurements, when protecting a transmission line with distance protection schemes it is necessary to rely on "stepped" zones of protection. This technique protects any given section of transmission line with multiple zones. Close in faults are cleared instantaneously by zone 1 protection. This protects roughly 85-90% of the line. When a fault is at 95% of the line its location becomes uncertain, based again on accuracy of impedance measurements, whether the fault is actually on that particular section of line or on an adjacent section. Therefore, it makes sense to delay tripping of faults which are perceived by the relay to be between the zone 1 upper limit and the zone 2 upper limit (120-150%) of the length of the line in question. Zone three provides backup for neighboring lines. Delaying a trip on zone 2 and 3 faults allows time for a zone 1 reaction of the relay on the adjacent line if the fault is in fact on that section of line. If it is actually at 95% of the line in question, then it will be cleared in zone 2. This delay insures proper coordination, and helps in the effort to avoid shutting down longer sections of line than are necessary to clear the fault. Figure 10.7 demonstrates the stepped distance protection zones. Criteria for setting various zones of distance relays are discussed in detail later.

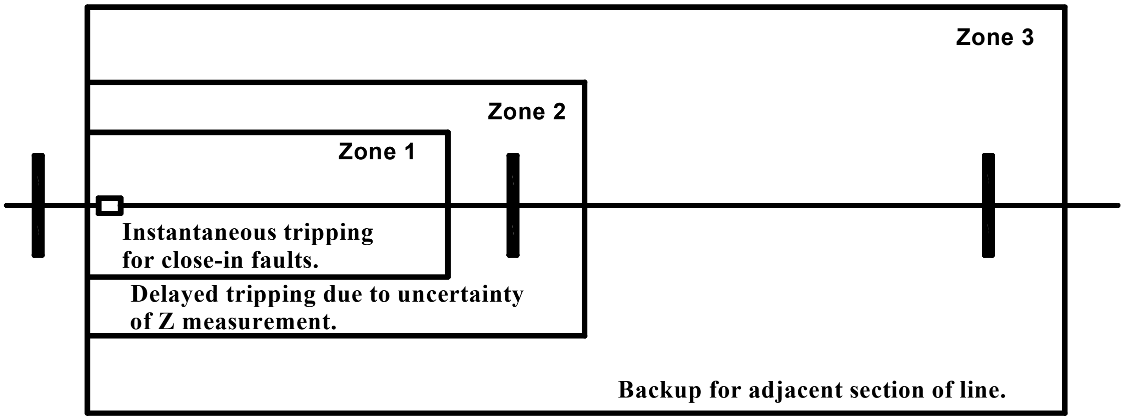


Figure10.7 - Stepped Distance Protection Zones

10.3.1 The Choice between Impedance, Mho and Reactance Relay

Because ground resistance can be so variable, a ground distance relay must be practically unaffected by large variations in fault resistance. Consequently, reactance relays are generally preferred for ground relaying. For phase-fault relaying, each type has certain advantages and disadvantages. For very short line sections, the reactance type is preferred for the reason that more of the line can be protected at high speed. This is because the reactance relay is practically unaffected by arc resistance which may be large compared with the line impedance. On the other hand, reactance-type distance relays at certain locations in a system are the most likely to operate undesirably on severe synchronizing power surges unless additional relay equipment is provided to prevent such operation.

The mho type is best suited for phase-fault relaying for longer lines, and particularly where severe synchronizing-power surges may occur. It is the least likely to require additional equipment to prevent tripping on synchronizing-power surges.1 When mho relaying is adjusted to protect any given line section, its operating characteristic encloses the least space on the R-X diagram, which means that it will be least affected by abnormal system conditions other than line faults; in other words, it is the most selective of all distance relays. Because the mho relay is affected by arc resistance more than any other type, it is applied to longer lines. The fact that it combines both the directional and the distance measuring functions in one unit with one contact makes it very reliable. The impedance relay is better suited for phase-fault relaying for lines of moderate length than for either very short or very long lines. Arcs affect an impedance relay more than a reactance relay but less than a mho relay. Synchronizing-power surges affect an impedance relay less than a reactance relay but more than a mho relay. If an impedance-relay characteristic is offset, so as to make it a modified relay, it can be made to resemble either a reactance relay or a mho relay but it will always require a separate directional unit.

There is no sharp dividing line between areas of application where one or another type of distance relay is best suited. Actually, there is much overlapping of these areas. Also, changes that are made in systems, such as the addition of terminals to a line, can change the type of relay best suited to a particular location. Consequently, to realize the fullest capabilities of distance relaying, one should use the type best suited for each application. In some cases much better selectivity can be obtained between relays of the same type, but, if relays are used that are best suited to each line, different types on adjacent lines have no appreciable adverse effect on selectivity.

10.3.2 Setting Procedure for Distance Relays

The phase distance relays are adjusted on the basis of the positive-phase sequence impedance between the relay location and the fault location beyond which operation of a given relay unit should stop. Ground distance relays are adjusted in the same way, although some types may respond to the zero-phase-sequence impedance. This impedance, or the corresponding distance, is called the "reach" of the relay or unit. For purposes of rough approximation, it is customary to assume an average positive-phase sequence- reactance value of about 0.8 ohm per mile for open transmission-line construction, and to neglect resistance. Accurate data are available in textbooks devoted to power-system analysis.

To convert primary impedance to a secondary value for use in adjusting a phase or ground distance relay, the following formula is used:

$$Zsec = Zpri\ (CT\ Ratio/\ VT\ Ratio)$$

where the CT ratio is the ratio of the high-voltage phase current to the relay phase current, and the VT ratio is the ratio of the high-voltage phase-to-phase voltage to the relay phase to phase voltage-all under balanced three-phase conditions. Thus, for a 50km, 66kV line with 600/5 wye-connected CTs, the secondary positive-phase-sequence reactance is given as:

$$50 \times 0.8 \times (600/5) \times (110/66000) = 8.00 \text{ ohms.}$$

As already discussed, it is the practice to adjust the first, or high-speed, zone of distance relays to reach to 80% to 90% of the length of a two-ended line or to 80% to 90% of the distance to the nearest terminal of a multiterminal line. There is no time-delay adjustment for this unit.

The principal purpose of the second-zone unit of a distance relay is to provide protection for the rest of the line beyond the reach of the first-zone unit. It should be adjusted so that it will be able to operate even for arcing faults at the end of the line. To do this, the unit must reach beyond the end of the line. Even if arcing faults did not have to be considered, one would have to take into account an underreaching tendency because of the effect of intermediate current sources, and of errors in:

1. the data on which adjustments are based
2. the current and voltage transformers
3. the relays.

It is customary to try to have the second-zone unit reach to at least 20% of an adjoining line section; the farther this can be extended into the adjoining line section, the more leeway is allowed in the reach of the third-zone unit of the next line-section back that must be selective with this second-zone unit.

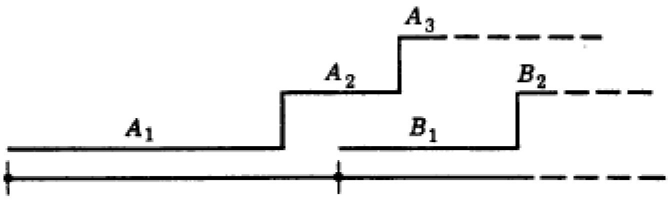


Figure 10.8 - Normal selectivity adjustment of second-zone unit.

The maximum value of the second-zone reach also has a limit. Under conditions of maximum overreach, the second-zone reach should be short enough to be selective with the second-zone units of distance relays on the shortest adjoining line sections, as illustrated in Figure 10.8. Transient overreach need not be considered with relays having a high ratio of reset to pickup because the transient that causes overreach will have expired before the second-zone tripping time. However, if the ratio of reset to pickup is low, the second zone unit must be set either

(1) with a reach short enough so that its overreach will not extend beyond the reach of the first-zone unit of the adjoining line section under the same conditions
(2) with a time delay long enough to be selective with the second-zone time of the adjoining section, as shown in Figure 10.9.

In this connection, any underreaching tendencies of the relays on the adjoining line sections must be taken into account. When an adjoining line is so short that it is impossible to get the required selectivity on the basis of react, it becomes necessary to increase the time delay, as illustrated in Figure10.9. Otherwise, the time delay of the second-zone unit should be long enough to provide selectivity with the slowest of

(1) bus-differential relays of the bus at the other end of the line,
(2) transformer-differential relays of transformers on the bus at the other end of the line
(3) line relays of adjoining line sections.

The interrupting time of the circuit breakers of these various elements will also affect the second-zone time. This second-zone time is normally about 0.2 second to 0.5 second.

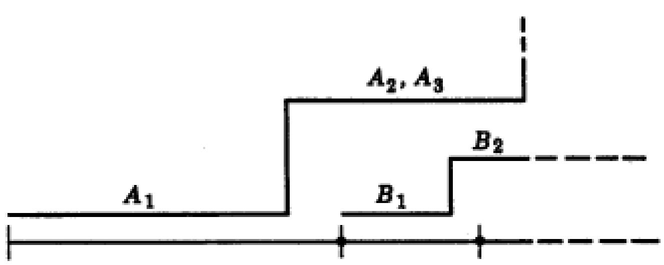


Figure 10.9 - Second-zone adjustment with additional time for selectivity with relay of a very short adjoining line section.

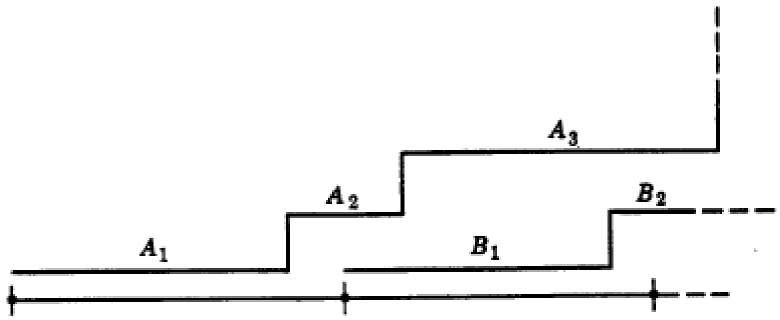


Figure 10.10 - Normal selective adjustment of third-zone unit.

The third-zone unit provides back-up protection for faults in adjoining line sections. So far as possible, its reach should extend beyond the end of the longest adjoining line section under the conditions that cause the maximum amount of underreach, namely, arcs and intermediate current sources. Figure10.10 shows a normal back-up characteristic. The third zone time delay is usually about 0.4 second to 1.0 second. To reach beyond the end of a long adjoining line and still be selective with the relays of a short line, it may be necessary to get this selectivity with additional time delay, as in Figure 10.11. and to provide back-up protection for a long adjoining line.

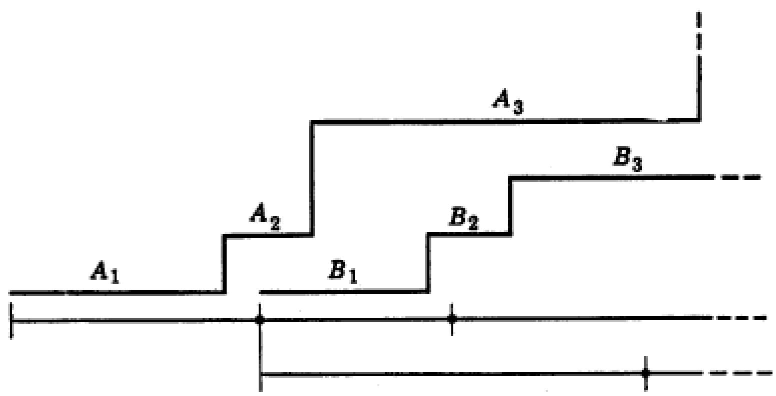


Figure 10.11 - Third-zone adjustment with additional time for selectivity with relay of a short adjoining line

When conditions of Figure 10.11 exist, the best solution is to use the type of back-up relaying described later under the heading "The Effect of Intermediate Current Sources on Distance-Relay Operation." Then, one has only the problem of adjusting the first- and second-zone units. Under no circumstances should the reach of any unit be so long that the unit would operate for any load condition or would fail to reset for such a condition if it had previously operated for any reason. To determine how near a distance relay may be to operating under a maximum load condition, in lieu of more accurate information, it is the practice to superimpose the relay's reset characteristic on an R-X diagram with the point representing the impedance when the equivalent generators either side of the relay location are 90º out of phase. To illustrate the process of selecting distance relay settings, a simple network configuration, with data given in Table 10.1, is considered in Figure 10.12.

Data	Line Impedances Line 1-2	 Line 2-3
Line impedance	1.0 + j1.0	1.0 + j1.0
Max load current	50MVA	50 MVA
Line Length	50 km	50 km
Line Voltages	66kV	66 kV

Table 10.12 Data Needed for Calculation of Settings for a Distance Relay

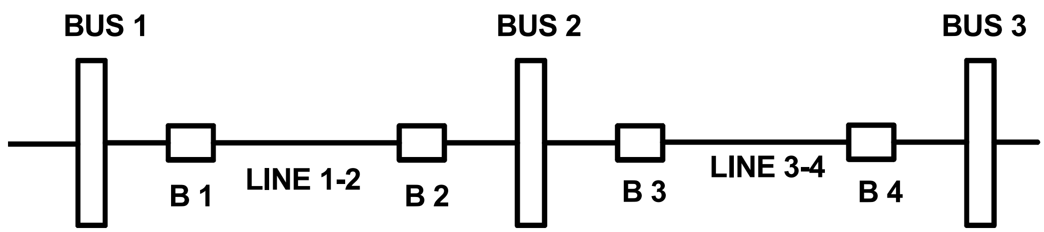


Figure 10.12 - A Sample System for Distance Relaying Application

The setting selection and coordination for the example given in Figure 10.12 can be formulated as follows:

Step 1: Determination of Maximum Load Current and Selection of CT and CT Ratios

From the data given in Table 10.1, the maximum load current is computed as:

$50(10^6)/ (1.732)(66000) = 200.1A$

The CT ratio is 400/5=80, which produces about 5 A in the secondary winding. If one assumes that CVT secondary phase to phase voltage needs to be 110V, then computing the actual primary voltage and selecting the ratio to produce the secondary voltage close to 110V allows one to calculate the CVT ratio. The primary phase to phase voltage is equal to 66 kV. CVT ratio is given as 66000/110 = 600

Step 2: Determination of the Secondary Impedance "Seen" by the Relay

The CT and CVT ratios are used to compute the impedance as follows:
Secondary impedance seen by relay = (80/600) (1 + j1)
Therefore, the secondary impedance "seen" by the relay is for both lines equal to 0.13 + j0.13.

Step 3: Computation of Apparent Impedance

Apparent impedance is the impedance of the relay seen under specific loading conditions. If we select the power factor of 0.8 lagging for the selected CT and CVT ratios as well as the selected fault current, the apparent impedance is equal to:

Z_{load} = [63.5/{200.1(5/400)}] (0.8 + j 0.6)
= (0.08 + j0.6) 25.39 = 20.3 + j15.2

Step 4: Selection of Zone Settings

Finally, the zone settings can now be selected by multiplying each zone's impedance by a safety factor. This factor is arbitrarily determined to be 0.8 for zone 1 and 1.2 for zone 2. As a result, the following settings for zone 1 and zone 2, respectively, are calculated as:

Zone 1 0.8(0.13 + j0.13) = (0.104+ 0.104) ohm
Zone 2 1.2(0.13 + j0.13) = (0.156 + 0.156) ohm

10.3.3 The Effect of Arcs on Distance Relay Operation

Characteristics of various distance relays have been plotted on the R-X diagram in chapter 5. It is only necessary, then, to superimpose the characteristic of any distance relay in order to see what its response will be when arc resistance is added to the fault resistance of the line. The critical arc location is just short of the point on a line at which a distance relay's operation changes from high-speed to intermediate time or from intermediate time to back-up time. We are concerned with the possibility that an arc within the high-speed zone will make the relay operate in intermediate time, that an arc within the intermediate zone will make the relay operate in back-up time, or that an arc within the back-up zone will prevent relay operation completely. In other words, the effect of an arc may be to cause a distance relay to underreach.

For an arc just short of the end of the first or high speed zone, it is the initial characteristic of the arc that concerns us. A distance relay's first-zone unit is so fast that, if the impedance is such that the unit can operate immediately when the arc is struck, it will do so before the arc can stretch appreciably and thereby increase its resistance. Therefore, we can calculate the arc characteristic for a length equal to the distance between conductors for phase to phase faults, or across an insulator string for phase-to-ground faults. On the other hand, for arcs in the intermediate-time or back-up zones, the effect of wind stretching the arc should be considered, and then the operating time for which the relay is adjusted has an important bearing on the outcome.

Tending to offset the longer time an arc has to stretch in the wind when it is in the intermediate or back-up zones is the fact that, the farther an arcing fault is from a relay, the less will its effect be on the relay's operation. In other words, the more line impedance there is between the relay and the fault, the less change there will be in the total impedance when the arc resistance is added. On the other hand, the farther away an arc is, the higher its apparent resistance will be because the current contribution from the relay end of the line will be smaller, as considered later.

A small reduction in the high-speed-zone reach because of an arc is objectionable, but it can be tolerated if necessary. One can always use a reactance-type or modified-impedance type distance relay to minimize such reduction. The intermediate-zone reach must not be reduced by an arc to the point at which relays of the next line back will not be selective; of course, they too will be affected by the arc, but not so much. Reactance-type or modified impedance type distance relays are useful here also for assuring the minimum reduction in second-zone reach. Figure 10.13 shows how an impedance or mho characteristic can be offset to minimize its susceptibility to an arc. One can also help the situation by making the second-zone reach as long as possible so that a certain amount of reach reduction by an arc is permissible. Conventional relays do not use the reactance unit for the back-up zone; instead, they use either an impedance unit, a modified-impedance unit, or a mho unit. If failure of the back-up unit to operate because of an arc extended by the wind is a problem, the modified-impedance unit can be used or the mho or "starting" unit characteristic can also be shifted to make its operation less affected by arc resistance. The low-reset characteristic of some types of distance relay is advantageous in preventing reset as the wind stretches out an arc.

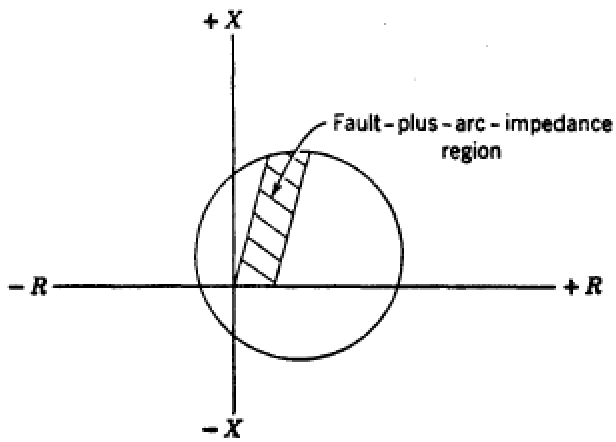


Figure 10.13 - Offsetting relay characteristic to minimize susceptibility to arcs.

Although an arc itself is practically all resistance, it may have a capacitive-reactance or an inductive-reactance component when viewed from the end of a line where the relays are. The impedance of an arc (Z_A) has the appearance:

$$Z_A = \{(I_1 + I_2)/I_1\}R_A$$

Where,

I_1 is the complex expression for the current flowing into the arc from the end of the line where the relays under consideration are.

I_2 is the complex expression for the current flowing into the arc from the other end of the line.

R_A is the arc resistance with current $(I_1 + I_2)$ flowing into it.

If I_1 and I_2 are out of phase, Z_A will be a complex number. Therefore, even a reactance-type distance relay may be adversely affected by an arc. This effect is small, however, and is generally neglected. Of more practical significance is the fact that, as shown by the equation, the arc resistance will appear to be higher than it actually is, and it may be very much higher. After the other end of the line trips, the arc resistance will be higher because the arc current will be lower. However, its appearance to the relays will no longer be magnified, because I_2 will be zero. Whether its resistance will appear to the relays to be higher or lower than before will depend on the relative and actual magnitudes of the currents before and after the distant breaker opens.

10.3.4 Effect of Intermediate Current Sources on Distance Relay Operation

An "intermediate-current source" is a source of short-circuit current between a distance relay location and a fault for which distance-relay operation is desired. Consider the example of Figure 10.14. The true impedance to the fault is $Z_A + Z_B$, but, when the intermediate current I_2 flows, the impedance appears to the distance relays as $Z_A + Z_B + (I_2/I_1) Z_B$; in other words, the fault appears to be farther away because of the current I_2. This effect has been called the "mutual impedance" effect. It will be evident that, if I_1 and I_2 are out of phase, the impedance $(I_2/I_1) Z_B$ will have a different angle from Z_B. If the distance relays are adjusted to operate for a fault at a given location when a given value of I_2 flows, they will operate for faults beyond that location for smaller values of I_2. Therefore, it is the practice to adjust distance relays to operate as desired on the basis of no intermediate current source. Then, they will not overreach and operate undesirably. Of course, when current flows from an intermediate source, the relays will "underreach," i.e., they will not operate for faults as far away as one might desire, but this is to be preferred to overreach.

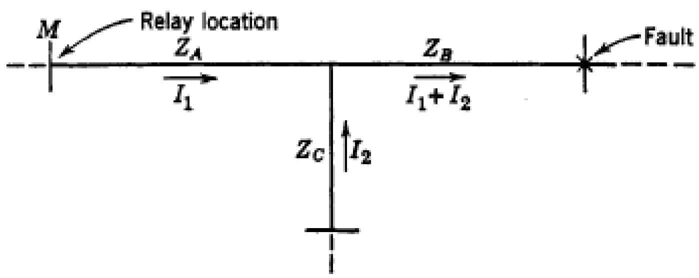


Figure 10.14 - Illustrating the effect of intermediate current sources on distance-relay operation.

Because of the effect of intermediate current sources, the full capabilities of distance relaying cannot be realized on multiterminal lines. It is the practice to adjust the high speed zone of the relays at a given terminal to reach 80% to 90% of the distance to the nearest terminal, neglecting the effect of an intermediate current source. Thus, in Figure 10.14, the maximum reach of the high-speed zone of the relays at M would be 80% to 90% of $Z_A + Z_B$ or of $Z_A + Z_C$, whichever was smaller. Neglecting the effect of an arc, if this maximum reach of the high-speed zone is less than Z_A, it will become evident that intermediate current cannot affect the high-speed-zone reach; if the maximum reach is greater than Z_A, intermediate current will cause the reach to approach Z_A, as a minimum limit. If the second-zone reach is made to include double the impedance of the common branch, tripping will always be assured although it might be sequential.

In Figure 10.15, consider the problem of adjusting relays at A to provide back-up for the fault location shown, in the event that breaker B fails to trip for any reason. The problem is similar whether inverse-time or distance relays are involved at A. The magnitude of the fault current flowing at A, or the impedance measured by a distance relay at A, may vary considerably, depending on the magnitude of fault current fed into the intermediate station from other sources. The range of such variations must be taken into account in determining the back-up adjustment. In some extreme cases, the apparent impedance between A and the fault may be such as to put the fault beyond the reach of the relays at A. Obviously, this problem may apply also to the relays in the other lines except the faulted one.

A solution that has been resorted to, when a fault can be beyond the reach of conventional back-up relays, is to have the back-up unit of the relaying equipment of each line at the intermediate station operate a timer which, after a definite time, will energize a multicontact auxiliary tripping relay to trip all the breakers connected to the bus of the intermediate station. Admittedly, this solution violates one of the fundamental principles of back-up protection by assuming that the failure to trip is owing only to failure in the breaker or in the tripping circuit between the relay and the breaker; it assumes that the protective-relaying equipment or the source of tripping voltage will not fail. However, it is a practical solution, and it has been considered worth the risk. A more reliable arrangement is to use separate CT's and protective relays to energize the multicontact tripping relay, employing only the battery in common. It is also possible to have the backup relay first try to trip the breaker of the faulty line before tripping all the other breakers.

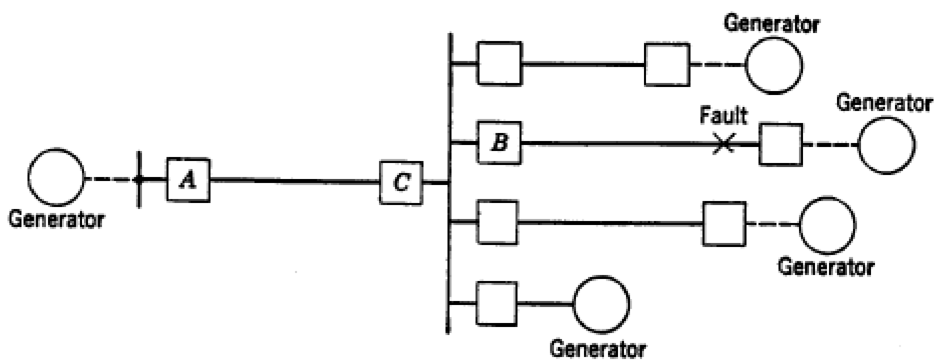


Figure 10.15 A situation in which conventional back-up relaying is inadequate.

The back-up elements of mho-type distance relays can be made to operate for faults in the direction opposite to the conventional back-up direction. In fact, the reversed back-up direction, called "reversed third zone," is normally provided when mho-type distance relays are used with directional-comparison carrier-current-pilot relaying. This feature gives some relief in the problem of reaching far enough to provide back-up protection for adjoining line sections, since the backup elements, being closer to these adjoining line sections, do not have to reach so far. Referring to Figure 10.15, for example, if the back-up elements located at breaker C are arranged to operate for current flow toward the fault, their reach can be reduced by the distance from A to C as compared with back-up elements at A looking toward the fault. Various other solutions have been resorted to, depending on how many different possibilities of failure one may wish to anticipate.

10.3.5 Effect of Coupling Capacitor Voltage Transformer (CCVT) Transients on Distance Protection of Lines

Coupling capacitor voltage transformers are an economical way to obtain the potential required to operate distance (and directional) type relays. They also provide a means to couple communication channels to the power line for use with various relaying schemes. Unfortunately, a CCVT may not reproduce the primary voltage exactly and can introduce significant error into the distance relay measurement. The transient error that is produced by the CCVT becomes more pronounced as the change in the voltage from prefault to fault is increased (a fault at the end of a line with a high source to line impedance (Z_S/Z_L) impedance ratio, for example). If a transient like the one discussed in chapter-3 were to occur for a fault at the end of a line with a high Z_S/Z_L ratio, it could cause a zone 1 distance function to overreach. To see how this could occur, refer to Figure 10.16.

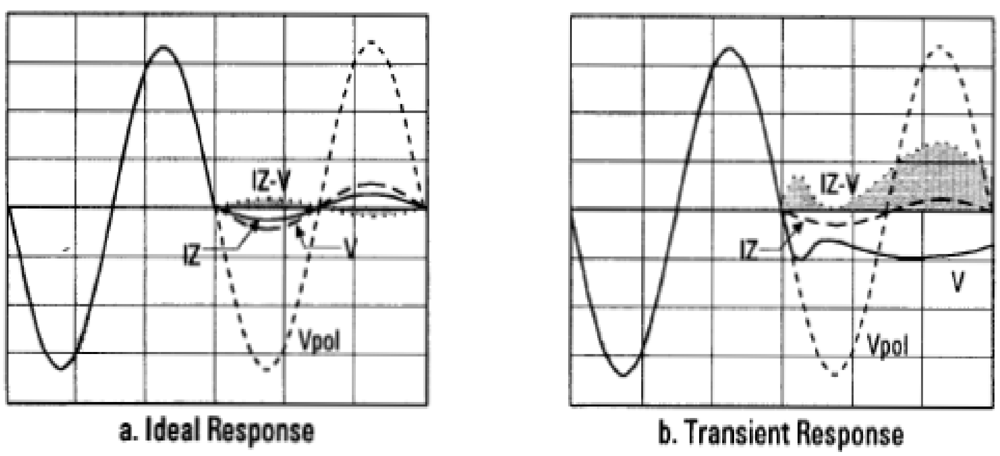


Figure 10.16 Distance Function Operation for Ideal and Transient CVT Response

The operation is shown for the distance function with the assumption that the source to line impedance ratio (Z_S/Z_L) is approximately 15. The ideal response shows that the function will not operate because the operating quantity, IZ-V, and the polarizing quantity, Vpol, are 180° out of phase. The transient response on the other hand shows that the function will operate during the second half cycle because the operating quantity and the polarizing quantity are in phase with each other (see shaded area). This example shows that care should be taken in the application of zone 1 distance functions and that the recommendation of the manufacturer should be followed in making the reach settings on the functions. CCVT transients may also cause loss of directionality for zero voltage bus faults behind the relay. The use of memory voltage and cross-polarization will reduce this tendency.

CHAPTER – 11

SHUNT CAPACITOR BANKS

11.1 Introduction

Shunt capacitor banks (SCB) are mainly installed to provide capacitive reactive compensation/power factor correction. The use of SCBs has increased because they are relatively inexpensive, easy and quick to install and can be deployed virtually anywhere in the network. Its installation has other beneficial effects on the system such as: improvement of the voltage at the load, better voltage regulation (if they are adequately designed), reduction of losses and reduction or postponement of investments in transmission. The main disadvantage of SCB is that its reactive power output is proportional to the square of the voltage and consequently when the voltage is low and the system needs them most, they are the least efficient.

11.2 The Capacitor Unit and Bank Configurations

11.2.1 The Capacitor Unit

The capacitor unit shown in figure 11.1 is the building block of a shunt capacitor bank. The capacitor unit is made up of individual capacitor elements, arranged in parallel/series connected groups, within a steel enclosure. The internal discharge device is a resistor that reduces the unit residual voltage to 50V or less in 5 min. Capacitor units are available in a variety of voltage ratings (240V to 24940V) and sizes (2.5 kVar to about 1000 kVar).

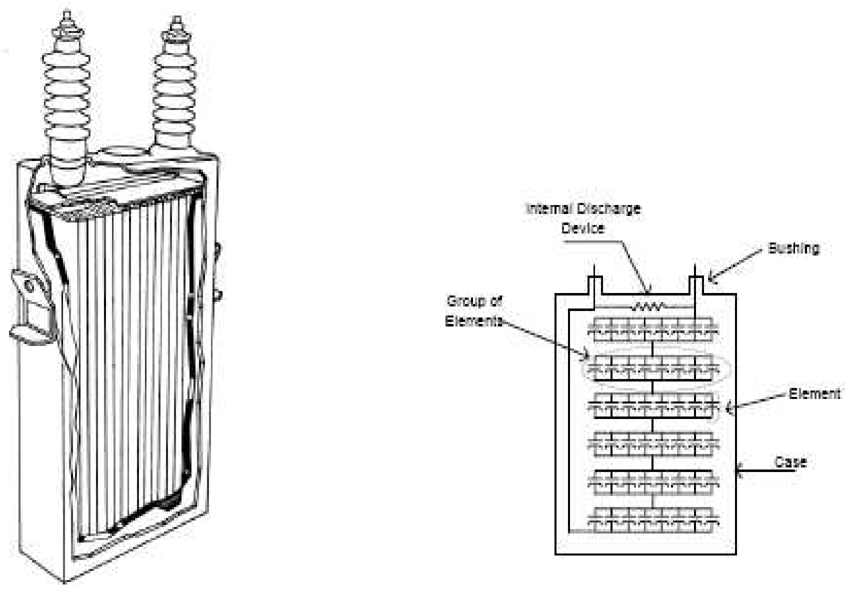


Figure 11.1 – Capacitor Bank Unit

11.2.2 Capacitor Unit Capabilities

Relay protection of shunt capacitor banks requires some knowledge of the capabilities and limitations of the capacitor unit and associated electrical equipment including: individual capacitor unit, bank switching devices, fuses, voltage and current sensing devices. Capacitors are intended to be operated at or below their rated voltage and frequency as they are very sensitive to these values; the reactive power generated by a capacitor is proportional to both of them (kVar = 2лfV^2). The IEEE standards specify the standard ratings of the capacitors designed for shunt connection to ac systems and also provide application guidelines. These standards stipulate that:

a) Capacitor units should be capable of continuous operation up to 110% of rated terminal rms voltage and a crest voltage not exceeding 1.2 x √2 of rated rms voltage, including harmonics but excluding transients. The capacitor should also be able to carry 135% of nominal current.
b) Capacitors units should not give less than 100% nor more than 115% of rated reactive power at rated sinusoidal voltage and frequency.
c) Capacitor units should be suitable for continuous operation at up to 135% of rated reactive power caused by the combined effects of:

1. Voltage in excess of the nameplate rating at fundamental frequency, but not over 110% of rated rms voltage.
2. Harmonic voltages superimposed on the fundamental frequency.
3. Reactive power manufacturing tolerance of up to 115% of rated reactive power.

11.2.3 Bank Configurations

The use of fuses for protecting the capacitor units and it location (inside the capacitor unit on each element or outside the unit) is an important subject in the design of SCBs. They also affect the failure mode of the capacitor unit and influence the design of the bank protection. Depending on the application any of the following configurations are suitable for shunt capacitor banks:

a) Externally Fused

An individual fuse, externally mounted between the capacitor unit and the capacitor bank fuse bus, typically protects each capacitor unit. The capacitor unit can be designed for a relatively high voltage because the external fuse is capable of interrupting a high-voltage fault. Use of capacitors with the highest possible voltage rating will result in a capacitive bank with the fewest number of series groups. A failure of a capacitor element welds the foils together and short circuits the other capacitor elements connected in parallel in the same group. The remaining capacitor elements in the unit remain in service with a higher voltage across them than before the failure and an increased in capacitor unit current. If a second element fails the process repeats itself resulting in an even higher voltage for the remaining elements. Successive failures within the same unit will make the fuse to operate, disconnecting the capacitor unit and indicating the failed one. Externally fused SCBs are configured using one or more series groups of parallel-connected capacitor units per phase as shown in Figure 11.2. The available unbalance signal level decreases as the number of series groups of capacitors is increased or as the number of capacitor units in parallel per series group is increased. However, the kVar rating of the individual capacitor unit may need to be smaller because a minimum number of parallel units are required to allow the bank to remain in service with one fuse or unit out.

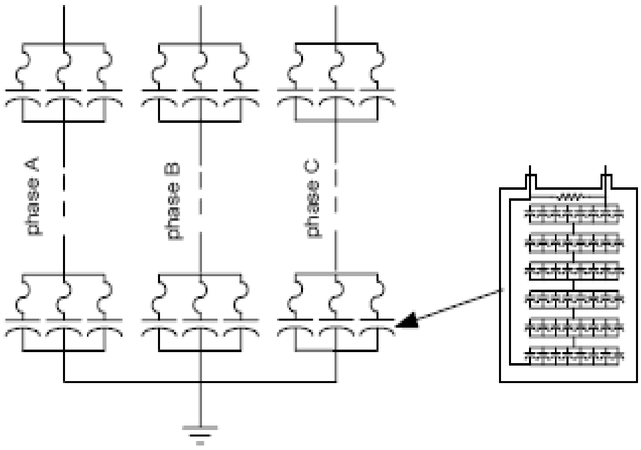


Figure 11.2 - Externally fused shunt capacitor bank and capacitor unit

b) Internally Fused

Each capacitor element is fused inside the capacitor unit. The fuse is a simple piece of wire enough to limit the current and encapsulated in a wrapper able to withstand the heat produced by the arc. Upon a capacitor element failure, the fuse removes the affected element only. The other elements, connected in parallel in the same group, remain in service but with a slightly higher voltage across them. Figure 11.3 illustrates a typical capacitor bank utilizing internally fused capacitor units. In general, banks employing internally fused capacitor units are configured with fewer capacitor units in parallel and more series groups of units than are used in banks employing externally fused capacitor units. The capacitor units are normally large because a complete unit is not expected to fail.

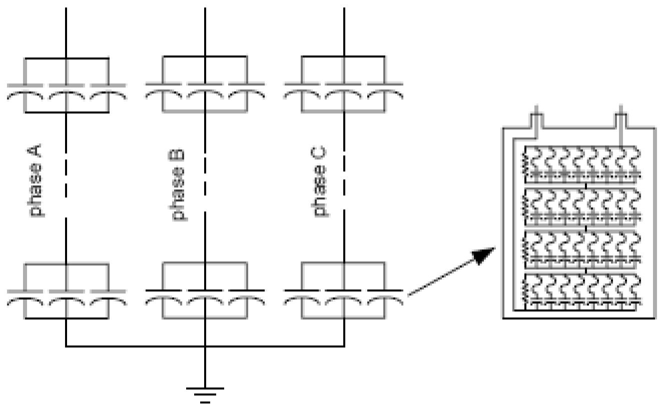


Figure 11.3 - Internally fused shunt capacitor bank and capacitor unit

c) Fuseless Shunt Capacitor Banks

The capacitor units for fuseless capacitor banks are identical to those for externally fused described above. To form a bank, capacitor units are connected in series strings between phase and neutral as shown in figure 11.4. The protection is based on the capacitor elements (within the unit) failing in a shorted mode, short- circuiting the group. When the capacitor element fails it welds and the capacitor unit remains in service. The voltage across the failed capacitor element is then shared among all the remaining capacitor element groups in the series. For example, if there are 6 capacitor units in series and each unit has 8 element groups in series there is a total of 48 element groups in series. If one capacitor element fails, the element is shortened and the voltage on the remaining elements is 48/47 or about a 2% increase in the voltage. The capacitor bank continues in service; however, successive failures of elements will lead to the removal of the bank. The fuseless design is not usually applied for system voltages less than about 34.5 kV. The reason is that there shall be more than 10 elements in series so that the bank does not have to be removed from service for the failure of one element because the voltage across the remaining elements would increase by a factor of about E / (E – 1), where E is the number of elements in the string. The discharge energy is small because no capacitor units are connected directly in parallel. Another advantage of fuseless banks is that the unbalance protection does not have to be delayed to coordinate with the fuses.

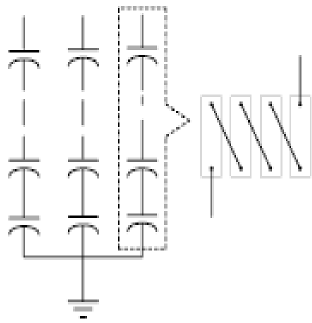


Figure 11.4 - Fuseless Shunt Capacitor Bank and Series String

d) Unfused Shunt Capacitor Banks

Contrary to the fuseless configuration, where the units are connected in series, the unfused shunt capacitor bank uses a series/parallel connection of the capacitor units. The unfused approach would normally be used on banks below 34.5 kV, where series strings of capacitor units are not practical, or on higher voltage banks with modest parallel energy. This design does not require as many capacitor units in parallel as an externally fused bank.

11.3 Capacitor Bank Design

The protection of shunt capacitor banks requires understanding the basics of capacitor bank design and capacitor unit connections. Shunt capacitors banks are arrangements of series/paralleled connected units. Capacitor units connected in paralleled make up a group and series connected groups form a single-phase capacitor bank.

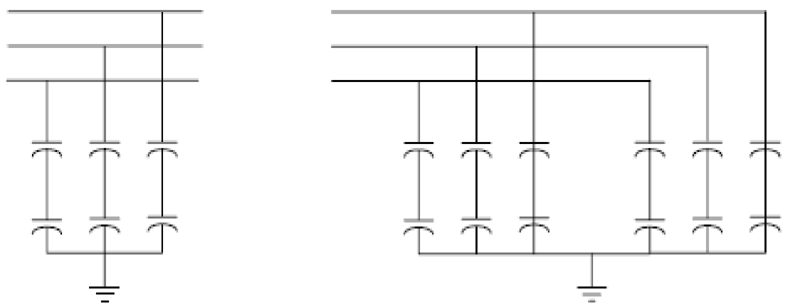
As a general rule, the minimum number of units connected in parallel is such that isolation of one capacitor unit in a group should not cause a voltage unbalance sufficient to place more than 110% of rated voltage on the remaining capacitors of the group. Equally, the minimum number of series connected groups is that in which the complete bypass of the group does not subject the others remaining in service to a permanent overvoltage of more than 110%. The maximum number of capacitor units that may be placed in parallel per group is governed by a different consideration. When a capacitor bank unit fails, other capacitors in the same parallel group contain some amount of charge. This charge will drain off as a high frequency transient current that flows through the failed capacitor unit and its fuse. The fuse holder and the failed capacitor unit should withstand this discharge transient.

The discharge transient from a large number of paralleled capacitors can be severe enough to rupture the failed capacitor unit or the expulsion fuse holder, which may result in damage to adjacent units or cause a major bus fault within the bank. To minimize the probability of failure of the expulsion fuse holder, or rupture of the capacitor case, or both, the standards impose a limit to the total maximum energy stored in a paralleled connected group to 4659 kVar. In order not to violate this limit, more capacitor groups of a lower voltage rating connected in series with fewer units in parallel per group may be a suitable solution. However, this may reduce the sensitivity of the unbalance detection scheme. Splitting the bank into 2 sections as a double Y may be the preferred solution and may allow for better unbalance detection scheme. Another possibility is the use of current limiting fuses.

The optimum connection for a SCB depends on the best utilization of the available voltage ratings of capacitor units, fusing, and protective relaying. Virtually all substation banks are connected wye. Distribution capacitor banks, however, may be connected wye or delta. Some banks use an H configuration on each of the phases with a current transformer in the connecting branch to detect the unbalance.

11.3.1 Grounded Wye-Connected Banks

Grounded wye capacitor banks are composed of series and parallel-connected capacitor units per phase and provide a low impedance path to ground. Figure 11.5 shows typical bank arrangements.



Multiple units grounded single Wye   Multiple units grounded double Wye

Figure 11.5 - Grounded Wye Shunt Capacitor Banks

Advantages of the grounded capacitor banks include:

a. Low-impedance path to ground provides inherent self-protection for lightning surge currents and give some protection from surge voltages. Banks can be operated without surge arresters taking advantage of the capability of the capacitors to absorb the surge.

b. Offer a low impedance path for high frequency currents and so they can be used as filters in systems with high harmonic content. However, caution shall be taken to avoid resonance between the SCB and the system.

c. Reduced transient recovery voltages for circuit breakers and other switching equipment.

Some drawbacks for grounded wye SCB are:

a. Increased interference on telecom circuits due to harmonic circulation.

b. Circulation of inrush currents and harmonics may cause misoperations and/or over-operation on protective relays and fuses.

c. Phase series reactors are required to reduce voltages appearing on the CT secondary due to the effect of high frequency, high amplitude currents.

When a capacitor bank becomes too large, making the parallel energy of a series group too great (above 4650 kVar) for the capacitor units or fuses, the bank may be split into two wye sections. The characteristics of the grounded double wye are similar to a grounded single wye bank. The two neutrals should be directly connected with a single connection to ground. The Double Wye design allows a secure and faster unbalance protection with a simple uncompensated relay because any system zero sequence component affects both wyes equally, but a failed capacitor unit will appear as un unbalanced in the neutral. Time coordination may be required to allow a fuse, in or on a failed capacitor unit, to blow. If it is a fuseless design, the time delay may be set short because no fuse coordination is required. If the current through the string exceeds the continuous current capability of the capacitor unit, more strings shall be added in parallel.

11.3.2 Ungrounded Wye-Connected Banks

Typical bank arrangements of ungrounded Wye SCB are shown in figure 11.6. Ungrounded wye banks do not permit zero sequence currents, third harmonic currents, or large capacitor discharge currents during system ground faults to flow. (Phase-to-phase faults may still occur and will result in large discharge currents). Other advantage is that overvoltages appearing at the CT secondaries are not as high as in the case of grounded banks. However, the neutral should be insulated for full line voltage because it is momentarily at phase potential when the bank is switched or when one capacitor unit fails in a bank configured with a single group of units. For banks above 15kV this may be expensive.

a) Multiple Units in Series Phase to Neutral - Single Wye

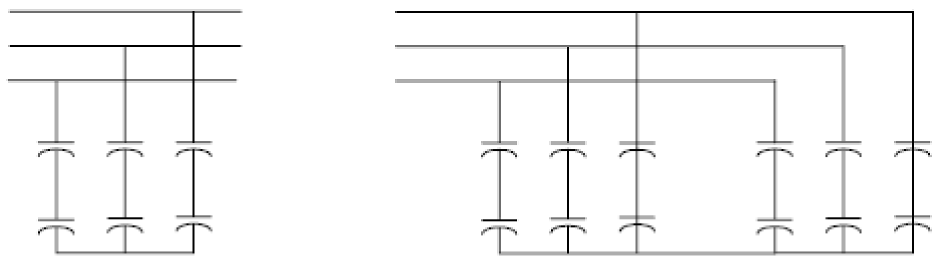
Capacitor units with external fuses, internal fuses, or no fuses (fuseless or unfused design) can be used to make up the bank. For unbalance protection schemes that are sensitive to system voltage unbalance, either the unbalance protection time delay shall be set long enough for the line protections to clears the system ground faults or the capacitor bank may be allowed to trip off for a system ground fault.

b) Multiple units in series phase to neutral-double wye

When a capacitor bank becomes too large for the maximum 4650 kvar per group the bank may be split into two wye sections. When the two neutrals are ungrounded, the bank has some of the characteristics of the ungrounded single-wye bank. These two neutrals may be tied together through a current transformer or a voltage transformer. As for any ungrounded why bank, the neutral instrument transformers should be insulated from ground for full line-to-ground voltage, as should the phase terminals.

11.3.3 Delta-connected Banks

Delta-connected banks are generally used only at distributions voltages and are configured with a single series group of capacitors rated at line-to-line voltage. With only one series group of units no overvoltage occurs across the remaining capacitor units from the isolation of a faulted capacitor unit. Therefore, unbalance detection is not required for protection and they are not treated further in this chapter.



Multiple units ungrounded single Wye   Multiple units ungrounded double Wye
Figure 11.6 - Ungrounded Wye Shunt Capacitor Banks

11.4 Capacitor Bank Protection

The protection of SCB's involves:
a) Protection of the bank against faults occurring within the bank including those inside the capacitor unit
b) Protection of the bank against system disturbances and faults.

11.4.1 Capacitor Unbalance Protection

The protection of shunt capacitor banks against internal faults involves several protective devices/ elements in a coordinated scheme. Typically, the protective elements found in a SCB for internal faults are: individual fuses (not discuss in this paper), unbalance protection to provide alarm/ trip and overcurrent elements for bank fault protection. Removal of a failed capacitor element or unit by its fuse results in an increase in voltage across the remaining elements/ units causing an unbalance within the bank. A continuous overvoltage (above 1.1pu) on any unit shall be prevented by means of protective relays that trip the bank.

Unbalance protection normally senses changes associated with the failure of a capacitor element or unit and removes the bank from service when the resulting overvoltage becomes excessive on the remaining healthy capacitor units. Unbalance protection normally provides the primary protection for arcing faults within a capacitor bank and other abnormalities that may damage capacitor elements/ units. Arcing faults may cause substantial damage in a small fraction of a second. The unbalance protection should have minimum intentional delay in order to minimize the amount of damage to the bank in the event of external arcing.

In most capacitor banks an external arc within the capacitor bank does not result in enough change in the phase current to operate the primary fault protection (usually an overcurrent relay). The sensitivity requirements for adequate capacitor bank protection for this condition may be very demanding, particularly for SBC with many series groups. The need for sensitivity resulted in the development of unbalance protection where certain voltages or currents parameters of the capacitor bank are monitored and compared to the bank balance conditions.

Capacitor unbalance protection is provided in many different ways, depending on the capacitor bank arrangement and grounding. A variety of unbalance protection schemes are used for internally fused, externally fused, fuseless, or unfused shunt capacitor.

a) Capacitor Element Failure Mode

For an efficient unbalance protection it is important to understand the failure mode of the capacitor element. In externally fused, fuseless or unfused capacitor banks, the failed element within the capacitor is short-circuited by the weld that naturally occurs at the point of failure (the element fails short-circuited). This short circuit puts out of service the whole group of elements, increasing the voltage on the remaining groups. Several capacitor elements breakdowns may occur before the external fuse (if exists) removes the entire unit. The external fuse will operate when a capacitor unit becomes essentially short circuited, isolating the faulted unit. Internally fused capacitors have individual fused capacitor elements that are disconnected when an element breakdown occurs (the element fails opened). The risk of successive faults is minimized because the fuse will isolate the faulty element within a few cycles. The degree of unbalance introduced by an element failure is less than that which occurs with externally fused units (since the amount of capacitance removed by blown fuse is less) and hence a more sensitive unbalance protection scheme is required when internally fused units are used.

b) Undetectable Faults

For certain capacitor bank configurations some faults within the bank will not cause an unbalance signal and will go undetected. For example: Rack-to-rack faults for banks with two series groups connected phase-over-phase and using neutral voltage or current for unbalance protection

c) Inherent Unbalance and System Unbalance

In practice, the unbalance seen by the unbalance relay is the result of the loss of individual capacitor units or elements and the inherent system and bank unbalances. The primary unbalance, which exists on all capacitor bank installations (with or without fuses), is due to system voltage unbalance and capacitor manufacturing tolerance. Secondary unbalance errors are introduced by sensing device tolerances and variation and by relative changes in capacitance due to difference in capacitor unit temperatures in the bank.

The inherent unbalance error may be in the direction to prevent unbalance relay operation, or to cause a false operation. If the inherent unbalance error approaches 50% of the alarm setting, compensation should be provided in order to correctly alarm for the failure of one unit or element as specified. In some cases, a different bank connection can improve the sensitivity without adding compensation. For example, a wye bank can be split into a wye-wye bank, thereby doubling the sensitivity of the protection and eliminating the system voltage unbalance effect.

A neutral unbalance protection method with compensation for inherent unbalance is normally required for very large banks. The neutral unbalance signal produced by the loss of one or two individual capacitor units is small compared to the inherent unbalance and the latter can no longer be considered negligible. Unbalance compensation should be used if the inherent unbalance exceeds one half of the desired setting. Harmonic voltages and currents can influence the operation of the unbalance relay unless power frequency band-pass or other appropriate filtering is provided.

d) Unbalance Trip Relay Considerations

The time delay of the unbalance relay trip should be minimized to reduce damage from an arcing fault within the bank structure and prevent exposure of the remaining capacitor units to overvoltage conditions beyond their permissible limits. The unbalance trip relay should have enough time delay to avoid false operations due to inrush, system ground faults, switching of nearby equipment, and non-simultaneous pole operation of the energizing switch. For most applications, 0.1s should be adequate. For unbalance relaying systems that would operate on a system voltage unbalance, a delay slightly longer than the upstream protection fault clearing time is required to avoid tripping due to a system fault. Longer delays increase the probability of catastrophic bank failures. With grounded capacitor banks, the failure of one pole of the SCB switching device or a single phasing from a blown bank fuse will allow zero sequence currents to flow in system ground relays. Capacitor bank relaying, including the operating time of the switching device, should be coordinated with the operation of the system ground relays to avoid tripping system load. The unbalance trip relay scheme should have a lockout feature to prevent inadvertent closing of the capacitor bank switching device if an unbalance trip has occurred.

e) Unbalance Alarm Relay Considerations

To allow for the effects of inherent unbalance within the bank, the unbalance relay alarm should be set to operate at about one-half the level of the unbalance signal determined by the calculated alarm condition based on an idealized bank. The alarm should have sufficient time delay to override external disturbances.

11.4.2 Unbalance Protection Methods for Grounded Wye Banks

a. Unbalance Protection for Grounded Single Wye Banks

An unbalance in the capacitor bank will cause current to flow in the neutral. Figure 11.8 shows a protection based on a current transformer installed on the connection between the capacitor bank neutral and ground. This current transformer has unusual high overvoltage and current requirements. The ratio is selected to give both adequate overcurrent capability and appropriate signal for the protection. Because of the presence of harmonic currents (particularly the third, a zero sequence harmonic that flows in the neutral-to-ground connection), the relay should be tuned to reduce its sensitivity to frequencies other than the power frequency. This neutral-to-ground current is the vector sum of the three-phase currents, which are 90° out of the phase with the system phase-to-ground voltages. Each time the capacitor bank is energized, momentary unbalanced capacitor charging currents will circulate in the phases and in the capacitor neutral. Where a parallel bank is already in service these currents can be of the order of thousands of amperes causing the relay to mal-operate and CT to fail. Relay generally used for unbalance protection of capacitor bank are

Sr.No.	Make	Type
1.	ALSTOM	CAG14
2.	ABB	SPAJ 160C
3.	ALSTOM	MICOM P120

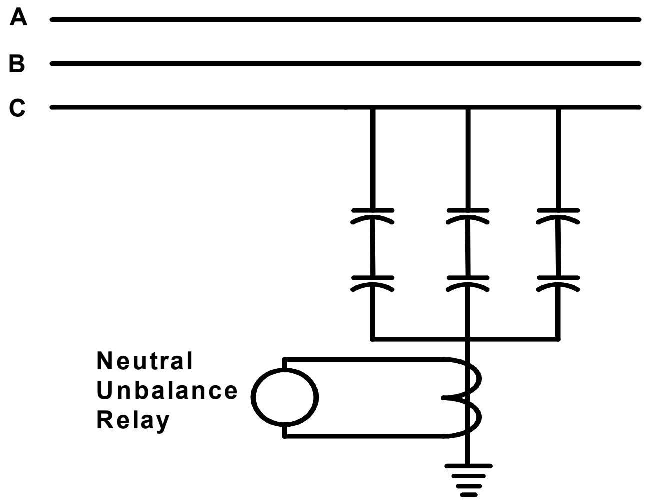


Figure 11.8 - Unbalance Protections for Grounded Single Wye Banks

b. Unbalance Protection for Grounded Double Wye Banks

Figure 11.9 shows a scheme where a current transformer is installed on each neutral of the two sections of a double wye SCB. The neutrals are connected to a common ground. The current transformer secondaries are cross-connected to an overcurrent relay so that the relay is insensitive to any outside condition that affects both sections of the capacitor bank in the same direction or manner. The current transformers can be subjected to switching transient currents and, therefore, surge protection is required. They should be sized for single-phase load currents if possible.

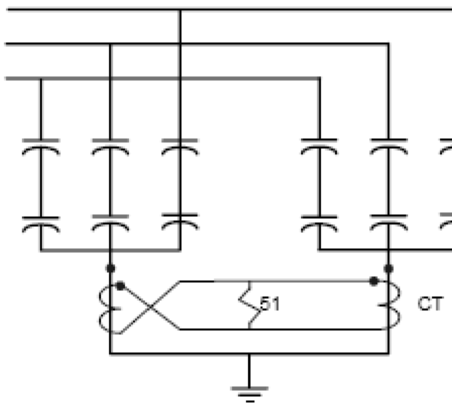


Figure 11.9 - Unbalance Protection for Grounded Double Wye Banks

11.4.3 Protection against Other Internal Bank Faults

There are certain faults within the bank that the unbalance protection will not detect or other means are required for its clearance.

a. Mid-Rack Phase to Phase Faults

Usually individual phases of a SCB are built on separate structures where phase to phase faults are unlikely. However, consider an ungrounded single Wye capacitor bank with two series groups per phase where all three phases are installed upon a single steel structure. A mid-rack fault between 2 phases as shown in figure 11.10 is possible and will go undetected. This fault does not cause an unbalance of the neutral voltage (or neutral current if grounded) as the healthy voltage is counter balance by the 2 other faulty phase voltages. The most efficient protection for mid-rack phase to phase faults is the negative sequence current. Tripping shall be delayed to coordinate with other relays in the system.

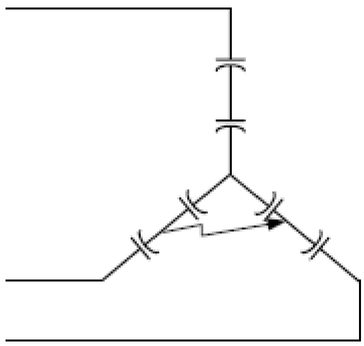


Figure 11.10 - Mid-rack Fault

b. Faults on the Capacitor Bank Bus

Time overcurrent relays for phase and ground are required to provide protection for phase and ground faults on the connecting feeder (or buswork) between the bank bus and the first capacitor unit. Two overcurrent and one Earthfault relay scheme already discussed in chapter-9 is generally used for protection against these faults.

11.4.4 Protection of the SCB against System Disturbances and Faults

a. System Overvoltage Protection

The capacitor bank may be subjected to overvoltages resulting from abnormal system operating conditions. If the system voltage exceeds the capacitor capability the bank should be removed from service. The removal of the capacitor bank lowers the voltage in the vicinity of the bank reducing the overvoltage on other system equipment. Time delayed or inverse time delayed phase overvoltage relays are used for this purpose. Some typical examples of these relays are as follows

1. VDG (Alstom make)
2. MICOM P127 (Alstom make)
3. 7RW6000 (Siemens make)
4. 7SJ62 (Siemens make)
5. SPAU160C (ABB make).

b. Relays for Bank Closing Control

Once disconnected from the system a shunt capacitor bank cannot be re-inserted immediately due to the electrical charge trapped within the capacitor units, otherwise catastrophic damage to the circuit breaker or switch can occur. To accelerate the discharge of the bank, each individual capacitor unit has a resistor to discharge the trapped charges within 5min. Undervoltage or undercurrent relays with timers are used to detect the bank

going out of service and prevent closing the breaker until the set time has elapsed. Some typical examples of undervoltage relays used are given below.
1. VDG (Alstom make)
2. MICOM P127 (Alstom make)
3. 7RW6000 (Siemens make)
4. 7SJ62 (Siemens make)
5. SPAU130C (ABB make).
From the above mentioned relays, MICOM P127 and 7SJ62 have built in timers. An example of undercurrent relay having the timer feature is SPAJ160C.

11.5 Capacitor Bank Switching Transients

The switching of shunt capacitor banks at utility substations and on distribution feeders creates voltage and current transients in the power system which may be damaging to power system equipment. Transient overvoltages due to the energizing of capacitor banks are the most common source of overvoltages on many power systems. The high incidence of capacitor-switching induced overvoltages is a result of a marked increase in the number of shunt capacitor banks used on transmission and distribution systems as well as the frequent switching thereof (in most instances at least one close-open operation per day).

11.5.1 Capacitor Overvoltages

The overvoltage transients created during shunt capacitor bank switching include: oscillatory transient overvoltages at the switched capacitor location and at other capacitor locations due to a phenomenon called "voltage magnification," overvoltages at radially-fed transformers or open-ended lines due to traveling wave phenomena, and fast transients coupled through transformers. Current transients include primarily the high magnitude, high frequency inrush currents during back-to-back capacitor switching (i.e., when energizing a capacitor bank with one or more already energized banks connected to the same bus). When the capacitor-bank switching device is closed to energize the capacitor bank, the voltage of the switched capacitor bank bus suddenly collapses to the level of the voltage on the capacitor bank which, with the capacitors discharged, is generally zero. The bus voltage then attempts to return to its normal power-frequency value, but overshoots this value and oscillates about the normal power-frequency wave until the oscillations are damped out. This oscillation typically lasts for one cycle of the power frequency. See Figure 11.11.

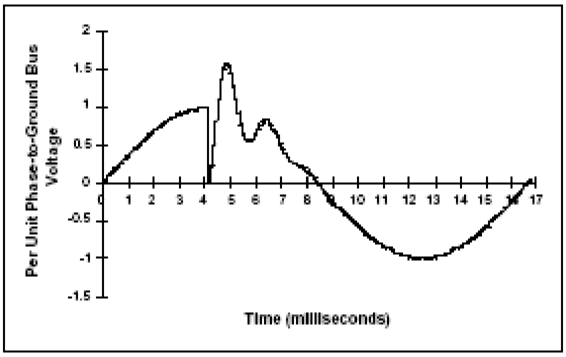


Figure 11.11 - Typical overvoltage transient at the switched capacitor bank bus when energizing a shunt capacitor bank.

If the bank is energized at peak voltage, a peak overvoltage of typically 1.5 to 1.8 per unit of peak phase to ground voltage results. The initial collapse of the bus voltage is very rapid - usually on the order of a few microseconds - whereas the oscillatory recovery of the bus voltage has a typical frequency of 300 to 800 Hz. This frequency is determined by the source inductance and the capacitance of the bank. The oscillatory transient overvoltage at the switched capacitor bank bus can excite other near-resonant portions of the power system, creating a magnified oscillatory overvoltage at the sites of other capacitor banks, e.g., other substation shunt capacitor banks, pole-mounted distribution capacitor banks, and power-factor correction capacitors at large industrial installations. These overvoltages can cause nuisance tripping, and possibly failure of sensitive electronic equipment.

The sudden collapse of the switched capacitor bank bus voltage when the shunt capacitor bank is energized transmits fast traveling waves along each line connected to the bus. These fast traveling waves can be doubled at radially-fed transformers and open-ended lines, and can be reflected many times between the substation bus and these locations before being finally damped out by line losses. If the length of line is such that the traveling wave arrival at the radially-fed transformer or open-ended line is coincident with the peak of the oscillatory transient at this location, high-magnitude overvoltages can result. Delta-connected transformers can be subjected to phase to phase overvoltages of up to 5.7 per unit of peak phase to ground voltage as a result of this traveling wave phenomenon, and can cause severe stress on the end windings of the transformer, resulting in insulation breakdown.

11.5.2 Current-Limiting Inductors Used in Capacitor Bank Applications

Current-limiting inductors are often connected in series with shunt capacitor banks to limit the severity of outrush currents into close-in bus faults. High-magnitude and high-frequency outrush currents that would otherwise occur can cause damaging overvoltages when line circuit breakers reignite and subsequently interrupt at high frequency current zeros. The rate of rise of the transient recovery voltage (TRV) which a line circuit breaker will be subjected to during a close-in fault is considerably lower than normal when a capacitor bank is present, while the peak of the TRV is higher. The lower rate of rise of the TRV will enable the line circuit breaker to interrupt with a very short arcing time, thereby increasing the possibility of re-ignitions in the circuit breaker if the dielectric withstand capability of the contact gap is exceeded after interruption with a small contact gap.

The size of the current-limiting inductor is generally selected to ensure that the product of the peak outrush current and the frequency is less than $2x10^7$ for general purpose circuit breakers. While the current-limiting inductor reduces the severity of the outrush current during close-in bus faults, it also presents a severe TRV to the circuit breaker protecting the capacitor bank(s) when a fault occurs in the capacitor bank(s) or between the inductor and the capacitor bank. This is due to the very high *inherent* frequency of the inductors, which results in a very high frequency oscillation on the load side of the circuit breaker when it attempts to interrupt the fault current.

CHAPTER – 12

BATTERY
AND
BATTERY CHARGERS

12.1 Introduction

Substation batteries play a vital role in overall reliability of a substation by providing DC power for protection, supervision and control of substation and line equipment. Frequently, transmission or distribution power will be lost or reduced in magnitude during system disturbances (faults) at precisely the same point in time that power is required to isolate the disturbance from the system. Power to control and supervise system components is necessary during any large-scale or system-wide loss of AC power in order to provide circuit-switching power during restoration operations. Continuous monitoring of equipment (and therefore, a continuous power source) is required to detect abnormal conditions.

To provide a continuous power source, most substation protection and control programs use dc power from batteries. These batteries can range in size from 50 Ahr at 24 V dc to more than 1000 Ahr at 250 VDC. These batteries are mostly lead-acid, although nickel cadmium (Ni-Cad) and other types are also used.

Batteries need continuous charging in order to be able to store energy and supply it whenever necessary. Thus Battery Chargers are used in substations to charge the batteries. Battery and battery chargers are therefore indispensable substation equipment. This chapter discusses the basic fundamentals of battery and battery chargers.

12.2 Battery

Battery consists of the following components:
a) Positive plates-Plates which act as cathode when battery is discharging
b) Negative plates-plates which act as anode when battery is discharging
c) Electrolyte-Chemical or its solution in water which conducts current inside the battery through ionization.
d) Separator-perforated/porous sheet of wood, ebonite, PVC or other material preventing metallic contact between the plates of opposite polarity within the cell but allowing the electrolyte permeates freely.

The capacity of a battery cell is expressed in Ampere-hour (Ah) which is the product of discharge current in Amperes and duration in hours under specific conditions such as temperature (27°c), rate of discharge (10 hour rate) and end voltage per cell. When the ambient temperature is less than 27°C, de rating of the battery should be considered. No up rating is considered for ambient above 27°C.

Two basic types of battery cells are available
1. Lead Acid Type
2. Alkaline Type

12.2.1 Lead Acid Type Battery

a. Electrochemical Process of Lead Acid Battery Cell

In this kind of battery the Positive plate is made of pure lead and the negative plate is pasted type lead alloy. Dilute Sulphuric acid is used as an electrolyte. Electrochemical process taking place in this battery is as follows:
During charging the lead surface in positive plate is converted into lead peroxide (PbO_2) and negative plate is converted into spongy lead. During discharge lead sulphate ($PbSO_4$) is formed on both the plates. Acid consumed is replaced by corresponding amount of water generated as per the following equation:

$$PbO_2 + Pb + 2H_2SO_4 = 2PbSO_4 + 2H_2O$$

During charge discharge cycles, newer layers of active material are formed out of the lead and older layers peel off as fresh layer is formed. In view of the chemical reaction the acid gets progressively diluted during discharge and specific gravity falls. During charging specific gravity rises again progressively. The specific gravity of a fully charged cell is around 1.205 and during discharge it progressively reduces as follows:-
At 25% discharge – 1.200
At 50% discharge – 1.160
At 75% discharge – 1.130
At 100% discharge – 1.100
Thus specific gravity reading is an indication to the state of charge. Voltage Per Cell (VPC) of Lead Acid battery for a fully charged cell is 2.0 volts

b. Construction Features of Lead Acid Battery

1. Containers
The containers for the cells are of impervious, moulded transparent plastic/glass material having heat resisting, high strength, non-reacting and low inflammable properties. The containers shall be mounted on insulator blocks. The containers are of robust construction and free from flaws, bubbles or foreign matter. The surface of the containers has a finish substantially free from blisters, rough spots, scales, blow-holes and other imperfections or deformations.

2. Plates
The positive plates shall be of pure lead lamellie type formation. The negative plates shall be pasted anti-monial lead grid type so designed as to hold the active material securely in place and in firm contact with the grid during service.

3. Separators
They are made from porous/perforated wood, ebonite, PVC or other material. These shall be inert chemically and oxidation resistant. High degree of porosity shall ensure minimum internal resistance.

4. Electrolyte

The electrolyte is prepared from the battery grade sulphuric acid and has a specific gravity of 1.2 at 27°C. The concentrated sulphuric acid is diluted with an equal volume of distilled water.

5. Buffer/Spring

Suitable buffers/springs are provided in the cells to keep the end plates in position. These shall have adequate length and strength.

6. Vent Plug

Vent plug is provided for closed top cells and is a micro porous filter which prevents acid sprays to come out of the cell but allows free exit of hydrogen and oxygen which are generated both during float and boost charging.

7. Terminal Posts

Terminal posts are provided for external bolted connections and made of lead or lead coated metal. All bolts and nuts shall be lead covered. The junctions between terminal posts and cell lid are sealed to prevent escape of electrolyte.

8. Marking:

Acid level line is permanently and indelibly marked around on all the containers. The following information is marked on the outside surface of each cell.

1. Manufacturer's name, type and trade mark.
2. Year of manufacture.
3. AH capacity at 10 hour rate.
4. Cell number.
5. Upper and lower electrolyte levels in case of transparent containers.

9. Battery Rack

The battery sets are installed on steel racks with acid proof paint and insulating sheets in a separate ventilated battery room. The cells shall be arranged on the racks in a "two tier/three tier" arrangement with two rows of cells on each tier or with some other suitable arrangement depending upon the availability of space inside the battery room. These racks are such that cells are located at convenient height to facilitate maintenance and they may be so constructed as to promote free access to floor directly beneath the rack to facilitate easy cleaning of the floor.

10. Connectors

Cell to cell connections and inter row/tier connections are made of lead or lead plated copper bars which are bolted to the terminal posts. Lead plated copper bars should be used where high discharge rate is involved. Tee-off connections from the battery units are made with acid-resisting cables of suitable size.

12.2.2 Alkaline Batteries

Alkaline batteries are available in two types

1. Nickel-Cadmium (Ni-Cad)
2. Nickel-Iron (Ni -Fe)

a. Nickel Cadmium (Ni-Cad) Battery
In this battery the positive plate is Nickel or nickel hydroxide. Negative plate is Cadmium. Caustic soda (KOH) with little quantity of lithium hydroxide (LiOH) diluted in distilled water is used as an electrolyte.

b. Nickel Iron (Ni-Fe) Battery
Positive plate is the same as that in Ni-Cad battery. Negative plate is an Iron alloy. Electrolyte is also the same as that in Ni-Cad battery.

c. Features of Alkaline Battery
a) Specific gravity remains unaffected by state of charge or discharge. The Specific gravity is around 1.200. Electrolyte is to be replaced when specific gravity falls to 1.165.
b) Fully charged condition is indicated by constant voltage per cell (VPC) for 3 – 4 hours.
c) VPC for fully charged cell is 1.3 volts
d) Minimum VPC on discharge is 1.00 volt

d. Advantages of Alkaline Batteries over Lead Acid Batteries
a) Longer life up to 20 years.
b) Very reliable, free from defects of sulphation and grid corrosion.
c) High resistance to electrical misuses.
d) Unaffected by overcharging.
e) Unaffected by ripple content in battery charger output.
f) Less time taken for recharging.
g) Less corrosion problem
f) However, cost is higher and availability of high capacity Batteries is limited

12.2.3 Battery Voltage

Standard DC voltages are 24, 50, 110 and 220 volts. Battery voltages used at BSES, Delhi are 50V and 220V. VPC for fully charged cell has already been mentioned. The required numbers of cells are to be connected in series to get the desired voltage. The trickle charge VCP will be higher than the open circuit VPC of battery eg: 2.2 VCP for lead acid battery charger. All electrical equipments are suitable for operation at maximum 110% of rated voltage. Hence numbers of cells are to be so selected such that system voltage is kept within limits during trickle charge. For example for 220V DC system, 108 lead acid cells are selected.

12.3 Battery Charger

Battery charger performs the following functions:
a) Charges the battery to compensate for the internal discharges to keep the battery fully charged as long as AC power is available.
b) Supplies the normal DC loads of the plant as long as AC power is available.
c) Whenever AC supply fails, battery starts supplying the DC loads without any interruption. After the emergency, the discharged battery is recharged to full capacity by the boost charger.

Battery charger is available as either separate Float and Boost chargers or one common float cum boost charger. The function of float and boost charging is given in the following discussion.

12.3.1 Constant Voltage/Float Mode

In this mode, the charger floats the battery at constant voltage level per cell with a voltage stabilization of ±1% and feeds the D.C. continuous load. The float charging output DC voltage should be as follows to compensate for self discharge:-
I. Lead Acid battery – 2.15 to 2.23 VPC
II. Alkaline battery – 1.19 to 1.42 VPC
The float charger can function in automatic or manual operation mode by selecting Auto/Manual selector switch on requisite mode. In automatic mode, the voltage is automatically maintained constant at set value. In case of manual mode of operation the voltage shall be set by operation of adjustable potentiometer.

12.3.2 Constant current/Boost Mode

Boost charging is required to recharge a battery after it has supplied the load due to AC mains failure. In this mode, the charger is capable of boost charging the batteries at any constant current settable/adjustable from 30% to 100% of rated current. The set constant current remains stabilized. During boost charging, DC loads are connected between positive and 80% tap of the battery. The boost charger can function in automatic/manual operation by selecting Auto/Manual selector switch on requisite mode. In automatic mode, the boost charging set current is maintained constant automatically. In manual mode boost charging current can be set by means of operation of adjustable potentiometer.

The boost charger should charge the battery at high rate limited to the maximum boost charging voltage. The boost charging voltage is generally as follows:
I. Lead acid battery – 2.65 to 2.75 VPC
II. Alkaline battery – 1.55 to 1.60 VPC
In this mode a fully discharged battery should be generally recharged within a period of
I. Lead acid battery – 10 hours
II. Alkaline battery – 8 hours
High ripple content in the DC output voltage of charger affects the life of lead acid battery. Hence ripple content of output voltage of both float and boost charger shall be limited to ±3%.Alkaline batteries are not much affected by ripple content.

12.3.3 Principle of Float cum Boost Charger (SCR)

The circuit of float cum boost charger works on AC phase control principle utilizing silicon controlled rectifier (SCR). The output voltage is controlled by changing the instant of firing/triggering of SCR. Potentiometers to adjust DC output voltage are provided on the panel for auto as well as manual mode.

The DC shunt is connected in the negative of the float charger output for sensing the load current. In the event of charger being over loaded beyond its set value, the voltage drop across shunt is sensed and DC output voltage corrected in such a way that the DC output voltage start dropping, thereby the DC output current is reduced to the set value. The current limiting feature is provided in constant voltage mode, apart from back up protection provided by the HRC fuses. The auxiliary control transformer supplies the Synchronising voltage to the controller. The transformer also supplies positive and negative DC voltage to the controller. A bleeder resistance is provided to give a latching current for the SCRs under no load condition.

The filter circuit comprising of a filter choke and filter condenser banks is connected in the output of the charger to limit the ripple content in the DC output voltage. A constant voltage/constant current selector switch is used for selection of the mode of charging the battery. When this switch is on “Constant Voltage” i.e. “Float” mode, the charger supplies the load and at the same time shall supply trickle charging current to the battery. For boost charging of the battery, this switch shall be put on “Constant Current” mode i.e. “boost” mode.

A selector switch is also provided for Auto/Manual mode of operation. In auto mode the DC output voltage is automatically kept constant with the help of solid state controller. For controlling the output voltage of the charger in manual mode, potentiometer is provided. Controls generally provided on float cum boost charger panel (FCB) are as follows:

1. Auto-Manual selector switch
2. Float/Boost mode selector switch
3. Auto current adjustment potentiometer in boost mode
4. Auto voltage adjustment potentiometer in float mode
5. Manual voltage/current potentiometer
6. Current limit adjustment potentiometer in float mode

12.3.4 Protection Provided for the Battery Charger System

Following protections are provided for each charger and associated equipment:

1. H.R.C. fuses for voltmeter, condenser, controller circuit and annunciation circuit.
2. Semiconductor HRC fuses and surge suppression devices for SCRs.
3. Overload and short circuit protection of MCCB.
4. Thermal overload protection of proper rating on A.C. side.
5. D.C. overload relay – For sensing the load current of magnitude beyond the charger capacity and for giving annunciation.
6. A.C. under voltage relay with timer is generally provided across A.C. main which shall operate when supply voltage reduces below certain limit (Adjustable voltage setting shall be possible).
7. D.C. under voltage relay is generally provided on load side. This operates when load voltage reduces below certain limit.
8. D.C. over voltage relay is provided for protection when load voltage increases beyond pre-determined or set value.
9. D.C. Earth fault relay is provided to detect the earth fault on DC circuits.

In case of occurrence of any fault on the battery charger equipment/DCDB panel, the visual and audible annunciation appears on the charger panel or DCDB panel. Microprocessor based LED type alarm/annunciation device are provided on each charger panel and DCDB panel comprising of required fascia windows (as per schedule of requirement) with individual fault indicating LED and with common Accept/Lamp Test/Reset Push Button, audible alarm.

12.4 Estimation of DC Loads

At the time of AC power supply failure the battery is required to supply DC power to essential circuits for vital controls as already mentioned. It is assumed that the emergency may continue for 10 hours during which period various loads are to be run for different time durations. Let us undertake a case study for estimating the battery and battery charger capacity. For this purpose let us group the substation loads as follows:

a. Up to one minute
- Closing and tripping of Circuit breakers
- Starting current of automatically started DC motors
- Solenoid valves for isolation, safety relief etc
- In rush currents of vital controls, instrumentation, communication system etc.

b. Up to 2 hours: Running loads of
- DC motors drives
- Uninterrupted Power Supply (UPS) loads, if separate battery is not Provided.
- Vital controls, instrumentation, Supervisory systems, annunciation etc.
- Communication systems
- Emergency lighting

c. Up to 10 hours
- Indicating lamps, annunciation, etc on control panels and switchgear
- Emergency lights in control room and other vital places
- Communication systems

The above load pattern is indicative only for the present case study. A particular substation may require different load pattern.

12.4.1 Estimation of Battery Capacity

a. Terminology used

C10- Capacity of battery at 10 hour discharge rate at 27°c
t- Period of discharge in hours
Ct = Capacity as percentage of C10 for the period of discharge time t.
Kt (factor) = t /(Ct/C10)

b. Typical values of the above parameters are as follows

t(hours)	1/60 (min)	1	2	4	6	8	10
Ct%	1.7	50	63.3	78.2	87.9	95	100
Ct/C10	0.017	0.5	0.633	0.782	0.879	0.95	1
Kt	0.98	2	3.16	5.115	6.826	8.421	10

c. Calculations

1. Assume current for
- One minute loads 700 Amps
- 2 hour loads 400 Amps
- 10 hour loads 40 Amps

2. Hence total load currents
- During first minute I1 = 700+400+40 = 1140A
- During next one hour, 59 minutes I2 = 400+40 = 440A
- During next 8 hours I3 = 40A

3. Factor Kt
- For 1 minute discharge K1 = 0.98
- For 2 hours discharge K2 = 3.16
- For 8 hours discharge K3 =8.421
- For 10 hours discharge K4 = 10.0
- For 1 hour 59 minutes Kt is taken as K2
- For 9 hours 59 minutes Kt is taken as K4

4. Capacity C10 for 1 minute discharge
C10 = K1 xI1 = 0.98 x 1140 = 1117 Ah

5. Capacity C10 for 2 hours discharge
C10 = K2 x I1 + K (1 hour 59 min) x (I2-I1)
= K2 x I1 + K2 (I2-I1)
= 3.16 x 1140 + 3.16 (440-1140)
= 3602 – 2212 = 1390 Ah

6. Capacity C10 for 10 hours discharge
C10 = K4 x I1 + K (9 hrs 59 m) x (I2 – I1)+k3(I3-I2)
=10 x 1140 + 10 (440- 1140) + 8.42(40 – 440)
=11400 – 7000 – 3368 = 1032Ah

7. The highest requirement is 1390Ah.With 10% margin C10 required is 1529. Select standard rating of 1500 Ah at 27°c

8. Temperature correction
The standard battery capacity is given at 27°c, the capacity gets de rated if the battery is to operate at a lower temperature. Hence to meet the same duty cycle at lower temperature the estimated battery capacity needs to be up rated.

9. Capacity variation factor per degree Celsius is 0.009. In the case study if the battery is to be operated at 20°c the required capacity will be
C10 = 1390 [1+0.009 x (27 – 20) =1390 x 1.063 = 1477Ah
With 10% margin C10 = 1.1 x 1477 = 1625Ah. Hence 1600Ah standard rating battery should be selected.

12.4.2 Estimation of Battery Charger Capacity

Estimation of capacity of FC

The FC has to supply following loads as long as AC mains supply is available:-

1. Trickle charging current of the battery
2. Continuous DC load of the plant
3. Maximum single 2 hour load. There maybe several emergency DC motors. One of them could be running due to trouble in the corresponding AC drive. Let us take the same case study as for the battery capacity estimation

DC load current of FC:-

1. Trickle charge of 1600Ah battery
2. (From manufacturers catalogue) 6.40A
3. Continuous DC load (10hour load) 40.00A
4. Largest 2 hour load (assume) 200.00A

Total DC load is 246.40A

Assume the following:

1. DC voltage of the plant 220 V DC
2. Charger efficiency 80%
3. Charger power factor 0.85

FC capacity = $(220 \times 246.4 \times 10^{-3})/(0.8 \times 0.85) = 79.71$
With 10% margin, 90 KVA Float charger should be selected.

APPENDIX-A

DEVICE NUMBERS
AND
DEFINITIONS

Device No. Definition and function .

1. **Master Element** is the initiating device, such as a control switch, voltage relay, or float switch, which serves either directly or through such permissive devices as protective and time-delay relays to place an equipment in or out of operation.

2. **Time-Delay Starting or Closing Relay** is a device that functions to give a desired amount of time delay before or after any point of operation in a switching sequence or protective relay system, except as specifically provided by device functions 48, 62, and 79.

3. **Checking or Interlocking Relay** is a relay that operates in response to the position of a number of other devices (or to a number of predetermined conditions) in equipment, to allow an operating sequence to proceed, or to stop, or to provide a check of the position of these devices or of these conditions for any purpose.

4. **Master Contactor** is a device, generally controlled by device function 1 or equivalent and the required permissive and protective devices, that serves to make and break necessary control circuits to place an equipment into operation under desired conditions and to take it out of operation under other or abnormal conditions.

5. **Stopping Device** is a control device used primarily to shut down an equipment and hold it out of operation. (This device may be manually or electrically actuated, but excludes the function of electrical lockout [see device function 86] on abnormal conditions.)

6. **Starting Circuit Breaker** is a device whose principal function is to connect a machine to its source of starting voltage.

7. **Anode Circuit Breaker** is device used in anode circuits of a power rectifier for the primary purpose of interrupting the rectifier circuit if an arc-back should occur.

8. **Control Power Disconnecting Device** is a disconnecting device, such as knife switch, circuit breaker, or pull-out fuse block, used for the purpose of respectively connecting and disconnecting the source of control power to and from the control bus or equipment.

9. **Reversing Device** is a device that is used for the purpose of reversing a machine field or for performing any other reversing functions.

10. **Unit Sequence Switch** is a switch that is used to change the sequence in which units may be placed in and out of service in multiple-unit equipments.

11. Reserved for future application.

12. **Over-speed Device** is usually a direct-connected speed switch which functions on machine overspeed.

13. **Synchronous-speed Device** is a device such as a centrifugal-speed switch, a slip-frequency relay, a voltage relay, an undercurrent relay, or any type of device that operates at approximately synchronous speed of a machine.

14. **Under-speed Device** is a device that functions when the speed of a machine falls below a predetermined value.

15. **Speed or Frequency Matching Device** is a device that functions to match and hold speed or frequency of a machine or of a system equal to, or approximately equal to, that of another machine, source, or system.

16. Reserved for future application.

17. **Shunting or Discharge Switch** is a switch that serves to open or to close a shunting circuit around any piece of apparatus (except a resistor), such as a machine field, a machine armature, a capacitor, or a reactor.

NOTE: This excludes devices that perform such shunting operations as may be necessary in the process of starting a machine by devices 6 or 42, or their equivalent, and also excludes device function 73 that serves for the switching of resistors.

18. **Accelerating or Decelerating Device** is a device that is used to close or to cause closing of circuits which are used to increase or decrease the speed of a machine.

19. **Starting-to-Running Transition Contactor** is a device that operates to initiate or cause the automatic transfer of a machine from starting to running power connection.

20. **Electrically Operated Valve** is an electrically operated, controlled, or monitored valve used in a fluid line.

21. **Distance Relay** is a relay that functions when circuit admittance, impedance, or reactance increases or decreases beyond predetermined limits.

22. **Equalizer Circuit Breaker** is a breaker that serves to control or to make and break equalizer or current-balancing connections for a machine field, or for regulating equipment, in a multiple-unit installation. temperature of a machine or other apparatus, or of any medium, when its temperature falls below, or rises above, a predetermined value.

23. **Temperature Control Device** is a device that functions to raise or lower temperature of a machine or other apparatus, or of any medium, when its temperature falls below, or rises above, a predetermined value.

NOTE: An example is a thermostat that switches on a space heater in a switchgear assembly when temperature falls to a desired value as distinguished from a device that is used to provide automatic temperature regulation between close limits and would be designated as device function 90T.

24. Reserved for future application

25. **Synchronizing or Synchronism-Check Device** is a device that operates when two a-c circuits are within the desired limits of frequency, phase angle, or voltage to permit or to cause the paralleling of these two circuits.

26. **Apparatus Thermal Device** is a device that functions when temperature of the shunt field winding of a machine, or that of a load limiting or load shifting resistor or of a liquid or other medium, exceeds a predetermined value: or if temperature of the protected apparatus, such as a power rectifier, or of any medium, decreases below a predetermined value.

27. **Undervoltage Relay** is a relay that functions on a given value of undervoltage.

28. **Flame Detector** is a device that monitors the presence of pilot or main flame in such apparatus as a gas turbine or a steam boiler.

29. **Isolating Contactor** is a device that is used expressly for disconnecting one circuit from another for purposes of emergency operation, maintenance, or test.

30. **Annunciator Relay** is a non automatically reset device that gives a number of separate visual indications upon functioning of protective devices, and which may also be arranged to perform a lockout function.

31. **Separate Excitation Device** is a device that connects a circuit, such as shunt field of a synchronous converter, to a source of separate excitation during starting sequence, or one that energizes the excitation and ignition circuits of a power rectifier.

32. **Directional Power Relay** is a device that functions on a desired value of power flow in a given direction or upon reverse power resulting from arc-back in the anode or cathode circuits of a power rectifier.

33. **Position Switch** is a switch that makes or breaks contact when the main device or piece of apparatus which has no device function number reaches a given position.

34. **Master Sequence Device** is a device such as a motor-operated multi-contact switch, or equivalent, or a programming device, such as a computer, that establishes or determines the operating sequence of major devices in an equipment during starting and stopping or during other sequential switching operations.

35. **Brush-operating or Slip-ring Short-circuiting Device** is a device for raising, lowering, or shifting brushes of a machine, or for short- circuiting its slip rings, or for engaging or disengaging contacts of a mechanical rectifier.

36. **Polarity or Polarizing Voltage Device** is a device that operates, or permits operation of, another device on a predetermined polarity only, or verifies presence of a polarizing voltage in an equipment.

37. **Undercurrent or Underpower Relay** is a relay that functions when current or power flow decreases below a predetermined value.

38. **Bearing Protective Device** is a device that functions on excessive bearing temperature, or on other abnormal mechanical conditions associated with the bearing, such as undue wear, which may eventually result in excessive bearing temperature or failure.

39. **Mechanical Condition Monitor** is a device that functions upon the occurrence of an abnormal mechanical condition (except that associated with bearings as covered under device function 38), such as excessive vibration, eccentricity, expansion, shock, tilting, or seal failure.

40. **Field Relay** is a relay that functions on a given or abnormally Iow value or failure of machine field current, or on excessive value of the reactive component of armature current in an a-c machine indicating abnormally Iow field excitation.

41. **Field Circuit Breaker** is a device that functions to apply or remove field excitation of a machine.

42. **Running Circuit Breaker** is a device whose principal function is to connect a machine to its source of running or operating voltage. This function may also be used for a device, such as a contactor, that is used in series with a circuit breaker or other fault protecting means, primarily for frequent opening and closing of the circuit.

43. **Manual Transfer or Selector Device** is a manually operated device that transfers control circuits in order to modify the plan of operation of switching equipment or of some of the devices.

44. **Unit Sequence Starting Relay** is a relay that functions to start the next available unit in a multiple-unit equipment upon failure or non availability of the normally preceding unit.

45. **Atmospheric Condition Monitor** is a device that functions upon occurrence of an abnormal atmospheric condition, such as damaging fumes, explosive mixtures, smoke, or fire.

46. **Reverse-phase or Phase-balance Current Relay** is a relay that functions when the polyphase currents are of reverse-phase sequence, or when polyphase currents are unbalanced or contain negative phase-sequence components above a given amount.

47. **Phase-Sequence Voltage Relay** is a relay that functions upon a predetermined value of polyphase voltage in the desired phase sequence.

48. **Incomplete Sequence Relay** is a relay that generally returns equipment to normal, or off, position and locks it out if normal starting, operating, or stopping sequence is not properly completed within a predetermined time. If the device is used for alarm purposes only, it should preferably be designated as 48A (alarm)

49. **Machine or Transformer Thermal Relay** is a relay that functions when temperature of a machine armature or other load-carrying winding or element of a machine or temperature of a power rectifier or power transformer (including a power rectifier transformer) exceeds a predetermined value.

50. **Instantaneous Overcurrent or Rate-of-rise Relay** is a relay that functions instantaneously on an excessive value of current or on an excessive rate of current rise, thus indicating a fault in apparatus or circuit being protected.

51. **A-C Time Overcurrent Relay** is a relay with either a definite or inverse time characteristic that functions when current in an ac-circuit exceeds a predetermined value.

52. **A-C Circuit Breaker** is a device that is used to close and interrupt an a-c power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.

53. **Exciter or D-C Generator Relay** is a relay that forces the d-c machine field excitation to build up during the starting or which functions when the machine voltage has built up to a given value.

54. Reserved for future application.

55. **Power Factor Relay** is a relay that operates when the power factor in an a-c circuit rises above or falls below a predetermined value.

56. **Field Application Relay** is a relay that automatically controls application of field excitation to an a-c motor at some predetermined point in the slip cycle.

57. **Short-circuiting or Grounding Device** is a primary circuit switching device that functions to short-circuit or to ground a circuit in response to automatic or manual means.

58. **Rectification Failure Relay** is a device that functions if one or more anodes of a power rectifier fail to fire, or to detect an arc-back, or on failure of a diode to conduct or block properly.

59. **Overvoltage Relay** is a relay that functions on a given value of overvoltage.

60. **Voltage or Current Balance Relay** is a relay that operates on a given difference in voltage, or current input or output, of two circuits.

61. Reserved for future application.

62. **Time-delay Stopping or Opening Relay** is a time-delay relay that serves in conjunction with the device that initiates shutdown, stopping, or opening operation in an automatic sequence or protective relay system.

63. **Pressure Switch** is a switch which operates on given values, or on a given rate of change, of pressure.

64. **Ground Protective Relay** is a relay that functions on failure of insulation of a machine, transformer, or of other apparatus to ground, or on flashover of a d-c machine to ground.

NOTE: This function is assigned only to a relay that detects flow of current from the frame of a machine or enclosing case or structure of a piece of apparatus to ground, or detects a ground on a normally ungrounded winding or circuit, it is not applied to a device connected in the secondary circuit of a current transformer, or in the secondary neutral of current transformers, connected in the power circuit of a normally grounded system.

65. **Governor** is the assembly of fluid, electrical, or mechanical control equipment used for regulating flow of water, steam, or other medium to the prime mover for such purposes as starting, holding speed or load, or stopping.

66. **Notching or Jogging Device** is a device that functions to allow only a specified number of operations of a given device, or equipment, or a specified number of successive operations within a given time of each other. It is also a device that functions to energize a circuit periodically or for fractions of specified time intervals, or that is used to permit intermittent acceleration or jogging of a machine at Iow speeds for mechanical positioning.

67. **A-C Directional Overcurrent Relay** is a relay that functions on a desired value of a-c overcurrent flowing in a predetermined direction.

68. **Blocking Relay** is a relay that initiates a pilot signal for blocking of tripping on external faults in a transmission line or in other apparatus under predetermined conditions, or cooperates with other devices to block tripping or to block reclosing on an out-of-step condition or on power swings.

69. **Permissive Control Device** is generally a two-position, manually operated switch that, in one position, permits closing of a circuit breaker, or placing of an equipment into operation, and in the other position prevents the circuit breaker or equipment from being operated.

70. **Rheostat** is variable resistance device used in an electric circuit, which is electrically operated or has other electrical accessories, such as auxiliary, position, or limit switches.

71. **Level Switch** is a switch which operates on given values or on a given rate of change, of level.

72. **D-C Circuit Breaker** is a circuit breaker that is used to close and interrupt a d-c power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.

73. **Load-resistor Contactor** is a contactor that is used to shunt or insert a step of loading limiting, shifting, or indicating resistance in a power circuit, or to switch a space heater in circuit, or to switch a light or regenerative load resistor of a power rectifier or other machine in and out of circuit.

74. **Alarm Relay** is a relay other than an annunciator, as covered under device function 30, that is used to operate, or to operate in connection with, a visual or audible alarm.

75. **Position Changing Mechanism** is a mechanism that is used for moving a main device from one position to another in an equipment: as for example, shifting a removable circuit breaker unit to and from the connected, disconnected, and test positions.

76. **D-C Overcurrent Relay** is a relay that functions when current in a d-c circuit exceeds a given value.

77. **Pulse Transmitter** is used to generate and transmit pulses over a telemetering or pilot-wire circuit to the remote indicating or receiving device.

78. **Phase-angle Measuring or Out-of-step Protective Relay** is a relay that functions at a predetermined phase angle between two voltages or between two currents or between voltage and current.

79. **A-C Reclosing Relay** is a relay that controls automatic reclosing and locking out of an a-c circuit interrupter.

80. **Flow Switch** is a switch which operates on given values, or on a given rate of change of flow.

81. **Frequency Relay** is a relay that functions on a predetermined value of frequency (either under or over or on normal system frequency) or rate of change of frequency.

82. **D-C Reclosing Relay** is a relay that controls automatic closing and reclosing of a d-c circuit interrupter, generally in response to load circuit conditions.

83. **Automatic Selective Control or Transfer Relay** is a relay that operates to select automatically between certain sources or conditions in an equipment, or perform a transfer operation automatically.

84. **Operating Mechanism** is the complete electrical mechanism or servomechanism, including operating motor, solenoids, position switches, etc., for a tap changer induction regulator. or any similar piece of apparatus which otherwise has no device function number.

85. **Carrier or Pilot-wire Receiver Relay** is a relay that is operated or restrained by a signal used in connection with carrier-current or d-c pilot-wire fault directional relaying.

86. **Lock-out Relay** is an electrically operated hand, or electrically, reset relay or device that functions to shut down or hold an equipment out of service, or both, upon occurrence of abnormal conditions.

87. **Differential Protective Relay** is a protective relay that functions on a percentage or phase angle or other quantitative difference of two currents or of some other electrical quantities.

88. **Auxiliary Motor or Motor Generator** is one used for operating auxiliary equipment, such as pumps, blowers, exciters, rotating magnetic amplifiers, etc.

89. **Line Switch** is a switch used as a disconnecting, load-interrupter, or isolating switch in an a-c or d-c power circuit, when this device is electrically operated or has electrical accessories, such as an auxiliary switch, magnetic lock, etc.

90. **Regulating Device** is a device that functions to regulate a quantity, or quantities, such as voltage, current, power, speed, frequency, temperature, and load, at a certain value or between certain (generally close) limits for machines, tie lines or other apparatus.

91. **Voltage Directional Relay** is a relay that operates when voltage across an open circuit breaker or contactor exceeds a given value in a given direction.

92. **Voltage and Power Directional Relay** is a relay that permits or causes connection of two circuits when the voltage difference between them exceeds a given value in a predetermined direction and causes these two circuits to be disconnected from each other when the power flowing between them exceeds a given value in the opposite direction.

93. **Field-changing Contactor** is a contactor that functions to increase or decrease, in one step, the value of field excitation on a machine.

94. **Tripping or Trip-free Relay** is a relay that functions to trip a circuit breaker, contactor, or equipment, or to permit immediate tripping by other device, or to prevent immediate reclosure of a circuit interrupter if it should open automatically even though its closing circuit is maintained closed.

Numbers from 95 to 99 should be assigned only for those functions in specific cases where none of the assigned standard device function numbers are applicable. Numbers which are "reserved for future application" should not be used.

APPENDIX-B

GLOSSARY
OF
RELAY TERMS

ACTUATOR. The parts of a relay that convert electrical energy into mechanical work.

ADJUSTMENT. The modification of any or all of the elements of tension shape or position of relay parts (to affect one or more of the operating characteristics or to meet mechanical requirements), for example, adjustments of armature gap, restoring spring force, contact gap. or contact force.

AMPERE-TURNS. The product of the number of turns in an electromagnetic coil winding and the current in amperes passing through the winding. With AC the RMS current value is generally used in the product of the current and turns and is referred to as RMS ampere-turns.

ARMATURE. The moving magnetic member of an electromagnetic relay structure.

BACKSTOP, ARMATURE. The part of the relay which limits the movement of the armature away form the pole face or core. In some relays a normally closed contact may serve as the backstop.

BIAS, MAGNETIC. A steady magnetic field (permanent magnet) applied to the magnetic circuit of a relay to aid or impede operation of the armature.

BOBBIN. A structure upon which a coil is wound.

BOUNCE, CONTACT. Internally caused intermittent and undesired opening of closed contacts or closing of open contacts of a relay, caused by one or more of the following:

1. Impingement of mating contacts.
2. Impact of the armature against the coil core on pickup or against the backstop on dropout.
3. From momentary hesitation, or reversal of the armature motion during the pickup or dropout stroke.

BREAK. The opening of closed contacts to interrupt an electric circuit.

BRIDGING. (1) Normal bridging: the normal make-before-break action of a make-break or "D" contact combination. In a stepping switch the coming together momentarily of two adjacent contacts, by a wiper shaped for that purpose, in the process of moving from one contact to the next. (2) Abnormal bridging: the undesired closing of the open contacts caused by metallic bridge or protrusion developed by arcing.

CHANGE OVER. A monostable relay changes over when it picks up or drops out. A bistable relay changes over when it passes from one condition to the other condition. (IEC)

CHANGE-OVER CONTACT: 2-WAY CONTACT (deprecated). A combination of two contact circuits including three contact members, one of them being common to the two contact circuits. When one of these contact circuits is open, the other is closed and vice versa. (IEC) (See double throw contact.)

CHATTER, ARMATURE. The undesired vibration of the armature due to inadequate ac performance or external shock and vibration.

CHATTER, CONTACT. Externally caused undesired vibration of mating contacts during which there may or may not be actual physical contact opening. If there is no actual opening but only a change in resistance, it is referred to as dynamic resistance.

COIL. An assembly consisting of one or more windings, usually wound over an insulated iron core or on a bobbin or spool, or self-supporting, with terminals, and other required parts such as a sleeve or slug.

COMB. An insulating member used to position a group of contact springs, as on wire spring relays.

CONTACT. (1) The portion of current-carrying members at which electric circuits are opened or closed.(2) The current carrying part of a relay that engages or disengages to open or close electric circuits.(3) Used to denote a combination or set. ("Contacts" also used).

CONTACT, ARMATURE. (1) A contact mounted directly on the armature. (2) Sometimes used for a movable contact.

CONTACT ASSEMBLY. An assembly of contact members, with their insulation, which close or open their contact circuit by their relative movement. (IEC)

CONTACT MEMBER. A conductive part of a contact assembly which is electrically isolated from other such parts when the contact circuit is open. (IEC)

CONTACT TIP. That part of a contact member at which the contact circuit closes or opens. (IEC)

CONTACT GAP. The gap between the contact tips (point), under specified conditions, when the contact circuit is open. (IEC)

CONTACT FORCE. The force which two contact tips (points) exert against each other in the closed position under specified conditions. (IEC)

CONTACT FOLLOW. The further specified movement of the contact tips (points) when making and after they have just touched and while they are travelling in the same direction as that of the moving contact member. (IEC)

CONTACT, BREAK-BEFORE-MAKE. A contact combination in which one contact opens its connection to another contact and then closes its connection to a third contact.

CONTACT, BRIDGING. A contact combination designed to close one contact before opening another contact (usually applied to stepping switches). (For relays, see contact, continuity transfer.)

CONTACT, NORMALLY CLOSED. A contact combination which is closed when the armature is in its unoperated position. Contact, normally open. A contact combination that is open when the armature is in its unoperated position.

CONTACT, STATIONARY. A member of a combination that is not moved directly by the actuating system.

CONTACTOR. See relay, power.

CURRENT, RATED COIL. The steady -state coil current on which the relay is intended to operate for the prescribed duty cycle.

CURRENT, RATED CONTACT. The current which the contacts are designed to handle for their rated life. (See also, rating, contact.)

DROPOUT A monostable relay drops out when it changes from an energized condition to the de-energized condition. (IEC)

DROPOUT VALUE As the current or voltage on an operated relay is decreased, the value at which all contacts restore to their unoperated positions.

ENERGIZATION. The application of power to a coil winding of a relay. With respect to an operating coil winding, use of the word commonly assumes enough power to operate the relay fully, unless otherwise stated.

FRAME. The main supporting portion of a relay, which may include parts of the magnetic structure.

FREQUENCY, OPERATING. The rate ac frequency of the supply voltage at which the relay is designed to operate.

GAP, ARMATURE. The distance between armature and pole face.

GAP, CONTACT. The distance between a pair of mating relay contacts when the contacts are open.

HOUSING. An enclosure or cover for one or more relays, with or without accessories, usually providing access to the terminals.

HUM. The sound caused by a mechanical vibration resulting from alternation current flowing in the coil, or in some cases by unfiltered rectified current.

INPUT. That portion of the relay to which a control signal is applied in order to achieve the switching function in a solid state or hybrid relay.

INSULATION RESISTANCE. The DC resistance between input and output of solid state relays and across contact and between contacts and coil for electromechanical and reed relays.

MAKE. The closure of the open contacts to complete an electric circuit.

MECHANICAL SHOCK, NON-OPERATING. That mechanical shock level (amplitude, duration and wave shape) to which the relay may be subjected without permanent electrical or mechanical damage.

MECHANICAL SHOCK, OPERATING. That mechanical shock level (amplitude, duration and wave shape) to which the relay may be subjected without electrical malfunction or mechanical damage.

NORMAL POSITION. The de-energized position of contacts, open or closed, due to spring tension, gravity, or magnetic polarity. The term is also used for the home position of a stepping switch.

OPERATE. A relay operates when sequentially it starts, it passes from an initial condition towards the prescribed operated condition, and it switches. (IEC)

OPERATING CHARACTERISTICS. Pickup, nonpickup, hold and dropout, voltage or current

PICKUP VALUE. As the current or voltage on an unoperated relay is increased, the value at which all contacts function.

PICKUP A monostable relay picks up when it changes from the unenergized condition to an energized condition. (IEC)

POLE, DOUBLE. A term applied to a contact arrangement to denote that it includes two separate contact combinations, that is, two single-pole contact assemblies.

POLE PIECE. The end of an electromagnet, sometimes separable from the main section, and usually shaped so as to distribute the magnetic field in a pattern best suited to the application.

POLE, SINGLE. A term applied to a contact arrangement to denote that all contacts in the arrangement connect in one position or another to a common contact.

RATING CONTACT. The electrical load handling capability of relay contacts under specified conditions and for prescribed number of operations.

RATING, SHORT TIME. The value of the current or voltage that the relay can withstand for specified short time intervals. (For ac circuits, the rms total value, including the dc component, should be used.) The rating recognizes the limitations imposed by both thermal and electromagnetic effects.

RELAY. An electrically controlled device that opens and closes electrical contacts to effect the operation of other devices in the same or another electrical circuit.

RELAY, ALL-OR-NOTHING. An electrical relay which is intended to be energized by a quantity, whose value is either:

1. higher than that at which it picks up, or
2. lower than that at which it drops out. (IEC)

Note - The adjective "all-or-nothing" can be deleted when no ambiguity may occur.

RELAY, ALTERNATING CURRENT. A relay designed for operation from an alternating current source.

RELAY, ARMATURE. A relay operated by an electromagnet, which, when energized, causes an armature to be attracted to a fixed pole, or poles, for the purpose of operating contacts.

RELAY, AUXILIARY. A relay that operates to assist another relay or device in the performance of function.

RELAY, CONTINUOUS-DUTY. A relay that may be energized with rated input power and carry rated load indefinitely without exceeding specified limitations.

RELAY, CURRENT-BALANCE. A relay that operates when the magnitude of one current exceeds the magnitude of another current by a predetermined amount.

RELAY, CURRENT-SENSING. A relay that functions at a predetermined value of current; an overcurrent or an undercurrent relay, or a combination of both.

RELAY, DIFFERENTIAL. A relay with multiple windings that functions when the current difference between the windings reaches a predetermined value.

RELAY, DIRECT CURRENT. A relay designed for operation from a direct current source.

RELAY, ELECTRICAL. A device designed to produce sudden, predetermined changes in one or more electrical output circuits, when certain conditions are fulfilled in the electrical input circuits controlling the device. (IEC)

Note 1 - The term relay shall be restricted to a relay unit having a single relaying function between its input circuits and its output circuits.

Note 2 - The term relay includes all the components which are necessary for its specified operation.

Note 3 - The adjective "electrical" can be deleted when no ambiguity may occur.

RELAY,ELECTROMAGNETIC. A relay whose operation depends upon the electromagnetic effects of current flowing in an energizing winding.

RELAY, ELECTROMAGNETIC TIME DELAY. A relay in which the actuation of the contacts is delayed by the inductive effect of a conducting sleeve or slug (usually nonmagnetic) or a shortcircuited winding over the core.

RELAY, ELECTROMECHANICAL. An electric relay in which the designed response is developed by the relative movement of mechanical elements under the action of a current in the input circuits. (IEC)

RELAY,ENCLOSED.

1. HERMETICALLY SEALED. A relay contained within an enclosure that is sealed by fusion or other comparable means to ensure a low rate of gas leakage. (Generally metal-to-metal or metal-to-glass sealing is employed.)
2. ENCAPSULATED. A relay embedded in a suitable potting compound.
3. SEALED. A relay that has both coil and contacts enclosed in a relatively airtight cover
4. COVERED. A Relay contained in an unsealed housing.

Note-The coil and contacts assemblies may be separately enclosed and isolated from each other by various combinations of the above enclosure.

RELAY, LATCHING. A relay that maintains its contacts in the last position assumed without the need of maintaining coil energization.

1. MAGNETIC LATCHING. An relay that remains operated, held by either remnant magnetism in the structure or by the influence of a permanent magnet, until reset. (See also relay, polarized bistable.)
2. MECHANICAL LATCHING. A relay in which the armature or contacts may be latched mechanically in the operated or unoperated position until reset manually or electrically.

RELAY, MANUAL REST. A relay that may be restored manually to its unoperated position.

RELAY, MEASURING. An electrical relay intended to switch when its characteristic quantity, under specified conditions and with a specified accuracy, attains its operating value. (IEC)

RELAY, MERCURY CONTACT. (1) Mercury wetted contact - a form of reed relay in which the reeds and contacts are glass enclosed and are wetted by a film of mercury obtained by capillary action from a mercury pool in the base of a glass capsule vertically mounted. (2) Mercury contact - a relay mechanism in which mercury establishes contact between electrodes in a sealed capsule.

RELAY, MONOSTABLE. An electrical relay which, having responded to an input energizing quantity (or characteristic quantity) and having changed its condition, returns to its previous condition when the quantity is removed. (IEC)

RELAY, NEUTRAL. A relay whose operation is independent of the direction of the coil current, in contrast to a polarized relay.

RELAY, OVERCURRENT. A relay hat operates when the current through its coil reaches or exceeds a predetermined value. (See also relay, current sensing.)

RELAY, OVERVOLTAGE. A relay that is specifically designed to operate when its coil voltage reaches or exceeds a predetermined value.

RELAY, PLUNGER. A relay whose contacts are operated by a movable core or plunger through solenoid action.

RELAY, POLARIZED. A relay whose operation is dependent upon the polarity of the energizing current.

BISTABLE. A bistable polarized relay is a 2-position relay that will remain in its last operated position keeping the operated contacts closed after the operating winding is de-energized.

RELAY, SENSITIVE. A relay that operates on comparatively low input power.

RELAY, SOLID STATE. A relay whose functions are achieved by means of electronic components and without the use of moving parts.

RELAY, SPECIFIED TIME SPECIFIED-TIME RELAY. An electrical relay such that one or more of the times which characterize it (e.g., operating time) are subject to specified requirements, in particular concerning accuracy. (IEC)

RELAY, TIME DELAY. A relay in which operation or release is delayed internally (coil slugs or sleeves) or by mechanical (clock-work, bellows, dashpot, etc.) means or by an accompanying solid state timing circuit.

RELAY, UNDERCURRENT. A relay specifically designed to function when its energizing current falls below a predetermined value. (See also relay, current sensing.)

RELAY, UNDERVOLTAGE. A relay specifically designed to function when its energizing voltage falls below a predetermined value

RESET. The return of contacts or a mechanism to the normal state.

RESET, AUTOMATIC**.** A qualifying term applied to (1) a stepping relay that returns to its home position either when it reaches a predetermined contact position or when a pulsing circuit fails to energize the driving coil within a given time. May either pulse forward or be spring reset to the home position. (2) An overload relay that restores the circuit as soon as an over-current situation is corrected.

RESET, ELECTRICAL. A qualifying term applied to a relay to indicate that it may be reset electrically after an operation.

RESET, MANUAL. A qualifying term applied to a relay to indicate that it may be reset manually after operation.

SENSITIVITY. Specified pickup expressed in watts.

SEQUENCE, CONTACT. The order in which contacts open and close in relation to other contacts and armature motion.

SHIELD, MAGNETIC. A ferromagnetic structure used to reduce magnetic coupling.

SPRING, CONTACT. A current-carrying spring to which a contact is fastened or which in itself serves as a contact.

SPRING, DAMPER. An auxiliary spring added to prevent unwanted movement of some relay member in the presence of vibration or shock.

TIME, OPERATE. (1) The time interval from coil energization to the functioning of the last contact to function. Where not otherwise stated, the functioning time of the contact in question is taken as its initial actuation time (that is, it does not include contact bounce time). (2) For a solid state or hybrid relay in a nonoperated state, the time from the application of the pickup voltage to the change of state of the output.

TIME, RELEASE. (1) The time interval from coil de-energization to the functioing of the last contact to function. Where not other wise stated, the functioning time of the contact in question is taken as its initial actuation time (that does not include contact bounce time). (2) For a solid state or hybrid relay in an operated state, the time from the application o f the dropout voltage to the change of the state output.

TIME, SEATING. The time interval from coil energization to the seating of the armature.

TIME, TRANSFER. The time interval between opening the closed contact and closing the open contact of a break-before-make contact combination.

TRAVEL, ARMATURE. The distance traveled during operation by a specified point on the armature.

UNENERGIZED. CONDITIION. The specified condition of an unenergized monostable relay. (IEC)

VIBRATION, NONOPERATING. That vibration level and frequency span to which the relay may be subjected without permanent electrical or mechanical damage.

VIBRATION, OPERATING. That vibration level and frequency span to which the relay may be subjected without electrical malfunction or mechanical damage.

VOLTAGE, MAXIMUM OFF STATE, V_{Dmax} (RMS). The maximum effective steady state voltage that the output is capable of withstanding when in the off state.

VOLTAGE, MAXIMUM RATE OF RISE OF OFF STATE, dV/dt. The maximum rate of rise of the off state voltage which the output can withstand without false operation.

VOLTAGE, MINIMUM OFF STATE, V_{Dmin} (RMS). The minimum effective voltage which the relay will switch.

VOLTAGE, NOMINAL. A single value of the source voltage (or a narrow voltage range) intended to be applied to the coil or input. (See also voltage, rated coil).

VOLTAGE, NOMINAL OFF STATE, V_D (RMS). The effective steady state voltage normally applied when in the off state.

VOLTAGE, NONREPETITIVE PEAK, V_{DSM} The maximum off state voltage that the output terminals are capable of withstanding without breakover or damage.

VOLTAGE,ON STATE. The output terminal wave form at a rated current consists of repetitive half cycles (+ and -) of distinctive voltage drops. Each voltage state is necessary for load current conduction and may be specified for specific applications.

MAXIMUM RMS ON STATE VOLTAGE, V_T(RMS). Maximum RMS voltage drop across the relay output at maximum load current IT_{RMS}

INSTANTANEOUS ON STATE VOLTAGE, V_T The instantaneous voltage across the output when in the "on" condition.

PEAK ON STATE VOLTAGE, V_{TM} The maximum value of V_T excluding $\pm 20^o$ of zero crossing of the voltage wave form.

MINIMUM POWER FACTOR LOAD, PF_{MIN} The minimum power factor load the relay will switch and still meet all of its electrical specifications.

CRITICAL RATE OF RISE OF COMMUTATION VOLTAGE, dV/dt. The minimum value of the rate of applied voltage which will cause switching from the off state to the on state.

VOLTAGE, RATED COIL. The coil voltage on which the relay is intended to operate for the prescribed duty cycle.

VOLTAGE, REVERSE POLARITY. The maximum allowable reverse voltage which may be applied to the input of a solid state relay without permanent damage.

WINDING. An electrically continuous length of insulated wire wound on a bobbin, spool, or form.

WINDING, BIAS. An auxiliary winding used to produce an electromagnetic bias.

WINDING, BIFILAR. Two windings with the wire if each winding alongside the other, matching turn for turn; may be either inductive.

WINDING, NONINDUCTIVE. A type of winding in which the magnetic fields produced by two parts of the winding cancel each other and provide noninductive resistance.

WIPE,CONTACT. The sliding or tangential motion between two mating contact surfaces as they open or close.

APPENDIX- C

CABLES

C-1 Construction of Cables

Figure - 1 shows the general construction of a 3-conductor cable. The various parts are:

1. **Cores or Conductors:** A cable may have one or more than one core (conductor) depending upon the type of service for which it is intended. For instance, the 3-phase service. The conductors are made of tinned copper or aluminum and are usually stranded in order to provide flexibility to the cable.

2. **Insulation:** Each core or conductor is provided with a suitable thickness of insulation, the thickness of layer depending upon the voltage to be withstood by the cable. The commonly used materials for insulation are impregnated paper, varnished cambric or rubber mineral compound.

3. **Metallic sheath:** In order to protect the cable from moisture, gases or other damaging liquids (acids or alkalies) in the soil and atmosphere, a metallic sheath of lead or aluminium is provided over the insulation as shown in Figure -1.

4. **Bedding:** Over the metallic sheath is applied a layer of bedding which consists of one or two layers of galvanized steel wire or steel tape. Its purpose is to protect the cable from mechanical injury due to armouring.

5. **Armouring:** Over the bedding, armouring is provided which consists of one or two layers of galvanized steel wire or steel tape. Its purpose is to protect the cable from mechanical injury while laying it and during the course of handing. Armouring may not be done in the case of some cables.

6. **Serving:** In order to protect armouring from atmospheric conditions, a layer of fibrous material (like jute) similar to bedding is provided over the armouring. This is known as serving.

It may not be out of place to mention here that bedding, armoring and serving are only applied to the cables for the protection of conductor insulation and to protect the metallic sheath from mechanical injury.

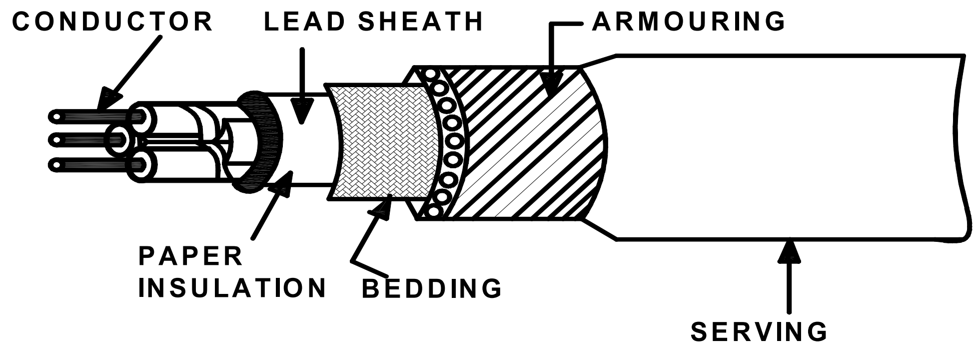


Figure-1 - Constructional Details of Cables

C-2 Insulating Materials for Cables

The satisfactory operation of a cable depends to a great extent upon the characteristics of insulation used. Therefore, the proper choice of insulating material for cables is of considerable importance. In general, the insulating materials used in cables should have the following properties:

1. High insulation resistance to avoid leakage current.
2. High dielectric strength to avoid electrical breakdown of the cable.
3. High mechanical strength to withstand the mechanical handling of cables.
4. Non hygroscopic i.e. it should not absorb moisture from air or soil. The moisture tends to decrease the insulation resistance and hastens the breakdown of the cable. In case the insulating material is hygroscopic, it must be enclosed in a waterproof covering like lead sheath.
5. Non inflammable.
6. Low cost so as to make the underground system a viable proposition.
7. Unaffected by acids and alkalies to avoid any chemical action.

No one insulating material possesses all the above mentioned properties. Therefore, the type of insulating material to be used depends upon the purpose for which the cable is required and the quality of insulation to be aimed at. The principal insulating materials used in cables are rubber, vulcanized India rubber, impregnated paper, varnished cambric and polyvinyl chloride.

1. **Rubber:** Rubber may be obtained from milky sap of tropical trees or it may be produced from oil products. It has relative permittivity varying between 2 and 3, dielectric strength is about 30kV/mm and resistivity of insulation is 10 ohms cm. Although pure rubber has reasonably high insulating properties, it suffers from some major drawbacks viz., readily absorbs moisture, maximum safe temperature is low (about 38 C), soft and liable to damage due to rough handling and ages when exposed to light. Therefore, pure rubber cannot be used as an insulating material.

2. **Vulcanized India Rubber (V.I.R):** It is prepared by mixing pure rubber with mineral matter such as zinc oxide, red lead etc. and 3 to 5% of sulphur. The compound so

formed is rolled into thin sheets and cut into strips. The rubber compound is then applied to the conductor and is heated to a temperature of about 150 C . The whole process is called vulcanization and the product obtained is known as vulcanized India rubber. Vulcanized India rubber has greater mechanical strength, durability and wear resistant property than pure rubber. Its main drawback is that sulphur reacts very quickly with copper and for this reason, cables using VIR insulation have tinned copper conductor. The VIR insulation is generally used for low and moderate voltage cables.

3. **Impregnated paper:** It consists of chemically pulped paper made from wood chippings and impregnated with some compound such as paraffinic or napthenic material. This type of insulation has almost superseded the rubber insulation. This is because it has the advantages of low cost, low capacitance, high dielectric strength and high insulation resistance. The only disadvantage is that paper is hygroscopic and even if it is impregnated with suitable compound, it absorbs moisture and thus lowers the insulation resistance of the cable. For this reason, paper insulated cables are always provided with some protective covering and are never left unsealed. If it is required to be left unused on the site during laying, its ends are temporarily covered with wax or tar. Since the paper insulated cables have the tendency to absorb moisture, they are used where the cable route has a few joints. For instance, they can be profitably used for distribution at low voltages in congested areas where the joints are generally provided only at the terminal apparatus. However, for smaller installations, where the lengths are small and joints are required at a number of places VIR cables will be cheaper and durable than paper insulated cables.

4. **Varnished cambric:** It is a cotton cloth impregnated and coated with varnish. This type of insulation is also known as empire tape. The cambric is lapped on to the conductor in the form of a tape and its surfaces are coated with petroleum jelly compound to allow for the sliding of one turn over another as the cable is bent. As the varnished cambric is hygroscopic, therefore, such cables are always provided with metallic sheath. It dielectric strength is bout 4 kV/mm and permittivity is 2.5 to 3.8.

5. **Polyvinyl chloride (PVC):** This insulating material is a synthetic compound. It is obtained from polymerization of acetylene and is in the form of white powder. For obtaining this material as cable insulation, it is compounded with certain materials known as plasticizers which are liquids with high boiling point. The plasticizers form a gell and render the material plastic over the desired range of temperature. Polyvinyl chloride has high insulation resistance, good dielectric strength and mechanical toughness over a wide range of temperature. It is inert to oxygen and almost inert to many alkalies and acids. Therefore, this type of insulation is preferred over VIR n extreme environmental conditions such as in cement factory or chemical factory. As the mechanical properties (i.e. elasticity etc.) of PVC are not so good as those of rubber, therefore, PVC insulated cables are generally used for low and medium domestic lights and power installations.

C-3 Classification of Cables

Cables for underground service may be classified in two ways according to (i) the type of insulating material used in their manufacture (ii) the voltage for which they are manufactured. However, the latter method of classification is generally preferred, according to which cables can be divided into the following groups:

1. Low tension (L.T.) cables – up to 1000 V
2. High tension (H.T.) cables – up to 11,000V
3. Super-tension (S.T.) cables – from 22 kV to 33 kV
4. Extra high tension (E.H.T.) cables – from 33 kV to 66 kV
5. Extra super voltage cables – beyond 132 kV

A cable may have one or more than one core depending upon the type of service for which it is intended. It may be

1. Single core
2. Two core
3. Three core
4. Four core etc.

For a 3 phase service, either 3 single core cables or three core cable can be used depending upon the operating voltage and load demand.

C-3.1 Single Core cable

Figure-2 shows the constructional details or a single core low tension cable. The cable has ordinary construction because the stresses developed in the cable for low voltages (Up to 6600 V) are generally small.

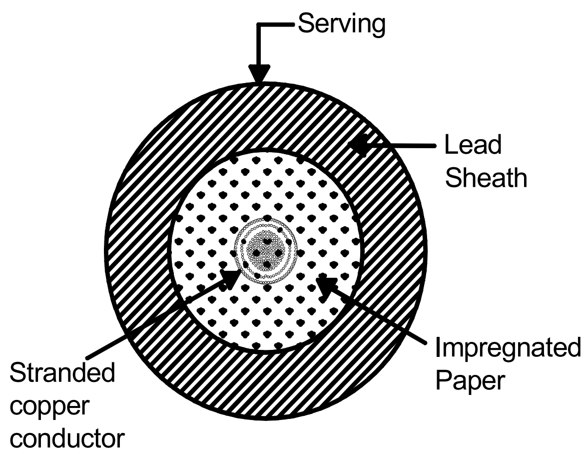


Figure-2 – Constructional Details of Single Core Cable

It consists of one circular core of tinned stranded copper (or aluminium) insulated by layers of impregnated paper. The insulation is surrounded by a lead sheath which prevents the entry of moisture into the inner parts. In order to protect the lead sheath from corrosion, an overall serving compounded fibrous material (jute etc.) is provided. Single core cables are not usually armoured in order to avoid excessive sheath losses. The principal advantages of single core cables are simple construction and availability of larger copper section.

C-3.2 Cables for 3-Phase Service

In practice, underground cables are generally required to deliver 3-Phase power. For the purpose either three core cable or three single core cables may be used. For voltages upto 66 kV, 3 core cable (i.e. multi core construction) is preferred due to economic reasons. However, for voltages beyond 66 kV, 3 core cables become too large and unwieldy and therefore, single core cables are used. The following types of cables are generally used for 3 phase service.

1. Belted cables – up to 11 kV
2. Screened cables – from 22 kV to 66 kV
3. Pressure cables – beyond 66 kV

1. Belted cables

These cables are used for voltages upto 11 kV but in extraordinary cases, their use may be extended up to 22 kV. Figure-3 shows the constructional details of a 3 core belted cable. The cores are insulated from each other by layers of impregnated paper. Another layer of impregnated paper tape, called paper belt is wound round the grouped insulted cores. The gap between the insulted cores is filled with fibrous insulating material (jute etc.) so as to give circular cross section to the cable. The cores are generally stranded and may be of non circular shape to make better use of available space. The belt is covered with lead sheath to protect the cable against ingress of moisture and mechanical injury. The lead sheath is covered with one or more layers of armouring with an outer serving.

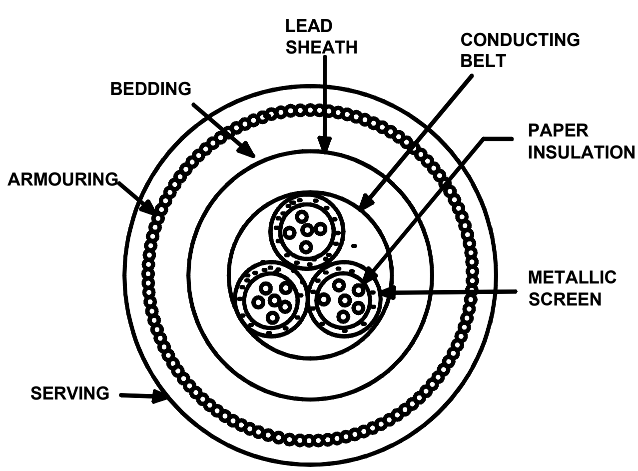


Figure-3 - Construction Details of Belted Cables

The belted type construction is suitable only for low and medium voltages as the electrostatic stresses developed in the cables for these voltages are more or less radial i.e. across the insulation. However, for high voltages (beyond 22 kV), the tangential stresses also become important. These stresses act along the layers of paper insulation. As the insulation resistance of paper is quite small along the layers, therefore, tangential stresses set up leakage current along the layers of paper insulation. The leakage current causes local heating, resulting in the risk of breakdown of insulation at any moment. In order to overcome this difficulty, screened cables are used where leakage current are conducted to earth through metallic screens.

2. Screened cables

These cables are meant for use up to 33 kV, but in particular cases their use may be extended to operating voltages up to 66 kV. Two principal types of screened cables are H type cables and S.L. type cables.

a. **H type cables:** This type of cable was first designed by H Hochstadter and hence the name. Fig. 11.4 shows the constructional details of a typical 3 core, H type cable. Each core is insulated by layers of impregnated paper. The insulation on each core is covered with a metallic screen which usually consists of a perforated aluminium foil. The cores are laid in such a way that metallic screens make contact with one another. An additional conducting belt (copper woven fabric tape) is wrapped round the three cores. The cable has no insulating belt but lead sheath, bedding, armouring and serving follow as usual. It is easy to see that each core screen is in electrical contact with the conducting belt and the lead sheath. As all the four screens (3 core screens and one conducting belt) and the lead sheath are at earth potential, therefore, the electrical stresses are purely radial and consequently dielectric losses are reduced.

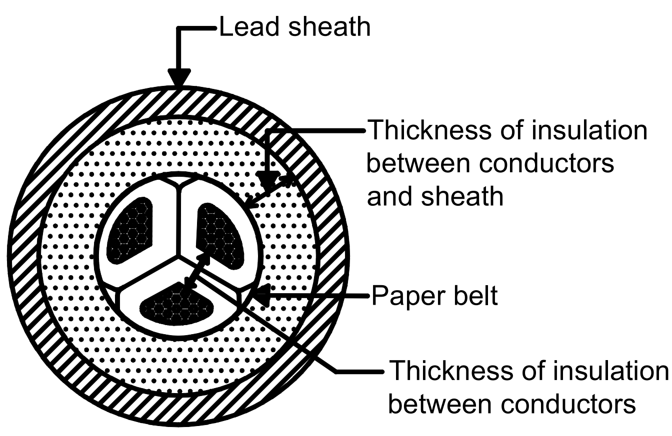


Figure-4 - Constructional Details of H Type Cable

Two principal advantages are claimed for H type cable. Firstly, the perforations in the metallic screens assist in the complete impregnation of the cable with the compound and thus the possibility of air pockets or voids (vacuous spaces) in the electric is eliminated. The voids if present tend to reduce the breakdown strength of the cable and may cause considerable damage to the paper insulation. Secondly, the metallic screens increase the heat dissipating power of the cable.

b. **S.L. type cables:** It is basically H type cable but the screen round each core insulation is covered by its own lead sheath. There is no overall lead sheath but only armouring and serving are provided. The S.L. type cables have two main advantages over H type cables. Firstly the separate sheaths minimize the possibility of core to core breakdown. Secondly, bending of cables becomes easy due to the elimination of overall lead sheath. However, the disadvantage is that the three lead sheaths of S.L. cable are much thinner than the single sheaths of H cable and therefore call for greater care in manufacture.

Limitations of solid type cables: All the cables of above construction are referred to as solid type cables because solid insulation is used and no gas or oil circulates in the cable sheath. The voltage limit for solid type cables is 66 kV due to the following reasons:

a. As a solid cable carries the load, its conductor temperature increases and the cable compound (i.e. insulting compound over paper) expands. This action stretches the lead sheath which may be damaged.
b. When the load on the cable decreases, the conductor cools and a partial vacuum is formed within the cable sheath. If the pinholes are present in the led sheath, moist air may be drawn into the cable. The moisture reduces the dielectric strength of insulation and may eventually cause the break down of the cable.
c. In practice, voids are always present in the insulation of a cable. Modern techniques of manufacturing have resulted in void free cables. However, under operating conditions, the voids are formed as a result of the differential expansion and contraction of the sheath and impregnated compound. The breakdown strength of voids is considerably less than that of the insulation. If the void is small enough, the electrostatic stress across it may cause its breakdown. The voids nearest to the conductor are the first to breakdown, the chemical and thermal effects of ionization causing permanent damage to the paper insulation.

3. Pressure cables

For voltages beyond 66 kV, solid type cables are unreliable because there is a danger of breakdown of insulation due to the presence of voids. When the operating voltages are greater than 66 kV, pressure cables re used. In such cables, voids are eliminated by increasing the pressure of compound and for this reason they are called pressure cables. Two types of pressure cables viz. oil filled cables and gas pressure cables are commonly used.

APPENDIX-D

TYPICAL TEST RESULTS OF POWER TRANSFORMER

DISSOLVED GAS ANALYSIS OF POWER TRANSFORMER

Name of Grid	**GH-2**
Make	**NGEF**
Capacity	**20MVA**
YOM	**2004**
Vector Grp	**Dyn11**
Sl. No	**2800056895**
Voltage Rating: HV	**66000**
LV	**11000**
Date of testing	**9/8/2006**

S.No	Name Of Dissolved Gases	Gas Content in ppm
1	Methane	47
2	Ethane	4
3	Ethylene	72
4	Acetylene	196
5	Carbon Dioxide	2860
6	Carbon Monooxide	Not Detected
7	Hydrogen	Not Detected
8	Total Gas Content per 100ml of Oil	6.1

Note: DGA shows presence of key gases ethylene and acetylene along with hydrocarbon gases indicating the presence of circulating currents and or arcing inside the transformer. Internal Inspection of transformer is recommended.

Tested by: CPRI Muradabad

APPENDIX-E

TYPICAL TEST RESULTS OF 11KV SWITCHGEAR

BSES	BREAKER SPECIFICATION & PHYSICAL INSPECTION	PROTECTION GROUP
BRPL / BYPL		
Grid Sub Station	GURU ANGAD NAGAR	

1) Circuit Breaker Specification :

Make :	ABB
Type:	VD4
Sr. No :	16877VG
Make Capacity	66kA
Make Capacity	26.3kA
Rated Voltage:	12KV
Highest System voltage:	28/75KV
Rated Current:	2000 A
Break Capacity(sym):	63.2 KA
Control DC Voltage:	50V

2) Physical Check

a) Installation Completion	Completed
b) Visual Inspection	OK
c) Wiring and TB status	OK

Tested by: Siddharth Singh

BSES	FUNCTIONALCHECK TEST REPORT FOR CIRCUIT BREAKER	PROTECTION GROUP
BYPL/BRPL		
Grid Sub Station	GURU ANGAD NAGAR	

1) Mechanical Checks :

Description	Result	Remark
a) Breaker Trolley Movement	OK / Not OK	OK
b) Contact Insertion	OK / Not OK	OK
c) Mechanical Interlock	OK / Not OK	OK

2) Operation Check :

a) Mechanical Operation at Switchgear :

Closing:	OK / Not OK	OK
Tripping :	OK / Not OK	OK
Emergency Tripping:	OK / Not OK	OK

b) Local Operation from TNC switch:

Closing:	OK / Not OK	OK
Tripping:	OK / Not OK	OK

c)Remote Operation :

Closing	OK / Not OK	OK
Tripping	OK / Not OK	OK
Tripping from relay	OK / Not OK	OK

d) SCADA Opeartion

Closing	OK / Not OK	OK
Tripping	OK / Not OK	OK

e) Anti-Pumping Check:	Operating/ Not Operating	Operating

f) Other SCADA Status Signals:

a) CB ON/OFF	OK / Not OK	OK
b) Local /Remote	OK / Not OK	OK
c) Test /Service Position	OK / Not OK	OK
d) Spring Charge	OK / Not OK	OK

3) Indication Check :

a) CB ON/OFF	OK / Not OK	OK
b) Test / Service	OK / Not OK	OK
c) Spring Charge	OK / Not OK	OK
d) Trip Ckt healthy	OK / Not OK	OK
e) DC fail	OK / Not OK	OK
f) AC fail	OK / Not OK	OK

4) Illumination / Heating Ckt. Check:

a) Door Lamp	OK / Not OK	OK
b) Space Heater	OK / Not OK	OK
c) Aux. Power sockets	OK / Not OK	OK

Tested by: Siddharth Singh

BSES	CIRCUIT BREAKER TEST REPORT	*PROTECTION GROUP*
BRPL / BYPL		
Grid Sub Station :	GURU ANGAD NAGAR	

1) **Timings:**

Phase	R(ms)	Y(ms)	B(ms)
Close	71	70	71
Open	51	50	48

2) **Contact Resistance:**

R Phase	**30 micro-ohm**
Y Phase	**28 micro-ohm**
B Phase	**29 micro-ohm**

3) **Coil Resistance :**

Coil	Resistance (Ω)
Close coil	4.41
Trip coil	3.39

4) **I.R.Test at 5kV**

Mode	R (MΩ)	Y (MΩ)	B (MΩ)
Across contacts	5000	5000	5000
Phase to ground	5000	5000	5000

Mode	RY (MΩ)	YB (MΩ)	BR (MΩ)
Phase to Phase	5000	5000	5000

5) Hipot Tests At 18 KV for 1 MIN

Mode	Leakage Current in mA		
	R	Y	B
Across contacts	0	0	0
Phase to ground	0	0	0

Mode	RY	YB	BR
Phase to Phase	0	0	0

Tested by: Siddharth Singh

BSES	CURRENT TRANSFORMER Test Report (Common for feeder and incomer)	PROTECTION GROUP
BRPL / BYPL		
Grid Sub Station	GURU ANGAD NAGAR	

1) **Specifications:**

Make	**Jyoti**
Feeder/Incomer	**NO.1**
System Voltage	**12KV**
Available Ratio	**1200/600/0.578-0.578**
Selected Ratio	**1200/0.578-0.578**

No. of Secondaries

Core no.	Accuracy Class	Used for
1	PS	DIFFERENTIAL
2	PS	REF

2) **General Inspection:**

Description	Result	Remark
a) Visual Inspection	OK / Not OK	OK
b) Wiring status checked	OK / Not OK	OK
c) Erection Completeness	Completed/Not Completed	Completed

3) **Insulation Resistance Test :**

S.NO	Tested Between	R(MΩ)	Y(MΩ)	B(MΩ)
1	Primary to Earth	5000	5000	5000
2	Primary to Secondary 1	5000	5000	5000
3	Primary to Secondary 2	5000	5000	5000
4	Seconadary 1 to Secondary 2	1000	1000	1000
5	Secondary 1 to Earth	1000	1000	1000
6	Secondary 2 to earth	1000	1000	1000

4) Polarity Check:

Core	R	Y	B
1	OK	OK	OK
2	OK	OK	OK

5) Primary Injection Test

Phase	Ratio Selected	Current Injected in Primary	Measured in Secondaries	
			Core 1	Core 2
R	1200/0.578-0.578	597 A	0.29	0.28
Y	1200/0.578-0.578	600 A	0.29	0.29
B	1200/0.578-0.578	595 A	0.28	0.28

6) CT Secondary current checked at relays and meter as per drawing and found OK

7) Kneepoint test (Only for PS class CT Secondary core):

Kneepoint voltage	616
Magnetizing current	<30 mA at Vk/2

S.no	Voltage applied	Current measured in secondary used for differential			Current measured in secondary used for REF		
		R	Y	B	R	Y	B
1	100	1.8	1.3	1.2	0.7	0.89	1.5
2	200	2.5	2.5	2.5	1.5	2.8	2.8
3	300	4.6	3.3	3.5	2.7	3.6	3.8
4	400	6.7	4.5	4.6	3.5	4.5	4.9
5	500	8.5	5.5	5.6	4.5	5.6	5.5
6	600	12.8	7.9	7.8	5.6	5.8	6.7
7	700	15	8.5	9.2	6	6.8	7.9

8) Measurement of Rct

	R(Ω)	Y(Ω)	B(Ω)
Rct of Secondary-1	5.89	5.96	6.2
Rct of Secondary-2	5.86	5.93	5.92

Tested by: B.S Rawat

BSES	POTENTIAL TRANSFORMER Test Report	PROTECTION GROUP
BRPL / BYPL		
Grid Sub Station :	GURU ANGAD NAGAR	

PT details :

Make	**ECS**
Ratio	**(11/1.732)KV/(110/1.732)V, (110/1.732)V**
No. of secondaries	**2**
Burden	**50 VA**
Class	**0.5/3P**
Serial No.	**R-1183,Y-1185,B-1184**
Type	**Epoxy**
Rated Voltage	**12kV**

1) Insualtion Resistance Test

S.No	Tested Between	R (MΩ)	Y (MΩ)	B (MΩ)
1	Primary to Earth	5000	5000	5000
2	Primary to Secondary 1	5000	5000	5000
3	Primary to Secondary 2	5000	5000	5000
4	Secondary 1 to Earth	1000	1000	1000
5	Secondary 1 to Secondary 2	1000	1000	1000
6	Secondary 2 to Earth	1000	1000	1000

2) Voltage Ratio Test

Phase	Name plate Ratio	Voltage applied in primary	Voltage checked in secondary
R	11/1.732KV/110/1.732	442	4.45
Y	11/1.732KV/110/1.732	442	4.45
B	11/1.732KV/110/1.732	442	4.45

3) Polarity check :

R phase		Y phase		B phase	
Core 1	**Core 2**	**Core 1**	**Core 2**	**Core 1**	**Core 2**
OK	OK	OK	OK	OK	OK

PT fuses checked: OK

Tested by: U.P Yadav

BSES	**OVER CURRENT & EARTH FAULT** **Relay Test Report**	***PROTECTION GROUP***
BRPL / BYPL		
Grid Sub Station	**GURU ANGAD NAGAR**	

Relay Details:

Relay Make: ABB	**Aux. Volts: 50V DC**
Relay Rating: 5A	**Serial No.: 11019**
Relay Type: SPAJ140C	**Frequency: 50Hz**

1) IDMT Characteristics Check:

Phase	Pickup In(A)	Actual pickup current (A)	Time Delay setting	Actual time taken for 2In	Remarks
O/C R	5	5	1	9.982	
O/C Y	5	5.01	1	9.987	
O/C B	5	5	1	9.906	
E/F	1	1.01	1	10.052	

2) Highset Characteristics Check:

Phase	Pickup In(A)	Actual pickup current (A)	Time Delay setting	Actual time taken for 2In	Remarks
O/C R	15	15	1	1.031	
O/C Y	15	15	1	1.031	
O/C B	15	15.01	1	1.092	
E/F	4	4.01	1	1.047	

3) Trip test mode function checked : OK

4) Master trip relay operation with relay pick up: OK

5) CB tripping checked with relay pick up : OK

6) Display (Operation Indication) checked : OK

7) **Memory check:** **OK**

Tested by: Pramod Kumar

BSES	**DIFFERENTIAL & REF** **Relay Test Report**	***PROTECTION GROUP***
BRPL / BYPL		
Grid Sub Station :	**GURU ANGAD NAGAR**	

Relay Details:

Relay Make :	**ABB**	**Aux. Volts:**	**50VDC**
Relay Rating :	**1 A**	**Serial No.:**	**11018**
Relay Type:	**SPAD346C**	**frequency:**	**50Hz**

1) Pickup Test :

Phase	**Pickup Seting(A)**	**Actual relay pickup(A)**
R	0.5	0.5
Y	0.5	0.5
B	0.5	0.5

2) Bias Test :

Phase	**Bias Setting (A)**	**Primary Bias current(A)**	**Secondary Bias Current(A)**	**Diff. Current**	**Relay Operation**
R	0.5	0.5	1	0.5	Satisfactory
Y	0.5	0.5	1	0.5	Satisfactory
B	0.5	0.5	1	0.5	Satisfactory

3) Instantaneous (Highset) Test:

Phase	**Highset(A)**	**Current Injected (A)**	**Time of Operation(sec.)**
R	10	10	0.03
Y	10	10	0.03
B	10	10	0.03

4) Master trip relay operation with relay pickup: **OK**

5) CB tripping checked with relay pickup: **OK**

Tested by: Manoj Solanki

BSES	HIGH VOLATGE BUS-BAR Test Report	*PROTECTION GROUP*
BRPL / BYPL		
Grid Sub Station	**GURU ANGAD NAGAR**	

1) **Insulation Resistance Test :**

S.No.	Tested Between	Before HV Test	After HV Test
1	R-phase to Earth	5000	5000
2	Y-phase to Earth	5000	5000
3	B-phase to Earth	5000	5000
4	R-Y phases	5000	5000
5	Y-B phases	5000	5000
6	B-R phases	5000	5000

2) **HV Test**

a) Condition- All Breaker in "ON"condition

S.No.	Tested Between	Voltage applied	Time
1	R-phase to Earth	18 KV	1MIN
2	Y-phase to Earth	18 KV	1MIN
3	B-phase to Earth	18 KV	1 MIN

Leakage current:

R(mA)	Y(mA)	B(mA)
0.67	0.52	0.54

b) Condition-All Breaker in 'OFF" condition

S.No.	Tested Between	Voltage applied	Time
1	R-phase to Earth	18 KV	1MIN
2	Y-phase to Earth	18 KV	1MIN
3	B-phase to Earth	18 KV	1 MIN

Leakage current: **NIL**

3) **Mili volt Test:** **OK**

Tested by: Manoj Solanki

APPENDIX-F

RELAY INDICATION ASSIGNMENTS AT BSES DELHI

1. ABB RELAYS INDICATION ASSIGNMENTS

SPAJ 140C-(O/C & E/F Relay)	
INDICATION	**ASSIGNMENT**
LED-2	Over current trip
LED-4	Instantaneous Over current trip
LED-6	Earth fault trip
LED-8	Instantaneous Earth fault trip

SPAS 348C2 (Directional O/C & E/F Relay)			
SPCS 4d11-Dirrectional O/C Module		**SPCS 2d26 Directional E/F Module**	
INDICATION	**ASSIGNMENT**	**INDICATION**	**ASSIGNMENT**
LED-3	Over current trip	**LED-2**	Residual Voltage Trip
LED-5	1st High Set Over current trip	**LED-4**	Earth fault trip
LED-7	2nd High Set Over current trip	**LED-6**	Instantaneous Earth fault trip

SPAD 346C (Differential Relay)			
Differential module (SPCD3d53)		**Restricted Earth fault module (SPCD2d55)**	
INDICATION	**ASSIGNMENT**	**INDICATION**	**ASSIGNMENT**
LED-1	Differential Trip	**LED-2**	High voltage side Restricted Earth fault
LED-2	Hi-set Differential Trip		
LED-4	Buchholz Trip	**LED-5**	Low voltage side Restricted Earth fault
LED-5	PRV/SPR Trip		
LED-6	WTI Trip		
LED-7	OTI Trip		
LED-8	OSR Trip		

SPAJ-160 C (O/C ,Under Current & Unbalance Current)	
INDICATION	**ASSIGNMENT**
LED-1	Over Current Alarm
LED-3	Over Current Trip
LED-4	Unbalance Current Alarm
LED-6	Unbalance Current Trip
LED-7	Under Current Trip

2. SIEMENS RELAYS INDICATION ASSIGNMENTS

7UT61-21(Differential Relay)	
INDICATION	**ASSIGNMENT**
LED-1	Differential Trip
LED-2	Highset Differential Trip
LED-3	Not Assigned
LED-4	Not Assigned
LED-5	Not Assigned
LED-6	Not Assigned
LED-7	Not Assigned

7SA610 (Distance Relay)	
INDICATION	**ASSIGNMENT**
LED-1	General trip
LED-2	Zone 1 trip
LED-3	Zone 2 trip
LED-4	PT MCB off
LED-5	Not Assigned
LED-6	Not Assigned
LED-7	Not Assigned

7SJ621(Directional O/C & E/F Relay)	
INDICATION	**ASSIGNMENT**
LED-1	Overcurrent Trip
LED-2	Earthfault Trip
LED-3	Directional Overcurrent Trip
LED-4	Directional Earthfault Trip
LED-5	PT MCB off
LED-6	Not Assigned
LED-7	Not Assigned

7SJ602(O/C & E/F Relay)	
INDICATION	**ASSIGNMENT**
LED-1	Overcurrent Trip
LED-2	Highset Overcurrent Trip
LED-3	Earthfault Trip
LED-4	Highset Earthfault Trip

3. ALSTOM RELAYS INDICATION ASSIGNMENTS

MICOM- P122 (O/C & E/F relay)	
INDICATION	**ASSIGNMENT**
LED-1	Trip
LED-2	Alarm
LED-3	Warning
LED-4	Relay Healthy
LED-5	Overcurrent Trip
LED-6	High Set O/C
LED-7	Earth Fault
LED-8	High Set E/F

MICOM-P127 (O/C & E/F, U/V & O/V Relay)	
INDICATION	**ASSIGNMENT**
LED-1	Trip
LED-2	Alarm
LED-3	Warning
LED-4	Relay Healthy
LED-5	Over Current
LED-6	Earth Fault
LED-7	Over Voltage
LED-8	Under Voltage

4. EASUN REYROLLE RELAY INDICATION ASSIGNMENTS

DCD413 (O/C & E/F Relay), Argus-8 (O/V & U/V Relay)
RED LED – Trip indication
Text Message Display on LCD screen

DUOBIAS (Differential Relay)	
INDICATION	**ASSIGNMENT**
LED-1	Data Block Off
LED-2	Diff. Phase A Operated
LED-3	Diff. Phase B Operated
LED-4	Diff. Phase C Operated
LED-5	HV REF
LED-6	LV REF

APPENDIX-G

PROTECTION SCHEMES
AT
BSES DELHI

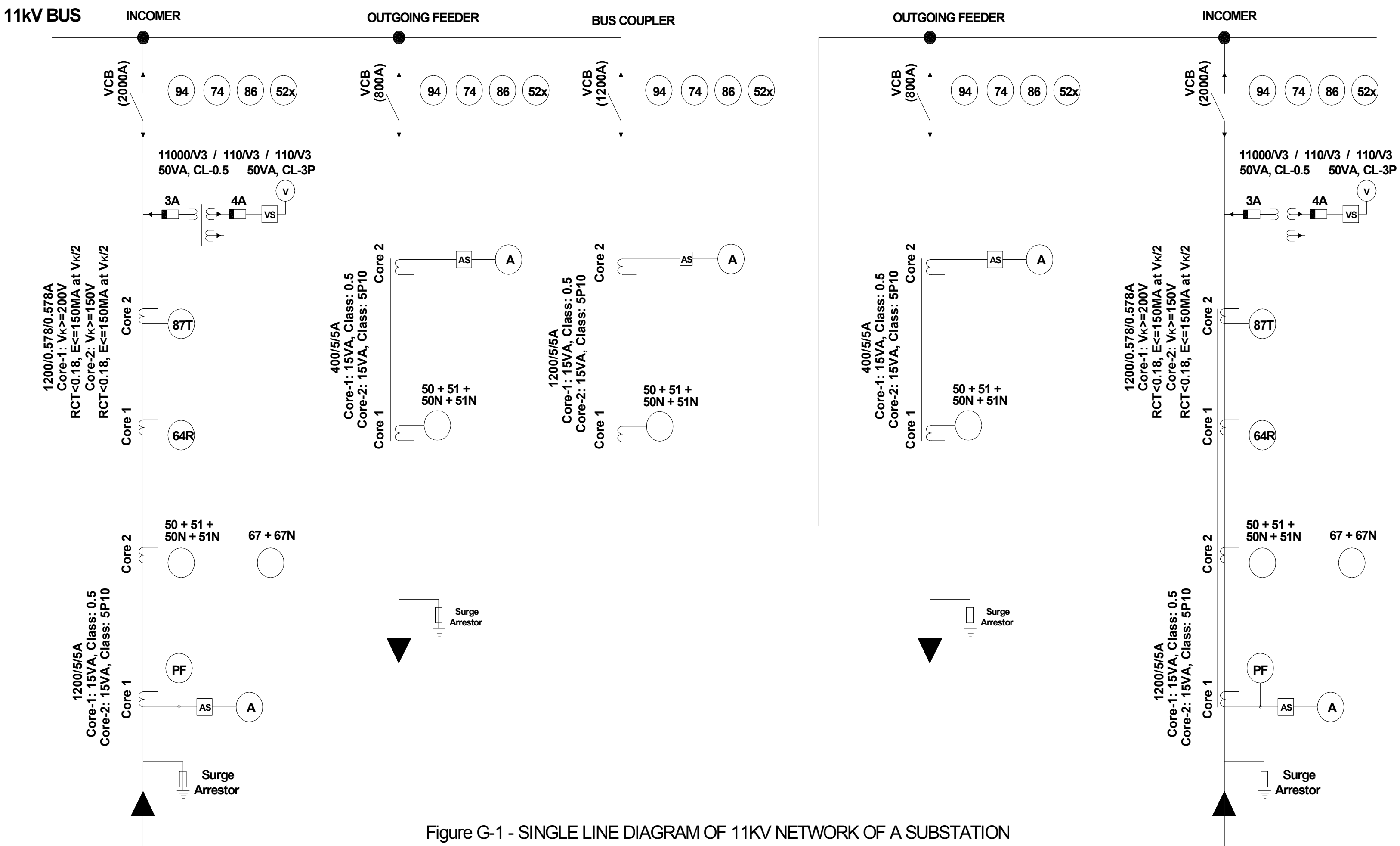


Figure G-1 - SINGLE LINE DIAGRAM OF 11KV NETWORK OF A SUBSTATION DEPICTING TYPICAL USAGE OF PROTECTIVE RELAYS AT BSES DELHI

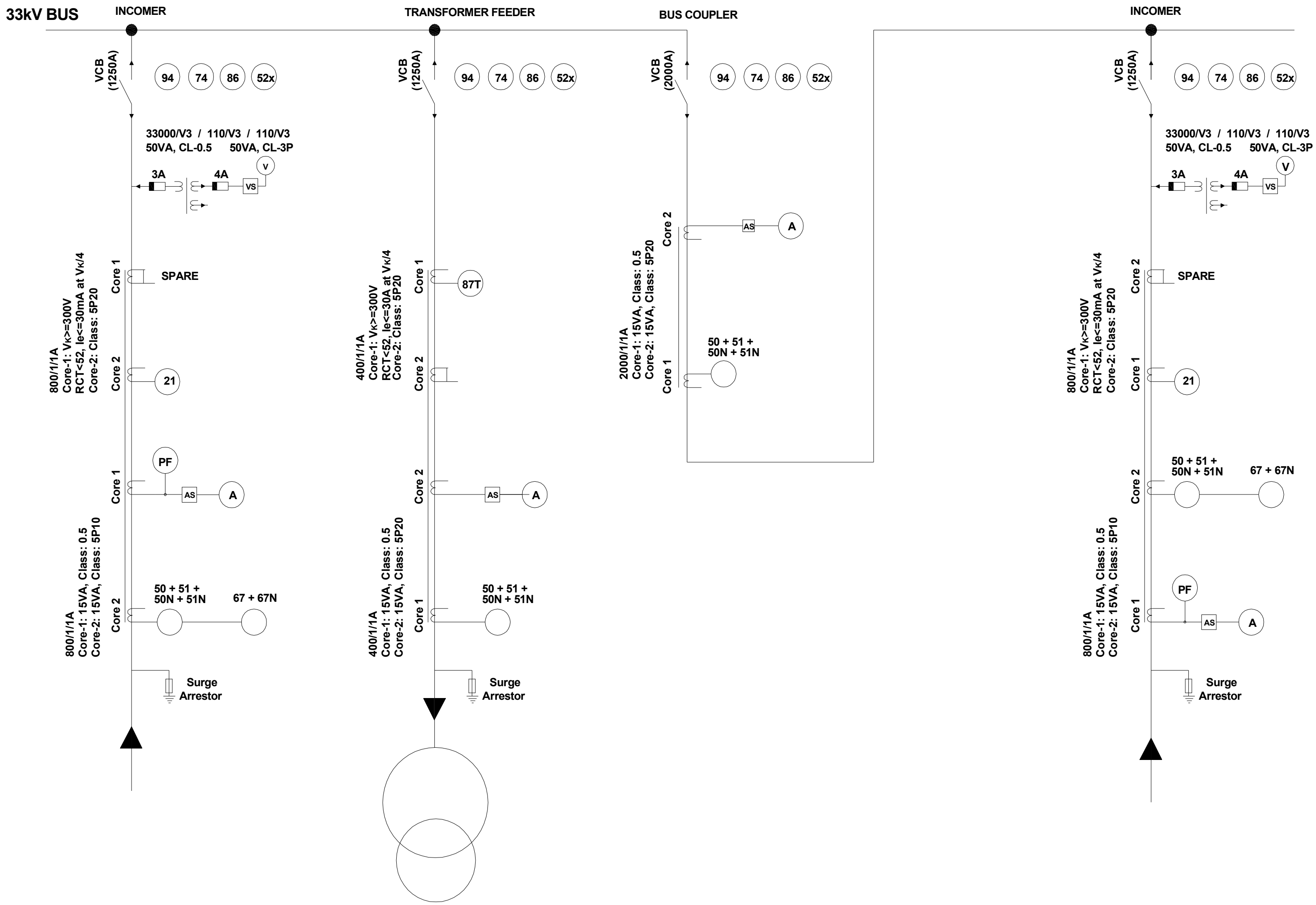


Figure G-2 - SINGLE LINE DIAGRAM OF 33KV NETWORK OF A SUBSTATION DEPICTING TYPICAL USAGE OF PROTECTIVE RELAYS AT BSES DELHI

PROTECTIVE RELAYS USED AT BSES DELHI

1. DIFFERENTIAL RELAYS (87)

S.NO	MODEL NUMBER	MAKE
1	SPAD 346C	ABB
2	7UT61	SIEMENS
3	DUOBIAS	ER
4	MBCH12	ALSTOM
5	DTH31	ALSTOM

2. DIRECTIONAL O/C AND E/F RELAYS (67 & 67N)

S.NO	MODEL NUMBER	MAKE
1	SPAS348C	ABB
2	7SJ62	SIEMENS
3	REX521	ABB
4	CDD21	ALSTOM
5	ARGUS-2	ER
6	TJM12	ER

3. DISTANCE RELAYS (21)

S.NO	MODEL NUMBER	MAKE
1	7SA610	SIEMENS
2	MICOM P430	ALSTOM
3	REL511	ABB

4.O/C AND E/F RELAYS (50, 50N, 51, 51N)

S.NO	MODEL NUMBER	MAKE
1	SPAJ140C	ABB
2	REJ525	ABB
3	7SJ602	SIEMENS
4	MICOM P122	ALSTOM

5.O/C AND E/F RELAYS (51, 51N)

S.NO	MODEL NUMBER	MAKE
1	ICM21	ABB
2	CDG11	ALSTOM
3	CDG31	ALSTOM
4	TJM10	ER

6. REF RELAYS (64)

S.NO	MODEL NUMBER	MAKE
1	P120	ALSTOM
2	CAG14	ALSTOM
3	SPAD 346C	ABB
4	DUOBIAS	ER

7. OVERVOLTAGE (59) AND UNDERVOLTAGE (27) RELAYS

S.NO	MODEL NUMBER	MAKE
1	SPAU 130C	ABB
2	MICOM P127	ALSTOM
3	ARGUS-8	ER
4	VDG	ALSTOM

8. MASTER RELAY (86)

S.NO	MODEL NUMBER	MAKE
1	VAJH	EE
2	PQ8nCH2J	ABB

APPENDIX-H

LINE PARAMETERS

Line Specification	Positrive sequence resistance	Positive Sequence Reactance	Positive Sequence Susceptance	Zero sequence resistance	Zero Sequence Reactance	Zero Sequence Susceptance
Line1	1.5400000	0.1190000	0.000039735000	3.85000	0.29750	0.000035730
1Cx25sqmm(3.3kV)	1.5400000	0.1190000	0.000039735000	3.85000	0.29750	0.000035730
1Cx25sqmm(3.8/6.6kV)	1.5400000	0.1340000	0.000036750000	3.85000	0.33500	0.000033030
1Cx25sqmm(6.35/11kV)	1.5400000	0.1410000	0.000030450000	3.85000	0.35250	0.000027360
1Cx25sqmm(11/11kV)	1.5400000	0.1520000	0.000022930000	3.85000	0.38000	0.000020610
1Cx35sqmm(3,3kV)	1.1000000	0.1140000	0.000044750000	2.77500	0.28500	0.000040230
1Cx35sqmm(3,8/6.6kV)	1.1000000	0.1290000	0.000040675000	2.77500	0.32250	0.000036540
1Cx35sqmm(6.35/11kV)	1.1000000	0.1340000	0.000033610000	2.77500	0.33500	0.000030240
1Cx35sqmm(11/11kV)	1.1000000	0.1450000	0.000024970000	2.77500	0.36250	0.000022410
1Cx35sqmm(12.7/22kV)	1.1000000	0.1470000	0.000023550000	2.77500	0.36750	0.000047100
1Cx50sqmm(3.3kV)	0.8220000	0.1090000	0.000050730000	2.05500	0.27250	0.000045630
1Cx50sqmm(3.8/6.6kV)	0.8220000	0.1220000	0.000045540000	2.05500	0.30500	0.000033570
1Cx50sqmm(6.35/11kV)	0.8220000	0.1270000	0.000037380000	2.05500	0.31750	0.000033570
1Cx50sqmm(11/11kV)	0.8220000	0.1380000	0.000027480000	2.05500	0.34500	0.000024660
1Cx50sqmm(12.7/22kV)	0.8220000	0.1400000	0.000025400000	2.05500	0.35000	0.000022860
1Cx50sqmm(19/33kV)	0.8220000	0.1540000	0.000020260000	2.05500	0.30500	0.000018180
1Cx70sqmm(3.3kV)	0.5680000	0.1000000	0.000058850000	1.42000	0.24100	0.000061830
1Cx70sqmm(3.8/6.6kV)	0.5680000	0.1130000	0.000051829000	1.42000	0.28250	0.000046620
1Cx70sqmm(6.35/11kV)	0.5680000	0.1180000	0.000042400000	1.42000	0.29500	0.000038160
1Cx70sqmm(11/11kV)	0.5680000	0.1270000	0.000030780000	1.42000	0.31750	0.000027630
1Cx70sqmm(12.7/22kV)	0.5680000	0.1290000	0.000029050000	1.42000	0.32250	0.000026100
1Cx70sqmm(19/33kV)	0.5680000	0.1430000	0.000022450000	1.42000	0.35750	0.000020660
1Cx95sqmm(3.3kV)	0.4110000	0.0964000	0.000068750000	1.02750	0.24100	0.000061830
1Cx95sqmm(3.8/6.6kV)	0.4110000	0.1070000	0.000060150000	1.02750	0.26750	0.000054090
1Cx95sqmm(6.35/11kV)	0.4110000	0.1100000	0.000048840000	1.02750	0.27750	0.000043920
1Cx95sqmm(11/11kV)	0.4110000	0.1200000	0.000035180000	1.02750	0.30000	0.000031590
1Cx95sqmm(12.7/22kV)	0.4110000	0.1240000	0.000032950000	1.02750	0.31000	0.000029610
1Cx95sqmm(19/33kV)	0.4110000	0.1350000	0.000025285000	1.02750	0.33750	0.000022680
1Cx120sqmm(3.3kV)	0.3250000	0.0929000	0.000075350000	0.81250	0.23250	0.000067770
1Cx120sqmm(3.8/6.6kV)	0.3250000	0.1030000	0.000065150000	0.81250	0.25750	0.000058590
1Cx120sqmm(6.35/11kV)	0.3250000	0.1070000	0.000052900000	0.81250	0.26750	0.000047610
1Cx120sqmm(11/11kV)	0.3250000	0.1170000	0.000037900000	0.81250	0.29250	0.000034110
1Cx120sqmm(12.7/22kV)	0.3250000	0.1190000	0.000035500000	0.81250	0.29750	0.000031860
1Cx120sqmm(19/33kV)	0.3250000	0.1290000	0.000026850000	0.81250	0.32250	0.000024120
1Cx150sqmm(3.3kV)	0.2650000	0.0903000	0.000082250000	0.66250	0.22575	0.000073980
1Cx150sqmm(3.8/6.6kV)	0.2650000	0.0998000	0.000070650000	0.66250	0.24950	0.000063540
1Cx150sqmm(6.35/11kV)	0.2650000	0.1040000	0.000057150000	0.66250	0.26000	0.000051340
1Cx150sqmm(11/11kV)	0.2650000	0.1130000	0.000040670000	0.66250	0.28750	0.000036540
1Cx150sqmm(12.7/22kV)	0.2650000	0.1150000	0.000038000000	0.66250	0.28750	0.000034200
1Cx150sqmm(19/33kV)	0.2650000	0.1250000	0.000028740000	0.66250	0.31250	0.000025830
1Cx185sqmm(3.3kV)	0.2110000	0.0878000	0.000090750000	0.52750	0.21950	0.000081630
1Cx185sqmm(3.8/6.6kV)	0.2110000	0.0966000	0.000077400000	0.52750	0.24150	0.000069660
1Cx185sqmm(6.35/11kV)	0.2110000	0.1010000	0.000062350000	0.52750	0.25250	0.000056070
1Cx185sqmm(11/11kV)	0.2110000	0.1100000	0.000044130000	0.52750	0.27500	0.000039690
1Cx185sqmm(12.7/22kV)	0.2110000	0.1110000	0.000041145000	0.52750	0.27750	0.000036990
1Cx185sqmm(19/33kV)	0.2110000	0.1220000	0.000030940000	0.52750	0.30500	0.000027810
1Cx240sqmm(3.3kV)	0.1620000	0.0846000	0.000103650000	0.40500	0.21150	0.000093200
1Cx240sqmm(3.8/6.6kV)	0.1620000	0.0944000	0.000087600000	0.40500	0.23600	0.000078840
1Cx240sqmm(6.35/11kV)	0.1620000	0.0976000	0.000070350000	0.40500	0.24400	0.000063270
1Cx240sqmm(11/11kV)	0.1610000	0.1050000	0.000049315000	0.40250	0.26250	0.000044370
1Cx240sqmm(12.7/22kV)	0.1610000	0.1060000	0.000046018000	0.40250	0.26500	0.000041400
1Cx240sqmm(19/33kV)	0.1610000	0.1160000	0.000034235000	0.40250	0.29000	0.000030780
1Cx300sqmm(3.3kV)	0.1300000	0.0822000	0.000113700000	0.32500	0.20550	0.000102330
1Cx300sqmm(3.8/6.6kV)	0.1300000	0.0921000	0.000089650000	0.32500	0.23025	0.000080640
1Cx300sqmm(6.35/11kV)	0.1300000	0.0944000	0.000076450000	0.32500	0.23600	0.000068760
1Cx300sqmm(11/11kV)	0.1300000	0.1010000	0.000053440000	0.32500	0.25250	0.000048060
1Cx300sqmm(12.7/22kV)	0.1300000	0.1030000	0.000049780000	0.32500	0.25750	0.000044730
1Cx300sqmm(19/33kV)	0.1290000	0.1130000	0.000036905000	0.32250	0.32500	0.000033120
1Cx400sqmm(3.3kV)	0.1020000	0.0807000	0.000127050000	0.25500	0.20175	0.000011430
1Cx400sqmm(3.8/6.6kV)	0.1020000	0.0903000	0.000091400000	0.25500	0.22575	0.000082260
1Cx400sqmm(6.35/11kV)	0.1020000	0.0913000	0.000084650000	0.25500	0.22825	0.000076140
1Cx400sqmm(11/11kV)	0.1020000	0.0987000	0.000058850000	0.25500	0.24675	0.000052920
1Cx400sqmm(12.7/22kV)	0.1020000	0.1000000	0.000005465000	0.25500	0.25000	0.000048600
1Cx400sqmm(19/33kV)	0.1010000	0.1090000	0.000040360000	0.25250	0.27250	0.000036270
1Cx500sqmm(3.3kV)	0.0811000	0.0792000	0.000132550000	0.20275	0.19800	0.000011925
1Cx500sqmm(3.8/6.6kV)	0.0804000	0.0891000	0.000097200000	0.20100	0.22275	0.000087480
1Cx500sqmm(6.35/11kV)	0.0804000	0.0894000	0.000094850000	0.20100	0.22350	0.000000000
1Cx500sqmm(11/11kV)	0.0801000	0.0950000	0.000065450000	0.20025	0.23750	0.000058860
1Cx500sqmm(12.7/22kV)	0.0800000	0.0970000	0.000060900000	0.20000	0.24250	0.000054810
1Cx500sqmm(19/33kV)	0.0797000	0.0104600	0.000044605000	0.19925	0.26150	0.000040140
1Cx630sqmm(3.3kV)	0.0647000	0.0773000	0.000144000000	0.16175	0.19325	0.000129600
1Cx630sqmm(3.8/6.6kV)	0.0639000	0.0864000	0.000115250000	0.15975	0.21600	0.000103680
1Cx630sqmm(6.35/11kV)	0.0639000	0.0867000	0.000112250000	0.15975	0.21675	0.000100980
1Cx630sqmm(11/11kV)	0.0635000	0.0922000	0.000076950000	0.15875	0.22550	0.000069210
1Cx630sqmm(12.7/22kV)	0.0634000	0.0934000	0.000071450000	0.15850	0.23350	0.000064260
1Cx630sqmm(19/33kV)	0.0630000	0.1003000	0.000051800000	0.15750	0.25750	0.000046620
1Cx800sqmm(3.3kV)	0.0528000	0.0765000	0.000150750000	0.13200	0.19125	0.000135630
1Cx800sqmm(3.8/6.6kV)	0.0518000	0.0844000	0.000128300000	0.12950	0.21100	0.000115470
1Cx800sqmm(6.35/11kV)	0.0518000	0.0847000	0.000125000000	0.12950	0.21175	0.000112500
1Cx800sqmm(11/11kV)	0.0514000	0.0896000	0.000085250000	0.12850	0.22400	0.000076725
1Cx800sqmm(12.35/22kV)	0.0508000	0.0907000	0.000079000000	0.12825	0.22675	0.000071100
1Cx800sqmm(19/33kV)	0.0508000	0.0971000	0.000057000000	0.12700	0.24275	0.000051300
1Cx1000sqmm(3.3kV)	0.0442000	0.0760000	0.000157000000	0.11050	0.19000	0.000141300
1Cx1000sqmm(3.8/6.6kV)	0.0432000	0.0828000	0.000138200000	0.10800	0.20700	0.000124380
1Cx1000sqmm(6.35/11kV)	0.0432000	0.0828000	0.000138200000	0.10800	0.20700	0.000124380
1Cx1000sqmm(11/11kV)	0.0427000	0.0870000	0.000094000000	0.10675	0.21750	0.000084600
1Cx1000sqmm(12.7/22kV)	0.0426000	0.0884000	0.000087000000	0.10650	0.22100	0.000078300
1Cx1000sqmm(19/33kV)	0.0420000	0.0943000	0.000062500000	0.10500	0.23750	0.562500000
3Cx25sqmm(3.3kV)	1.5400000	0.1020000	0.000039735000	3.85000	0.25500	0.000035730
3Cx5sqmm(3.8/6.6kV)	1.5400000	0.1210000	0.000036750000	3.85000	0.25500	0.000033030
3Cx25sqmm(6.35/11kV)	1.5400000	0.1290000	0.000030450000	3.85000	0.32250	0.000027360
3Cx25sqmm(11/11kV)	1.5400000	0.1430000	0.000022930000	3.85000	0.35750	0.000020610
3Cx25sqmm(3,3kV)	1.1000000	0.0974000	0.000044750000	2.77500	0.24350	0.000040230
3Cx35sqmm(3,8/6.6kV)	1.1000000	0.1160000	0.000040675000	2.77500	0.29000	0.000036540
3Cx35sqmm(6.35/11kV)	1.1000000	0.1220000	0.000033610000	2.77500	0.30500	0.000030240
3Cx35sqmm(11/11kV)	1.1000000	0.1360000	0.000024970000	2.77500	0.34000	0.000022410
3Cx35sqmm(12.7/22kV)	1.1000000	0.1390000	0.000023550000	2.77500	0.34750	0.000021150
3Cx50sqmm(33kV)	0.8220000	0.0935000	0.000050730000	2.05500	0.23375	0.000045630
3Cx50sqmm(3.8/6.6kV)	0.8220000	0.1100000	0.000045540000	2.05500	0.27500	0.000040950
3Cx50sqmm(6.35/11kV)	0.8220000	0.1170000	0.000037380000	2.05500	0.29250	0.000033570

Line Specification	Positrive sequence resistance	Positive Sequence Reactance	Positive Sequence Susceptance	Zero sequence resistance	Zero Sequence Reactance	Zero Sequence Susceptance
3Cx50sqmm(11/11kV)	0.8220000	0.1290000	0.000027480000	2.05500	0.32250	0.000024660
3Cx50sqmm(12.7/22kV)	0.8220000	0.1320000	0.000025400000	2.05500	0.33000	0.000022860
3Cx50sqmm(19/33kV)	0.8220000	0.1480000	0.000020260000	2.05500	0.37000	0.000018180
3Cx70sqmm(3.3kV)	0.5690000	0.0868000	0.000058850000	1.42250	0.21700	0.000010593
3Cx70sqmm(3.8/6.6kV)	0.5680000	0.1020000	0.000051829000	1.42000	0.25500	0.000046620
3Cx70sqmm(6.35/11kV)	0.5680000	0.1080000	0.000042400000	1.42000	0.27000	0.000038160
3Cx70sqmm(11/11kV)	0.5680000	0.1190000	0.000030780000	1.42000	0.29750	0.000027630
3Cx70sqmm(12.7/22kV)	0.5680000	0.1220000	0.000029050000	1.42000	0.30500	0.000026100
3Cx70sqmm(19/33kV)	0.5680000	0.1370000	0.000022450000	1.42000	0.34250	0.000020160
3Cx95sqmm(3.3kV)	0.4110000	0.0833000	0.000068750000	1.02750	0.20825	0.000061830
3Cx95sqmm(3.8/6.6kV)	0.4110000	0.0971000	0.000060150000	1.02750	0.24275	0.000054090
3Cx95sqmm(6.35/11kV)	0.4110000	0.1020000	0.000048840000	1.02750	0.25500	0.000043920
3Cx95sqmm(11/11kV)	0.4110000	0.1130000	0.000035180000	1.02750	0.28250	0.000031590
2Cx95sqmm(12.7/22kV)	0.4110000	0.1170000	0.000032950000	1.02750	0.29250	0.000029610
3Cx95sqmm(19/33kV)	0.4110000	0.1290000	0.000025285000	1.02750	0.32250	0.000022680
3Cx120sqmm(3.3kV)	0.3250000	0.0806000	0.000075350000	0.81250	0.20150	0.000067770
3Cx120sqmm(3.8/6.6kV)	0.3250000	0.0935000	0.000065150000	0.81250	0.23375	0.000058590
3Cx120sqmm(6.35/11kV)	0.3250000	0.0984000	0.000052900000	0.81250	0.24600	0.000047610
3Cx120sqmm(11/11kV)	0.3250000	0.1100000	0.000037900000	0.81250	0.27500	0.000034110
3Cx120sqmm(12.7/22kV)	0.3250000	0.1120000	0.000035500000	0.81250	0.28000	0.000031860
3Cx120sqmm(19/33kV)	0.3250000	0.1240000	0.000026850000	0.81250	0.31000	0.000024120
3Cx150sqmm(3.3kV)	0.2650000	0.0790000	0.000082250000	0.66250	0.19750	0.000073980
3Cx150sqmm(3.8/6.6kV)	0.2650000	0.0910000	0.000070650000	0.66250	0.22750	0.000063540
3Cx150sqmm(6.35/11kV)	0.2650000	0.9560000	0.000057150000	0.66250	0.23900	0.000051390
3Cx150sqmm(11/11kV)	0.2650000	0.1060000	0.000040670000	0.66250	0.26500	0.000036540
3Cx150sqmm(12.7/22kV)	0.2650000	0.1090000	0.000038000000	0.66250	0.27250	0.000034200
3Cx150sqmm(19/33kV)	0.2650000	0.1200000	0.000028740000	0.66250	0.30000	0.000025830
3Cx185sqmm(3.3kV)	0.2120000	0.0774000	0.000090750000	0.52750	0.19350	0.000081630
3Cx185sqmm(3.8/6.6kV)	0.2110000	0.0885000	0.000077400000	0.52750	0.22120	0.000069660
3Cx185sqmm(6.35/11kV)	0.2110000	0.9280000	0.000062350000	0.52750	0.23200	0.000056070
3Cx185sqmm(11/11kV)	0.2110000	0.1030000	0.000044130000	0.52750	0.25750	0.000039690
3Cx185sqmm(12.7/22kV)	0.2110000	0.1050000	0.000041145000	0.52750	0.26250	0.000036990
3Cx185sqmm(19/33kV)	0.2110000	0.1170000	0.000030940000	0.52750	0.29250	0.000027810
3Cx240sqmm(3.3kV)	0.1620000	0.0754000	0.000103650000	0.40500	0.18850	0.000093200
3Cx240sqmm(3.8/6.6kV)	0.1620000	0.0865000	0.000087600000	0.40500	0.21625	0.000078840
3Cx240sqmm(6.35/11kV)	0.1620000	0.0903000	0.000070350000	0.40500	0.22575	0.000063270
3Cx240sqmm(11/11kV)	0.1620000	0.0984000	0.000049315000	0.40500	0.24625	0.000044370
3Cx240sqmm(12.7/22kV)	0.1620000	0.1000000	0.000046018000	0.40500	0.25000	0.000041400
3Cx240sqmm(19/33kV)	0.1610000	0.1110000	0.000034235000	0.40250	0.27750	0.000030780
3Cx300sqmm(3.3kV)	0.1310000	0.0737000	0.000113700000	0.32750	0.18425	0.000102330
3Cx300sqmm(3.8/6.6kV)	0.1300000	0.0849000	0.000089650000	0.32500	0.21220	0.000080640
3Cx300sqmm(6.35/11kV)	0.1300000	0.0876000	0.000076450000	0.32500	0.21900	0.000068760
3Cx300sqmm(11/11kV)	0.1300000	0.0952000	0.000053440000	0.32500	0.23800	0.000048060
3Cx300sqmm(12.7/22kV)	0.1300000	0.0970000	0.000049780000	0.32500	0.24250	0.000044730
3Cx300sqmm(19/33kV)	0.1300000	0.1070000	0.000036905000	0.32500	0.26750	0.000033120
3Cx400sqmm(3.3kV)	0.1030000	0.0724000	0.000127050000	0.32500	0.18100	0.000011430
3Cx400sqmm(3.8/6.6kV)	0.1020000	0.0839000	0.000091400000	0.25500	0.20975	0.000082260
3Cx400sqmm(6.35/11kV)	0.1020000	0.0850000	0.000084650000	0.25500	0.21250	0.000076140
3Cx400sqmm(11/11kV)	0.1020000	0.0929000	0.000058850000	0.25500	0.23250	0.000052920
3Cx400sqmm(12.7/22kV)	0.1020000	0.0946000	0.000005465000	0.25500	0.23650	0.000004860
3Cx400sqmm(19/33kV)	0.1020000	0.1030000	0.000040360000	0.25500	0.25750	0.000036270
Zebra 220kV	0.0748746	0.3992516	0.000001466942	0.21998	1.33923	0.000000920
Triple Zebra 400kV	0.0224160	0.2992000	0.000001831250	12.18560	1.11184	0.000001182
Quad AAAC 400kV	0.0156640	0.2681600	0.000002184370	8.51200	1.00160	0.000001409
Quad Zebra 400kV	0.0168000	0.2544000	0.000002078120	9.13280	0.95040	0.000001342
Twin AAAC 400kV	0.0309440	0.3304000	0.000001771870	0.16816	1.23680	0.000001144
Quad Bersimis 765kV	0.0114194	0.2618800	0.000002050490	0.26335	1.05341	0.000001201
Rabbit 11kV	0.6384627	0.3634279	0.000001581023	0.78652	1.59890	0.000000642
Weasel 11kV	1.0688130	0.3823492	0.000001499307	1.21687	1.61782	0.000000628
Squirrel 11kV	1.6137710	0.3952294	0.000001448351	1.76183	1.63070	0.000000619
Racoon 11kV	0.4291611	0.3536387	0.000001626900	0.57722	1.58911	0.000000649
Dog 11kV	0.2573526	0.3446806	0.000001671280	0.40541	1.58015	0.000000656
Coyote 11kV	0.2598321	0.3373927	0.000001709213	0.40789	1.57286	0.000000662
Rabbit 22kV	0.6384627	0.3634279	0.000001581023	0.78652	1.59890	0.000000642
Weasel 22kV	1.0688130	0.3823492	0.000001499307	1.21687	1.61782	0.000000628
Squirrel 22kV	1.6137710	0.3952294	0.000001448351	1.76183	1.63070	0.000000619
Racoon 22kV	0.4291611	0.3536387	0.000001626900	0.57722	1.58911	0.000000649
Dog 22kV	0.2573526	0.3446806	0.000001671280	0.40541	1.58015	0.000000656
Coyote 22kV	0.2598321	0.3373927	0.000001709213	0.40789	1.57286	0.000000662
Rabbit 33kV	0.6384627	0.3634279	0.000001581023	0.78652	1.59890	0.000000642
Weasel 33kV	1.0688130	0.3823492	0.000001499307	1.21687	1.61782	0.000000628
Squirrel 33kV	1.6137790	0.3952275	0.000001448597	1.83282	1.58789	0.000000647
Racoon 33kV	0.4291611	0.3536387	0.000001626900	0.57722	1.58911	0.000000649
Dog 33kV	0.2573659	0.3446466	0.000001671602	0.42464	1.23396	0.000000688
Coyote 33kV	0.2598321	0.3373927	0.000001709213	0.40789	1.57286	0.000000662
Dog 66kV	0.2573575	0.4082288	0.000001416028	0.49785	1.40183	0.000000804
Coyote 66kV	0.2598370	0.4009409	0.000001443148	0.43033	0.99743	0.000000812
Panther 66kV	0.1619293	0.3834193	0.000001512805	0.40242	1.37702	0.000000834
Lynx 66kV	0.1863336	0.3879796	0.000001494036	0.42682	1.38158	0.000000828
Drake 66kV	0.0854064	0.3650281	0.000001593538	0.32590	1.35863	0.000000858
Deer 66kV	0.0804623	0.3612369	0.000001611264	0.32095	1.35484	0.000000863
Zebra 66kV	0.0801700	0.3639653	0.000001598468	0.32066	1.35757	0.000000859
Moose 66kV	0.0656738	0.3574038	0.000001629591	0.30616	1.35101	0.000000868
Dog 66kV Double Circuit	0.2573575	0.4165113	0.000001381067	0.49326	1.38703	0.000000969
Coyote 66kV Double Circuit	0.2598370	0.4092235	0.000001406852	0.49574	1.37975	0.000000984
Panther 66kV Double Circuit	0.1619293	0.3917018	0.000001472969	0.39783	1.36222	0.000001022
Lynx 66kV Double Circuit	0.1863336	0.3962621	0.000001455170	0.42223	1.36678	0.000001012
Drake 66kV Double Circuit	0.0854064	0.3733106	0.000001549399	0.32131	1.34383	0.000001066
Deer 66kV Double Circuit	0.0804623	0.3695194	0.000001566152	0.31636	1.34004	0.000001075
Zebra 66kV Double Circuit	0.0801700	0.3722478	0.000001554060	0.31607	1.34277	0.000001068
Moose 66kV Double Circuit	0.0656738	0.3656863	0.000001583462	0.30157	1.33621	0.000001085
Dog 66kV Twin Circuit	0.1286788	0.2698980	0.000002133969	0.36917	1.26350	0.000000993
Coyote 66kV Twin Circuit	0.1299185	0.2662541	0.000002164620	0.37041	1.25986	0.000001000
Panther 66kV Twin Circuit	0.0809647	0.2574932	0.000002242043	0.32146	1.25110	0.000001016
Lynx 66kV Twin Circuit	0.0931668	0.2597734	0.000002221364	0.33366	1.25338	0.000001012
Drake 66kV Twin Circuit	0.0427032	0.2482977	0.000002329498	0.28319	1.24190	0.000001034
Deer 66kV Twin Circuit	0.0402311	0.2464020	0.000002348381	0.28072	1.24001	0.000001037
Zebra 66kV Twin Circuit	0.0400850	0.2477662	0.000002334761	0.28058	1.24137	0.000001035
Moose 66kV Twin Circuit	0.0328369	0.2444855	0.000002367786	0.27333	1.23809	0.000001041
Dog 110kV	0.2573575	0.4324630	0.000001335048	0.48474	1.35846	0.000000793

Line Specification	Positrive sequence resistance	Positive Sequence Reactance	Positive Sequence Susceptance	Zero sequence resistance	Zero Sequence Reactance	Zero Sequence Susceptance
Coyote 110kV	0.2598370	0.4251751	0.000001359128	0.48722	1.35117	0.000000802
Panther 110kV	0.1619293	0.4076534	0.000001420737	0.38931	1.33365	0.000000823
Lynx 110kV	0.1863336	0.4122138	0.000001404171	0.41371	1.33821	0.000000817
Drake 110kV	0.0854064	0.3892623	0.000001491713	0.31278	1.31525	0.000000846
Deer 110kV	0.0804623	0.3854710	0.000001507234	0.30784	1.31146	0.000000851
Zebra 110kV	0.0801700	0.3881994	0.000001496032	0.30755	1.31419	0.000000847
Moose 110kV	0.0656738	0.3816379	0.000001523260	0.29305	1.30763	0.000000856
Dog 110kV Double Circuit	0.2573575	0.4377949	0.000001312435	0.48198	1.34888	0.000000935
Coyote 110kV Double Circuit	0.2598370	0.4305070	0.000001335699	0.48446	1.34159	0.000000949
Panther 110kV Double Circuit	0.1619293	0.4129853	0.000001395157	0.38655	1.32407	0.000000984
Lynx 110kV Double Circuit	0.1863336	0.4175456	0.000001379178	0.41096	1.32863	0.000000975
Drake 110kV Double Circuit	0.0854064	0.3945942	0.000001463538	0.31003	1.30568	0.000001024
Deer 110kV Double Circuit	0.0804623	0.3908029	0.000001478476	0.30509	1.30189	0.000001032
Zebra 110kV Double Circuit	0.0801700	0.3935313	0.000001467695	0.30479	1.30462	0.000001026
Moose 110kV Double Circuit	0.0656738	0.3869698	0.000001493892	0.29030	1.29806	0.000001041
Dog 110kV Twin Circuit	0.1286788	0.2698980	0.000002133969	0.36917	1.26350	0.000000993
Coyote 110kV Twin Circuit	0.1299185	0.2904882	0.000001980939	0.35730	1.21648	0.000000984
Panther 110kV Twin Circuit	0.0809647	0.2817274	0.000002045584	0.30834	1.20772	0.000000999
Lynx 110kV Twin Circuit	0.0931668	0.2840075	0.000002028357	0.32055	1.21000	0.000000995
Drake 110kV Twin Circuit	0.0427032	0.2725318	0.000002118136	0.27008	1.19852	0.000001016
Deer 110kV Twin Circuit	0.0402311	0.2706361	0.000002133737	0.26761	1.19663	0.000001020
Zebra 110kV Twin Circuit	0.0400850	0.2720004	0.000002122487	0.26746	1.19799	0.000001017
Moose 110kV Twin Circuit	0.0328369	0.2687196	0.000002149745	0.26022	1.19471	0.000001024
Dog 132kV	0.2573575	0.4324630	0.000001335048	0.48474	1.35846	0.000000793
Coyote 132kV	0.2598370	0.4251751	0.000001359128	0.48722	1.35117	0.000000802
Panther 132kV	0.1619293	0.4076534	0.000001420737	0.38931	1.33365	0.000000823
Lynx 132kV	0.1863336	0.4122138	0.000001404171	0.41371	1.33821	0.000000817
Drake 132kV	0.0854064	0.3892623	0.000001491713	0.31278	1.31525	0.000000846
Deer 132kV	0.0804623	0.3854710	0.000001507234	0.30784	1.31146	0.000000851
Zebra 132kV	0.0801700	0.3881994	0.000001496032	0.30755	1.31419	0.000000847
Moose 132kV	0.0656738	0.3816379	0.000001523260	0.29305	1.30763	0.000000856
Dog 132kV Double Circuit	0.2573575	0.4377949	0.000001312435	0.48198	1.34888	0.000000935
Coyote 132kV Double Circuit	0.2598370	0.4305070	0.000001335699	0.48446	1.34159	0.000000949
Panther 132kV Double Circuit	0.1619293	0.4129853	0.000001395157	0.38655	1.32407	0.000000984
Lynx 132kV Double Circuit	0.1863336	0.4175456	0.000001379178	0.41096	1.32863	0.000000975
Drake 132kV Double Circuit	0.0854064	0.3945942	0.000001463538	0.31003	1.30568	0.000001024
Deer 132kV Double Circuit	0.0804623	0.3908029	0.000001478476	0.30509	1.30189	0.000001032
Zebra 132kV Double Circuit	0.0801700	0.3935313	0.000001467695	0.30479	1.30462	0.000001026
Moose 132kV Double Circuit	0.0656738	0.3869698	0.000001493892	0.29030	1.29806	0.000001041
Dog 132kV Twin Circuit	0.1286788	0.2941321	0.000001955239	0.35606	1.22012	0.000000977
Coyote 132kV Twin Circuit	0.1299185	0.2904882	0.000001980939	0.35730	1.21648	0.000000984
Panther 132kV Twin Circuit	0.0809647	0.2817274	0.000002045584	0.30834	1.20772	0.000000999
Lynx 132kV Twin Circuit	0.0931668	0.2840075	0.000002028357	0.32055	1.21000	0.000000995
Drake 132kV Twin Circuit	0.0427032	0.2725318	0.000002118136	0.27008	1.19852	0.000001016
Deer 132kV Twin Circuit	0.0402311	0.2706361	0.000002133737	0.26761	1.19663	0.000001020
Zebra 132kV Twin Circuit	0.0400850	0.2720004	0.000002122487	0.26746	1.19799	0.000001017
Moose 132kV Twin Circuit	0.0328369	0.2687196	0.000002149745	0.26022	1.19471	0.000001024
Coyote 220kV	0.2598370	0.4497039	0.000001283500	0.47494	1.30703	0.000000794
Panther 220kV	0.1619293	0.4321823	0.000001338305	0.37703	1.28951	0.000000814
Lynx 220kV	0.1863336	0.4367426	0.000001323596	0.40144	1.29407	0.000000809
Drake 220kV	0.0854064	0.4137911	0.000001401102	0.30051	1.27112	0.000000837
Deer 220kV	0.0804623	0.4099999	0.000001414787	0.29557	1.26733	0.000000842
Zebra 220kV	0.0801700	0.4127283	0.000001404911	0.29527	1.27006	0.000000838
Moose 220kV	0.0656738	0.4061668	0.000001428897	0.28078	1.26350	0.000000847
Coyote 220kV Double Circuit	0.2598370	0.4586858	0.000001254104	0.47070	1.29082	0.000000915
Panther 220kV Double Circuit	0.1619293	0.4411641	0.000001306376	0.37279	1.27329	0.000000947
Lynx 220kV Double Circuit	0.1863336	0.4457245	0.000001292357	0.39719	1.27785	0.000000938
Drake 220kV Double Circuit	0.0854064	0.4227730	0.000001366145	0.29627	1.25490	0.000000982
Deer 220kV Double Circuit	0.0804623	0.4189818	0.000001379152	0.29132	1.25111	0.000000990
Zebra 220kV Double Circuit	0.0801700	0.4217102	0.000001369767	0.29103	1.25384	0.000000985
Moose 220kV Double Circuit	0.0656738	0.4151487	0.000001392558	0.27653	1.24728	0.000000998
Coyote 220kV Twin Circuit	0.1299185	0.3150171	0.000001824269	0.34502	1.17235	0.000000972
Panther 220kV Twin Circuit	0.0809647	0.3062563	0.000001878952	0.29607	1.16359	0.000000987
Lynx 220kV Twin Circuit	0.0931668	0.3085364	0.000001864407	0.30827	1.16587	0.000000983
Drake 220kV Twin Circuit	0.0427032	0.2970607	0.000001939989	0.25781	1.15439	0.000001004
Deer 220kV Twin Circuit	0.0402311	0.2951651	0.000001953068	0.25533	1.15249	0.000001007
Zebra 220kV Twin Circuit	0.0400850	0.2965292	0.000001943638	0.25519	1.15386	0.000001005
Moose 220kV Twin Circuit	0.0328369	0.2932485	0.000001966471	0.24794	1.15058	0.000001011
Coyote 400kV	0.2598370	0.4466231	0.000001288910	0.53349	1.26360	0.000000816
Panther 400kV	0.1619293	0.4291015	0.000001344188	0.43558	1.24608	0.000000838
Lynx 400kV	0.1863336	0.4336617	0.000001329350	0.45999	1.25064	0.000000832
Drake 400kV	0.0854064	0.4107103	0.000001407551	0.35906	1.22769	0.000000862
Deer 400kV	0.0804623	0.4069191	0.000001421362	0.35412	1.22390	0.000000867
Zebra 400kV	0.0801700	0.4096474	0.000001411396	0.35382	1.22663	0.000000863
Moose 400kV	0.0656738	0.4030860	0.000001435605	0.33933	1.22007	0.000000872
Coyote 400kV Double Circuit	0.2598370	0.4847569	0.000001187489	0.50234	1.20460	0.000000895
Panther 400kV Double Circuit	0.1619293	0.4672353	0.000001234253	0.40443	1.18708	0.000000924
Lynx 400kV Double Circuit	0.1863336	0.4717956	0.000001221731	0.42883	1.19164	0.000000916
Drake 400kV Double Circuit	0.0854064	0.4488441	0.000001287470	0.32791	1.16869	0.000000957
Deer 400kV Double Circuit	0.0804623	0.4450529	0.000001299016	0.32296	1.16490	0.000000964
Zebra 400kV Double Circuit	0.0801700	0.4477813	0.000001290686	0.32267	1.16762	0.000000959
Moose 400kV Double Circuit	0.0656738	0.4412198	0.000001310901	0.30817	1.16106	0.000000971
Coyote 400kV Twin Circuit	0.1299185	0.3119362	0.000001835218	0.40357	1.12892	0.000001006
Panther 400kV Twin Circuit	0.0809647	0.3031754	0.000001890568	0.35462	1.12016	0.000001022
Lynx 400kV Twin Circuit	0.0931668	0.3054555	0.000001875844	0.36682	1.12244	0.000001018
Drake 400kV Twin Circuit	0.0427032	0.2939798	0.000001952375	0.31636	1.11096	0.000001040
Deer 400kV Twin Circuit	0.0402312	0.2920842	0.000001965622	0.31389	1.10907	0.000001043
Zebra 400kV Twin Circuit	0.0400850	0.2934484	0.000001956071	0.31374	1.11043	0.000001041
Moose 400kV Twin Circuit	0.0328369	0.2901676	0.000001979199	0.30649	1.10715	0.000001047