I. Power System

1. Power System Concept - PSC

MO1 -	Fundamental Concepts of Power System (Power Generation, Transmission and Distribution)	**7**
MO2 -	DC Electrical theory	**24**
MO3 -	AC Electrical theory	**36**
MO4 -	The fundamentals of interconnected power system operations	**56**

2. Power System Operation - PSO

MO1 -	Active & Reactive Power	**75**
MO2 -	Frequency Control	**89**
MO3 -	Voltage Control	**101**
MO4 -	Voltage Stability	**115**
MO5 -	Angle Stability	**131**
MO6 -	Power System Restoration	**148**

3. Metering and Instrumentation - MI

MO1 -	Burden & Saturation Characteristic of Instrument Transformers	**161**
MO2 -	Energy Meters and 3 Phase	**184**

4. Power System Protection - PSP

MO1 -	Basic Concepts of Power System Protection	**197**
MO2 -	Fault Characteristics and Calculations	**267**
MO3 -	Substation Protective System	**306**
MO4 -	Bus and Breaker Fail Protection	**348**
MO5 -	Transformer and Reactor Protection	**364**
MO6 -	Mechanical Protections on Transformer	**385**
MO7 -	Transmission Line Protection	**397**
MO8 -	Retrieval and Analysis of Fault and Event Records	**426**

1. POWER SYSTEM CONCEPT

Ghana Grid Company Limited

M01 – FUNDAMENTAL CONCEPT OF POWER SYSTEM

1.1 Objectives

Upon completion of this module the participant will be able to:

- Describe the basic concepts of power systems
- List various components of the grid and explain how they work
- Identify all the key players in the Ghana National Interconnected Transmission System.

1.2 Introduction

Electric power systems are comprised of components that produce electrical energy and transmit this energy to consumers. A modern electric power system has six main components:

i. Power plants which generate electric power,
ii. Transformers which raise or lower the voltages as needed,
iii. Transmission lines to carry power,
iv. Substations at which the voltage is stepped down for carrying power over the distribution lines,
v. Distribution lines, and
vi. Distribution transformers which lower the voltage to the level needed for the consumer equipment.

The intermediate network, which connects the transmission and distribution systems, is referred to as the sub-transmission system.

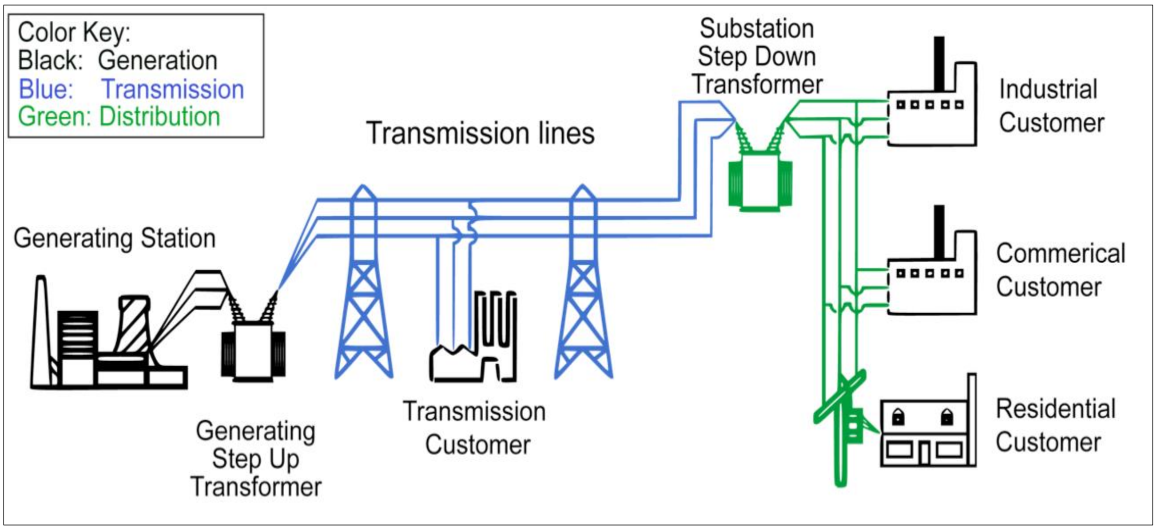


Figure 1-1. Simplified Power System

The generation and transmission of electricity are relatively efficient and inexpensive, although unlike other forms of energy, electricity is not easily stored, and thus, must be produced based on the demand.

1.3 How Power Systems Work

Bulk power systems comprise three main sub-systems – generation, transmission and bulk distribution centers. Bulk power is typically generated at low voltages such as 13 kV to 24 kV at power stations. For example, the bulk power station at Akosombo generates power at 14.4 kV. This bulk power must be transmitted over long distances to bulk load centres such as Accra, Kumasi and Tamale. To minimize transmission losses, the power must be transmitted at very high voltages. Therefore the output from bulk power generators is passed through step-up transformers located at the power station switchyard onto the transmission system. The primary bulk power transmission voltage in Ghana is 161 kV. At the bulk power distribution centre, the power is stepped down through step-down transformers for wholesale power buyers such as ECG and NEDCo for further distribution through their respective distribution networks to their customers (see Figure 1-2).

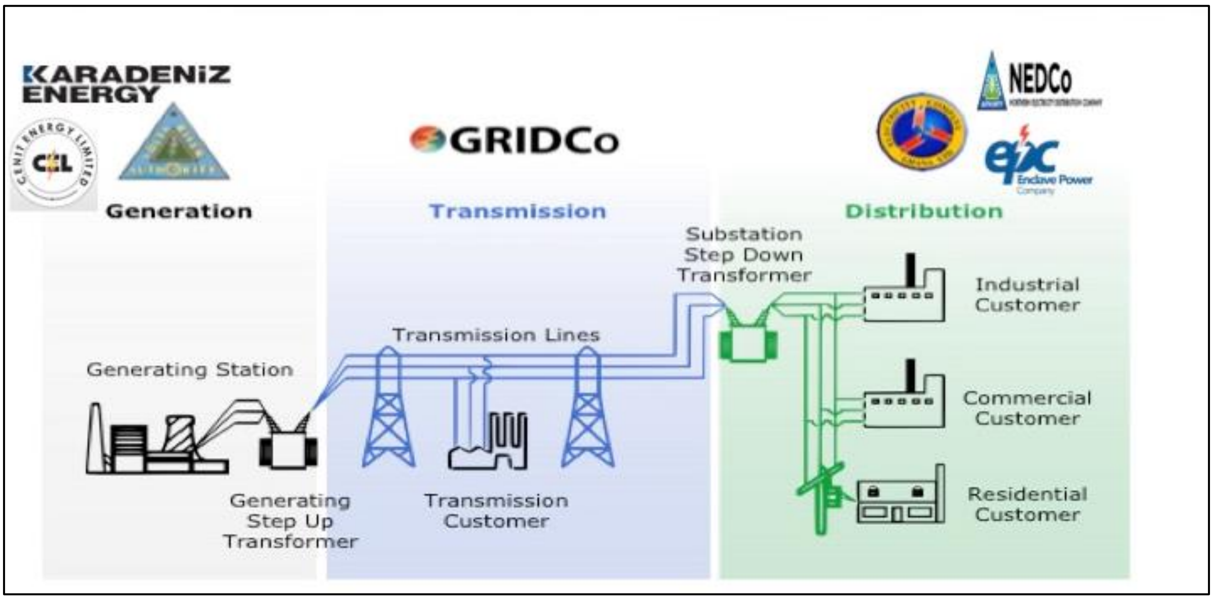


Figure 1-2. The Ghana Power System

Thus, the transmission of power from bulk power generators to bulk power distribution centres is very similar to the haulage of farm produce from commercial farms to bulk market centres.

In this case the farmer who cultivates and harvests the farm produce is analogous to a generation owner such as VRA or an IPP who generates the power. The trucker who carts the farm produce in a truck from the farm across trunk roads to the bulk market centre is analogous to a transmission company such as GRIDCo.

The marketer who receives the farm produce at the bulk market centre is analogous to a bulk power distribution company such as ECG, NEDCo or Enclave Power Company (EPC)

Each of the three sub-systems of a wholesale power system comprises many interconnected elements. When each one of these elements functions as expected, we get a functioning sub-system, and combined with other functioning sub-systems, a reliable wholesale power system.

Any elemental failure can compromise the reliability of the entire system; therefore, planners and operators allow necessary redundancies for critical elements to ensure reliable supply.

1.4 Power System Voltages

All the portions of the power system operate at different voltage levels. Typical voltage ranges are:

- **Generator –** which produces power at 14.4 kV, 13.8 kV or 11 kV.
- **Unit Transformers** or **Generator Step-up Transformers** – which step up the voltage to the transmission level. e.g., from 13.8 kV to 161 kV or 11 kV to 330 kV.
- **Transmission Substation Transformers** – which step down voltage to the sub-transmission level e.g., from 161 kV to 34.5 kV
- **Distribution Substation Transformers** – which step down voltage to the primary distribution level e.g. from 34.5kV to say 11.5kV
- **Distribution Transformers** – which effect the final voltage transformation to the user levels of 240/415 V, etc.
- However, **large customers**, such as the **Mines** and some **Big industries** are supplied power at the transmission substations (at 34.5, 11.5 or 6.6kV).

1.5 Generation System

It is not always practicable to generate electric energy at the location of its use. For economic, environmental and reliability reasons local generation may be unacceptable. Consequently, the power station, where power is generated in bulk, is usually located at some distance from the points of consumption of power. The huge electric energy must therefore be transmitted over a power transmission network connecting the power generating stations with the load centres.

Generally, any individual power station contains several large generating units, including a vast array of auxiliary equipment. Synchronous generators cannot generate power at voltage levels in excess of about 25 kV.

The generator voltage magnitude is limited in practice by the number of conductors that can physically be placed in stator slots.

It must also be remembered that the conductors must have a minimum cross-sectional area in order to carry the required stator current.

There are several energy sources for power generation. These include hydro, fossil fuel (e.g. gas, light crude oil, diesel, coal), Solar, Wind, Nuclear etc.

1.5.1 Hydroelectric Plants

Hydroelectric plants convert potential energy from running or falling water into electrical energy.

- Typically, a series of dams and reservoirs on river basins collect water to form an upper reservoir, which is then directed through large pipes called **penstocks** to **turbines** coupled to **generators**.
- The **generators** convert mechanical energy into electrical energy – to create electricity.
- The water then discharges through a **tailrace**, at a lower elevation than the upper reservoir.
- The electrical output from the generator is controlled by adjusting the **flow-rate** of water.

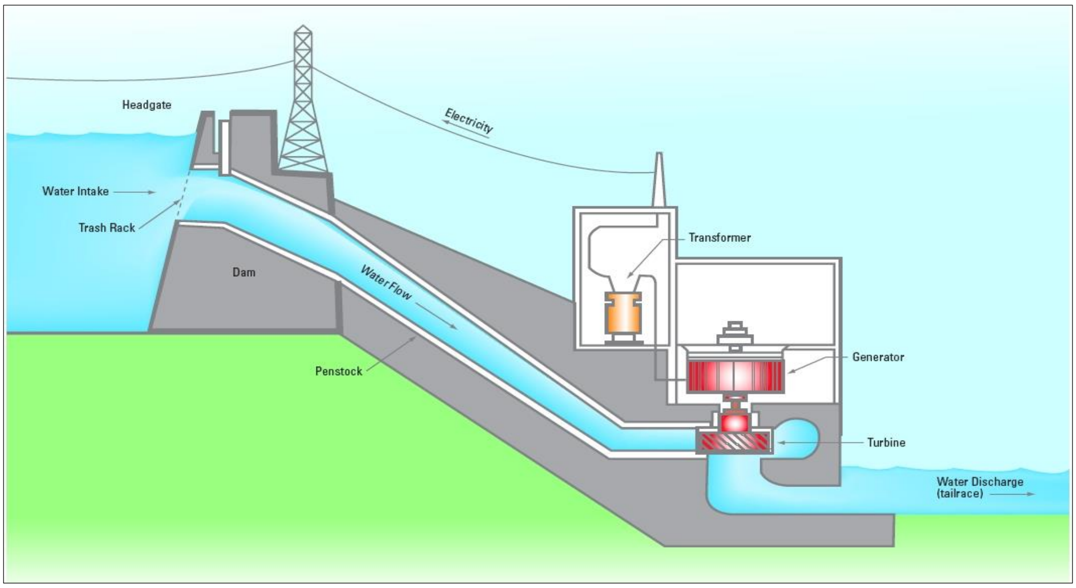


Figure 1-3. Hydro Electric Power Plant

The dams and reservoirs act like batteries, and allow operators to have some control of power production levels over time.

1.5.2 Fossil Fuel Plants

Thermal plants convert chemical energy released by burning fossil fuels such as coal, oil, and natural gas into mechanical energy using turbines. The mechanical energy is subsequently converted into electricity using a generator. This happens in heat engines with internal combustion (e.g. gas turbines). Often the heat is used to produce steam in a boiler. The steam then drives a steam turbine coupled to a generator.

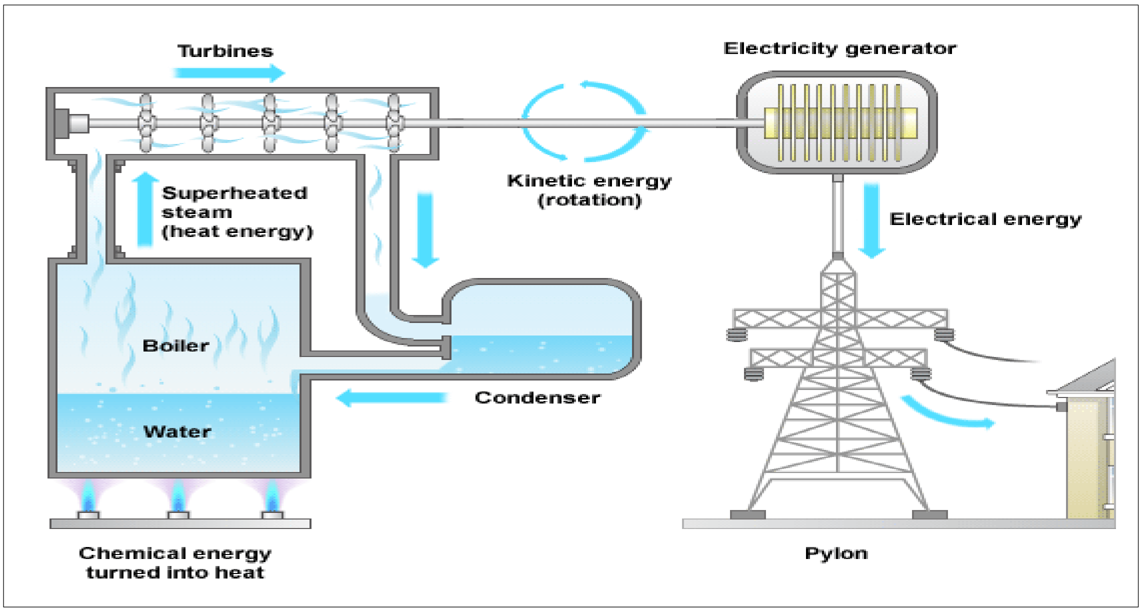


Figure 1-4. Thermal Generation

Another type of fossil generation is the diesel engine, which burns oil to generate electricity. In all of the fossil generation methods mentioned, the amount of electrical energy produced can be changed by controlling the amount of energy supplied to the unit, i.e., in order to generate more electricity, more fuel must be burned.

1.5.3 Renewable Energy Generation

1.5.3.1 Solar

Solar – powered photovoltaic (PV) panels convert the sun's rays into electricity by exciting electrons in silicon cells using the photons of light from the sun. This electricity can be used to supply renewable energy to homes or businesses

Light striking a silicon semiconductor causes electrons to flow, creating electricity. Solar power generating systems take advantage of this property to convert sunlight directly into electrical energy.

Solar panels (also called "solar modules") produce direct current (DC), which goes through a power inverter to become alternating current (AC) – electricity that can be used for distribution.

Two types of solar power generating systems are commonly known: i. grid – connected systems, which are connected to the commercial power infrastructure and ii. stand – alone systems, which feed electricity to a facility for immediate use, or to a battery for storage.

Grid – connected systems are used for homes. Public facilities such as schools and hospitals and commercial facilities such as offices and shopping centres. Electricity generated during the daytime can be used right away, and in some cases surplus electricity can be sold to the utility power company. If the system doesn't generate enough electricity, or generates none at all (for example, on a cloudy or rainy day, or at night) electricity is purchased from the utility power company. Power production levels and surplus selling can be checked in real time on a monitor, an effective way to gauge daily energy consumption.

Stand – alone systems are used in a variety of applications, including emergency power supply and remote power where traditional infrastructure is unavailable.

1.5.3.2 Wind

Wind power converts the kinetic energy in wind to generate electricity or mechanical power. This is done using a large wind turbine usually consisting of propellers; the turbine can be connected to a generator to generate electricity, or the wind used as mechanical power to perform tasks such as pumping water or grinding grain. As the wind passes through the turbines, it moves the blades, which spins the shaft. There are currently two different kinds of wind turbines in propellers or ‘fan – style’ blades, and HAWT are usually in an ‘egg – beater’ style.

Wind is converted by the blades of wind turbines. The blades of the wind turbines are designed in two different ways, the drag type and lift type.

Drag type: This blade design uses the force of the wind to push the blades around. These blades have a higher torque than lift designs but with a slower rotating speed. The drag type blades were the first designs used to harness wind energy for activities such as grinding and sawing. As the rotating speed of the blades are much slower than the lift type, this design is usually never used for generating large scale energy.

Lift type: Most modern Horizontal Axis Wind Turbines (HAWT) use this design. Both sides of the blades have air blown across it resulting in the air taking longer to travel longer across the edges. In this way, lower air pressure is created on the leading edge of the blade, and higher air pressure created on the tail edge. Because of this pressure difference, the blade is pushed and pulled around, creating a higher rotational speed that is needed for generating electricity.

To create electricity from wind, the shaft of the turbine must be connected to a generator. The generator uses the turning motion of the shaft to rotate a rotor which has oppositely charged magnets and is surrounded by copper wire loops. Electromagnetic induction is created by the rotor spinning around the inside of the core, generating electricity.

1.6 Generation In Ghana

Ghana relies on two main primary types of generation facilities: hydroelectric plants and thermal plants. Ghana also generates electricity from solar on a small scale.

There are eight major generation facilities in Ghana, three hydroelectric and five thermal plants. Historically, Ghana has been largely dependent on hydroelectric power.

Three hydroelectric plants, located at Akosombo, Kpong and Bui on the Volta River, represent the core of Ghana's generation system, accounting for 1,580 MW of generation capacity. Akosombo, Ghana's first large-scale power generation facility, became operational in 1966.

It remains the largest single generation facility in the country with an installed capacity of 1,020 MW, Kpong, whose role is to optimize the extraction of energy from the Volta Lake, operates directly downstream of Akosombo and has an installed capacity of 160 MW. The Bui dam located on the Black Volta river at Bui in the Brong-Ahafo Region has an installed capacity of 400MW and was fully operational in December 2013. Ghana's main thermal plants are located at Aboadze near Takoradi and in Tema.

Most of these plants are dual fired, ie can be operated on light crude oil (LCO) or natural gas (NG). In Ghana, thermal plants are typically located on or near the coast, closer to fuel supply sources.

LCO and diesel are delivered via tankers, and natural gas is delivered via the West African Gas Pipeline (WAGP) and the Ghana Gas pipeline, which run off the coast of Ghana. Table 1-1 presents a list of all the installed generation in the Ghana Power System.

Plants	Installed Capacity (MW)	Fuel Type
Akosombo GS	1020	HYDRO
Kpong GS	160	HYDRO
Bui HEP	400	HYDRO
TAPCO (T1)	330	LCO/Gas
TICO (T2)	350	LCO/Gas
TT1PP	126	LCO/Gas
CENIT	126	LCO/Gas

Plants	Installed Capacity (MW)	Fuel Type
TT2PP	49.5	Gas
MRP	49	Gas
SAPP	560	Gas
VRA Solar Plant	2.5	Sunlight
BXC Solar	20	Sunlight
Karpower	450	HFO
Ameri	250	Gas
AKSA	370	HFO
KTPP	220	Diesel/Gas
Takoradi Thermal Expansion	132	Gas
TOTAL	**4,615**	

Table 1-1. List of Installed Generation plants in Ghana

1.7 Transmission System

Transmission and distribution lines are major components of the electric power network. Essentially, there is no difference between transmission and distribution lines, except for voltage level and power-handling capability.

Transmission lines usually are capable of transmitting large quantities of electric power over relatively long distances and operate at higher voltages. Distribution lines, on the other hand, carry smaller amounts of power over shorter distances and usually operate at lower voltages.

1.8 Ghana National Interconnected Transmission System (Nits)

Ghana's interconnected grid covers most of the country and this ensures that the needed electrical energy is transmitted from the generating sites in Akosombo, Aboadze, Kpong, Bui, Tema etc to the various load centres along the length and breadth of the country. GRIDCo operates the transmission grid linking the generating stations located mostly in the south to the primary sub-transmission substations of the two main Distribution Companies, ECG and NEDCo for distribution to residential, commercial and industrial customers connected to the distribution grid. There are other industrial customers like the Mines that are also supplied directly from the high voltage grid through dedicated substations. The NITS is interconnected with the systems of Ivory Coast to the West and Togo/Benin to the East.

The transmission system, as shown in Figure 1-5 below comprises of a 161kV loops serving the southern and northern parts of the country with a few kilometres of 69 kV lines in the Volta Region and a single 225 kV line from Prestea in the Western half of the network to Riviera in La Cote d'Ivoire serving as the only interconnection with the neighboring utility, CIE of La Cote d'Ivoire to the West. The transmission system comprises approximately 4,000 km of HV lines (330, 225, 161 and 69 kV) and over 50 primary substations. The interconnections with other countries consist of:

- 225 kV, 220 km Single circuit line Prestea-Riviera (La Cote d'Ivoire);
- 161 kV, 129 km Double circuit line Akosombo-Lome (Togo/Benin);

There also exists a single 330 kV line linking the Thermal Power Enclave in Aboadze to the main Substation at Volta in Tema. These transmission lines that connect the over 50 substations that either serve as switching stations with no power transformers, step-up stations for the generation plants and/or step-down stations that step down the high voltages to various medium voltages (34.5kV, 11.5kV, 6.6kV) to serve the loads within the distribution system.

With the prospects of increased power export to neighboring countries within West Africa, a 330 kV Transmission line from Aboadze in the South Western part of the country to Kumasi that continues to Kintampo and terminates at Bolgatanga in the Northern Part of Ghana is underway. There are also a number of reinforcements and expansions at the 161 kV voltage level and these are meant to improve the overall supply reliability in the north and other portions in the south.

GRIDCo manages the Ghana transmission network. Because transmission interconnects both the supply side (generation) and demand side (distribution), the transmission authority is a natural candidate to coordinate the electricity system. Hence GRIDCo functions as an independent system operator (ISO) for Ghana's electricity system, and consequently has the dispatch responsibility. With this comes the responsibility to maintain reliability at the wholesale supply level.

Figure1-5. National Interconnected Transmission System of Ghana

Electricity demand in Ghana is divided across over 40 load centres, which include cities, clusters of smaller towns and villages, and large industrial sites such as mines. In Ghana, a relatively small number of load centres account for a large fraction of total demand.

Ghana's ten largest load centres together account for nearly 68% of peak demand and 72% of energy consumption. Most of these load centres coincide with urban centres – Accra, Tema and Kumasi alone account for approximately 49% of total national peak demand.

The remaining major load centres are associated with heavy industrial activity. Industrial customers are characterized by very high, consistent power demands. The four largest mines alone account for 12.5% of national peak demand, and each mine consume a significant amount of energy relative to their peak demand. Large industrial customers like mines often buy power on the wholesale market, and hence have direct relationships with transmission and generation entities.

This is partially because the size of their demand requires special reliability requirements, and also because of the traditionally strong link between the development of electricity infrastructure to support specific industrial activity. For example, the need to supply electricity to VALCO was a major driver in the construction and financing of the Akosombo hydroelectric facility.

1.9 Distribution System

Distribution networks carry power over a few kilometres from transmission or sub transmission to consumers. Power is carried in distribution networks through wires either on poles or, in many urban areas, underground. Distribution networks are distinguished from transmission networks by their voltage level and topology. Lower voltages are used in distribution networks, as lower voltages require less clearance. Typically lines up to 34.5 kV are considered part of the distribution network.

The connection between distribution networks and transmission or sub transmission occurs at distribution substations. Distribution substations have transformers to step voltage down to the primary distribution level. Like transmission substations, distribution substations also have circuit breakers and monitoring equipment. However, distribution substations are generally less automated than transmission substations.

Primary distribution lines leaving distribution substations are called “feeders.” They also carry three-phase ac voltage, which is why one sees three wires on many poles in rural and suburban areas.

These individual phases are then separated and feed different neighborhoods. Distribution networks usually have a radial topology, referred to as a “star network,” with only one power flow path between the distribution substation and a particular load.

Distribution networks sometimes have a ring (or loop) topology, with two power flow paths between the distribution substation and the load. However, these are still operated as star networks by keeping a circuit breaker open. In highly dense urban settings, distribution networks also may have a mesh network topology, which may be operated as an active mesh network or a star network. The presence of multiple power flow paths in ring and mesh distribution networks allows a load to be serviced through an alternate path by opening and closing appropriate circuit breakers when there is a problem in the original path.

Distribution networks usually are designed based on the assumption that power flow is in one direction. However, the addition of large amounts of distributed generation may make this assumption questionable and require changes in design practices. Industrial and large commercial users usually get three-phase supply directly from the primary distribution feeder, as they have their own transformers and in certain cases can directly utilize the higher voltages.

However, for the remaining consumers, who generally require only single-phase power, power is usually transmitted for the last half-mile or so over lateral feeders that carry one phase. A distribution transformer, typically mounted on a pole or located underground near the customer, steps this voltage down to the secondary distribution level, which is safe enough for use by general consumers. Residential power consumption in the Ghana occurs at 240 V. In suburban neighborhoods, one distribution transformer serves several houses. A conceptual diagram of Sub transmission and Distribution services is presented in Figure 1-6. Because the most of the major load centres are located in the southern part of the country, ECG handles a very high fraction of customers and serves a very high fraction of demand and energy consumption compared to NEDCo.

1.10 Distribution in Ghana

The distribution system is a network of low voltage distribution lines that deliver electricity directly to customers. The distribution system is generally considered to begin at the bulk power substation where GRIDCo delivers power to the wholesale power buyers, and end at the retail consumer's meter. Beyond the meter lies the customer's electric system, which consists of wires, equipment, and appliances.

In Ghana, the Electricity Company of Ghana (ECG), the government-owned entity is responsible for the distribution of electricity in the southern part of Ghana--namely Ashanti, Central, Eastern, Greater Accra, Volta, and Western Regions--covering approximately 80% of the population in Ghana. The Northern Electricity Distribution Company (NEDCo) is a wholly-owned subsidiary of VRA, responsible for the distribution of electricity in the northern regions of Ghana. The Enclave Power Limited – a private company also offers distribution services to some small parts of Tema, an industrial town. Figure 1-6 shows a map of distribution zones in Ghana

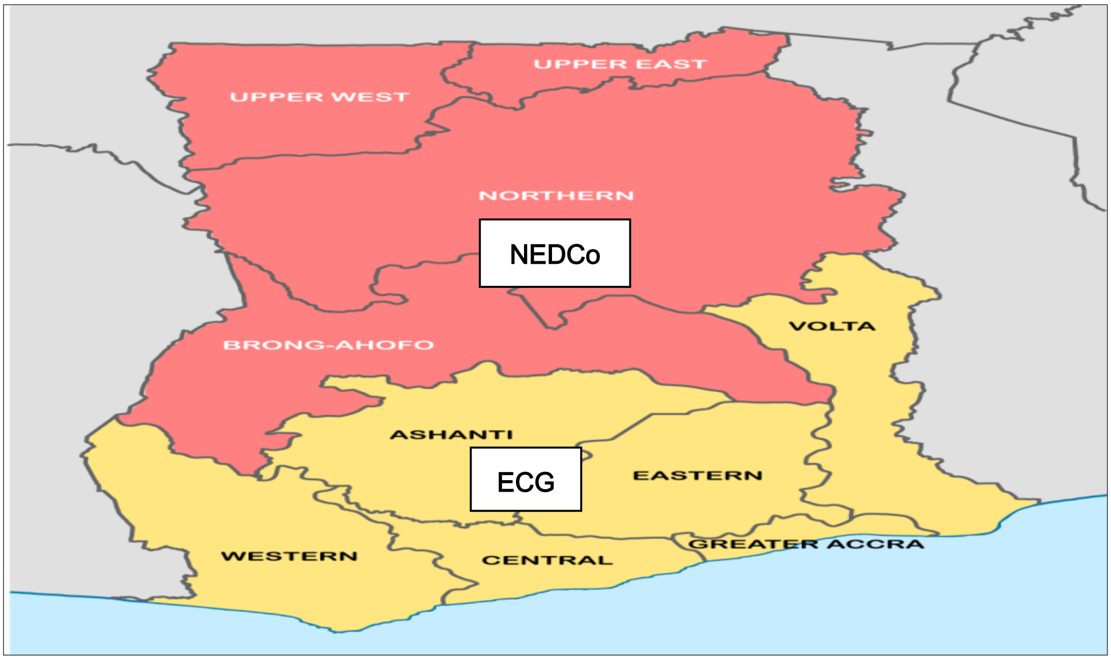


Figure 1-6. Distribution Zones of ECG and NEDCo in Ghana

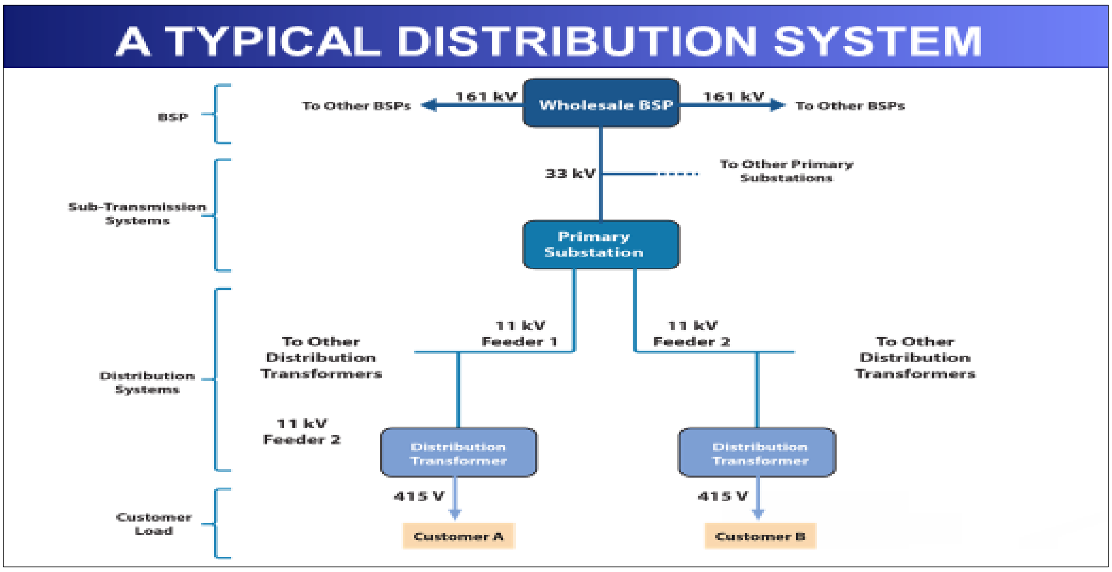


Figure 1-7. Typical Distribution System

LIST OF NATIONAL GENERATING STATIONS AND SUBSTATIONS

1. Akosombo GS (A1GS)
2. Volta Substation 161/330KV (V2)
3. Smelter Substation (S3)
4. New Tema Substation (E4)
5. Achimota Substation (H5)
6. Winneba Substation (W6)
7. Cape Coast Substation (C7)
8. Takoradi Substation (T8)
9. Tarkwa Substation (R9)
10. Prestea Substation 161/225kV (P10)
11. Dunkwa Substation (D11)
12. Obuasi Substation (B12)
13. Kuamsi Substation(K13)
14. Nkawkaw Substation (N14)
15. Tafo Substation (F15)
16. Akwatia Substation (Q16)
17. Old Kpong Substation (G17)
18. Konongo Substation (J18)
19. Kpong GS (Z19GS)
20. Asawinso Substation (AS20)
21. New Obuasi Substation (NB21)
22. Asiekpe Substation (AP22)
23. HO Substation (HO23)
24. Kpeve Substation (PE24)
25. Kpandu Substation (PU25)
26. Techiman Substation (TH26)
27. Sunyani Substation (SN27)
28. Tamale Substation (TM28)
29. Bolga Substation (BG29)
30. Bogoso Substation (BS30)
31. Tema Diesel Plant (TDS31GS)- **OP**
32. Takoradi Thermal 161/330KV
    a. (TT32GS)
33. Sogakope Substation (SK33)
34. Essiama Substation (EA34)
35. Yendi Substation (YD35)
36. Elubo Substation (EL36)
37. Malam Substation (M37)
38. Sawla Substation (SA38)
39. Aflao Substation (AF39)
40. Strategic Reserve (SRP40) - **OP**
41. New Tarkwa Substation (NR41)
42. Akyempim Substation (AY42)
43. Kenyasi Substation (KY43)
44. Tema Reserve P. Plant (TR44GS) (Trojan)
45. New Tema Reserve P. Plant (ER45GS) (Trojan)
46. Mines Reserve P. Plant (MR46GS)
47. Tema Thermal 1 P. Plant (TP47GS)
48. Kumasi Reserve P. Plant (KR48GS) (Trojan)
49. Dormunli Thermal P. Plant (DT49GS) – **UC**
50. Tema Thermal 2 P. Plant (ST50GS)
51. Sunon Asogli P. Plant (SG51GS)
52. Effasu Barge (EF52GS) – **UC**
53. Zebila Substation (ZB53)
54. Bui Generating Station (BU54GS)
55. Buipe Substation (BP55)
56. Kintampo Substation (KP56)
57. Ayanfuri Substation (AR57)
58. Anwomaso Substation (AW58)
59. Accra East Substation (AE59)
60. Smelter II Substation (SM60)
61. New Abiriem Substation (NA61
62. Mim Substation (MM62)
63. Berekum Substation (BR63) - **UC**
64. Juabeso Substation (JB64)
65. Atebubu Substation (AT65) - **UC**
66. Takoradi Thermal Expansion (TE66GS)
67. Kpone Thermal P. Station (KT67GS
68. WA Substation (WA68)
69. Tumu Substation (TU69)
70. Kadjebi Substation (KD70)
71. Afienya Substation (AN71) **UC**
72. Freezonei Substation (FZ72)
73. Bawku Substation (BK73)

UC – Under Construction,

OP – Out of Operation

NS – Not Started

SINGLE LINE DIAGRAM OF THE GHANA NATIONAL GRID — rev. MARCH 2017

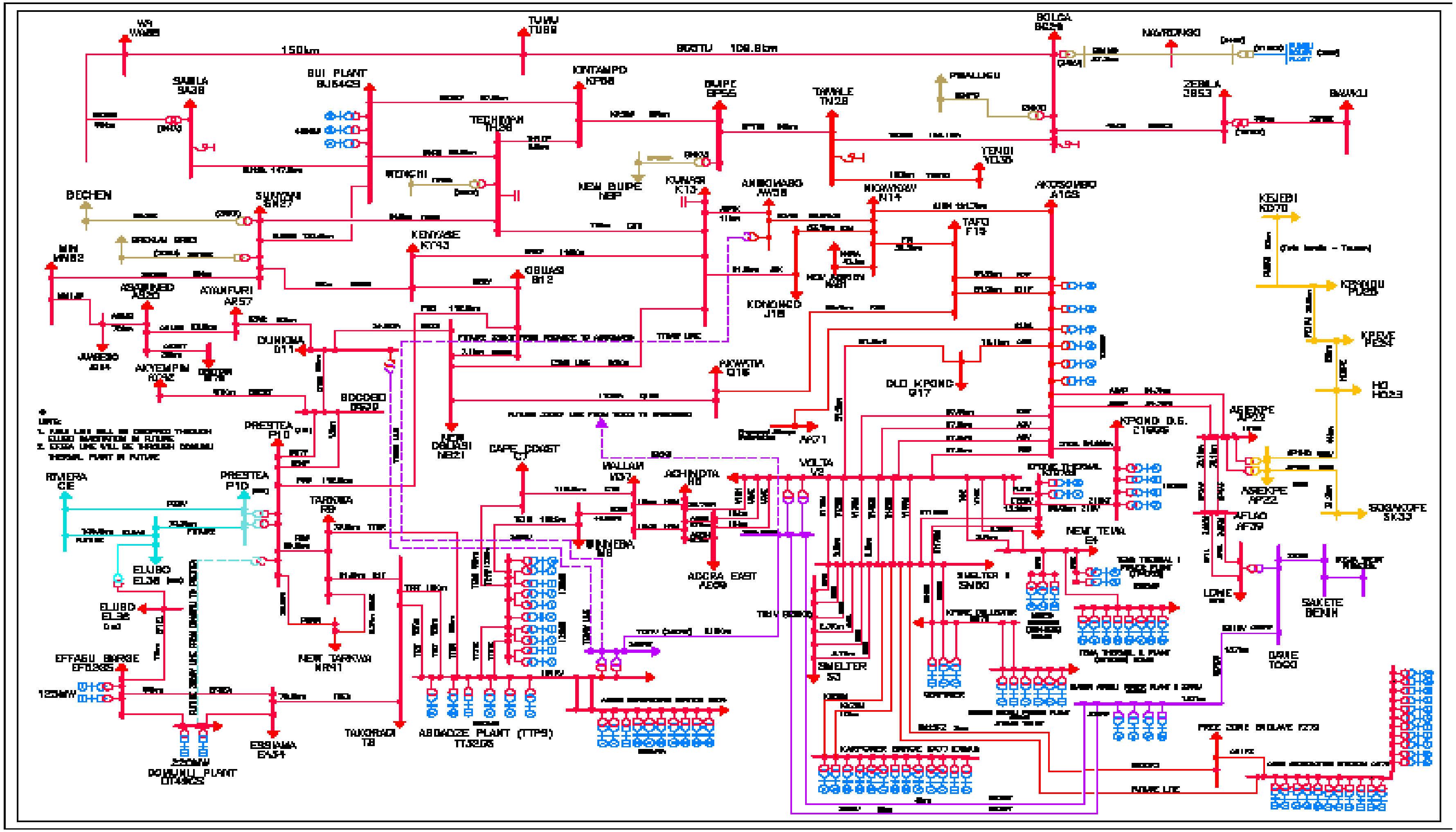


Figure 1-8. Single Line Diagram of the Ghana NITS

M02 – DC ELECTRICAL THEORY

2.1 Objectives

Upon completion of this module participants will be able to:

- Understand the basic concepts of DC circuit laws and theorems
- Identify DC circuit elements including active and passive elements, resistors in series and in parallel, and Delta-star transformation

2.2 Introduction

Electrical circuits connect power supplies to loads such as motors, heaters, or lamps. The connection between the supply and the load is made by soldering with wires that are often called leads, or with many kinds of connectors and terminals. Energy is delivered from the source to the user on demand at the click of a switch. Electrical energy comes in the form of electromotive force (emf) or voltage (V) which drives current (I) through the circuit when it is closed. For DC circuits, the emf has constant amplitude and direction.

Sometimes many circuit elements are connected to the same lead, which is called a common lead for those elements. Various components of circuits are called circuit elements, which can be in series or in parallel. A node is a point in a circuit where three or more elements are soldered together. A branch is a current path between two nodes. Each branch in a circuit can have only one current in it although a branch may have no current. A loop is a closed path that may consist of different branches with different currents in each branch.

2.3 Dc Circuit Elements

2.3.1 Active and Passive Elements

The sources and loads of an electric circuit are represented using elements. Such representations allow for easy analysis of circuits. Circuit elements are categorised into active elements and passive elements.

2.3.1.1 Active Elements

Active elements generate electrical energy. Examples of active voltage source elements are batteries, generators, operational amplifier and photovoltaic cells. However, only batteries and photovoltaic cells qualify as active elements in DC circuits since they provide supplies which have constant amplitude and direction.

Figure 2-1. Active voltage elements

There are also some **current sources**, such as photoelectric cells and metadyne generators. An active source may be classified into either dependent source or independent source. Photoelectric cells are DC current sources.

An ideal independent source is an active element that provides a specified voltage or current that is completely independent of other circuit elements. An ideal voltage source is that element which supplies voltage between two terminals to maintain current through the circuit. It maintains a fixed voltage which is not affected by any other quantity. Generators, batteries are the ideal voltage sources in circuits. Figure 2-2 shows the circuit symbol of an ideal battery.

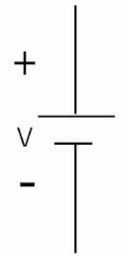


Figure 2-2. Circuit symbol of an ideal battery

An ideal independent current source is also an active element which supplies a specified current to a circuit. It maintains a fixed current which is not affected by any other quantity. Figure 2-3 shows the independent current source symbol where arrow sign indicates the direction of flowing current i.

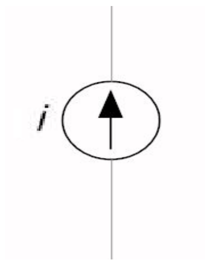


Figure 2-3. Independent current source

An ideal dependent source is an active element in which the source quantity is controlled by another voltage or current. The voltage or current varies with some other variable. The four types of possible dependent sources are: current controlled voltage source (CCVS), voltage controlled voltage source (VCVS), current controlled current source (CCCS), and voltage controlled current source (VCCS). The figures below show circuit symbols of dependent sources.

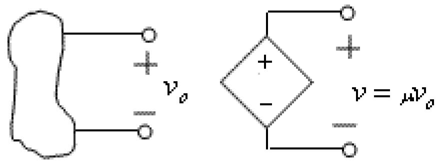


Figure 2-4. Voltage controlled voltage source

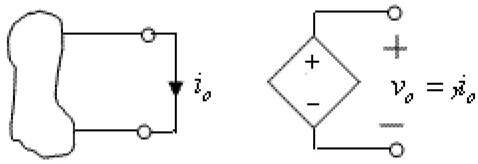


Figure 2-5. Current controlled voltage source

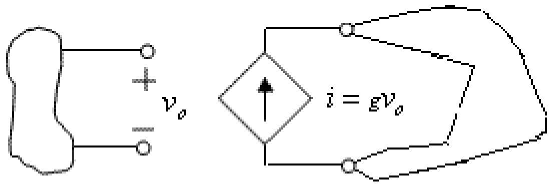


Figure 2-6. Voltage controlled current source

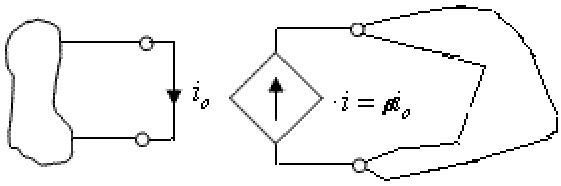


Figure 2-7. Current controlled current source

2.3.1.2 Passive elements

Passive elements do not and cannot generate electrical energy. They rather consume electrical energy by changing them into various forms such as heat and motion. Electrical loads are represented in circuits using combinations of passive elements. In electric circuits, there are three passive elements. These are resistors (R), inductors (L) and capacitors (C). Figure 2-8 shows the three passive elements.

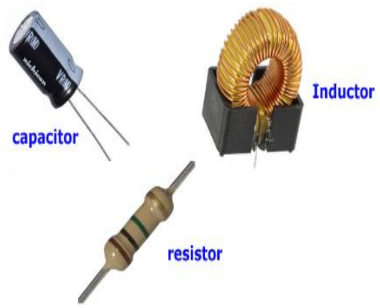


Figure 2-8. Passive elements

Resistors transform electrical energy into heat energy. The electrical energy supplied to inductors by an external circuit is stored in their magnetic fields and can be fully recovered. The energy supplied to a capacitor by an external circuit is stored in its electric field. Here too, the energy can be fully recovered.

Figure 2-9 shows circuit symbols of the three passive elements. The numerical value of a resistor is called resistance and is measured in ohms (Ω) while that of an inductor is called inductance which is measured in Henries (H). The value of a capacitor is capacitance and is measured in Farads (F)

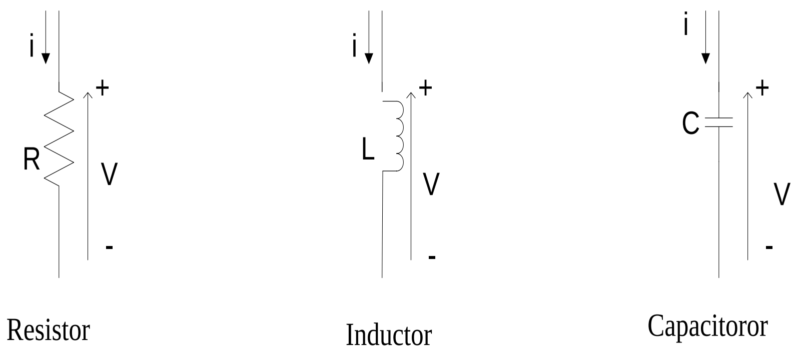


Figure 2-9. Circuit Symbols for Passive elements

The Terminal relations for the passive elements are given below.

(a) Resistance $v = Ri$

(b) Inductance $v = L\frac{di}{dt}$

(c) Capacitance $i = C\frac{dv}{dt}$

2.3.2 Resistors in Series and in Parallel

Two or more resistors are said to be in series when the same current is flowing through them (in other words, there is no junction between them).

2.3.2.1 Series connection of resistors

Resistors are said to be in series when the same current flows through them. The voltages across them may be different. The physical identification mark for series resistors in a circuit is the absence of a node (junction) between them. This is so because current splits when it get to a node. For example in the circuit shown below, all the resistors are in series; there is no node between them.

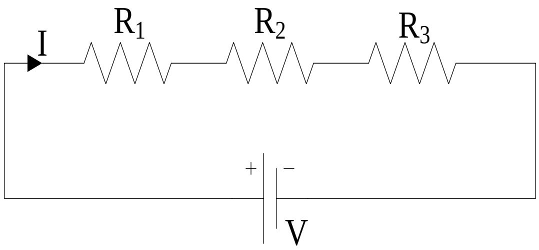


Figure 2-10. Circuit Symbol for resistors in series

The total resistance R_T of resistors with resistances R_1, R_2, R_3, ..., R_N connected in series is given as

$$R_T = R_1 + R_2 + R_3 + ... + R_N$$

2.3.2.2 Parallel connection of resistors

Resistors are in parallel when the voltage across each is the same. In other words, it is possible to traverse any two without passing through any other circuit element.

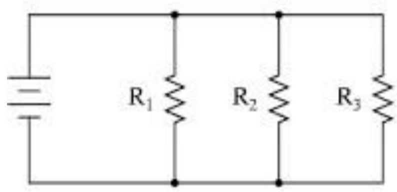


Figure 2-11. Circuit Symbols for Resistors in Parallel

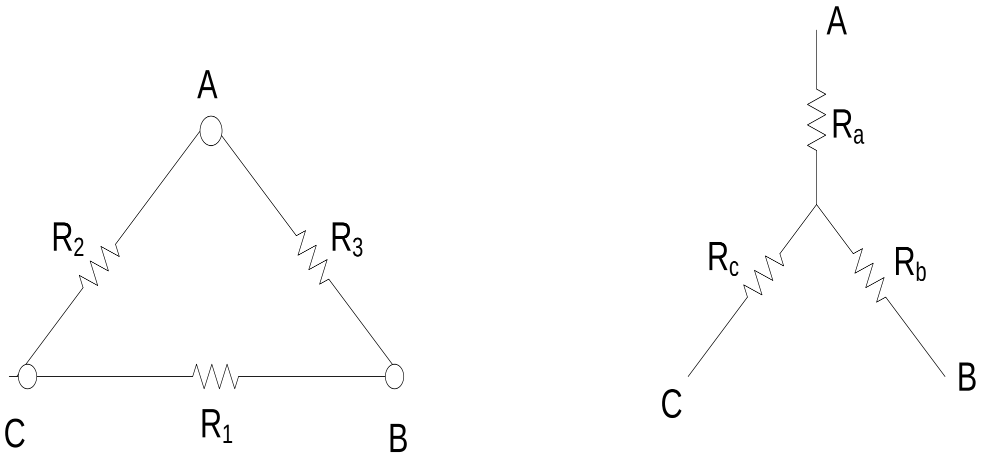
The total resistance R_T of resistors with resistances R_1, R_2, R_3, ..., R_N connected in parallel is given as

$$\frac{1}{R_T} = \frac{1}{R_1} + \frac{1}{R_2} + \frac{1}{R_3} + ... + \frac{1}{R_N}$$

2.3.3 Delta-Star Transformation

Figure 2-12 shows three-element, three-terminal networks. The arrangements (a) and (b) are said to be delta- and star- connected respectively.

It is possible to transform one into another using the following equations:



(a) Delta-connected resistors (b) Star-connected resistors

Figure 2-12. Delta- and Star-connected resistors

Delta to star transformation ($\Delta \rightarrow Y$):

$$R_a = \frac{R_2 R_3}{R_1 + R_2 + R_3}$$

$$R_b = \frac{R_3 R_1}{R_1 + R_2 + R_3}$$

$$R_c = \frac{R_1 R_2}{R_1 + R_2 + R_3}$$

Star to delta transformation ($Y \rightarrow \Delta$):

$$R_1 = R_b + R_c + \frac{R_b R_c}{Ra}$$

$$R_2 = R_c + R_a + \frac{R_c R_a}{Rb}$$

$$R_3 = R_a + R_b + \frac{R_a R_b}{Rc}$$

These transformations have to be carried out before some networks will permit a straightforward reduction by series and parallel combinations.

2.4 Dc Circuit Laws And Theorems

2.4.1 Ohm's Law

Ohm's Law deals with the relationship between voltage and current in an ideal conductor. This relationship states that: The potential difference (voltage) across an ideal conductor is proportional to the current through it.

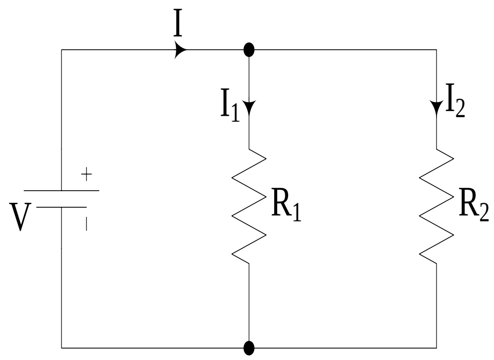
The constant of proportionality is called the "resistance", R. Ohm's Law is given by:

$$V = IR$$

where V is the potential difference between two points which include a resistance *R*. *I* is the current flowing through the resistance.

2.4.2 Current Division and Voltage Drop

The current division rule is applied to share current between parallel branches. Consider the circuits below.



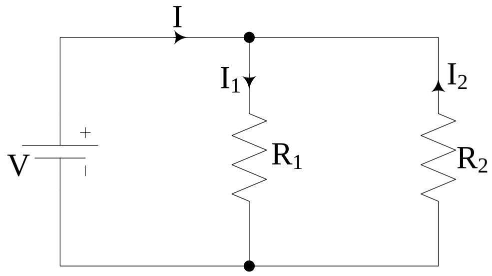
$$R_T = R_1 // R_2 = \frac{R_1 R_2}{R_1 + R_2}$$

$$V = IR_T = I\frac{R_1 R_2}{R_1 + R_2}$$

$$I_1 = \frac{V}{R_1} = \frac{I\dfrac{R_1 R_2}{R_1 + R_2}}{R_1} = I\frac{R_1 R_2}{R_1 + R_2} \times \frac{1}{R_1} = I\frac{R_2}{R_1 + R_2}$$

$$I_2 = I\frac{R_1}{R_1 + R_2}$$

For the circuit below,



$$I_1 = \frac{R_2}{R_1 + R_2} I \text{, and}$$

$$I_2 = -\frac{R_1}{R_1 + R_2} I$$

2.4.3 Kirchoff's Laws

Kirchoff's laws form the basis for all network analysis. The laws are two, which are:

(a) Kirchoff's Current Law (KCL): It states that the algebraic sum of the currents entering a node at any instant is zero. Alternatively, the law can be stated as: the algebraic sum of the currents entering a node equals the algebraic sum of the currents leaving the node. Consider the figure below,

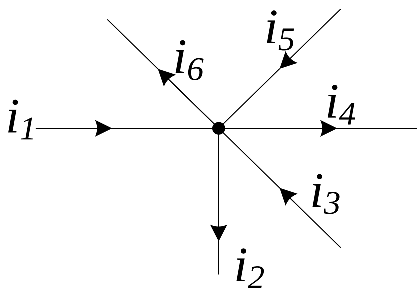


Figure 2-13. Kirchoff's Current Law

The sum of currents entering the node $= i_1 + i_3 + i_5$

The sum of currents leaving the node $= i_2 + i_4 + i_6$

Applying Kirchoff's current law,

$$i_1 + i_3 + i_5 = i_2 + i_4 + i_6$$

(b) Kirchoff's Voltage Law (KVL): It states that algebraic sum of the voltages around a closed path in a circuit at any instant is zero. Alternatively, in a loop, the algebraic sum of voltage sources equals the algebraic sum of voltage drops.

The following equations can be written from the circuit below using Kirchoff's voltage law.

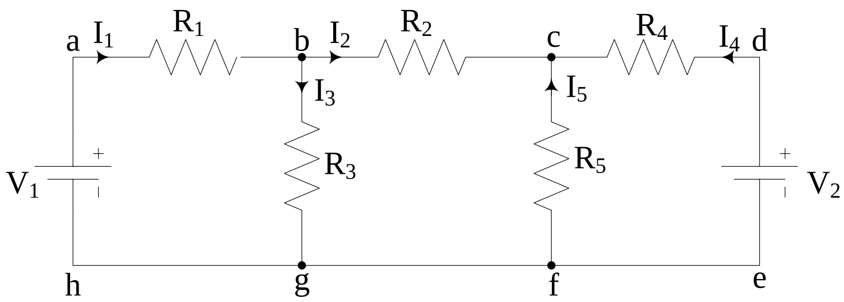


Figure 2-14. Kirchoff's Voltage Law

Loop abgha: $V_1 = I_1R_1 + I_3R_3$

Loop cbgfc: $0 = -I_2R_2 + I_3R_3 + I_5R_5$

Loop adeha: $V_1 - V_2 = I_1R_1 + I_2R_2 - I_4R_4$

2.4.4 Thevenin's Theorem

It states that any linear circuit connected between two terminals can be replaced by a Thevenin's voltage V_{TH} in series with a Thevenin's resistance R_{TH} where V_{TH} is equal to the open-circuit voltage appearing between the two terminals and R_{TH} is equal to the resistance viewed between the two terminals when all internal sources are deactivated (i.e. voltage sources short-circuited, and current sources open-circuited).

The Thevenin's equivalent circuit is shown below where R is the resistance of the resistor whose current is being sought.

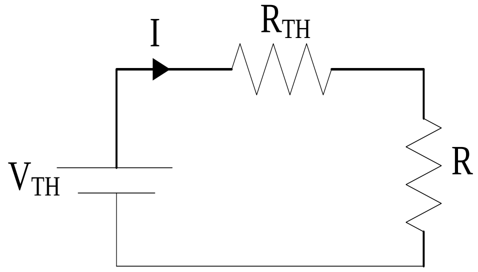


Figure 2-15. Equivalent Thevenin Circuit

Thevenin's theorem is extremely useful in finding the current through or the voltage across any resistor in a circuit.

2.4.5 Norton's Theorem

It is very similar to Thevenin's Theorem and provides an equally powerful method for simplifying complex circuits. Norton's Theorem states that any linear circuit connected between two terminals can be replaced by a Norton current source I_N in parallel with a Norton resistance R_N connected between the same two terminals.

The Norton current I_N is equal to the current that flows in a short circuit connected between the two terminals. The Norton resistance R_N is equal to the resistance viewed between the two terminals when all sources are deactivated.

Note the following important relationships:

$$R_N = R_{TH}\ ,\ I_N = \frac{V_{TH}}{R_{TH}}$$

2.4.6 Superposition Theorem

Superposition theorem states that the current through (or the voltage across) any element in a multiple-source linear circuit can be found by taking the algebraic sum of the current through (or the voltage across) that element due to each individual source acting alone.

Application of this theorem means finding the response in an element due to each source (all other sources replaced by their internal resistances) and then adding these individual responses to obtain the overall response.

2.4.7 Reciprocity Theorem

The Reciprocity theorem can be stated in two ways:

(a) An ideal ammeter and ideal voltage source when inserted in two different branches of a linear network can be interchanged without changing the reading of the ammeter. See Figure 2-16 (a) and (b).

(b) An ideal voltmeter and ideal current source when connected across two different branches of a network can be interchanged without changing the reading of the voltmeter. See Figure 2-16 (c) and (d).

The reciprocity theorem is applicable only to single-source networks.

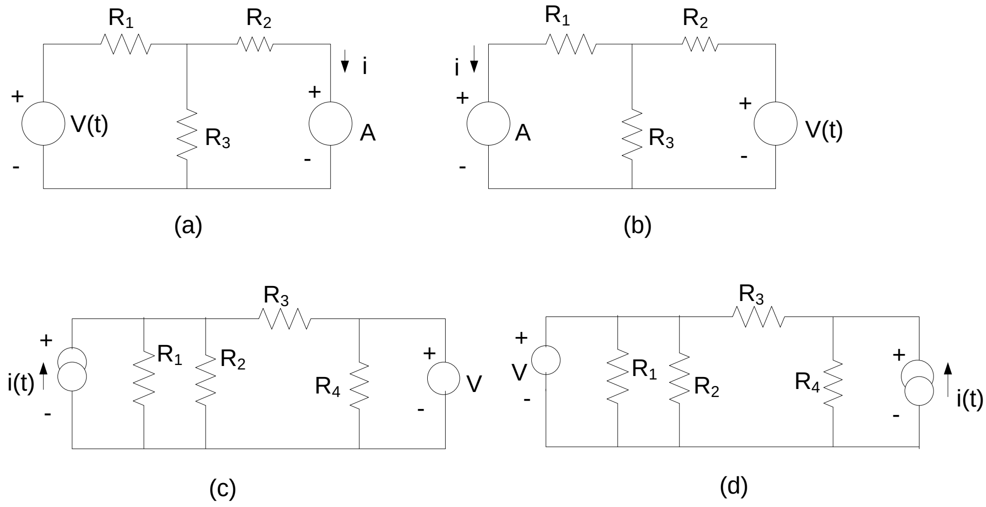


Figure 2-16. Circuits illustrating reciprocity theorem

M03 – AC ELECTRICAL THEORY

3.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of AC circuit laws and theorems including single-phase and three-phase AC circuits
- Identify application of network theorems to AC networks

3.2 Introduction

When voltages, currents and impedances are treated as complex numbers or phasors, the solution of ac circuits becomes the same as that of dc circuits.

Therefore the only variation in applying the network theorems to ac circuit is that we will be working with impedances and phasors instead of just resistors and real numbers.

3.3 Single-Phase AC Circuits

3.3.1 SINUSOIDAL VOLTAGES AND CURRENTS

The ac voltage generated by commercial ac generators (or alternators) is very nearly a perfect sine wave.

It may therefore be expressed by the equation

$$v = V_m \sin 2\pi ft$$

where

V_m = peak value of the sinusoidal voltage

f = frequency [Hz]

Sinusoidal voltages always produce sinusoidal currents unless the circuit is non-linear. The current may lag or lead the voltage depending on the type of circuit.

If a current lags behind the voltage given above by an angle φ, it is expressed as

$$i = I_m \sin(2\pi ft - \varphi)$$

and if it leads the voltage, it is expressed as

$$i = I_m \sin(2\pi ft + \varphi)$$

where

I_m = peak value of the sinusoidal current.

R.M.S. value of a sinusoidal current and voltage

The root mean square voltage is given by

$$V = \left[\frac{1}{T}\int_0^T V_m^2 \sin^2 2\pi f t dt\right]^{\frac{1}{2}}$$

$$= \left[\frac{1}{T}\int_0^T \frac{V_m^2}{2}(1-\cos 4\pi f t)dt\right]^{\frac{1}{2}}$$

$$= \left[\frac{V_m^2}{2}\frac{T}{T}\right]^{\frac{1}{2}}$$

$$= \frac{V_m}{\sqrt{2}}$$

Similarly, the root mean square current is

$$I = \frac{I_m}{\sqrt{2}}$$

3.3.2 Harmonics

Non-sinusoidal periodic voltages and currents can be expressed as the sum of sine waves in which the lowest frequency is f and all other frequencies are integral multiples of f. By definition, the sine wave with the lowest frequency is called the fundamental and all other waves are called harmonics.

Effective value of a non-sinusoidal wave

Let the wave be expressed as the sum of fundamental and harmonic components as

$$v(t) = a_o + a_1 \sin(\omega t + \phi_1) + a_2 \sin(2\omega t + \phi_2) + a_3 \sin(3\omega t + \phi_3) + \ldots\ldots\ldots$$

Then the root mean square value of the voltage is given by

$$V = \sqrt{a_o^{\,2} + \left(\frac{a_1}{\sqrt{2}}\right)^2 + \left(\frac{a_2}{\sqrt{2}}\right)^2 + \left(\frac{a_3}{\sqrt{2}}\right)^2 + \ldots\ldots\ldots\ldots}$$

where

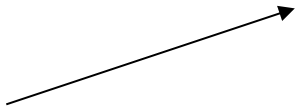
a_o = dc component

$\frac{a_1}{\sqrt{2}}$ = rms value of the fundamental component

$\frac{a_2}{\sqrt{2}}$ = rms values of second harmonic and so on.

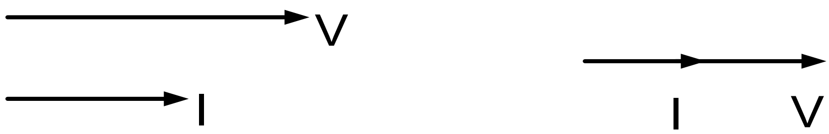
3.3.3 Phasors

Phasors are used to represent sinusoidal quantities to avoid drawing the sine waves. A phasor is a straight line whose length is proportional to the rms voltage or current it represents. To show the phase angle or phase displacement between voltages and currents, the phasors bear an arrow. See figure below.

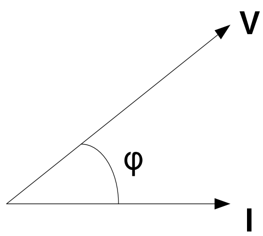


The following rules apply to phasors:

(a) Two phasors are said to be in phase when they point in the same direction. The phase angle between them is then zero. See the figures below.

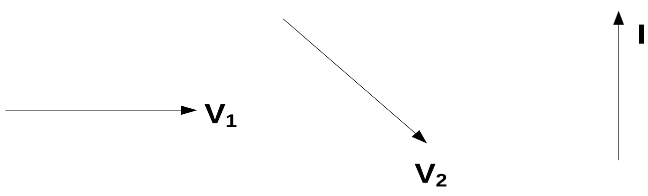


(b) Two phasors are said to be out of phase when they point in different directions. The phase angle between them is the angle through which one of them has to be rotated to make it point in the same direction as the other. See figure below.



(c) Phasor **V** is said to lead **I** by φ and **I** is said to lag behind **V** by φ if **I** has to be rotated anticlockwise through φ to make it point in the direction of **V** ($\varphi \leq 180^o$)

(d) Phasors need not have a common origin as shown below.



Phasor diagram

It is used to show at a glance the magnitude and phase relations among the various quantities within a network. This is often helpful in the analysis of the network.

Addition and subtraction of sinusoidal quantities

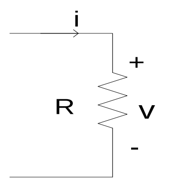
The sum of two or more sinusoidal voltages (or currents) of the same frequency is obtained by taking the vector sum of their respective phasors. Subtraction is best achieved by first reversing the phasor to be subtracted and then adding it as a vector to the other phasors.

3.3.4 Impedance

In an ac circuit the opposition to current flow is due to resistive, inductive and capacitive elements. The opposition due to inductance is termed inductive reactance and that due to capacitance is termed capacitive reactance. The general term for opposition in ac circuits is called impedance.

Current in simple ac circuits

(a) Current in a pure resistor (R):



Let the voltage across the resistor be

$$v = V_m \sin \omega t$$

Then the instantaneous current in it is given by

$$i = \frac{v}{R} = \frac{V_m \sin \omega t}{R} = I_m \sin \omega t$$

where

$$I_m = \frac{V_m}{R}$$

Therefore

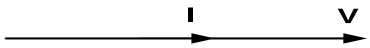
$$I_{rms} = \frac{I_m}{\sqrt{2}} = \frac{V_m}{\sqrt{2}R} = \frac{V_{rms}}{R}$$

We note that

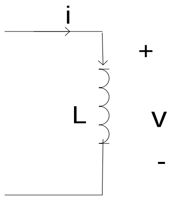
(i) The current is in phase with the voltage

(ii) V = IR (Ohm's law)

(iii) Phasor for circuit:



(b) **Current in an inductor (L):**



The voltage across an inductor is

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

Therefore if the current in it is defined as

$$i = I_m \sin \omega t$$

then

$$v = \omega L I_m \cos \omega t = \omega L I_m \sin (\omega t + 90°) = V_m \sin (\omega t + 90°)$$

where

$$V_m = \omega L I_m$$

Hence

$$V = \frac{V_m}{\sqrt{2}} = \frac{\omega L I_m}{\sqrt{2}} = \omega L I = X_L I$$

The product $X_L = \omega L$ is the reactance in ohms if L is in henries

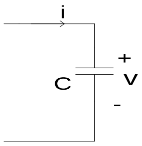
We note that

(i) The current lags behind the voltage by 90°

(ii) $V = X_L I$ (Ohm's law)

(iii) Phasor diagram for circuit:

(c) **Current in a capacitor (C):**



The current in a capacitor is given by

$$i = C\frac{dv}{dt}$$

If the voltage across it is defined as

$$v = V_m \sin \omega t$$

then

$$i = \omega C V_m \cos\omega t = \omega C V_m \sin(\omega t + 90°)$$

That is $i = I_m \sin(\omega t + 90°)$ where $I_m = \omega C V_m$

Hence

$$I = \frac{I_m}{\sqrt{2}} = \frac{\omega C V_m}{\sqrt{2}} = \omega C V$$

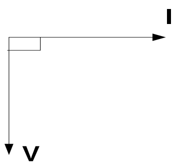
The term $X_c = \dfrac{1}{\omega C}$ is the capacitive reactance in ohms if C is in farads.

We note that

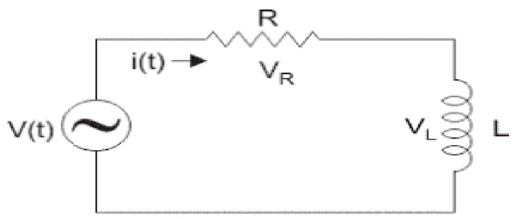
(i) The current leads the voltage across the capacitor by 90°

(ii) $V = X_c I$ (Ohm's law)

(iii) Phasor diagram for circuit:



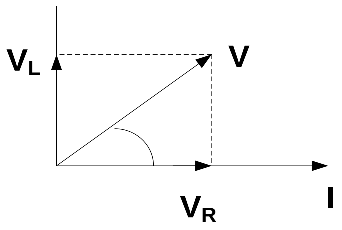
(d) **Series circuit containing R and L**: The total voltage across the element is



$$v = v_R + v_L$$

These are all sinusoidal quantities. Therefore

$\mathbf{V = V_R + V_L}$



From the phasor diagram for the circuit above,

$V^2 = V_L^2 + V_R^2 = I^2(X_L^2 + R^2)$ or

$V = I\sqrt{X_L^2 + R^2} = IZ$

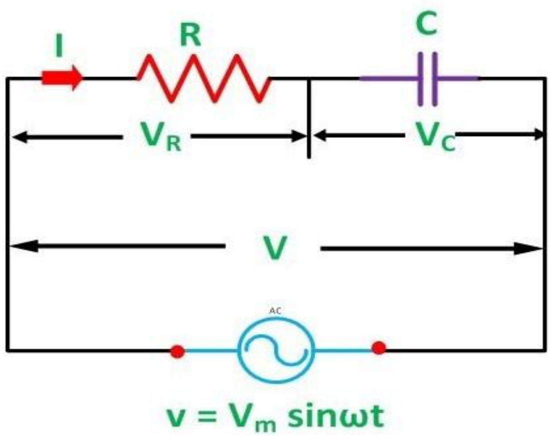
where

$$Z = \sqrt{X_L^2 + R^2}$$

and the angle by which the current lags the impressed voltage is

$$\varphi = \tan^{-1}\left(\frac{X_L}{R}\right)$$

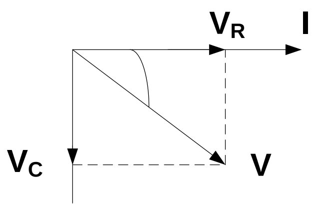
(e) **Series circuit containing R and C**: Total voltage across the element is



$V = V_R + V_C$

These are all sinusoidal quantities. Therefore

$\mathbf{V = V_R + V_C}$



From the phasor diagram for the circuit,

$$V^2 = V_C^2 + V_R^2 = I^2\left(X_C^2 + R^2\right) or$$
$$V = I\sqrt{X_C^2 + R^2} = IZ$$

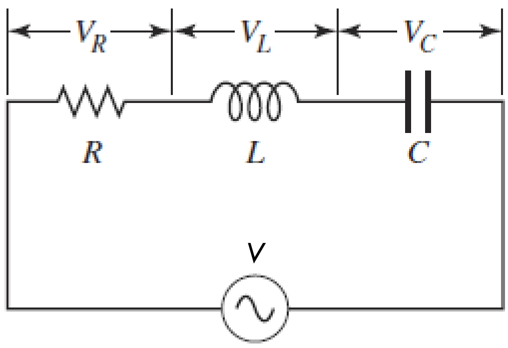
where

$$Z = \sqrt{X_C^2 + R^2}$$

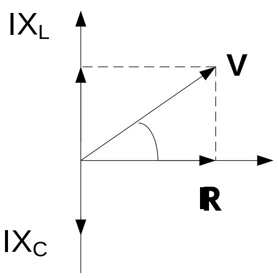
And the angle by which the current leads the impressed voltage is

$$\varphi = \tan^{-1}\left(\frac{X_C}{R}\right)$$

(f) **Series circuit containing R, L and C**



From the phasor diagram for the circuit



$$V^2 = (IX_L - IX_C)^2 + I^2R^2 \ or$$
$$V = I\sqrt{(X_L - X_C)^2 + R^2} = I\,Z$$
where
$$Z = \sqrt{(X_L - X_C)^2 + R^2}$$

and the angle by which the current lags the impressed voltage is

$$\varphi = \tan^{-1}\left(\frac{X_L - X_C}{R}\right)$$

We note that

(i) If $X_L > X_C$, $\tan\varphi$ is positive and the current lags behind the supply voltage

(ii) If $X_L < X_C$, $\tan\varphi$ is negative and the current leads the supply voltage

3.3.5 Power in AC Circuit

(a) Circuit is non-reactive having constant resistance R: Let the supply voltage be

$v = V_m \sin \omega t$

Then the supply current is given by

$$i = \frac{V_m}{R}\sin \omega t = I_m \sin \omega t$$

The instantaneous power drawn by the circuit is

$$v.i = V_m I_m \sin^2 \omega t = \frac{V_m I_m}{2}(1-\cos 2\omega t)$$

The average power is

$$P = \frac{1}{T}\int_0^T v.i\,dt = \frac{V_m I_m}{2} = \left(\frac{V_m}{\sqrt{2}}\right)\left(\frac{I_m}{\sqrt{2}}\right) = V\,I = I^2 R$$

This power is termed the active power. Its unit is watt (W). Larger units are kW (=10^3 W) and MW (=10^6 W).

(b) Circuit is purely inductive having inductance L: If the supply voltage is defined as above, then

$$i = \frac{V_m}{\omega L}\sin(\omega t - 90°) = -I_m \cos\omega t$$

$$v.i = -V_m I_m \sin \omega t \cos\omega t = -\frac{V_m I_m}{2}\sin 2\omega t \quad and$$

$$P = \frac{1}{T}\int_0^T v.i\ dt = 0$$

That is active power = 0

(c) Circuit is purely capacitive having capacitance C: For the same supply voltage

$$i = \omega C V_m \sin(\omega t + 90°) = I_m \cos\omega t$$

$$v.i = V_m I_m \sin \omega t \cos\omega t = \frac{V_m I_m}{2}\sin 2\omega t \quad and$$

$$P = \frac{1}{T}\int_0^T v.i\ dt = 0$$

The active power drawn is zero.

(d) Circuit having resistance and reactance in series: Let the supply voltage be defined as above and the current as

$i = I_m \sin(\omega t - \varphi)$

Then the instantaneous power

$$
\begin{aligned}
v.i &= V_m I_m \sin\omega t \sin(\omega t - \varphi) \\
&= \frac{1}{2} V_m I_m \cos\varphi - \frac{1}{2} V_m I_m \cos(2\omega t - \varphi)
\end{aligned}
$$

and the active power

$$
\begin{aligned}
P &= average\left(\frac{1}{2} V_m I_m \cos\varphi\right) - average\left(\frac{1}{2} V_m I_m \cos(2\omega t - \varphi)\right) \\
&= \frac{1}{2} V_m I_m \cos\varphi - 0 \\
&= \frac{V_m}{\sqrt{2}} \frac{I_m}{\sqrt{2}} \cos\varphi \\
&= V\, I \cos\varphi
\end{aligned}
$$

Apparent power and power factor

In ac circuit, the product of the voltage V (i.e. rms value) applied to a circuit and the current I (also rms value) drawn by the circuit gives what we call the apparent power S. That is

S = V I [VA]

Larger units are kVA and MVA.

The power in watts or active power or average power drawn by the circuit is given by the product of apparent power and power factor (pf) or

$$power\ \ factor = \frac{power\ in\ watts}{apparent\ \ power\ in\, VA}$$

For sinusoidal voltage and current

power factor = cos φ

where φ is the phase difference between the current i drawn by the circuit and the voltage v. The power factor is said to be lagging when the current lags behind the voltage and leading when the current leads the voltage.

Active and reactive current

The current I can be resolved into two components:

(a) a component in phase with the voltage I_a called active component

(b) a component in quadrature with the voltage I_r called reactive component

The active power drawn by the circuit is

$$
\begin{aligned}
P &= V\, I \cos\varphi \\
&= V\, I_a \text{ watts (W)}
\end{aligned}
$$

The power due to the component I_r is wattless. This is called reactive power Q defined as

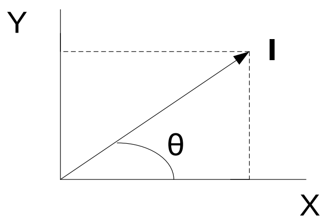
$$Q = V\,I\,\sin\varphi = V\,I_r \text{ vars (VAr)}$$

Larger units are kVAr and MVAr.

Note that

$$(\text{apparent power})^2 = (\text{active power})^2 + (\text{reactive power})^2$$

3.3.6 Representation of Phasors as Complex Numbers



A phasor shown can be represented as follows:

$\mathbf{I} = I_x + jI_y$ (rectangular or Cartesian notation)

$\mathbf{I} = I\angle\theta$ (polar notation)

Note the following:

(a) the symbol j denotes that $I_y = I\sin\theta$ is the component of I along the Y-axis

(b) $I_x^2 + I_y^2 = I^2$

(c) $I_x = I\cos\theta$ is called its real component and I_y or $I\sin\theta$ its imaginary or quadrature component.

Properties of j

(a) $j = \sqrt{(-1)}$

(b) the operator "j" when applied to a phasor, turns the phasor through 90° in anticlockwise direction without altering its length.

(c) $j \times j = -1$

(d) $\frac{1}{j} = -j$

Some useful complex algebra

$$(a)\frac{r_1\angle\theta}{r_2\angle\theta}=\left(\frac{r_1}{r_2}\right)\angle(\theta_1-\theta_2)$$
$$(b)(x+jy)^{\bullet}=x-jy$$
$$(c)(r\angle\theta)^{\bullet}=r\angle-\theta$$
$$(d)(x_1+jy_1)+(x_2+jy_2)=(x_1+x_2)+j(y_1+y_2)$$

Using complex numbers to solve ac circuits

Voltages and currents are represented as complex numbers. The impedance Z is also treated as a phasor or complex number:

(a) A resistance is represented as a real number because $\mathbf{V}_R$ = **I**R should be in phase with its current **I**.

(b) An inductive reactance is represented as a pure imaginary number with a plus sign because $\mathbf{V}_L$ = **I** X_L should lead **I** by 90°.

(c) A capacitive reactance is represented as a pure imaginary number with a negative sign because $\mathbf{V}_C$ = **I** X_C should lag behind **I** by 90°.

When voltages, currents and impedances are treated as complex numbers, the solution of ac circuit becomes the same as that of dc circuits. This method is very practical when the ac circuit is more involved.

Calculation of complex power

Let **V** be the voltage across a circuit and **I** the current drawn by the circuit. Then the apparent power in complex notation is

$$\mathbf{S} = \mathbf{V}.\mathbf{I}^{\bullet} = P + jQ$$

Q is positive when the current is lagging behind the voltage and negative when it is leading.

3.4 Three-Phase Alternating Current Circuits

A single-phase generator produces a single sinusoidal voltage. A 3-phase generator on the other hand produces three equal voltages which are out of phase with one another by 120°. The three voltages are generated in three separate windings arranged in a special way in the machine. A power supply system consisting of three voltages which are 120^o out of phase with one another is referred to as 3-phase system. This unit introduces this system and presents also the techniques for its analysis under balanced and unbalanced conditions. In general, electric power is generated, transmitted and distributed in the form of three-phase power. Three-phase power is preferred over single-phase power for the following reasons:

- Three-phase motors, generators and transformers are simpler, cheaper and more efficient
- Three-phase transmission lines can deliver more power for a given weight and cost
- The voltage regulation of three-phase transmission lines is inherently better

If a single-phase power is required, it can be supplied by one phase of a three-phase generating system.

3.4.1 Connection of Three-Phase Generator Windings

The three windings of a three-phase generator can be connected in star or delta as shown in Figure 1. Other three phase equipment such as 3-phase motors, heaters and transformers can also be either star or delta connected. Generators are generally star-connected and the neutral point (the point at which all the three windings are connected, see Figure 3-1) used for earthing or grounding. The conductors connected from the terminals a, b and c of the generator to its load are called lines.

The phasor diagram of the voltages produced by the 3-phase generator is shown in Figure 3-2. The phasors are usually denoted as abc, RYB or 1-2-3. The naming of the phasors is in the clockwise direction. Thus to a stationary observer the phasors will appear in the following sequence: abcabc etc for a positive phase sequence of rotation i.e rotation in anticlockwise direction. If the sequence of rotation is reversed, then the phasors will appear in the following sequence: acbacb etc. This is called negative phase sequence. The letters R, Y and B denote red, yellow and blue. These are the colours used to identify the three phases.

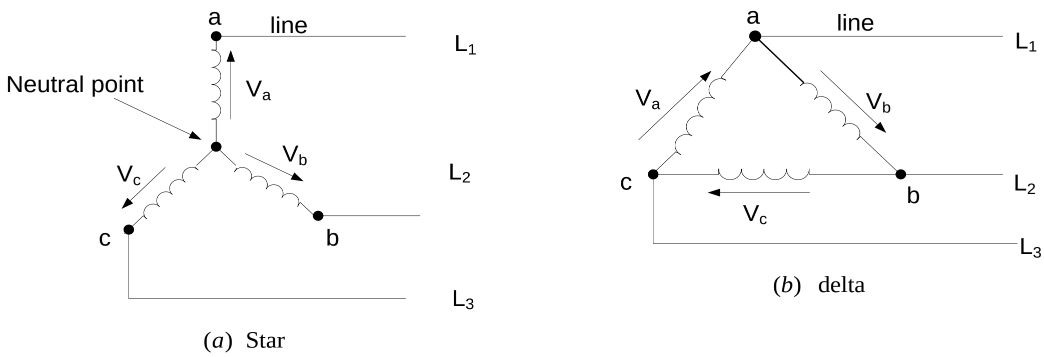


Figure 3-1. Connection of 3-phase generator or transformer

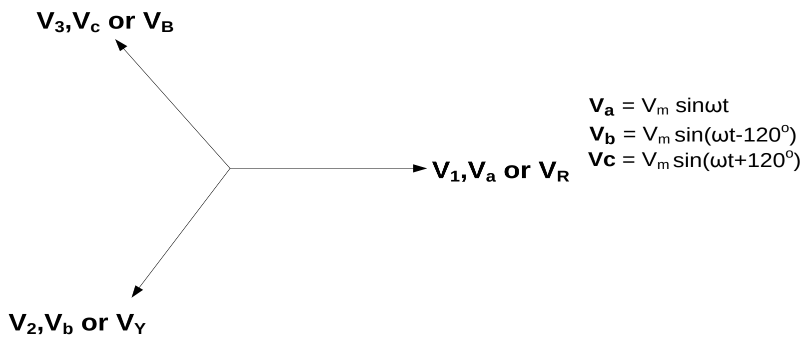


Figure 3-2. Phasor diagram of 3-phase voltages

Relationship between line and phase voltages

The voltage from one line to another is called a line-to-line voltage or simply a line voltage. On the phasor diagram it will be the phasor drawn from the end of one phase to another in the anticlockwise direction. They are given by $\mathbf{V_{ab}}$, $\mathbf{V_{bc}}$ and $\mathbf{V_{ca}}$.

Case A: Generator is star connected. See Figure 3-3.

Let the voltages generated or induced in the phases be $\mathbf{V_{an}}$, $\mathbf{V_{bn}}$ **and** $\mathbf{V_{cn}}$. Then applying KVL, we obtain

$$
\begin{aligned}
\mathbf{V_{ab}} &= \mathbf{V_{an}} - \mathbf{V_{bn}} \\
&= V\angle 0^\circ - V\angle -120^\circ \\
&= V[1 - 1\angle -120^\circ] \\
&= V[1 - cos(-120^\circ) - j\, sin(-120^\circ)] \\
&= V\left[\frac{3}{2} + j\frac{\sqrt{3}}{2}\right] \\
&= \sqrt{3}V\angle 30^\circ
\end{aligned}
$$

Hence

line voltage $V_L = \sqrt{3} \times$ phase voltage V_p (Figure 3-1 (a))

This relationship can also be obtained using phasor diagram.

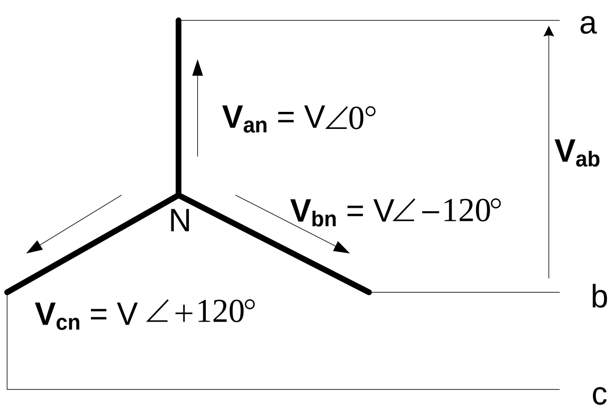


Figure 3-3. Voltages in star-connected generator winding

Case B: Generator is delta connected. See Figure 3-1 (b).

Line voltage V_L = phase voltage V_p (Figure 3-1 (b))

3.4.2 Three-Phase Loads

They are either star or delta connected. Examples are three-phase motors and three-phase heating equipment. A 3-phase load is said to be balanced if it has the same impedance in each phase.

Balanced three-phase system

It is a three-phase system in which identical loads are connected in each phase. The currents that flow in a balanced three-phase system are equal in magnitude and also 120° out of phase.

Relationship between line and phase currents in a generator supplying power to a balanced load

Case A: Generator is star connected. See Figure 3-1 (a).

For this connection, the phase current I_p = the line current I_L.

We note that even when the load is unbalanced, the line current = the phase current for each phase.

Case B: Generator is delta connected. See Figure 3-4.

Applying KCL, line current $\mathbf{I_{La}} = \mathbf{I_a} - \mathbf{I_b}$

Let $\mathbf{I}_a = I\angle 0°$ and $\mathbf{I}_b = I\angle -120°$. Then from (3.1.a), $\mathbf{I}_L = \sqrt{3}\angle 30°$.

Hence, line current $I_L = \sqrt{3} \times$ phase current I_p

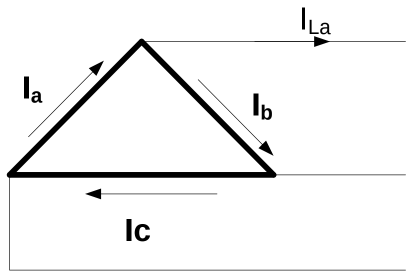


Figure 3-4. Current in delta connected generator winding

Relationships between line and phase voltages and currents for a balanced load

Case A: Load is star connected. See Figure 3-5 (a).

As in the case for the generator, the relationships are found to be as follows:

$$I_p = I_L$$

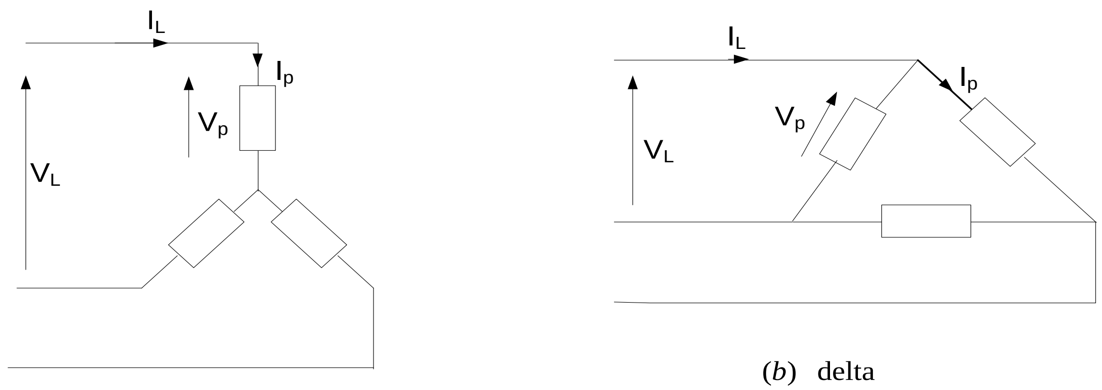
$$V_p = \frac{V_L}{\sqrt{3}}$$

Case B: Load is delta connected. See Figure 3-5 (b).

These are also found to be as follows:

$$I_p = \frac{I_L}{\sqrt{3}}$$

$$V_p = V_L$$



(a) Star (b) delta

Figure 3-5. Connection of three-phase loads

3.4.3 Power in a Three-Phase Circuit

The total power in a three-phase circuit is the sum of the power in the three phases. In a balanced system, delta or star connected, the total apparent power is

$$S = \sqrt{3} V_L I_L$$

In the case of star-connected system:

i. Phase voltage $V_p = \frac{Line\ voltage}{\sqrt{3}} = \frac{V_L}{\sqrt{3}}$

ii. Phase current I_P = Line current I_L

iii. $Apparent\ power\ per\ phase = \frac{V_L}{\sqrt{3}} \times I_L$

iv. $Total\ apparent\ power = 3 \times \frac{V_L}{\sqrt{3}} \times I_L = \sqrt{3} V_L I_L$

The active power for any balanced system is

$$P = \sqrt{3}\, V_L\, I_L \cos\varphi$$

where $\cos\varphi$ is the power factor. The angle φ is the phase angle between the phase voltage and the phase current. Most three-phase apparatus such as motors can be assumed to be a balanced load.

3.4.4 Analysing Three-Phase Circuits

Three-phase currents are determined by considering only one phase and calculating the phase current from the phase voltage and impedance in the same way as single-phase circuits. Single-phase representation of a three-phase balanced circuit is shown in Figure 3-6.

The load is generally considered to be star connected and the impedance per phase is understood to be the line-to-neutral impedance. Hence $V_p = V_L/\sqrt{3}$ and $I_p = I_L$. If the load is delta connected with impedance Z per phase, it can be replaced by its equivalent in star with impedance Z/3 per phase. If we do not know whether a three-phase load is connected in delta or star, it is assumed that it is star connected.

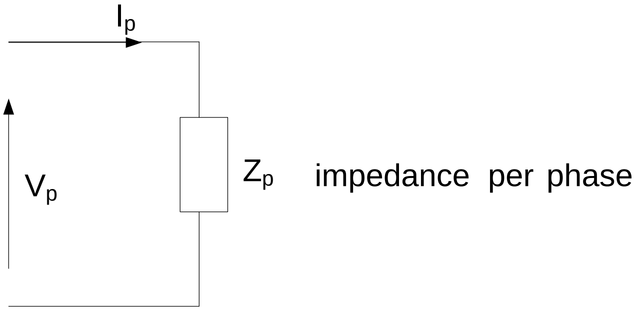


Figure 3-6. phase representation of 3-phase balanced circuit

Three-phase, four-wire supply feeding unbalanced star-connected load

Three-phase unbalanced load does not have the same impedance in all the three phases. However, since the neutral points of the source and the load are the same, the voltage across each phase of the load is the phase voltage of the source. See Figure 3-7.

Three-phase four-wire system is used for low-voltage power distribution in Ghana. There are three lines and a neutral.

The voltage between any one line and neutral is 240 V and the voltage between the lines is √3 times the voltage to neutral, giving a voltage of 415 V. Single-phase loads are connected between a line and the neutral and three-phase loads to the three lines as shown in Figure 3-8.

If the load is balanced, the neutral will carry no current.

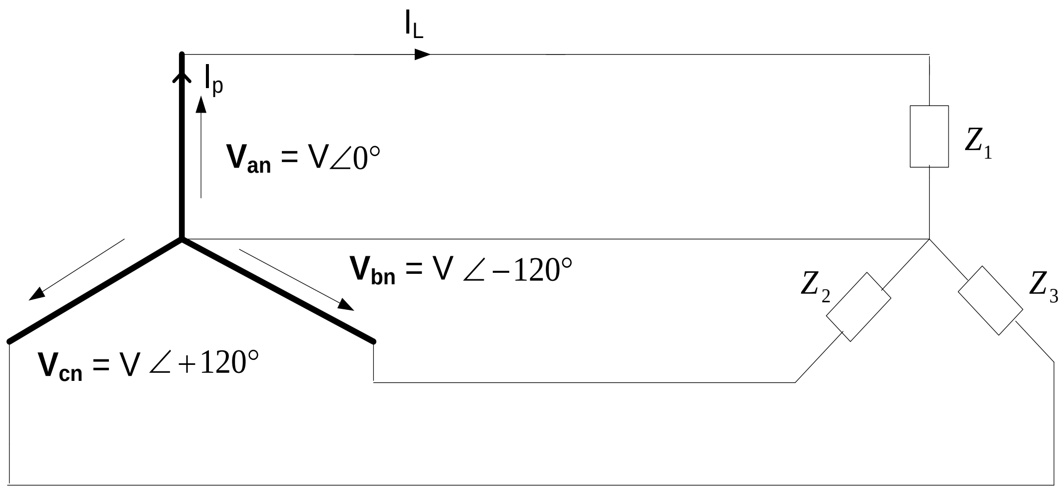


Figure 3-7. Three-phase four-wire supply feeding unbalanced star-connected load

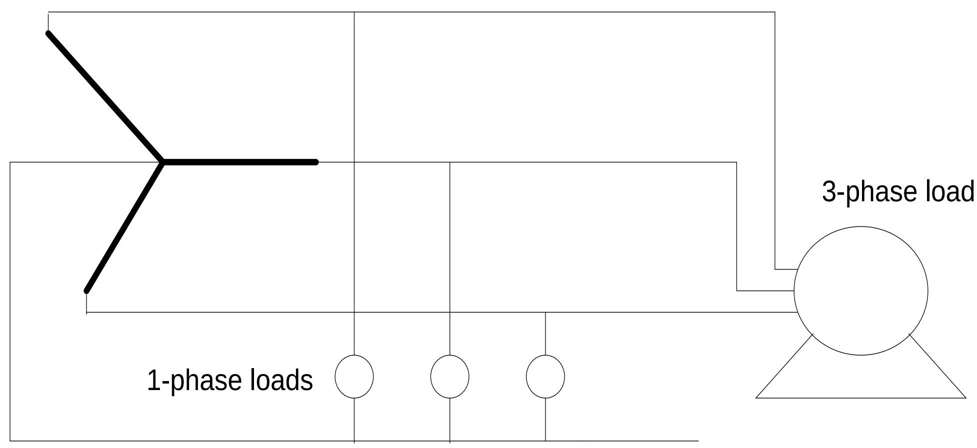


Figure 3-8. 3-phase 4-wire supplying 1-phase loads and 3-phase load

3.5 Application of Network Theorems to AC Networks

In the previous lesson on DC Network Theory, a number of network theorems applied to dc networks were considered. In this chapter we extend their application to ac circuits. When voltages, currents and impedances are treated as complex numbers or phasors, the solution of ac circuits becomes the same as that of dc circuits. Therefore the only variation in applying the network theorems to ac circuit is that we will be working with impedances and phasors instead of just resistors and real numbers.

3.5.1 Thevenin's Theorem

The only change is replacement of the term resistance with impedance. Unlike the superposition, it is applicable to only one frequency since reactance is frequency dependent. (Note: it has to be one frequency so that we can have one Thevenin's impedance)

3.5.2 Norton's Theorem

Here too, resistance is replaced with impedance and it is applicable to only one frequency since reactance is frequency dependent.

3.5.3 Maximum Power Transfer Theorem

Here, maximum power is delivered to the load when its impedance is the conjugate of the Thevenin impedance. This implies that power factor under maximum power condition is unity.

M04 – THE FUNDAMENTALS OF INTERCONNECTED POWER SYSTEM OPERATIONS

4.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of power system interconnections between countries and regions
- Identify all the considerations and benefits for power system interconnection

4.2 Introduction

Power systems of countries are interconnected with neighbouring power systems with the goal of achieving economic and technical benefits. In pooling the resources of neighbouring power systems together through interconnection, increased reliability, improved stability and economic exchange of power can be achieved between countries and regions. Interconnected power systems also save cost by operating at lower reserve margin than if the power systems were separated.

4.2.1 Power Systems

An electric power system is a complex network in which electricity is produced and transmitted to users. A power system has the following basic components:

- Power plants which generate electric power
- Transformers which raise or lower the voltages as required. At generating stations, the transformers raise the voltage and feed the power into the transmission network. At load centres the transformers lower the voltage and send the power either directly to large consumers or to distribution networks.
- Transmission lines which carry the power from the power plants to the load centres

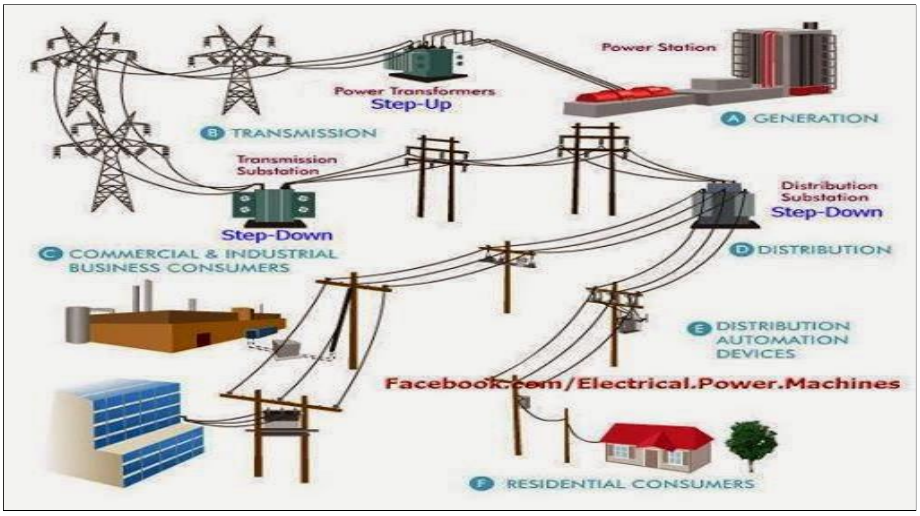


Figure 4-1. Structure of a power system

4.2.2 Introduction to Power System Operation

There are two general characteristics of AC power systems:

- It is very difficult to store huge quantities of electric power in AC power systems
- The exact amount of power needed must be produced in real time and at the time needed.

Due to these two characteristic of AC power systems there is the need for constant coordination and monitoring to ensure that:

- there is a balance between electricity supply and electricity demand in real time and at all times
- the power flows in the transmission and generation system equipment are within the thermal ratings of the equipment
- voltages at the power system nodes are within the required limits
- tie line power flows are at scheduled transaction values

The monitoring of the power system parameters and the control of the power system equipment are carried out at a central location called the Central Control Centre. A set of computerised systems and communication networks are used to remotely monitor and control transmission equipment and generation facilities from the Central Control Centre. This system is called supervisory control and data acquisition (SCADA). The SCADA system comprises of

- master station computers at the Central Control Centre
- remote terminal units (RTUs) at the substations and
- communication links between the master station computers and the RTUs

Figure 4-2. Central Control Centre

RTUs gather information at the substations and transmit it through communication channels to the master station server computers at the Central Control Centre. Workstation computers at the Central Control Centre are used to retrieve data from the server and display some of the information that is needed for the real time monitoring and control of the power system.
The workstation computers can also query the information stored in the servers to display historical data for analysis purposes. For instance, historical information can be retrieved from the server to analyse and find out the cause of a disturbance that has occurred.

The functions of the Central Control Centre include:

- Dispatch generating units in a manner to ensure real time balance between demand and supply of electricity and maintain system frequency within required limits
- Monitor all digital signals (e.g. switchgear open and close statuses and transformer tap positions) and analogue signals (e.g. voltage, current, active/reactive/apparent power in both generation facilities and transmission equipment and tie line power flows) needed for the real time operation of the power system
- Implement tie line interchange transactions
- Remotely open or close circuit breakers and disconnecting switches to isolate or restore transmission system equipment as may be needed

The SCADA system is also integrated with a secondary frequency control functionality called automatic generation control (AGC). The functions of the AGC are to:

- Monitor the system frequency and the active power of all generating units in service
- Monitor and maintain tie line flows at scheduled transaction values
- Increase or decrease generator active power as required to maintain system frequency at nominal value

In performing these functions, the Central Control Centre is called the Balancing Authority. The geographical area which is under the supervision and control of the balancing authority is called a Control Area. A control area therefore, has one balancing authority which carries out its functions from the Central Control Centre.

A control area usually comprises of the power system of a country (like Ghana) or a state (like some states in the USA). The Ghana power system has one Central Control Centre located at Tema.

The balancing authority is vested in the Ghana Grid Company Ltd. However, two or more countries may combine their power systems to form one control area.

Togo and Benin have combined their power systems into one control area, with a common Central Control Centre located in Lomé.

The balancing authority is vested in Communauté Electrique du Bénin (CEB).

4.3 Interconnection of Power Systems

Two or more power system control areas may be interconnected together to achieve economic and technical benefits. It is now the established practice to interconnect power systems and to operate them for mutual benefits.

The transmission line which interconnects any two power system control areas is called a tie line.

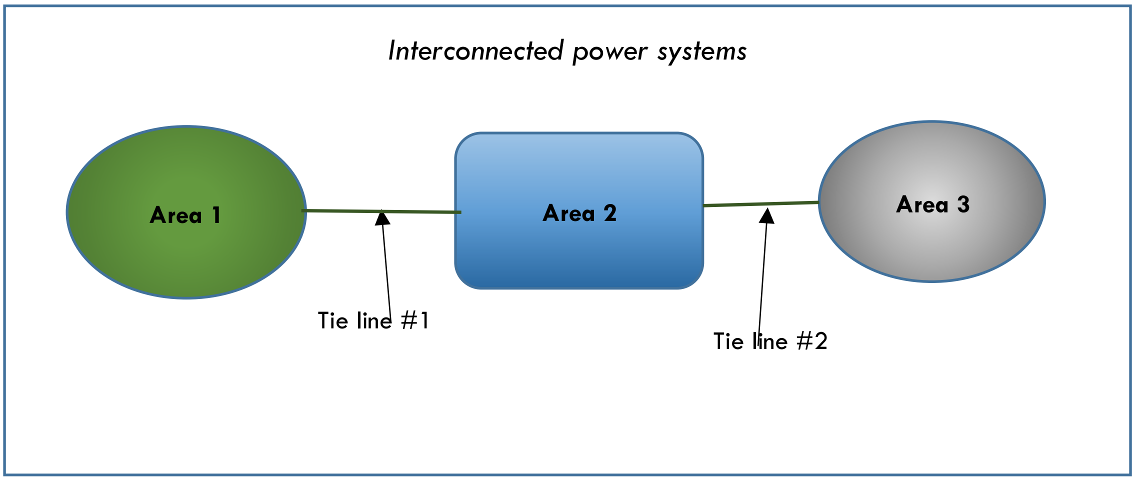


Figure 4-3. Interconnected Power Systems

In the diagram above, tie line #1 interconnects Area 1 and Area 2 while tie line #2 also interconnects Area 2 and Area 3.

For example, the Ghana power system is interconnected on the west with the La Côte d'Ivoire power system (with balancing authority vested in Compagnie Ivoirienne d'Electricité, CIE) and on the east with the Togo-Benin power system (CEB) as shown in the diagram below:

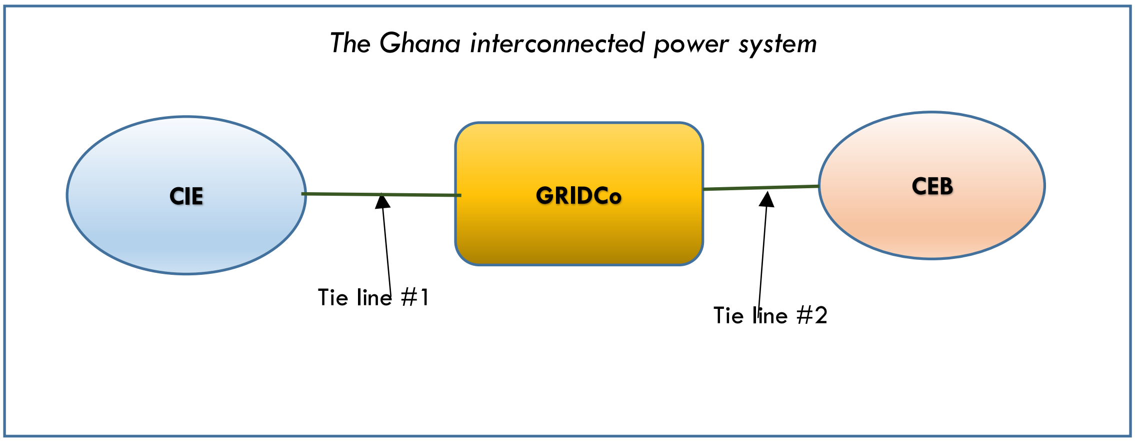


Figure 4-4. Ghana Interconnected Power System

The interconnection between two power systems can be achieved through three alternatives. These are:

- AC transmission interconnection
- High voltage DC (HVDC) transmission interconnection
- Hybrid AC/DC transmission interconnection

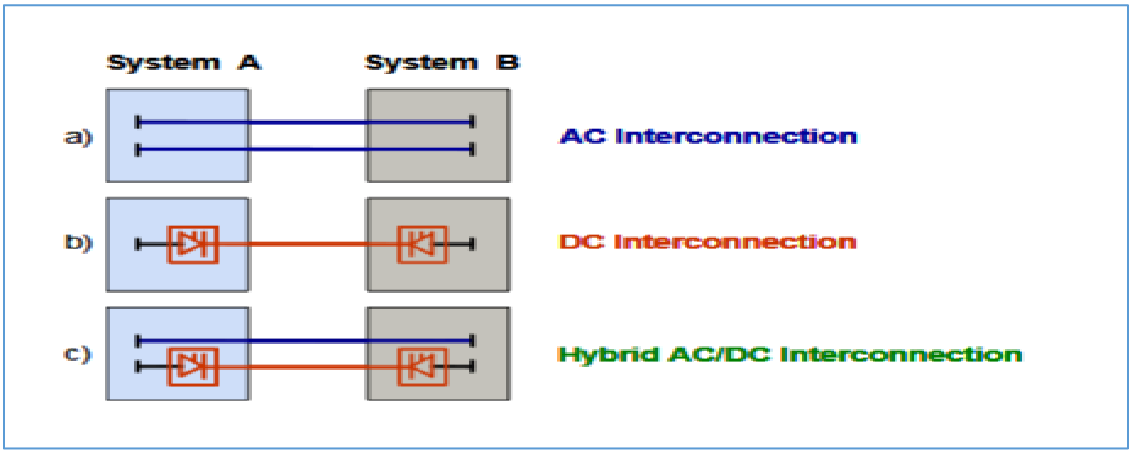


Figure 4-5. Interconnection Alternatives

The characteristics of the individual power systems determine the kind of interconnection to be adopted. The interconnection between two power systems must be very strong. Otherwise the interconnected power system becomes unstable.

4.3.1 High Voltage AC Transmission Interconnections

If two or more power systems have the same nominal frequency, then the usual interconnection is through high voltage AC transmission circuits. In power systems which are interconnected through AC transmission circuits, all the synchronous generating machines operate in synchronism with each other and with the entire interconnected power system.

If voltage magnitude or angle variations exist between the power systems, then they cannot be interconnected through an AC transmission circuit. Also power systems with different nominal frequencies cannot be interconnected through AC transmission circuits. Due to differences in frequency and voltage, the power systems cannot be synchronized together and therefore cannot be interconnected through AC transmission circuits.

4.3.2 High Voltage DC Interconnections

Another approach through which power systems are interconnected is by using high voltage DC (HVDC) transmission circuits. Power systems which have different nominal frequencies or different voltages can be interconnected through HVDC transmission circuits.

HVDC transmission interconnection has a number of advantages over high voltage AC transmission interconnection. A summary of the advantages of HVDC interconnection over HVAC is provided as follows.

4.3.2.1 Lower Cost of HVDC Transmission over Long Distance

High voltage DC (HVDC) transmission is better suited than HVAC when the interconnection between the power systems is very long. It is cheaper to transport bulk power over very long distances using HVDC than HVAC. The total cost of transporting power over distances longer than about 500 km using HVDC is lower than using HVAC.

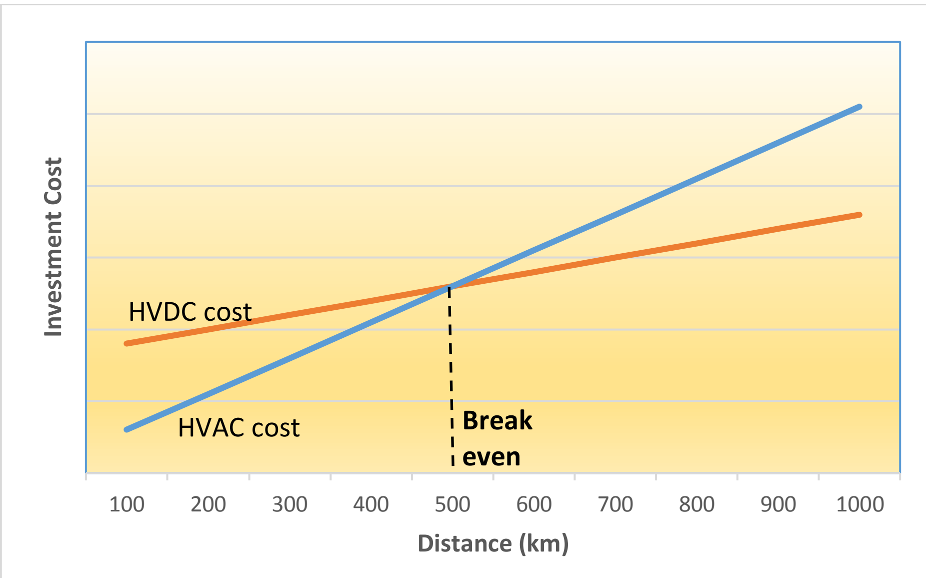


Figure 4-6. Investment Cost against Distance

The lower cost of long distance HVDC transmission than HVAC transmission can be attributed to a number of reasons:

- HVDC requires only two conductors per circuit while HVAC requires three conductors per circuit
- HVDC requires less insulation and clearance from the ground
- HVDC has less transmission losses
- HVDC towers are smaller and require less right of way to transmit the same amount of power as HVAC

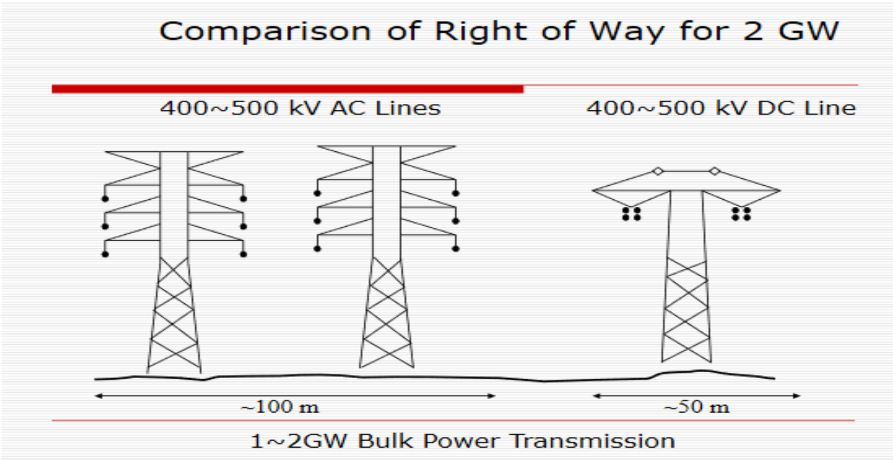


Figure 4-7. Comparison of Right of Way

4.3.2.2 Other Advantages of HVDC over HVAC Transmission

The other advantages of HVDC over HVAC are summarised as follows:

- HVDC can be used to interconnect AC power systems which have different frequencies and voltages and are therefore asynchronous with each other
- HVDC can transfer more power where HVAC is limited by its short circuit current. HVDC does not contribute to short circuit current of interconnected power systems
- HVDC improves AC power system stability
- HVDC can deliver constant power at constant frequency due to its advanced control systems. It also provides better voltage control
- The effect of fault conditions in one power system cannot to transferred to other power systems when interconnected with HVDC
- HVDC lends itself effectively to under water crossing. The interconnection between Sardinia Island and mainland Italy is a submarine HVDC transmission circuit.

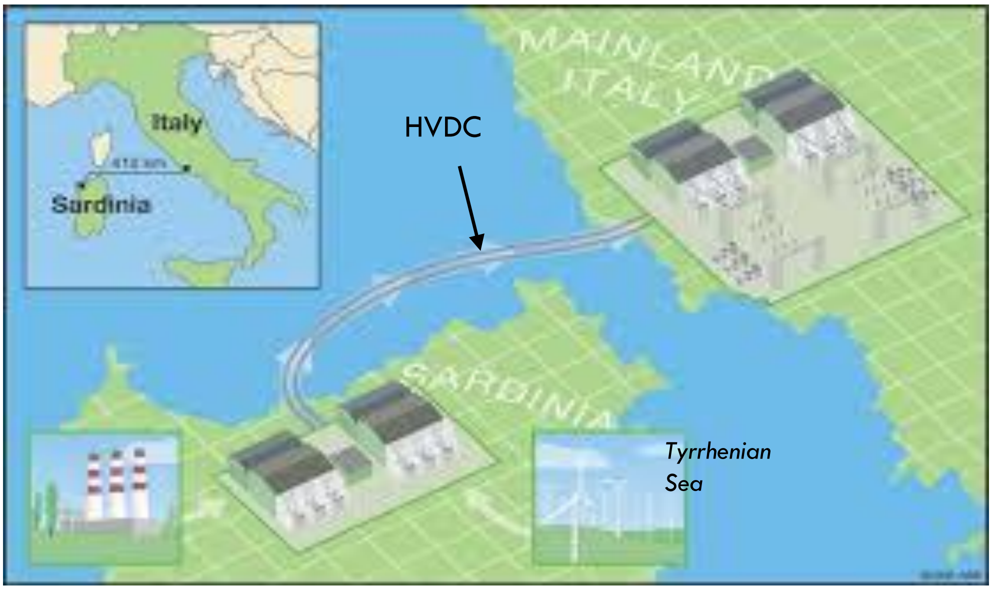
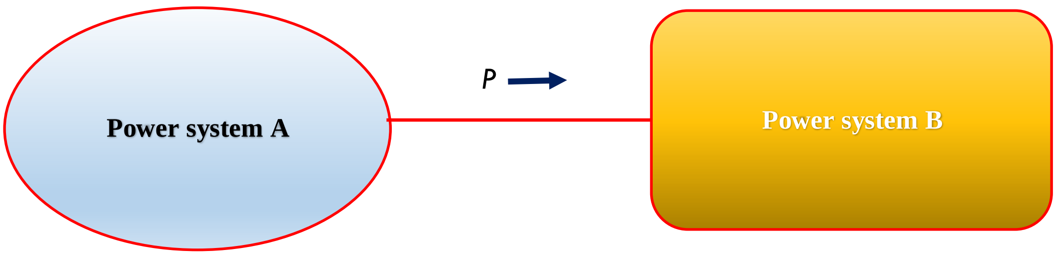


Figure 4-8. HVDC System Configuration

5.4 Operation of Interconnected Power Systems

The interconnection of electric power systems enables the interconnected utilities to exchange electric power among them. The amount of power to be exchanged must be clearly specified together with the time period over which the exchange will take place.

Suppose two interconnected power systems A and B desire to exchange P MW from time t_1 to time t_2. The magnitude P of the power to be exchanged, the start time t_1 of the exchange and the end time t_2 must all be clearly specified.



Power System A exports power to Power System B

Since power system A is exporting to power system B, the total power generated G_A in power system A is equal to the total load L_A (plus losses) within power system A plus the amount of power P being exported:

$G_A = L_A + P$ or

$G_A - L_A - P = 0$

Similarly, since power system B is importing from power system A, the total power generated G_B in power system B is equal to the total load L_B (plus losses) within power system B minus the amount of power P being imported:

$$G_B = L_B - P \text{ or}$$

$$G_B - L_B + P = 0$$

This means that when a power system exports power P, then it must generate P MW more than its load. Also when a power system imports power P, then it must generate P MW less than its load. When the system frequency is maintained at the nominal value and the power exchanges are maintained at the scheduled interchange transaction values, the total power supply and the total power demand are said to be in a state of balance.

4.4.1 Interchange Error

It is expected that the scheduled power P MW will flow from power system A to power system B during the scheduled period of time t_1 to t_2. However, due to power system dynamics, i.e. changing frequency, demand and generator power output, the actual power P_{actual} that flows on the tie line may be greater or less than the scheduled transaction value P. The difference between the scheduled power and the actual power is called the interchange error.

Interchange error $\Delta P = P_{actual} - P$

Interchange error is caused by the following conditions:

- When the power generated in a power system is more than the load plus the power export (i.e. if $G > L + P$), the frequency f of that power system increases above the nominal value f_0 causing the power system to export more than the scheduled power.
- When the power generated in a power system is less than the load plus the power export (i.e. if $G < L + P$), the frequency f of that power system decreases below the nominal value f_0 causing the power system to export less than the scheduled power.
- An imbalance in the power supply and power demand causes system frequency to deviate from the nominal value

4.4.2 Area Control Error

Huge interchange errors occurring over prolonged periods of time are not desired in power system interconnection operation. It is the responsibility of the system dispatcher in the control area to minimise the interchange error at all times and maintain the power flowing on the tie line to the scheduled value. The secondary frequency control system of the power system continuously monitors the power flows on the tie line and the system frequency. This is achieved automatically by the automatic generation control (AGC) system. The AGC generates a signal called area control error (ACE) which it uses to regulate generating units to maintain the tie line flows to the scheduled transaction value and also maintain frequency to its nominal value.

The ACE error signal is generated from the sum of the interchange error and the frequency bias. The interchange error is the difference between the scheduled power transaction P and the actual power P_{actual} measured on the tie line:

$$\Delta P = P_{actual} - P$$

The frequency bias is the product of the frequency deviation Δf (difference between actual frequency f and nominal frequency f_0) and the system frequency bias factor β. The system frequency bias factor is the amount of MW change in the power system that causes 1 Hz change in frequency. This value is usually referred to as the system MW/Hz value. By convention, this value is negative.

Area control error = Interchange error + frequency bias

$$ACE = (P_{actual} - P) - \beta \times (f - f_0)$$

$$ACE = \Delta P - \beta \times \Delta f$$

The ACE is the signal that the AGC system uses to control the power output of generating units to maintain tie line power flows at schedule values and also maintain frequency at nominal value.

For the AGC system to operate efficiently, some of the generating units in the power system must be designated to participate in secondary frequency control. During operation, these generating units are dispatched below their rated capacity (e.g. at 95%

of the rated capacity) so that the spinning reserve margin can be used for frequency regulation, load following and contingency reserve.

A 400 MW gas turbine for instance when participating in AGC, is dispatched at 95% (380 MW) of its rated capacity, leaving the 5% (20 MW) reserve margin to be used by the AGC for frequency control, load following and contingency reserve.

4.5 The Ghana Interconnected Power System

The Ghana power system is interconnected on the west with La Côte d'Ivoire power system (CIE) through a 220 km, 225 kV AC single circuit linking Prestea in Ghana with Reviera in La Côte d'Ivoire. The conductor type is AAAC (All Aluminium Alloy Conductors) and has a cross sectional area of 570 mm^2 with a thermal capacity of 327 MVA.

The interconnection between Ghana and the Togo-Benin power system on the east consists of 74 km, 161 kV AC double-circuit linking Asiekpe in Ghana with Lomé in Togo. The conductor type is AAC (Aluminium Alloy Conductors) and has a cross sectional area of 177 mm^2 with a thermal capacity of 128 MVA × 2.

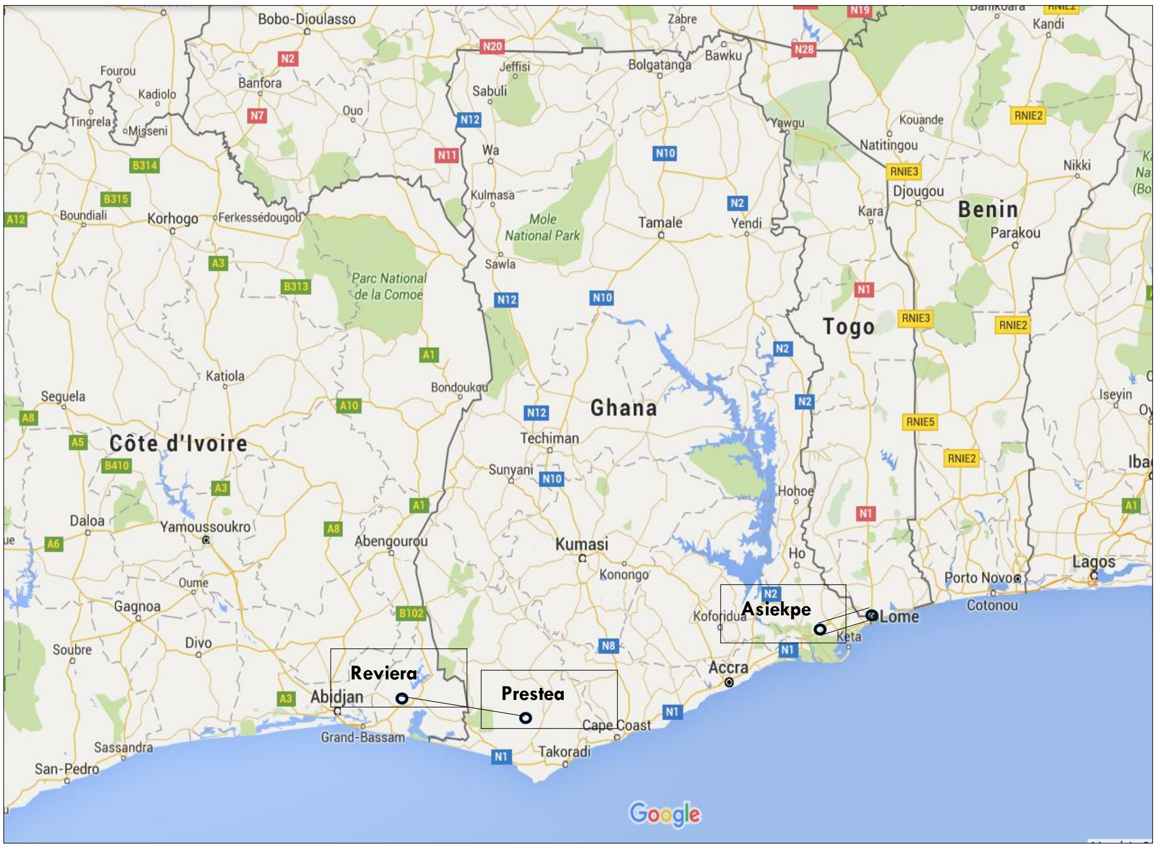


Figure 4-9. Interconnected Power System in Ghana

4.6 A BRIEF DESCRIPTION OF THE GHANA POWER SYSTEM

The Ghana power system comprises of 161 kV, 225 kV and 330 kV high voltage AC transmission network of 5000 c-km. Ghana transmission grid is interconnected on the west with La Côte d'Ivoire power system (CIE) through a 225 kV AC transmission circuit and with the Togo-Benin power system on the east through two 161 kV AC transmission circuits.

Aside direct customers such as mining companies who take power directly from the transmission grid, there are two major distribution companies which distribute power in the country. The Electricity Company of Ghana (ECG) distributes power in the southern part of the country and the Northern Electricity Distribution Company (NEDCO) also distributes power in the northern part of the country. The map below shows the geographical coverage of the distribution companies.

Figure 4-10. Geographical Coverage of Distribution Companies

The Ghana Grid Company Ltd (GRIDCo) is the balancing authority responsible for carrying out monitoring, control and dispatch functions on the Ghana power system. These functions are carried out from a central location called the System Control Centre in Tema.

Ghana has bilateral power exchange agreements with CIE and CEB. CEB also buys power directly from CIE and this is wheeled across the Ghana power system from CIE to CEB.

4.7 Operation of the Ghana Interconnected Power System

The main objective of the Ghana-La Côte d'Ivoire-Togo-Benin interconnection is to facilitate electricity trade among the three utilities. Ghana and La Côte d'Ivoire have bilateral agreement to exchange power across the interconnection.

Accordingly, by 16:00 h each preceding day, the Ghana dispatch centre at Tema and the La Côte d'Ivoire dispatch centre in Abidjan communicate to set the power to be traded across the interconnection for the day ahead.

If Ghana has a deficit in its available generation capacity to meet its forecast demand for the day ahead and La Côte d'Ivoire has surplus power, Ghana buys power from La Côte d'Ivoire. If on the other hand, La Côte d'Ivoire has a deficit in its available generation capacity to meet its forecast demand for the day ahead and Ghana has surplus power, La Côte d'Ivoire buys power from Ghana.

The overall energy to be traded during the year is concluded between the utilities in the preceding year. The agreement between Ghana and the Togo-Benin power system (CEB) is also bilateral in which power is traded across the interconnection.

Historical records however, show that CEB always buys power from the Ghana power system. This situation can be attributed to the fact that the installed capacity of CEB is far less than its peak demand which makes CEB a net importer of electricity.

CIE and CEB also have a bilateral agreement to trade power between the two utilities. The power purchased by CEB from CIE is wheeled across the Ghana network from Reviera to Lomé. The maintenance of the tie lines is harmonised and coordinated among the interconnected power system utilities to minimise the number and duration of maintenance outages on the lines.

The maintenance personnel of the utilities plan their maintenance activities to coincide so that the maintenance work is jointly carried out to minimise outages on the lines.

4.8 Benefits of Operation of the Ghana Interconnected Power System

The interconnection of the Ghana power system with its neighbouring countries has several mutual benefits accrued to the interconnected utilities. The most obvious benefit is the facilitation of electricity trade among the interconnected utilities.

In addition to importing power from neighbouring countries to offset internal supply deficit, member utilities can also plan to shut down expensive power plants and import power whenever cheaper imports are available.

Pulling the resources of the individual power systems together through the interconnection has increased the overall inertia of the interconnected power system. This has improved the frequency control of the interconnected power system and better response to transient instability. The reliability of the overall interconnected power system has accordingly improved.

The interconnection has made it possible for the individual interconnected utilities to reduce their spinning reserve margin, which if operating independent of each other, would have had to maintain for reliable operation.

For instance, the largest single contingency generating units in GRIDCo, CIE and CEB power systems are 170 MW (one hydro unit at Akosombo), 225 MW (a combined cycle thermal plant at Azito) and 32 MW (a hydro unit at Nangbeto) respectively.

Therefore, if these utilities were not interconnected, the total spinning reserve to be maintained by the three utilities is 427 MW (170 MW + 225 MW + 32 MW). However, due to the interconnection of the utilities, the spinning reserve maintained by the interconnected power system is only 225 MW since this is the largest single contingency of the overall interconnected system.

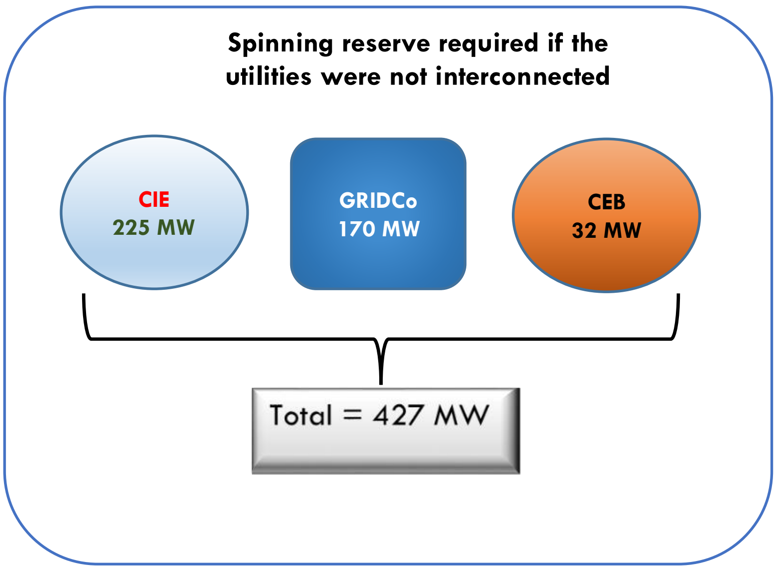


Figure 4-11. Spinning Reserve without Interconnection

A West African Power Pool (WAPP) protocol requires that the total spinning reserve of 225 MW for the interconnected power system should be shared in proportion to each utilitiy's share of the previous year's energy supply of the interconnected power system. The spinning reserve may therefore be shared in the ratio e.g. GRIDCo 50%, CIE 38% and CEB 12%.

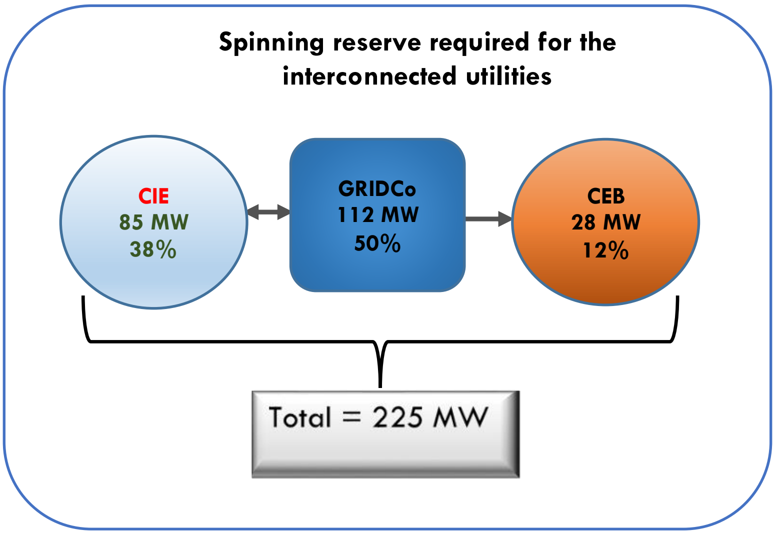


Figure 4-12. Spinning Reserve with Interconnection

The reduction in the spinning reserve allocations for the member utilities of the interconnected power system results in cost savings for the utilities.

2. POWER SYSTEM OPERATION

Ghana Grid Company Limited

M01 – ACTIVE AND REACTIVE POWER

1.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of active and reactive power
- Define active power, reactive power and apparent power
- Explain power triangle and the effect of power factor on power system

1.2 Introduction

Power is the rate of doing work or expending energy. The electrical unit of power is the watt (W) and one watt is the rate of expending energy at the rate of one joule per second. The form and characteristics of power vary dependent on whether it is applied in Direct Current (DC) or Alternating Current (AC) circuit. This lesson shall mainly focus on the form and behavior of power in AC power systems.

1.3 Power in a DC Circuit

In DC circuit the power dissipated in a resistive circuit is given by:

$$P = VI = \frac{V^2}{R}$$

where:
P = power (W)
V = potential difference (V)
I = current (A)
R = resistance (Ω)

The circuit in Figure 1-1 shows a battery of 18V suppling electric current to a lamp of resistance 3 Ω.

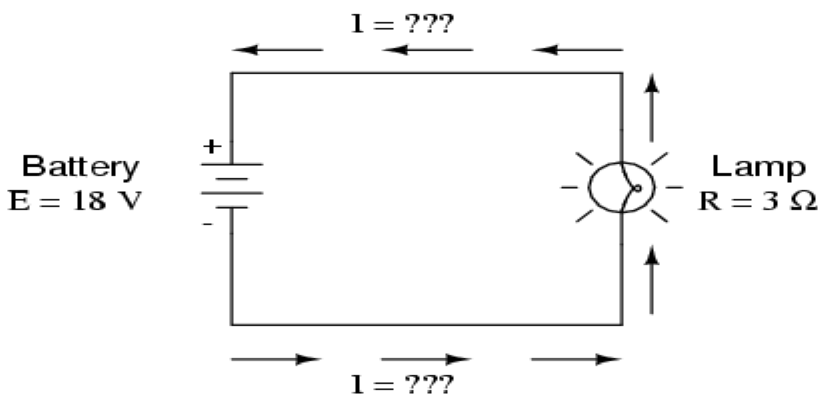


Figure 1-1. DC Circuit

In the above circuit, using Ohm's Law, the current being delivered through the lamp can be determined as follows;

$$I = \frac{E}{R} = \frac{18\ V}{3\ \Omega} = 6\ A$$

The power can also be determined using the power formula as;

$$P = I\,E = (6\ A)(18\ V) = 108\ W$$

This implies that the lamp is dissipating (releasing) 108 watts of power, most likely in the form of both light and heat.

1.4 Power in an AC Circuit

In AC circuits, the instantaneous values of voltage, current and therefore power are constantly changing. However, at any instant power can still be expressed as:

$$p = vi$$

where:
p = instantaneous power (W)
v = instantaneous voltage (V)
i = instantaneous current (A)

The RMS values (U, I and P) can be easily used in AC circuits with only resistance, however, matters are more complicated when capacitance and inductance are involved. Remember that the RMS values are defined so that a current of RMS 1A AC will produce the same heating effect in a resistor as 1A DC.

1.4.1 Power in a Resistive AC Circuit

For a resistive circuit current and voltage are in phase and the power at any instant can be found by multiplying the voltage by the current at that instant. Figure 1-2 shows the voltage, current and power waves and it is clear that when the voltage is positive, so is the current and the power is positive. Also, when the voltage is negative, so is the current and therefore the power is again positive. Because of this in-phase relationship, RMS values can be used in the DC power equation:

$$P = VI = \frac{V^2}{R}$$

Many electrical loads, such as heaters, irons, kettles and filament bulbs can be considered to be wholly resistive.

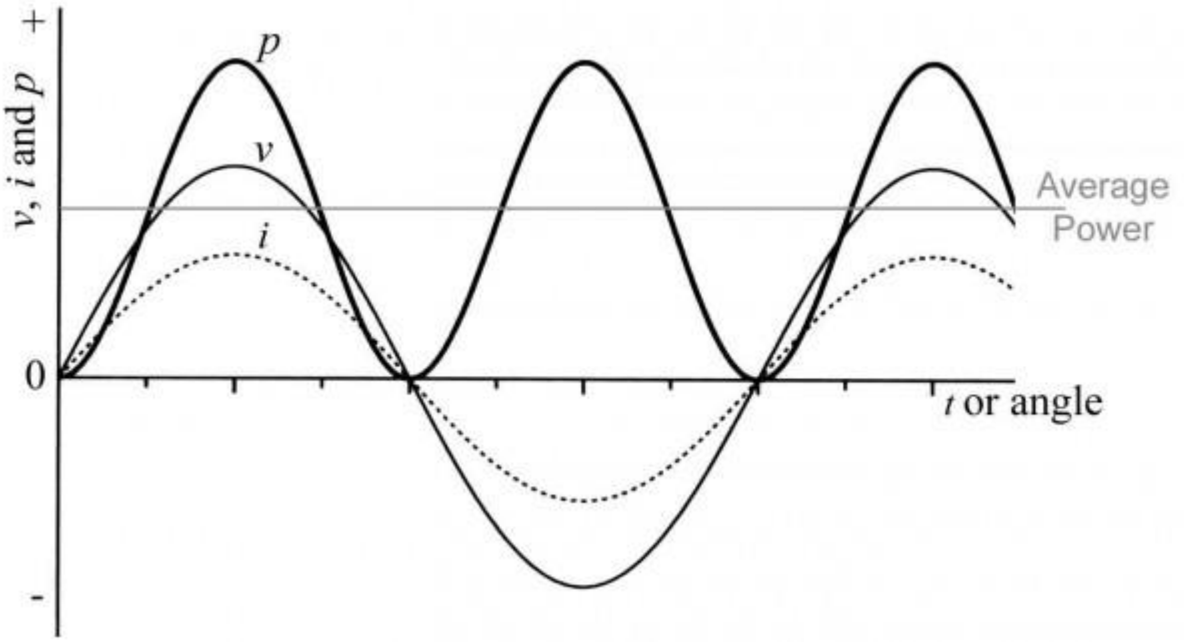


Figure 1-2. Power in an AC resistive circuit. Note that v, i and p are not plotted on the same scale.

1.4.2 Power in a Capacitive AC Circuit

In a capacitive circuit, the voltage V and current I are out of phase with the current leading the voltage by an angle of 90°. Figure 1-3 shows the wave diagram for an AC capacitive circuit with the current leading the voltage by 90°.

In the first-quarter cycle both v and i are positive, therefore the power is also positive (since p = vi, at any instant). In the second quarter-cycle v stays positive while i has gone negative, therefore p is negative.

In the third-quadrant both i and v are negative and so p is positive. Finally, in the fourth-quadrant i is positive and v is still negative resulting in p being negative.

The power wave is thus a series of identical positive and negative pulses whose average value over a half-cycle of voltage is zero, also note that its frequency is twice the frequency of the voltage.

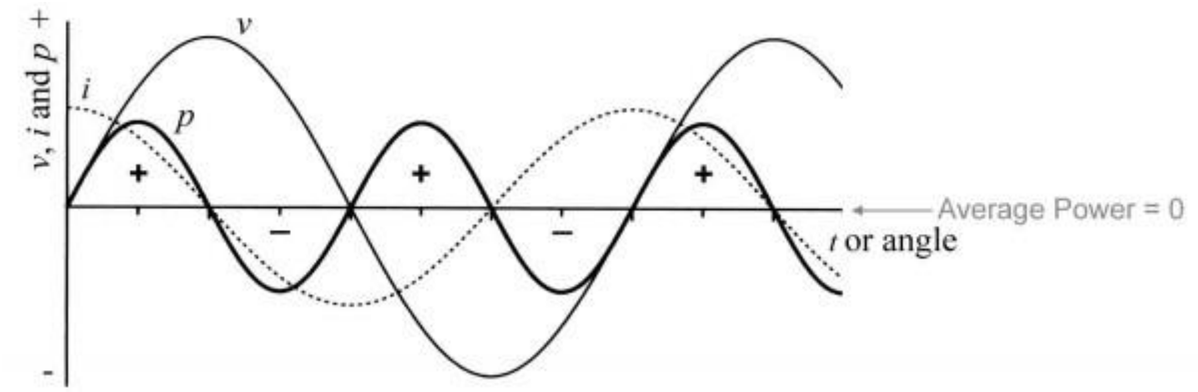


Figure 1-3. Power in an AC capacitive circuit. Note that v, i and p are not plotted on the same scale.

During the first and third quarter-cycles the power is positive, meaning that power is supplied by the circuit to charge the capacitor. In the second and fourth quarter-cycles the capacitor is discharging and thus supplies the energy stored in it back to the circuit, thus p has a negative value.

Although negative power may seem like an odd concept the minus or plus signs simply indicate the direction in which the power is flowing. Since this interchange of energy dissipates no average power no heating will occur and no power is lost (for a perfect capacitor that experiences no current leakage, at least).

Since we have a voltage and current but no power dissipated, the expression P = IV (using RMS value) is no longer valid. The product of current and voltage in this case is called reactive power or reactive voltamperes and is measured in voltamperes (VA_r). (The reactive power is not really power at all and the name is slightly deceptive).

The current that flows through the capacitor (that does not have resistance), causes no heating and is called reactive current.

1.4.3 Power in an Inductive AC Circuit

In an inductive AC circuit, the voltage and current are displaced with the current lagging the voltage by 90°.

Figure 1-4 presents the wave diagram from an inductive AC circuit and shows the current lagging the voltage by 90°.

As was the case with power in capacitive circuit, the power in an inductive circuit consists of positive and negative pulses.

The average of these pulses over a half-cycle is zero and therefore no heating occurs (for a perfect inductor, although in practice the wire that forms the coil will have resistance). In this case the negative power is due to energy that has been stored in the magnetic field, being fed back into the circuit.

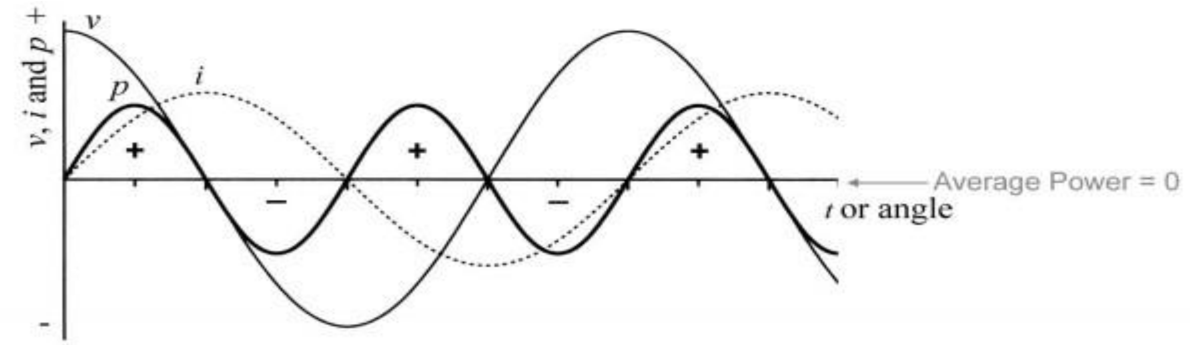


Figure 1-4. Power in an AC inductive circuit. Note that v, i and p are not plotted on the same scale.

1.5 Power in Resistive and Capacitive Circuits (RC Circuits)

In a circuit consisting of a resistance and a capacitive reactance in series, the voltage and current will have a relative phase angle between 0° and 90°, depending on the ratio of resistance to reactance.

Figure 1-5 shows the wave diagram for such a circuit, with the current leading the voltage by ϖ°. Because energy is dissipated in the resistor, less energy is returned to the circuit than for a pure capacitive circuit and the negative pulses are considerably smaller.

Thus there is a net power drawn from the supply which will be dissipated as heat. However, the energy dissipated will be less than that dissipated in a purely resistive circuit because the current is out of phase with the voltage.

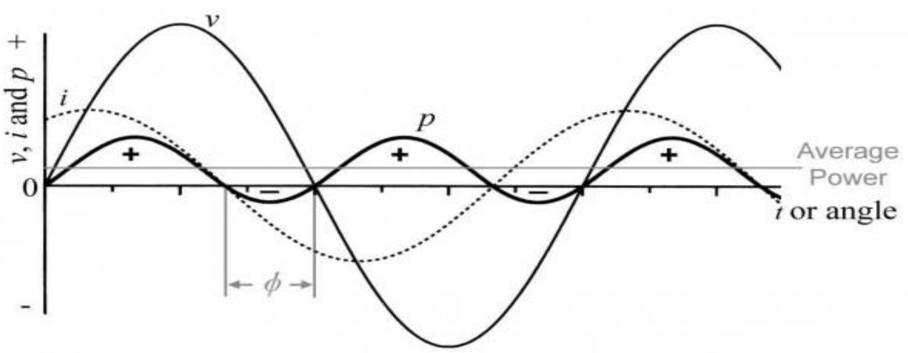


Figure 1-5. Power in an AC resistive and capacitive circuit. Note that v, i and p are not plotted on the same scale.

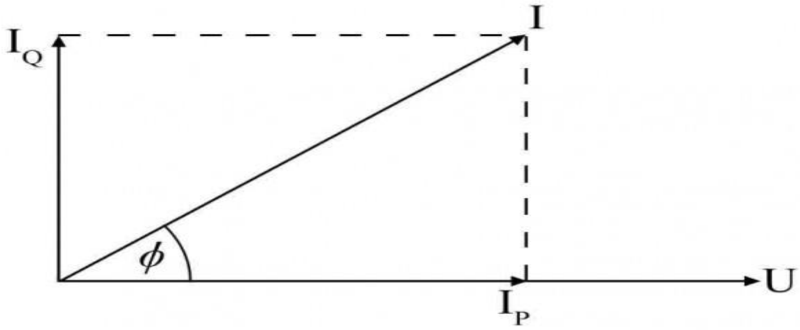


Figure 1-6. The phasor diagram for a resistive and capacitive AC circuit

The current phasor can be split into two component currents; these do not actually exit but as vector quantities can be split into components to make sums easier. I_P is the in-phase or active component of current, being in-phase with the voltage.

It is the part of the current that is considered to causes heat to be dissipated. While the quadrature or reactive component I_Q leads the voltage by 90° and is considered to be the part of the current that causes energy to be stored and then returned to the circuit but causing no heating. In figure 1-6, the supply voltage (V) is taken as the reference and so in a RC circuit the supply current (I) leads this by °.

We can see from figure 1-6 that since I_P is in-phase with V the power dissipated in the resistive part of the circuit is given by:

$$P = VI$$

And

$$\cos\phi = \frac{I_P}{I}$$

$$I_P = I\cos\phi \qquad \text{and} \qquad P = V\cos\phi$$

Cosϕ is known as the power factor of the circuit. Since this result has been derived from a phasor diagram it only applies to sin waves and in such cases average power = RMS voltage × RMS current × the cosine of the phase angle between voltage and current.

We can also see that since the power is only dissipated in the resistive part of the circuit, it follows that:

$$P = I^2R = \frac{V_R^2}{R}$$

Note that the above equations do not mix current and voltage (unlike P = UI) and so there is no problem with phase differences. For this reason the power losses in wires and cables carrying AC supplies are calculated using $P = I^2R$.

1.6 Power in Resistive and Inductive Circuits (RL Circuit)

When resistance and inductive reactance are in series, current lags supply voltage by an angle of ° which will vary from almost 0° to nearly 90°. Figure 1-7 shows the wave diagram for such a circuit.

Like the RC circuit the amount of energy taken from the supply is greater that the energy returned to the circuit by the inductor and a net energy is consumed. The average power (P) consumed is illustrated in figure 1-7.

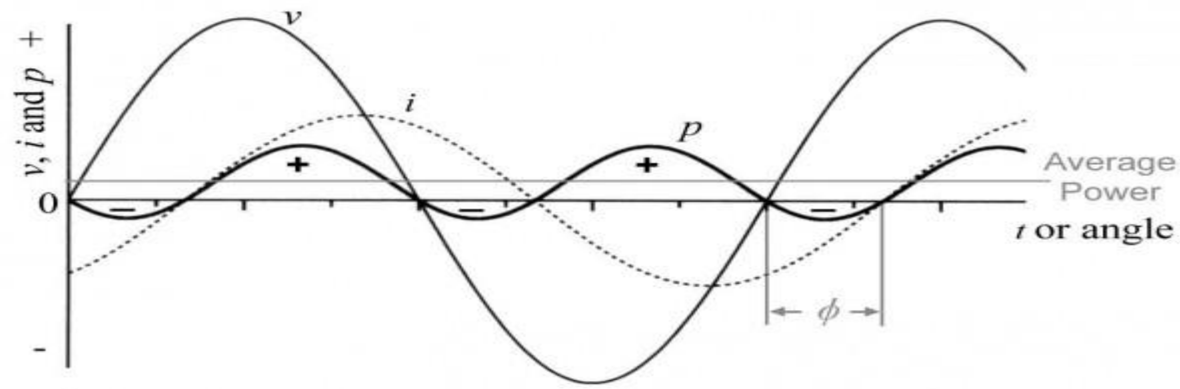


Figure 1-7. Power in an AC resistive and inductive circuit. Note that v, i and p are not plotted on the same scale.

Figure 1-8 shows the phasor diagram which corresponds to the wave diagram, since I and U are out of phase, P = IU is not valid, however once again the power consumed can be found from:

$$P = VI_P = VIcos\phi$$

This equation only holds true for sine waves.

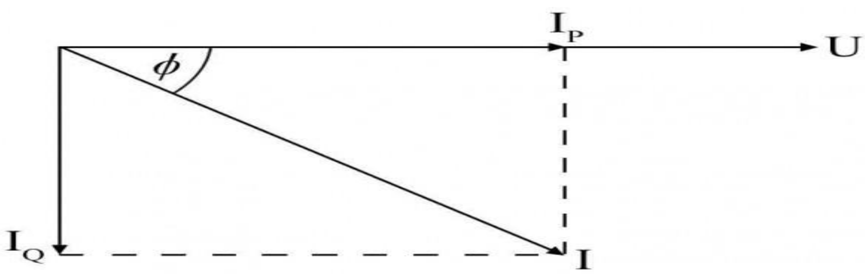


Figure 1-8. The phasor diagram for a resistive and inductive AC circuit.

1.7 Power in Three Phase Circuit

The main difference between a three phase system and a single phase system is the voltage. In a three phase system we have the line to line voltage (V_L) and the phase voltage (Vp).

The total power in a three-phase circuit is the sum of the power in the three phases. In a balanced system, delta or star connected, the total apparent power is

$$S = \sqrt{3} V_L I_L$$

In the case of star-connected system:

i. Phase voltage $V_p = \frac{Line\ voltage}{\sqrt{3}} = \frac{V_L}{\sqrt{3}}$
ii. Phase current I_P = Line current I_L
iii. $Apparent\ power\ per\ phase = \frac{V_L}{\sqrt{3}} \times I_L$
iv. $Total\ apparent\ power = 3 \times \frac{V_L}{\sqrt{3}} \times I_L = \sqrt{3} V_L I_L$

In the case of delta-connected system:

i. Phase current $I_p = \frac{Line\ current}{\sqrt{3}} = \frac{I_L}{\sqrt{3}}$
ii. Phase voltage V_P = Line voltage V_L
iii. $Apparent\ power\ per\ phase = \frac{I_L}{\sqrt{3}} \times V_L$
iv. $Total\ apparent\ power = 3 \times \frac{I_L}{\sqrt{3}} \times V_L = \sqrt{3} V_L I_L$

The active power for any balanced system is

$$P = \sqrt{3}\ V_L\ I_L \cos\varphi$$

And the reactive power for any balanced system is

$$Q = \sqrt{3}\ V_L\ I_L \sin\varphi$$

where $\cos\varphi$ is the power factor. The angle φ is the phase angle between the phase voltage and the phase current.

Most three-phase apparatus such as motors can be assumed to be a balanced load and calculations for currents can be made using these formulae.

1.8 Active Power, Reactive Power and Apparent Power

There are three kinds of power in an AC system, namely; Active power, Reactive power and Apparent power.

1.8.1 Active Power

The active power, also referred to as real power, useful power or true power, is the actual power being used, or dissipated, in a circuit. It is measured in watts and symbolized by the capital letter P. It represents the capacity of the circuit for performing work in a particular time

1.8.2 Reactive Power

The reactive power is usually referred to as the non-useful power and is represented by the capital letter (Q). It is measured in the unit Volt-Ampere-Reactive (VAR).

It has been established that reactive loads such as inductors and capacitors dissipate zero power, yet the fact that they drop voltage and draw current gives the deceptive impression that they actually do dissipate power.

1.8.3 Apparent Power

Represented by (S) and measured in the unit of Volt-Amperes (VA), the Apparent power is a function of a circuit's total impedance. A combination of active and reactive power.

There are several power mathematical equations that relate the three types of power to resistance, reactance, and impedance (all using scalar quantities):

$\mathbf{P}$ = true power $\quad P = I^2R \quad P = \dfrac{E^2}{R}$

Measured in units of ***Watts***

$\mathbf{Q}$ = reactive power $\quad Q = I^2X \quad Q = \dfrac{E^2}{X}$

Measured in units of ***Volt-Amps-Reactive (VAR)***

$\mathbf{S}$ = apparent power $\quad S = I^2Z \quad S = \dfrac{E^2}{Z} \quad S = IE$

Measured in units of ***Volt-Amps (VA)***

As a rule, true power is a function of a circuit's dissipative elements, usually resistances (R). Reactive power is a function of a circuit's reactance (X). Apparent power is a function of a circuit's total impedance (Z).

Since we're dealing with scalar quantities for power calculation, any complex starting quantities such as voltage, current, and impedance must be represented by their polar magnitudes, not by real or imaginary rectangular components.

1.9 The Power Triangle

The three types of power—true, reactive, and apparent—relate to one another in trigonometric form. This is called the power triangle as shown in Figure 1-9.

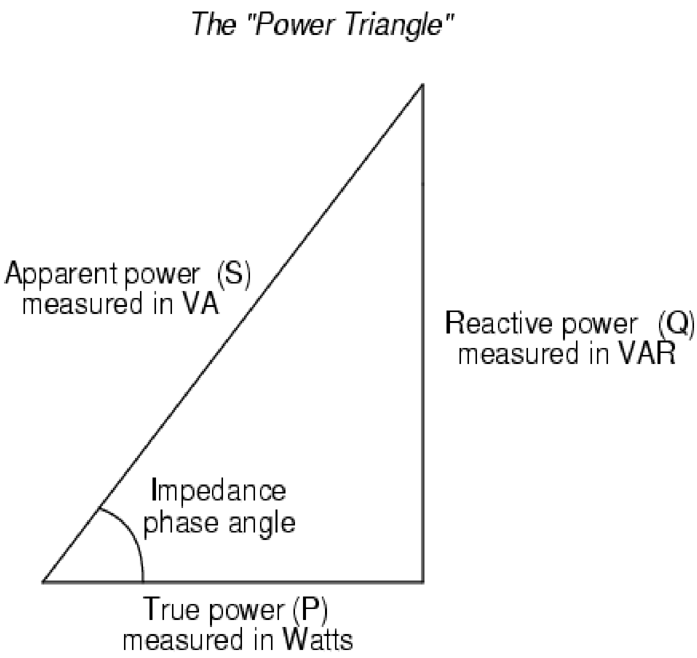


Figure 1-9. Power triangle relating apparent power to true power and reactive power.

Using the laws of trigonometry, the length of any side can be calculated for provided the length of any other two sides or the length of one side and an angle are given.

From the Power triangle, the true power extends horizontally in the i direction as it represents a purely real component of AC power.

The reactive power, on the other hand, extends vertically in the direction of ĵ as it represents a purely imaginary component of AC power. Apparent power represents a combination of both real and reactive power.

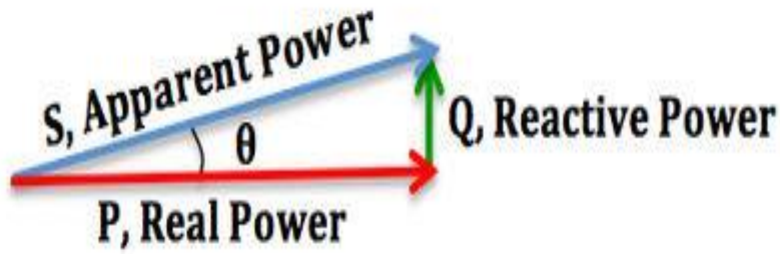
1.10 Power Factor

Power factor is defined as the ratio of real power to apparent power, It is the cosine of the angle between voltage and current in an AC circuit, a dimensionless number between **-1** and **1**

As power is transferred along a transmission line, it does not consist purely of real power that can do work once transferred to the load, but rather consists of a combination of real and reactive power, called apparent power. The power factor, therefore, indicates the amount of real power transmitted along a transmission line relative to the total apparent power flowing in the line.

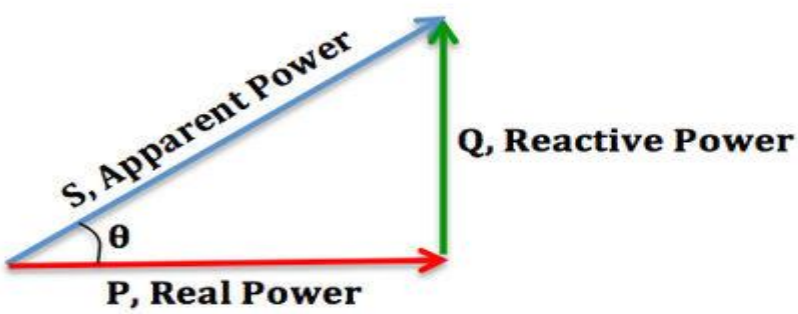
1.10.1 Increasing the Power Factor

As the power factor (i.e. cos θ) increases, the ratio of real power to apparent power (which = cos θ), increases and approaches unity (1), while the angle θ decreases and the reactive power decreases. [As $\cos\theta \to 1$, its maximum possible value, $\theta \to 0$ and so $Q \to 0$, as the load becomes less reactive and more purely resistive].



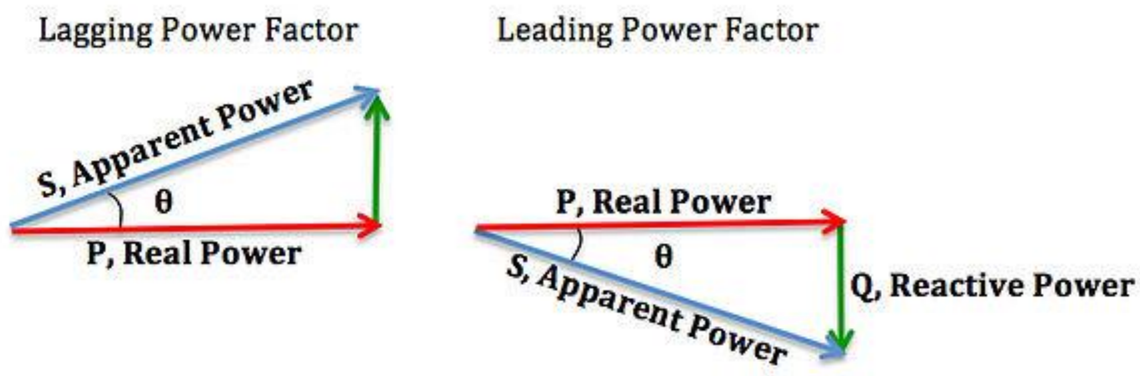
1.10.2 Decreasing the Power Factor

As the power factor decreases, the ratio of real power to apparent power also decreases, as the angle θ increases and reactive power increases.



When power factor is equal to 0, the energy flow is entirely reactive and stored energy in the load returns to the source on each cycle. When the power factor is 1, all the energy supplied by the source is consumed by the load. Power factors are usually stated as "leading" or "lagging" to show the sign of the phase angle. Capacitive loads are leading (current leads voltage), and inductive loads are lagging (current lags voltage).

A lagging power factor signifies that the load is inductive, as the load will "consume" reactive power, and therefore the reactive component Q is positive as reactive power travels through the circuit and is "consumed" by the inductive load. A leading power factor signifies that the load is capacitive, as the load "supplies" reactive power, and therefore the reactive component Q is negative as reactive power is being supplied to the circuit.



1.11 Summary

- In a purely resistive circuit, all circuit power is dissipated by the resistor(s). Voltage and current are in phase with each other.
- In a purely reactive circuit, no circuit power is dissipated by the load(s). Rather, power is alternately absorbed from and returned to the AC source. Voltage and current are 90^o out of phase with each other.
- In a circuit consisting of resistance and reactance mixed, there will be more power dissipated by the load(s) than returned, but some power will definitely be dissipated and some will merely be absorbed and returned. Voltage and current in such a circuit will be out of phase by a value somewhere between 0^o and 90^o.
- Power dissipated by a load is referred to as true power. True power is symbolized by the letter P and is measured in the unit of Watts (W).

- Power merely absorbed and returned in load due to its reactive properties is referred to as reactive power. Reactive power is symbolized by the letter Q and is measured in the unit of Volt-Amps-Reactive (VAR).
- Total power in an AC circuit, both dissipated and absorbed/returned is referred to as apparent power. Apparent power is symbolized by the letter S and is measured in the unit of Volt-Amps (VA).
- These three types of power are trigonometrically related to one another. In a right-angled triangle, P = adjacent length, Q = opposite length, and S = hypotenuse length. The opposite angle is equal to the circuit's impedance (Z) phase angle.

M02 – POWER SYSTEM FREQUENCY CONTROL

2.1 Objectives

Upon completion of this module the participant will be able to:

- Explain the essence of frequency in power system operation
- State the frequency requirements under contingency conditions
- List the benefits of frequency control in power system
- State and explain the levels of frequency control loops
- Demonstrate understanding in frequency control coordination.

2.2 Introduction

The function of an electric power system is to convert energy from one of the naturally available forms to the electrical form and to transport it to the points of consumption. Energy is seldom consumed in the electrical form but is rather converted to other forms such as heat, light and mechanical energy.

The advantage of the electrical form of energy is that it can be transported and controlled with relative ease and with a high degree of efficiency and reliability. A properly designed and operated power system should therefore meet the following fundamental requirements:

(a) The system must be able to meet the continually changing load demand for active and reactive power. Unlike other types of energy, electricity cannot be conveniently stored in sufficient quantities. Therefore, an adequate "spinning" reserve of active and reactive power should be maintained and appropriately controlled at all times.

(b) The system should deliver reliable and quality supply of energy at minimum cost and with minimum ecological impact. The "quality" of power supply by an electric power system must meet certain minimum standards with regard to the following factors:

   - constancy of frequency
   - constancy of voltage; and
   - level of reliability

This module focuses on the control of power system frequency in the delivery of quality and reliable power system.

2.3 The Essence of Frequency in Power System

At the most basic level, the input and output energy of a generator must balance. If more mechanical energy is being delivered to a generator than electrical energy is being received from the generator terminals then the excess energy will be stored in the generator's rotation (kinetic energy), resulting in acceleration of the generator. Likewise, if more electrical power is drawn out of the generator than mechanical power is put into it, then the generator will decelerate. The magnitude of acceleration depends upon the quantity of the power mismatch, and the inertia of the turbine-generator. Inertia is a physical constant of each turbine-generator that defines its ability to store rotational kinetic energy, and is analogous to mass. Power system frequency responds to a generation and load imbalance in the same manner. The rate at which frequency moves depends upon the magnitude of the energy imbalance and the inertia of all of the generators and loads within the system.

This implies that system frequency provides an indication of generation/load balance which is instantly available everywhere within the power system without the need for additional communications. Under normal circumstances, a lower system frequency than standard value is indicative of low generation capacity than demand, whereas higher system frequency shows high system generation reserve than demand. Frequency Control, therefore, has both direct and indirect reliability implications.

2.3.1 Commonly Operated Frequencies in Power System

There are two main frequency levels at which power systems around the world operate, namely **50Hz** and **60Hz**. For example, the power system in Ghana is operated at 50Hz while that of Korea is operated at 60Hz.

It is not always possible to maintain a perfect generation vs. load balance, due to dynamic system conditions, although active control systems attempt to do this by constantly adjusting the generators power input. Small mismatches between generation and load result in small frequency deviations. Small shifts in frequency do not degrade reliability or markets efficiency although large shifts can damage equipment, degrade load performance, and interfere with system protection schemes which may ultimately lead to system collapse. The maximum permissible deviation in power system frequency is $\pm 0.5Hz$.

2.3.2 Frequency Variation Interpretation

Standard frequency	Actual frequency	Interpretation
50Hz	<50 Hz	There is less available generation capacity compared to demand
50Hz	>50 Hz	There is more generation capacity available compared to demand
50Hz	50Hz	Available generation capacity and demand are in equilibrium

2.3.3 Frequency Response Under Contingency Condition

The sudden loss of a generator or load can instantaneously create a large imbalance between generation and load. The power system must be designed to recover from this type of credible imbalance rapidly if not frequency can deviate substantially.

Figure 2-1 shows the frequency response for a large loss of generation in a (relatively) small power system. Frequency did not drop "too" far and the system recovered within 10 minutes.

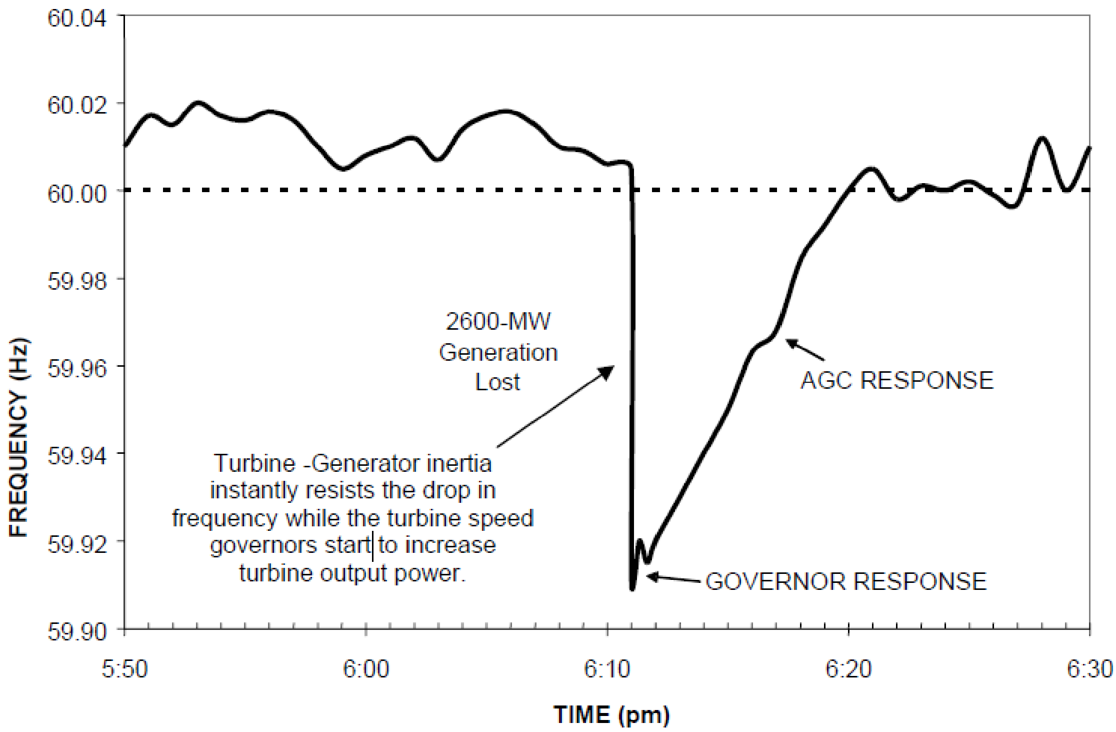


Figure 2-1. Contingency reserves rebalance the system after the sudden loss of generation

2.4 Frequency Control

2.4.1 The Importance of Frequency Control

At the heart of any stable power system is a well-controlled or regulated system frequency. This is necessary to;

- Maintain constancy in system frequency for a reliable delivery of supply to consumers
- Avoid unwarranted interference with network protection system
- Minimize/Avoid damage to system equipment due to frequency fluctuations
- Manage the cost of operations to engender economic viability.

2.4.2 Frequency Control Systems

Several levels of frequency control involving a complex array of devices are required in power systems to provide the constancy of frequency to ensure the delivery of reliable supply. That is because, in power systems, both active and reactive power demands are never steady. Continuous regulation of the fundamental elements is necessary for efficient and effective operation.

Since the frequency generated in an electric network is proportional to the rotation speed of the generator, frequency control may be directly translated into speed control of the turbine generator units.

This is initially overcome by adding a governing mechanism that senses the machine speed, and adjusts the input valve to change the mechanical output to track the load change to restore frequency to nominal value. Depending on the frequency deviation range, different frequency control loops may be required to maintain power system frequency stability.

A large deviation can damage equipment, degrade load performance, cause transmission line to be overloaded, interfere with system protection schemes and ultimately lead to an unstable condition for the power system.

Typically, frequency control loops can be categorized into four main levels

- Primary control
- Secondary control

- Tertiary control
- Emergency control

as shown in Figure 2-2 below.

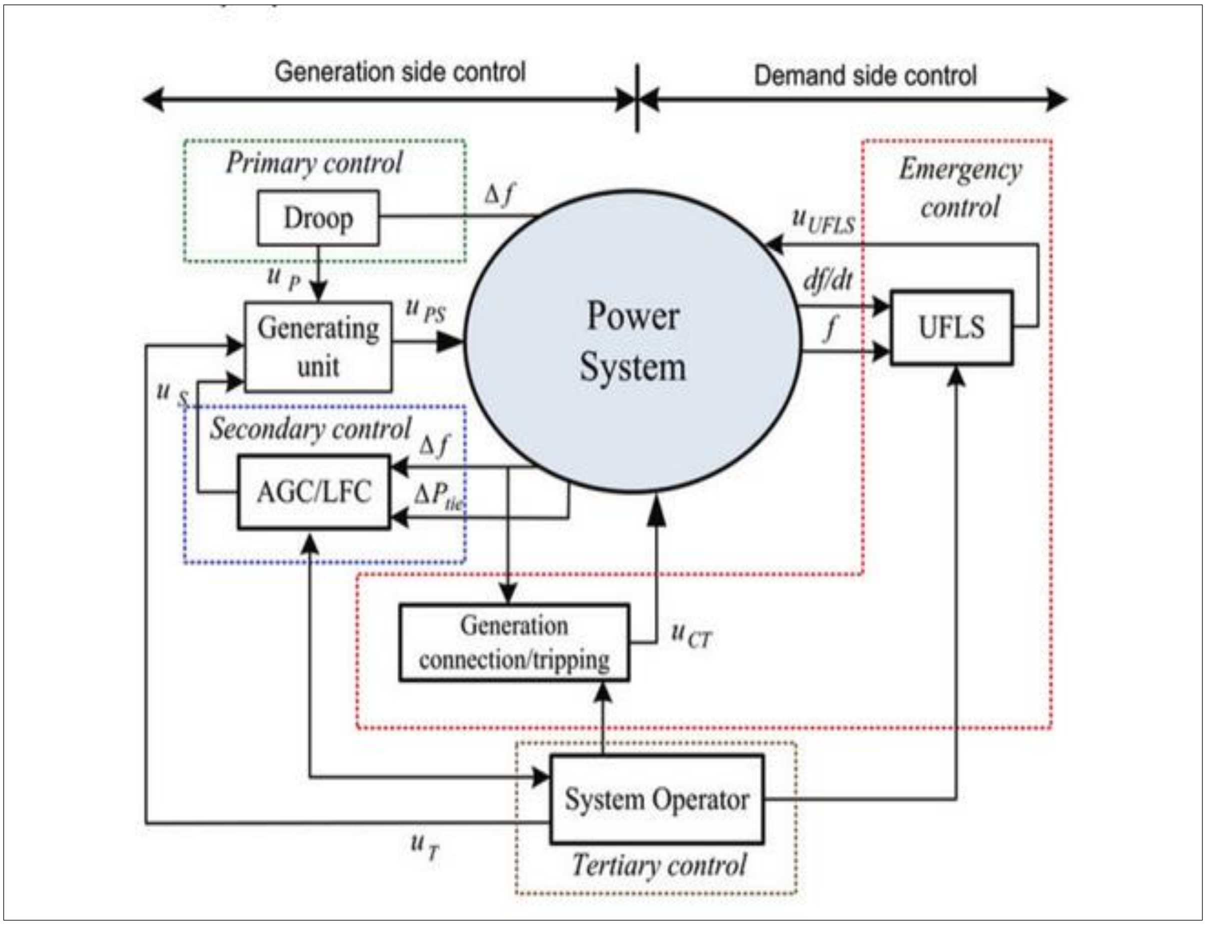


Figure 2-2. Frequency control loops.

2.4.2.1 Primary Frequency Control

Primary control consists of changing a generating unit's power versus the frequency, according to its static generation characteristic as determined by the governor speed settings.

The objective of primary control is to re-establish a balance between generation and demand within the synchronous area at a frequency different from the nominal value.

This is done at the expense of the kinetic energy of rotating masses of generating sets and connected motors.

The primary control action time is 0 to 30 s after disturbance of the balance between generation and demand.

Under normal conditions the system operates at nominal frequency, maintaining the condition of equality of generated power and demand. Each disturbance of this balance, due to, for example, disconnection of a large generating unit or connection of a large load, causes a change in frequency. At first, the frequency varies rapidly, practically linearly, and attains the maximum deviation from the nominal value, referred to as the dynamic frequency deviation (Figure 2-3).

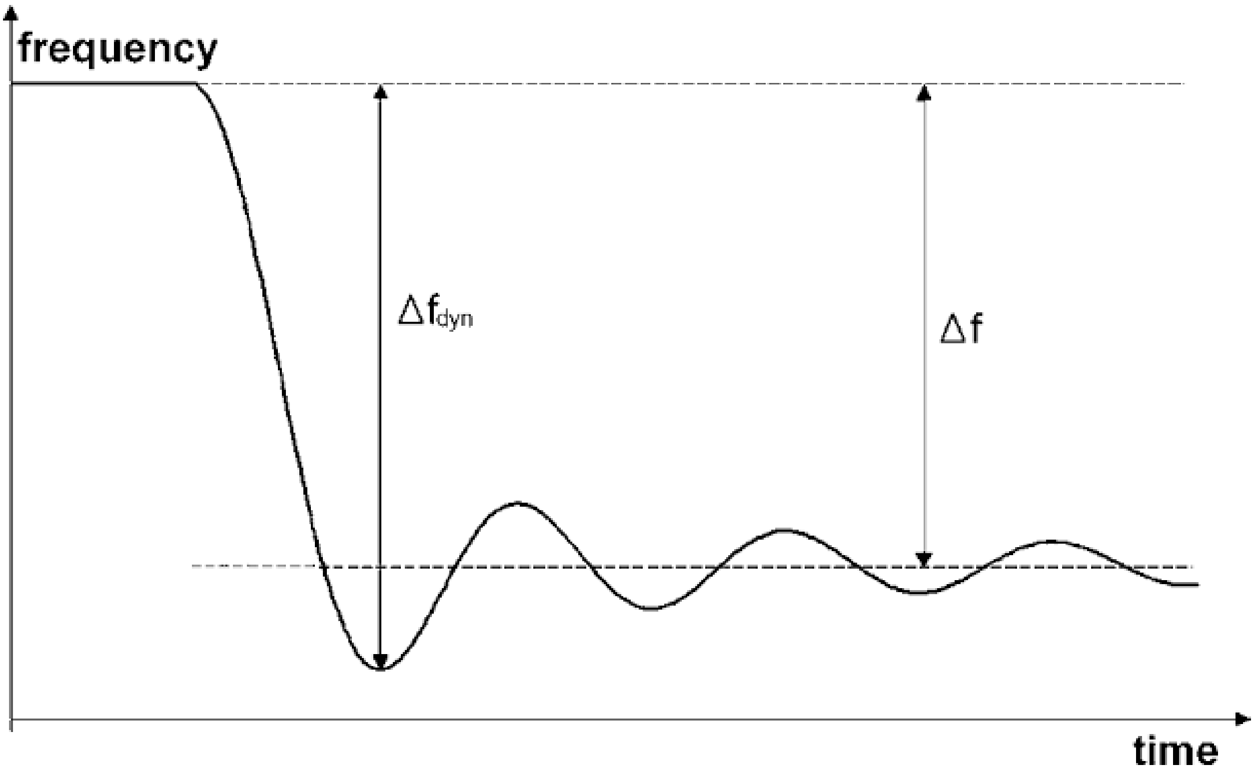


Figure 2-3. Definition of the dynamic (Δfdyn) and quasi-steady-state frequency (Δf) deviation

This deviation in the system frequency will cause the primary controllers of all generators subject to primary control to respond within a few seconds. The controllers alter the power delivered by the generators until a balance between the power output and consumption is re-established. At the moment when the balance is re-established, the system frequency stabilizes and remains at a quasi-steady-state value, but differs from the frequency set point because of the generators' droop.

The magnitude of the dynamic frequency deviation depends on: the amplitude and development over time of the disturbance affecting the balance between power output and consumption; the kinetic energy of rotating machines in the system; the number of generators subject to primary control; the dynamic characteristics of the machines (including controllers); and the dynamic characteristics of loads.

The quasi-steady-state frequency deviation is governed by the amplitude of the disturbance and the system stiffness.

The contribution of a generator to primary control depends upon the drop of the generator and the primary control reserve of the generator concerned. Figure 2-4 shows the characteristics of two generators a and b and of different droops under equilibrium conditions, but with identical primary control reserves.

In the case of a minor disturbance, for which the frequency offset is smaller than Δfa, the contribution of generator a (with the smaller droop) will be greater than that of generator b (the one with the greater droop).

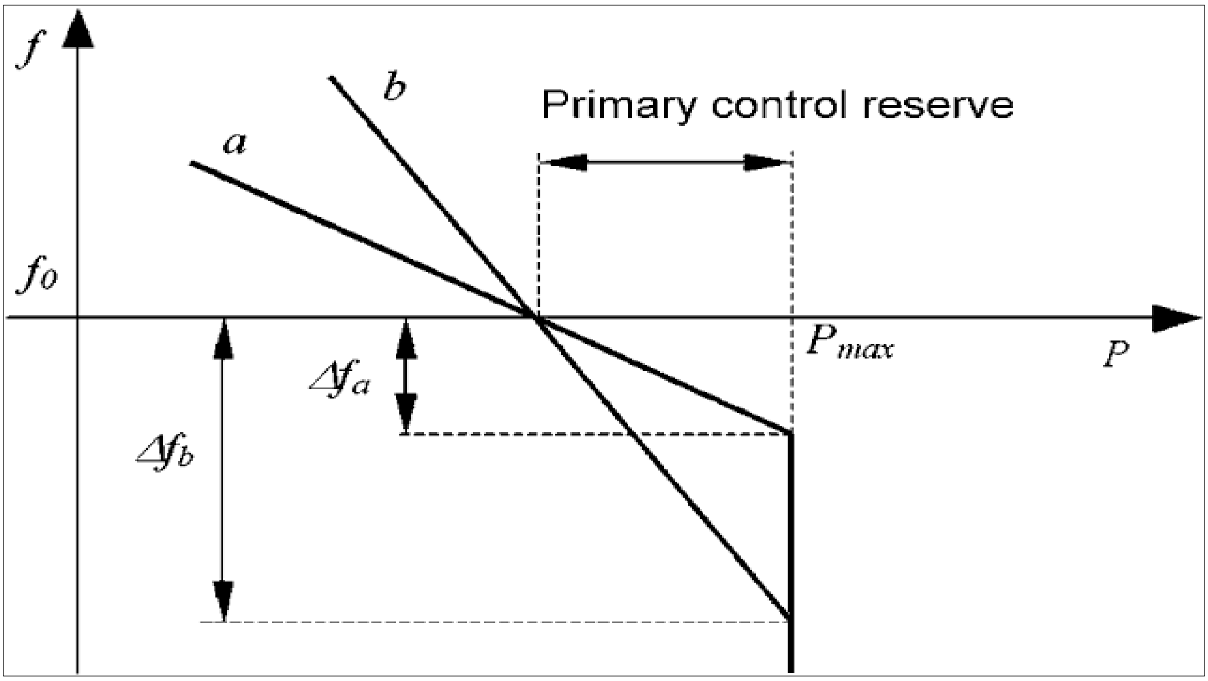


Figure 2-4. The contribution of two generators, with different droops, to primary control

The primary control reserve of generator a is exhausted (i.e. where the power generating output reaches its maximum value) earlier (at the frequency offset Δfa) than that of generator b (which will be exhausted at the frequency offset Δfb), even when both generators have identical primary control reserves.

For an adequate operation of frequency control it is crucial that the system has a proper level of primary control reserve at any instant of time allocated in a possibly large number of generating units and activated within a few seconds of detecting the frequency deviating from its nominal value.

2.4.2.2 Secondary Frequency Control

Secondary control makes use of a central regulator, modifying the active power set points of generating sets subject to secondary control, in order to restore power interchanges with adjacent control areas to their programmed values and to restore the system frequency to its set-point value at the same time. By altering the operating points of individual generating units, secondary control ensures that the full reserve of primary control power activated will be made available again. Secondary control operates slower than primary control, in a timeframe of minutes. Its action becomes evident about 30 s after a disturbance/event, and ends within 15 min. Since under normal operating conditions of a power system the power demand varies continuously, secondary control takes place continually in such way as not to impair the action of primary control. Secondary control requires: a central regulator; a system measuring the interchanged power in tie-lines; measurements of the system frequency; and a system for transmission of regulator signals to the relevant generating units. The central regulator minimizes in real time the system control error G, expressed as

$$G = P_{measure} - P_{program} + K\,(f_{measure} - f_0)$$

where $P_{measure}$ is the sum of the instantaneous measured active power transfers on the tie-lines; $P_{program}$ is the resulting programmed exchange with all the neighboring control areas; K, the system factor, is a constant in MW/Hz set on the secondary controller; $f_{measure}$ is the measured instantaneous value of system frequency; and f_0 is the set-point (nominal) frequency.

The desired behavior of secondary control over time will be obtained by assigning a proportional-integral (PI) characteristic of the central regulator, according to the following equation:

$$\Delta P_d = -B.G - 1T\int G dt$$

Where P_d is the correction signal of the central regulator governing the generating units subject to secondary control; B is the gain (proportional term) of the central regulator; T is the integral time constant of the central regulator; and G is the system control error.

A disturbance of the balance between power generation and demand in synchronous systems gives rise to variations in the system frequency observed over the entire system despite the location of the disturbance.

In such cases a joint reaction of primary control of all interconnected systems is foreseen in order to re-establish the balance between generation and demand. The result will be achieved at a frequency differing from its set-point value by Δf, and the power interchanges on tie-lines will be different from the scheduled values.

Whereas during primary control all systems provide mutual support, only the system in which the unbalance occurred is required to undertake secondary control action.

The controller of this system activates appropriate secondary control power restoring the nominal frequency and scheduled power exchanges.

In order to provide effective secondary control, the generating units that contribute to this control process must have sufficient power reserve to be able to respond to the regulator signal with both the required change in generated power and the required rate of change.

The rate of change in the power output at the generator terminals significantly depends on the generation technique.

Typically, for oil or gas-fired power stations this rate is about 8% per min, for lignite-fired and hard-coal-fired power stations it is up to 2% and 5% per min, respectively, and for nuclear power stations this rate is up to 5% per min. Even in the case of reservoir power stations the rate is 2.5% of the rated plant output per second.

The secondary control range is the range of adjustment of the secondary control power, within which the central regulator can operate automatically, in both directions (positive and negative) from the working point of the secondary control power.

The secondary control power is the portion of the secondary control range already activated at the working point. The secondary control reserve is the positive part of the secondary control range between the working point and the maximum value.

2.4.2.3 Tertiary Frequency Control

Tertiary control is any automatic or manual change in the working points of the generating units participating, in order to restore an adequate secondary control reserve or to provide desired (in terms of economic considerations) allocation of this reserve within the set of generating units in service.

Tertiary control may be achieved by means of: changing the set operating points of thermal power plant generation sets, around which the primary and secondary control acts; connection/disconnection of pump storage hydro power stations operated the an intervention mode; altering the power interchange program; and load control (centralized tele-command system or controlled load shedding). The timing of the primary, secondary and tertiary control ranges is shown in

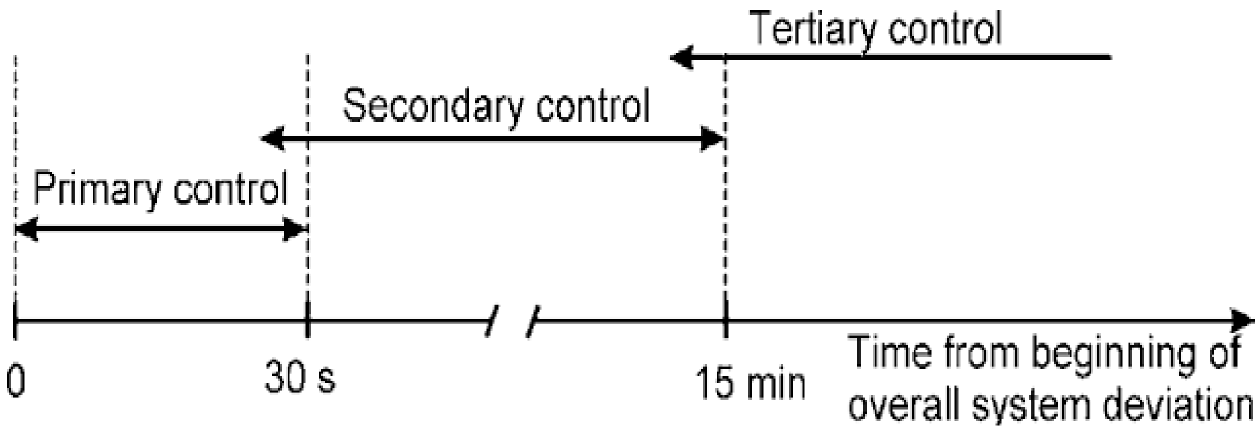


Figure 2-5. The timing of the primary, secondary and tertiary control ranges in a power system

2.4.2.4 Emergency Frequency Control

Frequency control system, comprising primary, secondary and tertiary control, ensures the frequency control under normal operating conditions of a power system. In such cases frequency remains within the range of permissible variation.

Where the frequency variation exceeds the permissible range, due to a significant loss of generation or consumed power, the system conditions are deemed impaired (emergency) conditions. In such circumstances supplementary actions are needed in order to re-establish the active power balance. These include:

- Emergency load tripping (system load shedding) in case of a major frequency drop;
- Emergency disconnection of generators in case of a large frequency increase.

2.4.2.5 Coordination of Frequency Control

While it is necessary to put in place systems and devises in a power system for the control of balance between generation and load to achieve constancy in frequency, it is equally important that effort is well coordinated to obtain the desired result.

Frequency coordination refers to the nested structure of the frequency control, protection and equipment damage limits. Figure 2-6 shows this nested coordination.

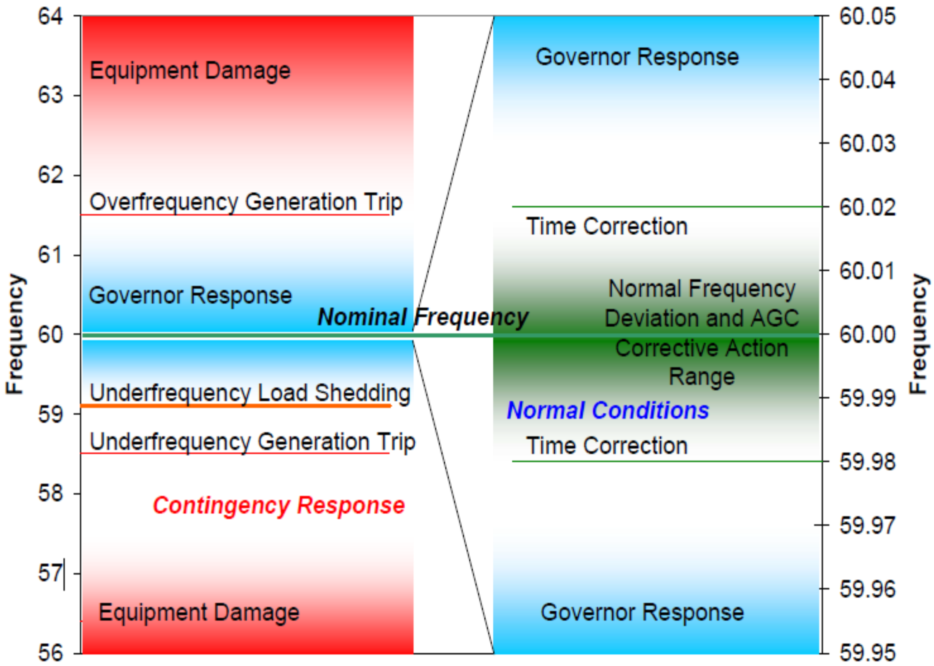


Figure 2-6. Coordination of Frequency Control

Expansion of any band within Figure 2-6 will require the re-coordination of all the other protection and control set points within the system. For example, allowing normal frequency variations to move within expanded limits (as is done on some other power systems) will require the re-coordination of Automatic Generation Control (AGC), time correction, governor response set points, generation and load trip set points, and other frequency controlled protection devices. Although this is possible, the engineering and labor to complete this task at a system wide level may be very economically costly.

M03 – VOLTAGE CONTROL

3.1 Objectives

Upon completion of this module the participant will be able to:

- Understand an overview of voltage and reactive power control
- Identify the parameters or equipment used in voltage and reactive power control
- Explain the methods of voltage and reactive power control
- List some benefits of proper voltage and reactive power control

3.2 Introduction

A power system must be designed in such a way so as to maintain the voltage variations at the **consumer terminals** within specified limits. In practice, all the equipment on the power system are designed to operate satisfactorily at the **rated voltages** or within specified limits, at most ± 5% at the **consumer terminals**. The main reason for the variation in voltage at the consumer terminals is the variation in load on the supply power system.

As the loads in the power system increase, voltages across the network tend to decrease and reactive power losses increase as a result of high current; the reactive loss is proportional to square of the current. This increased reactive power demand would be supplied by voltage regulating devices such as generators, static VAR compensators, or capacitors, if possible. However, due to physical limitations, such devices cannot supply unlimited amounts of reactive power. Often, sustained load growth will result in some source of reactive power, or perhaps a number of such sources, reaching their physical limits. Once a reactive power source has reached its maximum limit, it can no longer regulate voltage. Therefore, sustained load growth results in an accelerated voltage decay, and hence an even greater reactive power requirement. This may force other voltage regulating devices to their limits, with a subsequent further acceleration in the rate of decline of voltages. This leads to loss of voltage in a significant part of the system and is described as the voltage collapse phenomenon.

The diagrams below provide overview of ac transmission and electrical equations governing power transfer and voltage drop in an ac transmission system.

The Voltage drop across the reactance increases but stays at the same angle. Assuming zero line resistance and source voltage to be of constant magnitude:

$$\mathbf{V_S = V_R - jX_LI}$$

Voltage drop across reactance $\mathbf{jX_LI}$ will stretch between $\mathbf{V_R}$ and $\mathbf{V_S}$. Therefore, when a lagging load increases, the received voltage decreases.

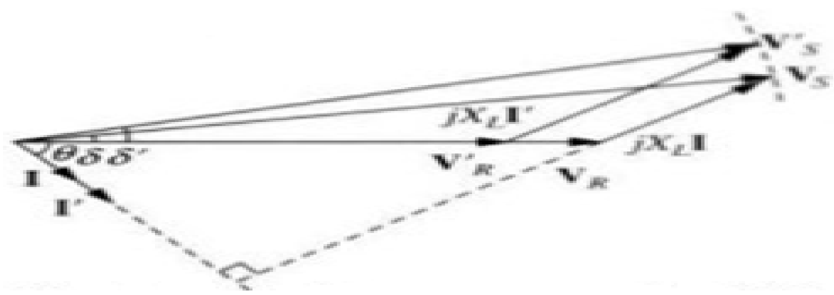


Figure 3-1. Voltage Drop

The line inductive reactance $\mathbf{X_L}$ is represented by the inductance and the distribution station is represented by the load. That is $V_R = V_S - jX_LI$, thus when the load increases, I increases and the voltage drop IX_L increases, thereby decreasing the receiving end voltage V_R. The increasing load current also increase the reactive power loss I^2X_L, and the active power losses I^2R.

These voltage variations due to load changes must be contained to ensure power quality and maintain overall system stability.

A power system, therefore, must be designed so as to maintain those voltage variations by providing voltage-control equipment at suitable places.

The most common method of maintaining the voltage profile is through injecting and absorbing reactive power. In general, increasing reactive power causes the system voltage to rise while decreasing reactive power causes voltage to fall.

As shown in the figure 3-2 below, a balance should be kept between reactive power demand and supply to maintain acceptable voltages across the various nodes and buses within the power system.

Any imbalance would create either low demand end voltages or excessively high supply end voltages.

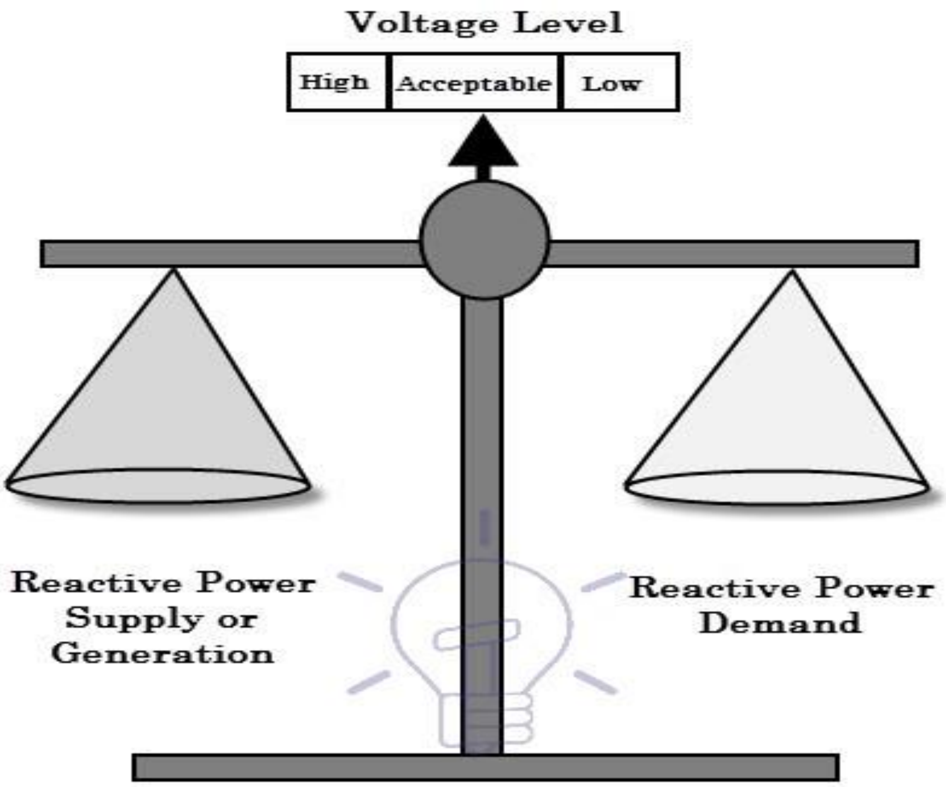


Figure 3-2. Balance Between Reactive Power Demand and Supply

3.3 The Need for Voltage Control

As explained above, imbalance of reactive power results in deviation of voltages across the power system. The control of voltage is thus closely related to the control of reactive power.

For example, an injection of reactive power at a bus that is not directly voltage regulated will in general increase the voltage of that bus and its surrounding network.

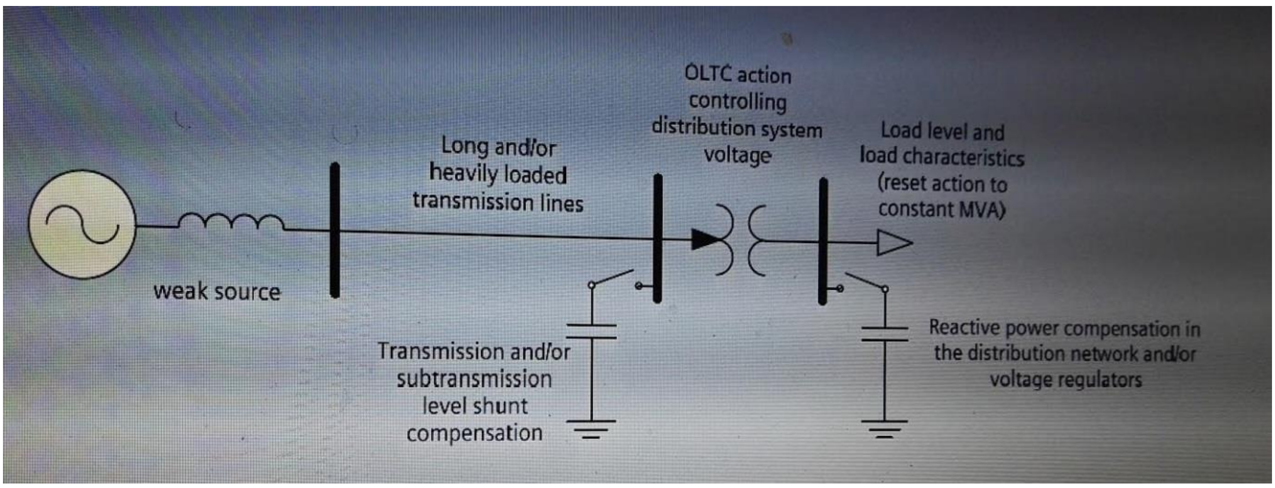


Figure 3-3. Reactive Power Injection

Hence proper coordination among the voltage and reactive power control equipment is critical in ensuring optimum voltage profile and optimum reactive power flows to enable satisfactory system operation. Generally, the need for voltage control could be looked at from both the demand and the supply sides.

3.3.1 Demand Side

Typically, all electrical equipment are designed to work within allowable voltage limits. For most equipment, the permissible voltage range is ± 5%. This means that the customer requires that his/her voltage is controlled within this fine band to ensure proper functioning of the equipment.

3.3.2 Supply Side

On the supply, the control of voltage is very important to ensure that all equipment are operated within prescribed safe limits to ensure overall system stability. This means that for generators, they must be operated within their capability curves as shown Figure 3-4 below.

Transmission lines must be loaded within their thermal limits whilst transformers and other electrical equipment must be operated within their nameplate ratings. Also, acceptable voltages must be maintained at all nodes or buses within the entire network.

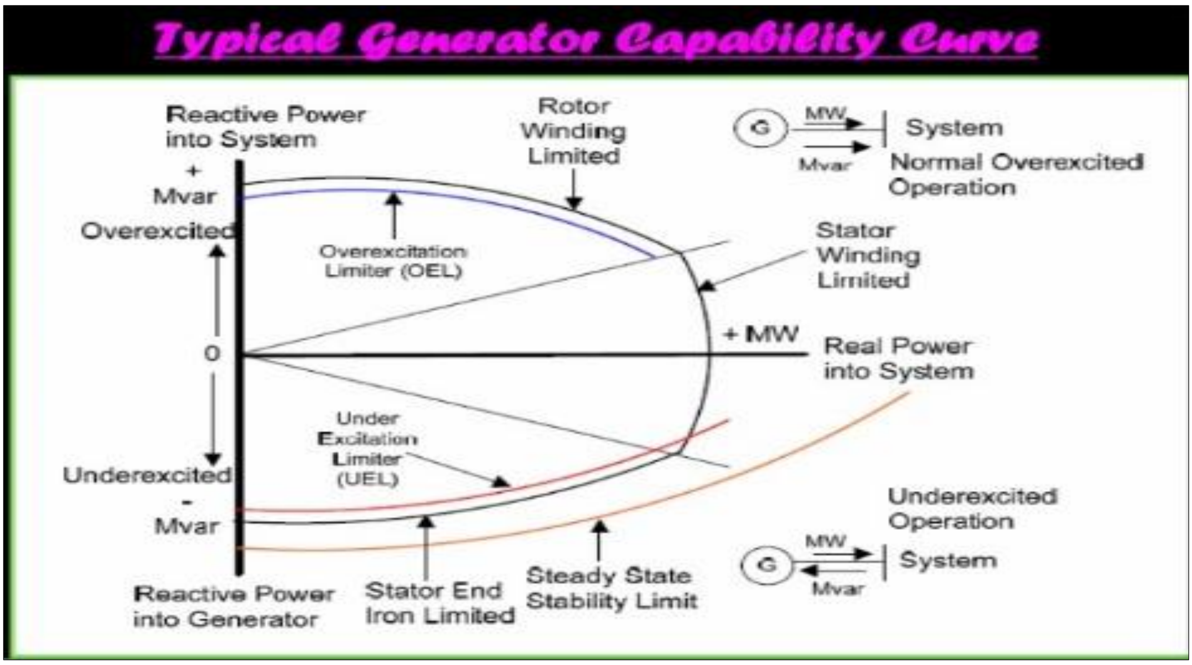


Figure 3-4. Typical Generator Capability Curve

3.3.3 Objectives for Voltage and Reactive Power Control

For efficient and reliable operation of power systems, the control of voltage and reactive power should satisfy the following objectives:

- Voltages at the terminals of all equipment in the power system are within acceptable limits.

This is because both utility and customer equipment are designed to operate at certain voltage ratings and prolonged operation outside this allowable range could cause them to damage.

- System stability is enhanced to maximize the utilization of the transmission system

This is because voltage levels and reactive power control have significant impact on stability as shown in the Power – Angle Curve and the power transfer equation below. The power-angle curve shows that at reduced voltage the maximum power transfer is reduced, requiring higher angles to move the same amount of power. The increasing load angle at decreasing voltage could lead to system instability.

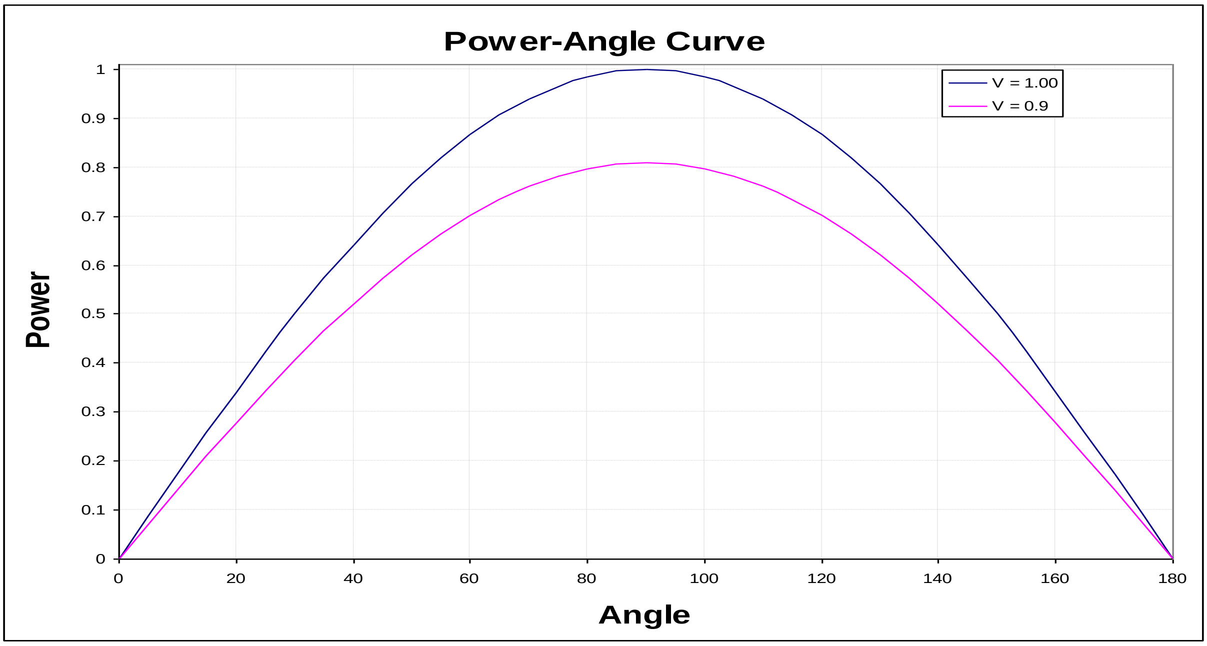


Figure 3-5. Power Angle Curve

- The reactive power flow is minimized so as to reduce I^2R and I^2X losses to the barest minimum possible.

The choice and method of reactive power control should be carefully selected to minimize both reactive power and active power losses. This will ensure that the transmission system operates efficiently.

3.4 Methods of Voltage and Reactive Power Control

As has been indicated in the previous sections, voltage in a power system decreases with an increasing load current. There is therefore the need to control voltages across the nodes or buses within the entire power system.

On an alternating current (ac) power system, voltage is controlled by managing the production, absorption and flow of reactive power at all levels in the system. Voltage control and reactive power management are two aspects of a single activity that both supports reliability and facilitates commercial transactions across transmission networks.

Various power system equipment provide variety of actions for the system operator to control the voltage and to schedule the production of reactive power. Synchronous generators are the backbone of the voltage control in the network. They are already available over the entire system and their voltage support are low-cost and simple to control. However, they are not the only ones provide all the reactive power needs of the system to control voltage. Other reactive power resources are required to control voltage throughout the system. These additional reactive power resources include automatic transformer tap changers, synchronous condensers, capacitor banks, capacitance of overhead lines and cables, static VAR compensators and FACTS devices. The figure 3-6 shows the various reactive power devices and their characteristics as either a source or sink.

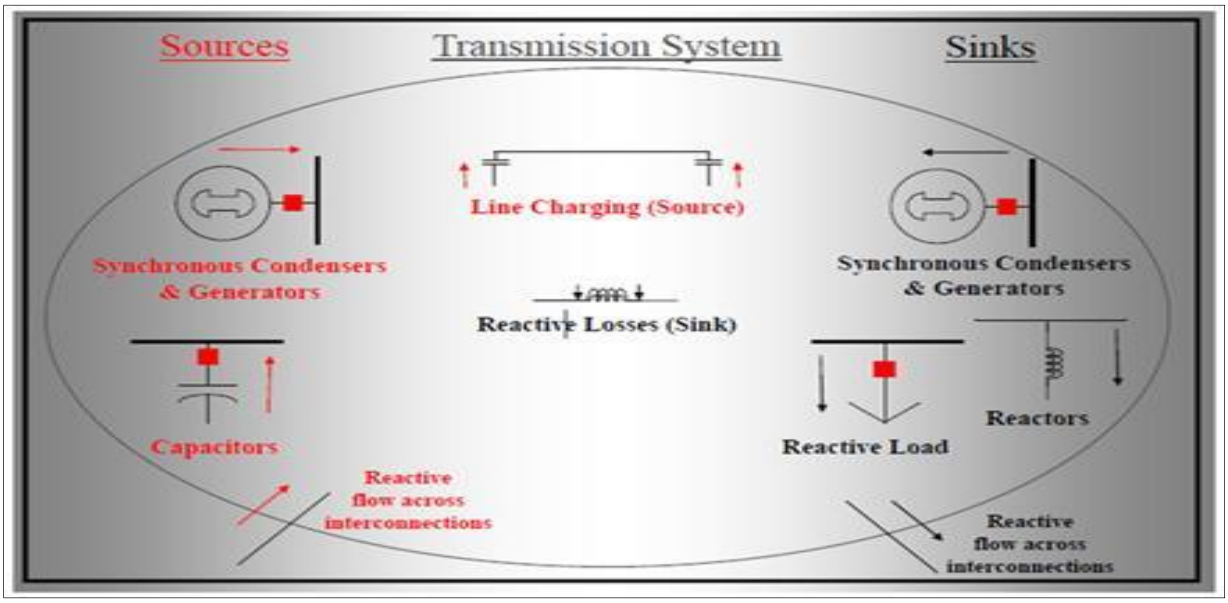


Figure 3-6. Various Reactive Power Devices

The most important reactive power sources and sinks in power systems are listed below:

- Overhead (AC) lines generate reactive power under light load since their reactive power production due to the line shunt capacitance exceeds the reactive losses in the line due to the line impedance. Under heavy load, lines absorb more reactive power than they produce.
- Underground (AC) cables always produce reactive power since the reactive losses never exceed the production because of their high shunt capacitance
- Transformers always absorb reactive power because of their reactive losses. In addition, transformers with adjustable ratio can shift reactive power between their primary and secondary sides.
- Shunt capacitors generate reactive power.
- Shunt reactors absorb reactive power.
- Loads seen from the transmission system are usually inductive and therefore absorb reactive power.
- Synchronous generators, synchronous condensers and static VAr compensators can be controlled to regulate the voltage of a bus and then generate or absorb reactive power depending on the need of the surrounding network.
- Series capacitors are connected in series with highly loaded lines and thereby reduce their reactive losses.

3.4.1 Active and Passive Reactive Power Sources

Reactive power sources could also be categorised under active and passive compensators.

Synchronous generators, synchronous condensers and SVCs which provide reactive power compensation by either absorbing or supplying reactive automatically are referred to as active compensators.

Shunt capacitors and reactors, and series capacitors provide passive compensation since they are either permanently connected to the transmission and distribution system, or switched.

They contribute to voltage control by modifying the network characteristics.

3.4.2 Reactive Power Sources

3.4.2.1 Synchronous Generators

The voltage control from generation resources is a necessary supplement to static reactive power devices to prevent voltage problem because:

- Generation supplied reactive resources do not lose effectiveness at low voltage as do static reactive devices.
- The response of a generator to an emergency reactive requirement is much faster and more accurate than the static reactive sources (except power electronic based devices).

However, synchronous generators just like all other reactive power devices have limitations. The voltage control capability of synchronous generators is limited by saturation of both:

- field current
- and armature current.

The generators under heavy real power loading require high amount of field current to maintain the desired terminal voltage which pushes the generator and exciter to the saturation region. When armature current limitation is in effect, a large reduction in the reactive power output is needed if the active power output is to remain constant.

Among different types of generating units, hydro power plants have less limitations and so higher capabilities in voltage and reactive power control. Pumped storage power plants, as a specific type of hydro power plants, not only can improve the frequency control but also can participate in reactive power control. New technologies like variable speed pumped storage power plants with higher capabilities than conventional ones, like frequency control during night time (at low loading) and independent active and reactive power control, bring more flexibility for the system control. However, the provided support by these generating units is usually affected by their far geographical location from load centers.

3.4.2.2 Synchronous Condensers

A synchronous condenser (sometimes called a synchronous capacitor or synchronous compensator) is a device identical to a synchronous motor, whose shaft is not connected to anything but allowed to spin freely. Its purpose is not to convert electric power to mechanical power or vice versa, but to adjust reactive power and voltage conditions on the electric power transmission grid. Its field is controlled by a voltage regulator to either generate or absorb reactive power as needed to adjust the grid's voltage, or to improve power factor. Increasing the device's field excitation results in its furnishing reactive power (vars) to the system. Its principal advantage is the ease with which the amount of correction can be adjusted. Unlike a capacitor bank, the amount of reactive power from a synchronous condenser can be continuously adjusted. Reactive power from a capacitor bank decreases when grid voltage decreases, while a synchronous condenser can increase reactive current as voltage decreases. However, synchronous machines have higher energy losses than static capacitor banks. Synchronous Condensers could also be used to improve power system stability. The kinetic energy stored in the rotor of the machine helps to stabilize power system during rapid loads fluctuations such as those created by short circuits or electric arc furnaces.

3.4.2.3 Shunt Compensators

Shunt Compensators are devices that are connected in parallel with the transmission line to provide voltage control, typically by regulating the voltage magnitude. It can be provided by either a current source, voltage source or a capacitor. An ideal shunt compensator provides the reactive power to the system. The most common shunt compensators are shunt reactors and shunt capacitors. Shunt-connected reactors are used to reduce the line over-voltages by consuming the reactive power, while shunt-connected capacitors are used to maintain the voltage levels by compensating the reactive power to transmission line.

3.4.2.4 Shunt Reactors

Shunt reactors are similar to a power transformer in winding design and insulation. They are absorber of reactive power and are one of the devices most commonly used for reactive power compensation to increase the energy efficiency of the system. Shunt reactors can be directly connected to the power line or to a tertiary winding of a three-winding transformer and conveniently switched as var requirements vary. They are used to compensate the undesirable voltage effects associated with line capacitance such as limiting voltage rise on open circuit or lightly loaded lines. Shunt compensation with reactors:

- increases effective Z_C
- reduces the effective natural load , i.e., voltage at which flat voltage profile is achieved

Line reactors could also be used in limiting switching surges.

3.4.2.5 Shunt Capacitors

Shunt capacitors are primarily used to provide capacitive reactive compensation – power factor correction in the network. They also improve the voltage stability and reduce network losses. Improving the power factor also means a higher power transmission capability and increased control of the power flow. The use of shunt capacitors 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 is: improvement of the voltage at the load, better voltage regulation (if they were adequately designed), reduction of losses and reduction or postponement of investments in transmission.

The main disadvantage of shunt capacitors is that its reactive power output is proportional to the square of the voltage and consequently when the voltage is low and the system need them most, they are the least efficient. The reactive power generated by a capacitor is proportional to both voltage and frequency, that is, $Q\ (kVAr) = 2\pi f v^2$.

3.4.2.6 Series Compensators

When a device is connected in series with the transmission line or feeder is called a series compensator. A series compensator can be connected anywhere in the transmission network. It works as a controllable voltage source. Series compensators are installed in transmission lines to compensate for the voltage decreasing effect of series inductance effect of transmission lines when large load currents flow through the line.

In series compensation, capacitors are connected in series with the transmission and distribution lines. This reduces the transfer reactance between buses to which the line is connected, increases the maximum power that can be transmitted, and reduces the effective reactive power losses. Although series capacitors are not usually implemented for voltage control, they do contribute to improving the system voltage and reactive power balance.

The reactive power produced by a series capacitor increases with transferred power of the transmission line.

Series capacitive compensation in ac transmission systems can yield several bene-fits such as increases in power transfer capability and enhancement in transient stability. For the series compensation, series capacitors are connected in series with the line conductors to compensate the inductive reactance of the line. This reduces the transfer reactance between buses to which the line is connected, increases maximum power that can be transmitted, and reduces effective reactive power loss. Although series capacitors are not usually installed for voltage control, they do contribute to improving the voltage profile of the line.

3.5 Facts Devices

The other type of active compensators aside synchronous generators and synchronous condensers are FACTS devices.

FACTS which refer to Flexible Alternating Current Transmission Systems are ac transmission system devices incorporating power electronic-based technology to enhance controllability and increase power transfer capability of transmission systems. They are based on power electronic switching converters and dynamic controllers to enhance the system utilization and power transfer capacity as well as the stability, security, reliability and power quality of AC system interconnections.

3.5.1 Facts Controllers

FACTS Controllers are power electronic-based system and other static equipment that provide control of one or more ac transmission parameters such as series impedance, shunt impedance, current, voltage and phase angle.

3.5.2 Advantages of Facts

Incorporation of FACTS in transmission systems provides the following advantages.

- increased loading capacity for transmission lines
- prevents blackouts
- improve generation productivity
- reduce circulating reactive power
- improves system stability limit
- Reduce voltage flicker
- Damping of oscillations which can threaten security or limit the usable line capacity

3.5.3 Classification of Facts Controllers

The classification of FACTS Controllers is done on the basis of their types of arrangement in the Power system. The various types of FACTS are shown figure 3-7 below.

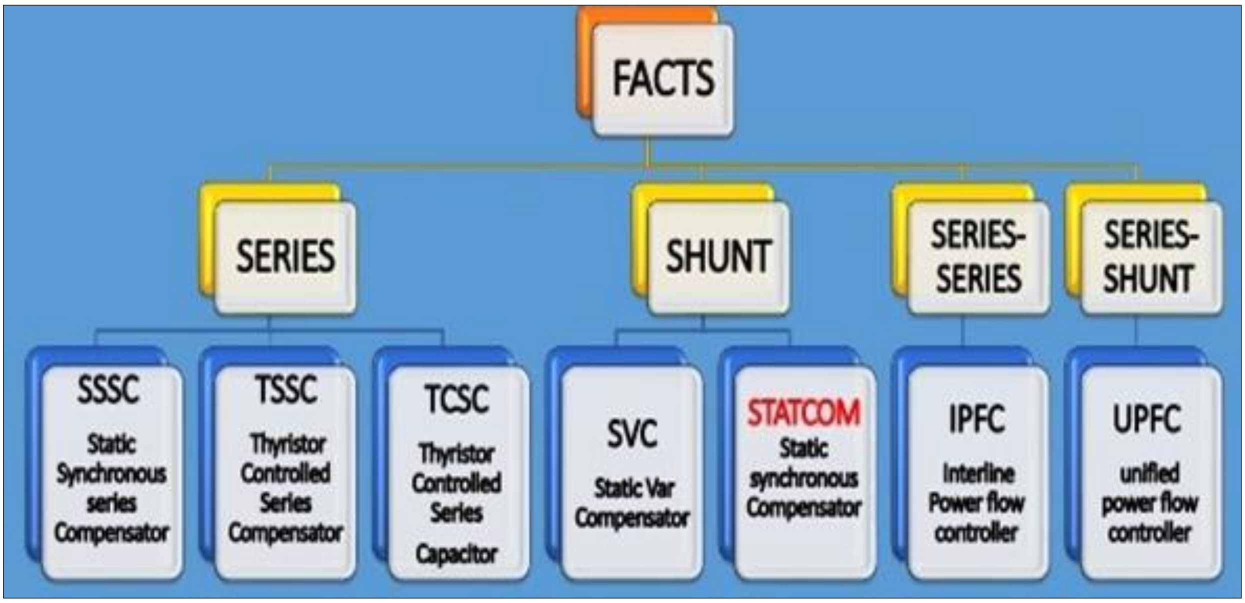


Figure 3-7. Classification of FACTS Devices

3.5.3.1 SERIES Type

- SSSC - Static Synchronous series Compensator
- TSSC - Thyristor Controlled Series Compensator
- TCSC - Thyristor Controlled Series Capacitor

3.5.3.2 SHUNT Type

- SVC - Static Var Compensator
- STATCOM - Static synchronous Compensator

3.5.3.3 SERIES - SERIES Type

- IPFC - Interline Power flow controller

3.5.3.4 SERIES- SHUNT Type

- UPFC - unified power flow controller

3.5.4 Working Principle of Facts

Consider a transmission line connecting generating station to a load. Assuming the line to be lossless and ignoring the line charging, the power flow (P= real power) and (Q=reactive power) are given by :

- $P = V_1 V_2 (\sin \Theta) / X$
- $Q = V_1 (V_1 - V_2 \cos \Theta) / X$

Where $\Theta = \Theta_1 - \Theta_2$ and X= the series line reactance.

FACTS can control the real power and reactive power flow by controlling one or more of the components ($\boldsymbol{V_1}$, $\boldsymbol{V_2}$, X , Θ) .

3.6 Benefits of Reactive Compensation

Proper control of voltage and reactive power presents a lot of benefits to the efficient operation of power systems. Some of the key benefits of voltage and reactive power control are as indicated in the diagram below.

These benefits include:

- Reduction in VAR DEMAND on the system
- Reduction in both active and reactive power LOSSES on the system
- Reduction in VOLTAGE DROP across the system
- Freeing up capacity on generators to produce more active power (MW)
- Freeing up capacity on Transmission Lines to deliver more active power (MW)
- Improvement in overall network stability due to improved voltages
- Savings in both Utility and Consumers Costs.

4.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of voltage stability
- State the classifications of voltage stability
- Explain voltage collapse
- State methods for preventing voltage collapse

4.2 Introduction

Voltage control and stability problems affect almost every power system in the world, especially the current stress on power systems brought about by deregulation in most utilities in the world. The key to success in dealing with voltage stability problems is understanding the nature of the problem and fashioning out appropriate remedial strategies to deal with it.

4.3 What Is Voltage Stability?

Voltage stability is concerned with the ability of a power system to maintain acceptable voltages at all buses in the system under normal conditions and after being subjected to a disturbance. A system enters a state of voltage instability when a disturbance, increase in load demand, or change in system condition causes a progressive and uncontrollable decline in voltage. The main factor causing voltage instability is the inability of the power system to meet the demand for reactive power. Voltage instability is a local phenomenon.

A key criterion for voltage stability is that bus voltage magnitude increases as reactive power injection at the same bus increases. That is, a system is voltage stable if V-Q sensitivity is positive for every bus and voltage unstable if V-Q sensitivity is negative for at least one bus.

4.3.1 Basic Concepts Related to Voltage Stability

Voltage stability problems normally occur in heavily stressed power systems. Whilst the disturbance leading to voltage collapse may be initiated by a variety of causes, the underlying problem is an inherent weakness in the power system.

Factors contributing to Voltage Collapse

In addition to the strength of the transmission network and power transfer levels, the principal factors contributing to voltage collapse are:

- Load characteristics
- Generator reactive power / voltage controls limits
- Characteristics of reactive power compensating devices
- Action of voltage control devices such as transformer on-load tap-changers.

4.3.2 Graphical Illustration of The Voltage Instability Problem

Here, voltage instability is illustrated by considering a two-terminal network. It consists of a constant voltage source E_S supplying a load Z_{LD} through a series impedance Z_{LN}. This is representative of a radial line serving a load or a load area being served from a transmission line.

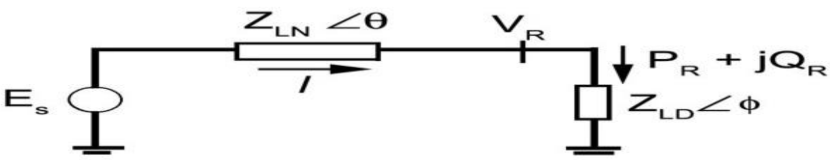


Figure 4-1. A simple radial system for illustration of voltage instability

$$I = \frac{Es}{ZLN + ZLD}$$

The corresponding graph is shown in the diagram below.

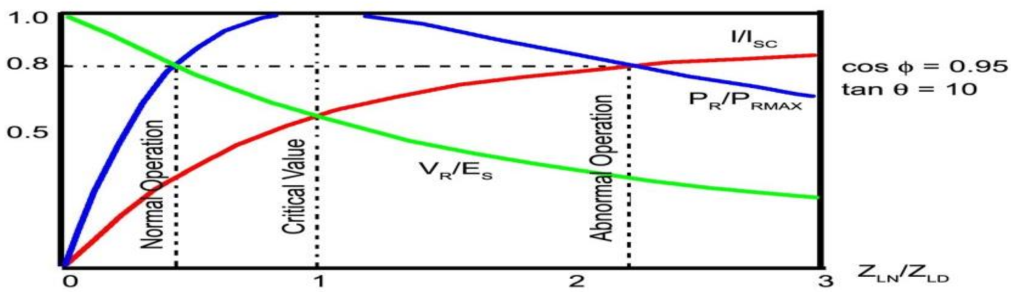


Figure 4-2. Graphical Illustration of Voltage Stability

Here the three quantities, current (I), power (P_R) and receiving end voltage (V_R) are plotted as normalized quantities. The blue graph shows the variation of receiving end voltage (V_R) with the variation of Z_{LD}/Z_{LN}. The receiving end voltage is shown as V_R divided by E_S. So the plotted receiving end voltage is in per unit considering the system voltage E_S.

From the graph it is seen that as the load demand increases (Z_{LD} decreases),

- I_R increases, and V_R decreases
- P_R increases rapidly at first, and then slowly before reaching a maximum, and finally decreases

P_R is maximum when voltage drop in the line is equal in magnitude to V_R, i.e. $Z_{LD} = Z_{LN}$

This limit represents satisfactory operation, i.e. critical operating point. For a load demand higher than the maximum, the control of power by varying load is unstable. With constant-admittance load characteristic, conditions stabilize at a voltage level lower than normal.

The power transmitted is maximum when the voltage drop in the line is equal to the voltage magnitude V_R, that is when $Z_{LN}/Z_{LD} = 1$. As Z_{LD} is decreased gradually, I increases and V_R decreases.

P - V Characteristics

A more traditional method of illustrating this phenomenon is shown below.
The Figure below shows V_R - P_R characteristic of the simple radial system for different values of load power factor.

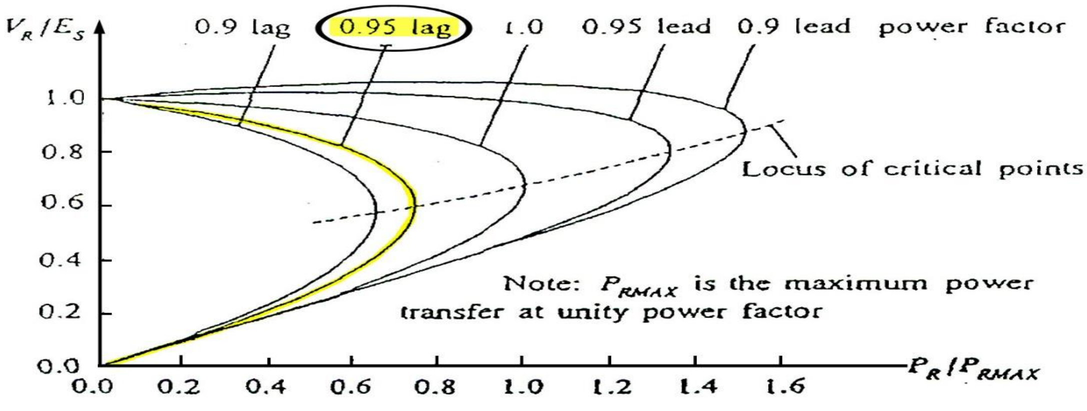


Figure 4-3. V_R-P_R characteristics of the radial system

V_R - P_R characteristics of a practical power system:

The graph similar to those in Figures 4-2 and 4-3, shows the gradual drop in voltage with increasing power transfer until the voltage limit point, Point C. Typically, in a power system the limit for stable operation will be set at B to provide a margin referred to as the stability margin.

The graph shows that, complex systems with large number of voltage sources and load buses have P-V characteristics similar to that of a simple radial system.

That is, it represents the basic property of networks with predominantly inductive elements.

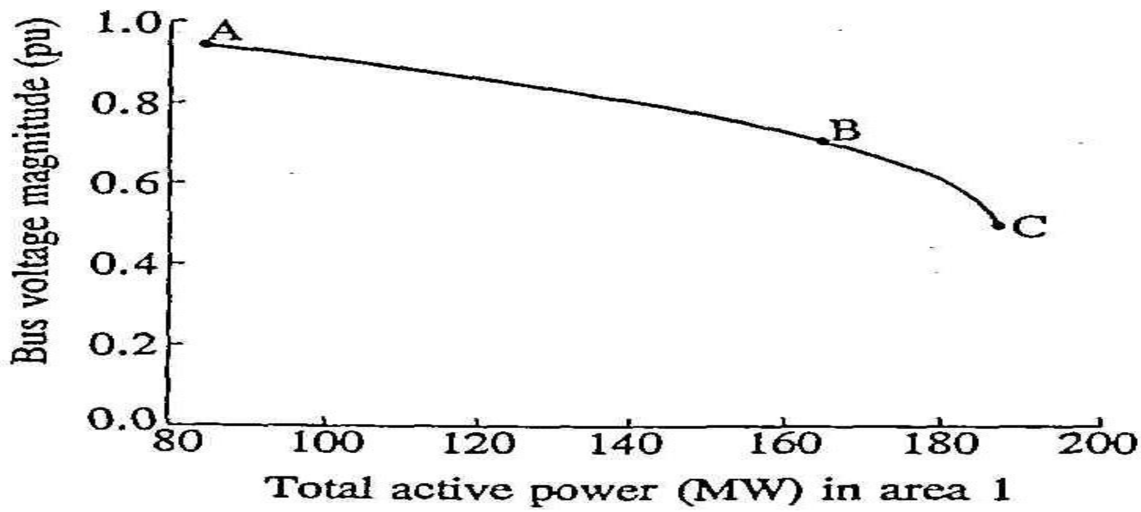


Figure 4-4. V-P curve at bus a Bus within an actual power system

4.4 Classification of Voltage Stability

Voltage stability is classified into four main sub-categories. These are:

- Large Disturbance Voltage Stability
- Small Signal Voltage Stability,
- Transient Voltage Stability,
- Longer Term Voltage Stability

4.4.1 Large Disturbance Voltage Stability (LDVS)

Large Disturbance Voltage stability is concerned with system's ability to control voltages following large disturbances such as system faults, loss of generator or critical contingency (e.g. Loss of a heavily loaded line).

The contributory factors are load characteristics and the interaction of both continuous and discrete controls and protections.

Determination Large Disturbance Voltage Stability requires the examination of the non-linear dynamic performance of a system over a period of time (ULTC and generator field current limiter).

A criterion of Large Disturbance Voltage Stability is that, following a given disturbance and system control actions, voltages at all buses must reach steady state levels.

Analysis of Large Disturbance Voltage Stability requires the use of long-term dynamic simulations.

4.4.2 Small Disturbance Voltage Stability (SDVS)

Small Disturbance Voltage Stability is concerned with a system's ability to control voltages following small disturbances, such as gradual changes in load.

Load characteristics and the interaction of both continuous and discrete controls and protections are the main contributory factors.

Its determination involves a basic steady state process. It requires determining the stability margin, identifying factors influencing stability, examining wide range of system conditions and large number of post contingency scenarios.

A Criterion for Small Disturbance Voltage Stability is, V- Q sensitivity. That is, a system is voltage stable if V-Q sensitivity is positive for every bus and voltage unstable if V-Q sensitivity is negative for at least one bus

4.4.3 Transient Voltage Stability

Transient Stability is concerned with voltage stability in the transient time frame, 0 to 10 seconds. It is also referred to as transient rotor angle voltage stability.

Voltage collapse is caused by unfavourable fast acting load components (Induction Motor and DC Converters).

For severe voltage dips, the reactive power demand of induction motors increases, contributing to voltage collapse.

The other contributory factor is electrical islanding and under-frequency load shedding resulting in voltage collapse when imbalance is greater than about 50%.

Here voltage decays faster than frequency and under-frequency relays may not operate. These are instances where voltages collapse before frequency decays to the under frequency load shedding set points.

4.4.4 Longer Term Voltage Stability

Longer Term Voltage Stability takes place in the order of minutes, 2 to 3 minutes typically, and it involves high loads, high power input from remote generators and sudden large disturbance (loss of a generator or loss of an important transmission line).

The disturbance causes high reactive power losses and voltages sag in load areas. The ULTCs sense low voltages and act to restore low voltages thereby restoring load power levels. This action results in further sags of transmission voltages. Generators further away act to provide reactive power which is insufficient and ineffective. With the system no longer being supported by generators and the transmission system, partial and / or complete voltage collapse occurs.

4.5 Assessment of The Voltage Stability Problem

The voltage stability problem is examined by studying

- transmission lines,
- characteristic of generators,
- load characteristics

since these characteristics affect voltage stability to a very large extent

Characteristics of reactive power compensating devices are also examined to determine how they affect voltage stability. These reactive power compensating devices include:

- Shunt Capacitors
- Regulated Shunt Compensation
- SVCs
- STATCOMs and the FACTS devices.
- Series Capacitors
-

4.6 Principal Factors That Lead to Voltage Instability

- Principal factors that cause voltage instability include:
- Heavily stressed transmission systems: while the disturbance leading to voltage collapse may be initiated by variety of causes, the underlying problem is an inherent weakness of the power system

- Strength of transmission network and power transfer level
- Generator reactive power/voltage control limits
- Load characteristics
- Characteristics of reactive power compensation devices
- Action of voltage control devices such as transformer ULTCs

4.6.1 Influence of Generator Characteristics

Generator AVRs are the most important means of voltage control in a power system. Under normal conditions, the terminal voltages of generators are maintained constant.

During conditions of low system voltages, the reactive power demand on generators may exceed their field and/or armature current limits. When reactive power output is limited, the terminal voltage is longer maintained constant.

The action of generators that contribute to voltage instability are follows:

- Action of generator automatic voltage regulators provide the most important source of voltage control
  - under normal conditions, terminal voltages are maintained constant
- During conditions of low system voltages,
  - the VAr demand on generators may exceed field current and/or armature current limits. With VAr output limited, terminal voltage is no longer maintained constant

The voltage control from generation resources is a necessary supplement to static reactive power devices to prevent voltage problem because:

- Generation supplied reactive resources do not lose effectiveness at low voltage as do static reactive devices.
- The response of a generator to an emergency reactive requirement is much faster and more accurate than the static reactive sources (except power electronic based devices).

However, synchronous generators just like all other reactive power devices have limitations. The voltage control capability of synchronous generators is limited by saturation of both:

- field current

- and armature current.

The generators under heavy real power loading require high amount of field current to maintain the desired terminal voltage which pushes the generator and exciter to the saturation region.

When armature current limitation is in effect, a large reduction in the reactive power output is needed if the active power output is to remain constant.

- With Q output limited due to field current limit
  - the point of constant voltage behind synchronous reactance
  - effective network reactance is increased, further aggravating the voltage control problem

- With Q output limited by armature current limit,
  - the terminal voltage drops and
  - the allowable Q output drops due to voltage reduction, further aggravating the situation

A figure buttressing the Point about the importance of Generator Voltage Control is shown below Figure 4-5.

- operating condition represented by point A is considerably more stable on curve 1 than on curve 2 in Figure 4-5.
- Results demonstrate the importance of maintaining the voltage control capability of generators
- Results show also that the degree of stability cannot be judged based on how close the bus voltage is to normal level

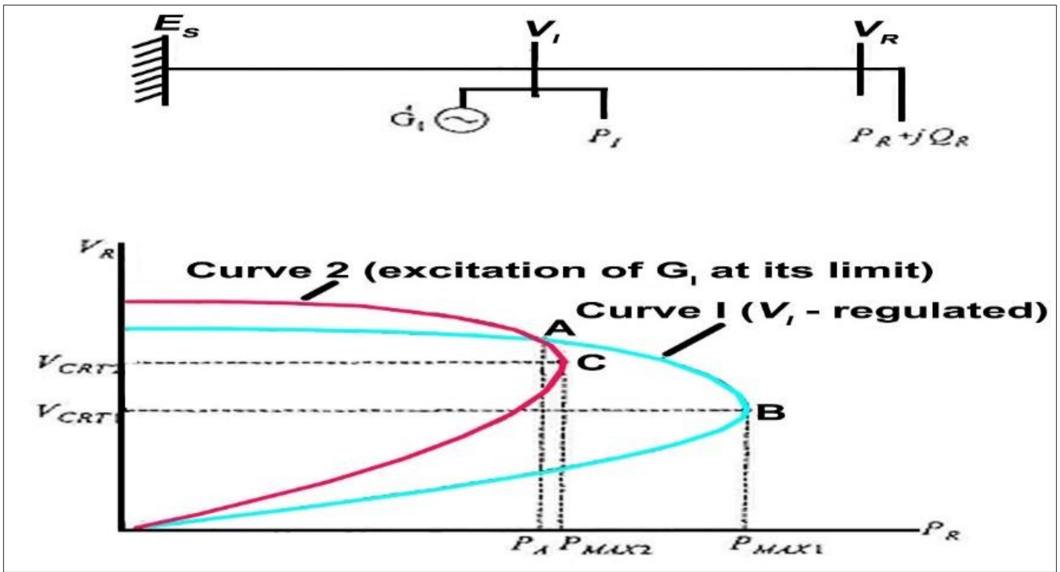


Figure 4-5. Effect of Generator Voltage Control

4.6.2 Influence of Load Characteristics

Load characteristics and distribution voltage control devices are among the key factors influencing system voltage stability. Loads whose active and reactive power components vary with voltage interact with the transmission characteristics by changing the power flow through the system.

The system voltages settle at values determined by the composite characteristics of the transmission system and the load. When the distribution voltages remain low for a few minutes, thermostats and other load regulating devices, as well as manual controls, tend to restore load. Consequently, more such devices will be operating at any given time.

The voltage will drop further. At low voltages below 85 – 90%, of the nominal value, some induction motors may stall and draw high reactive current. This action will bring the voltages down further. For voltage stability analysis, the loads need to be modelled accurately. Load characteristics and distribution system voltage control devices are among key factors influencing voltage stability

- Voltage and power flows settle at values determined by composite characteristic of the transmission system, and loads
- Substation transformer ULTCs and distribution voltage regulators attempt to maintain voltage at points of consumption
    - ☞ within normal control range, load P and Q effectively constant
    - ☞ may have destabilizing effect during conditions of voltage collapse
- When the ULTCs reach the end of their tap range, distribution voltages drop
    - ☞ residential load P and Q drop, reducing line loading and reactive losses
    - ☞ industrial loads with large components of induction motors change little, however, their capacitors will supply less VArs, causing a net increase in Q load
- Industrial and commercial motors usually controlled by magnetically held contactors
    - ☞ hence, voltage drop causes motors to drop out
    - ☞ loss of load results in voltage recovery

- motors restored after some time; voltages drop again of original problem still persists

4.6.3 Influence of Reactive Compensating Devices

(a) Shunt Capacitors:

Shunt Capacitors are the most inexpensive means of providing reactive power and voltage support. They help free up spinning reactive power reserve in generators.

The reactive power generated by a shunt capacitor is proportional to the square of the voltage, hence during system conditions of low voltage, the var support drops, thus compounding the problem.

- Can be effectively used to a certain point to extend power transfer limits by
  - correcting receiving-end power factor
  - freeing up spinning reactive reserve on generators
- However, shunt caps have a number of limitations
  - in heavily shunt compensated system, voltage regulation tends to be poor
  - Q generated is proportional to the square of V; during low voltage conditions VAr support drops; thus compounding the problem
  - beyond a certain level of compensation, stable operation is unattainable.

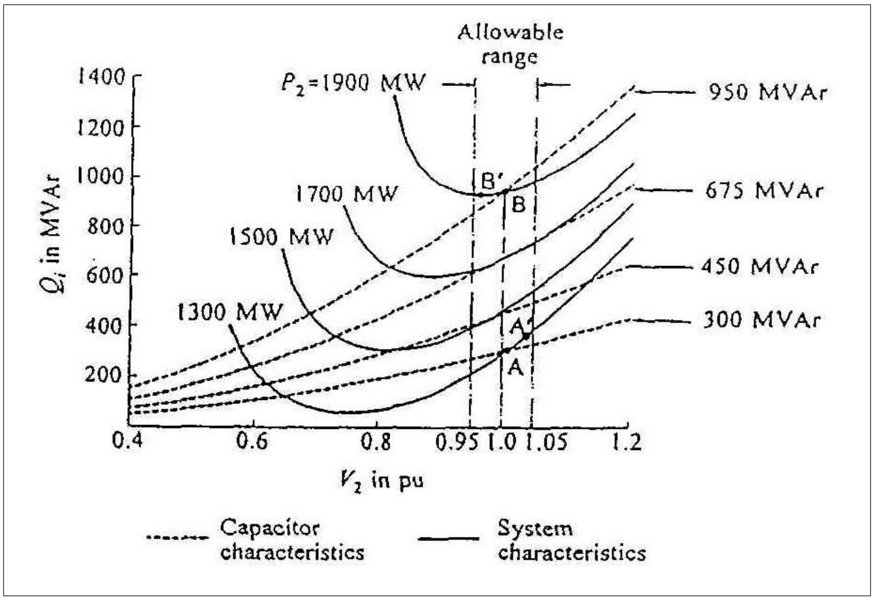


Figure 4-6. System and shunt capacitor Q-V characteristics (capacitor MVAr shown at rated voltage)

(b) Static VAr Compensator:

SVC of finite size will regulate voltage within the regulating range. When pushed to the limit, the SVC becomes a simple capacitor.

- A static VAr compensator of finite size will regulate up to it's maximum capacitive output
  - ☞ there are no voltage control or instability problems within the regulating range
  - ☞ When pushed to the limit, becomes a simple capacitor and the possibility of instability must be recognized

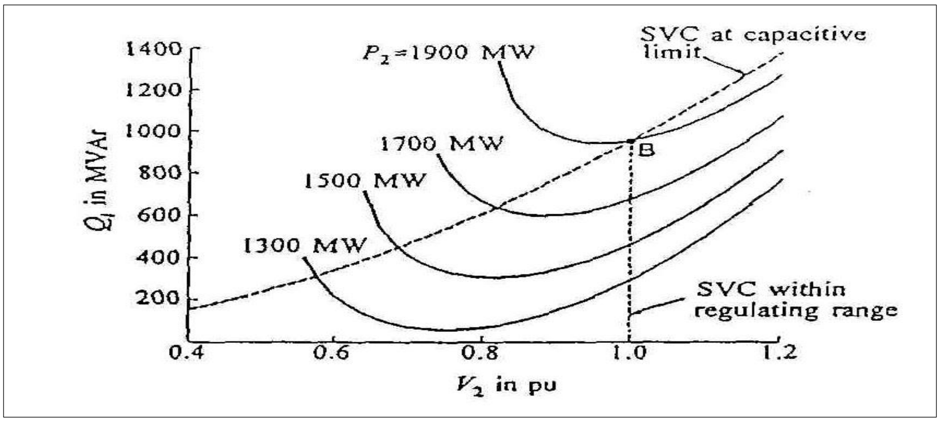


Figure 4-7. System and SVC Q-V characteristics (SVC capacitive limit 950 MVAr)

(c) STATCOM:

Other devices that are particularly used in voltage control are the static synchronous condenser, STATCOM and synchronous condenser.

Now the characteristic of the synchronous condenser and characteristic of STATCOM are exactly identical, only difference is one is rotating device, and the other a static device. But the advantage of these devices is that even when the voltage is low they are capable of injecting reactive power.

They have an internal voltage source and this continue to supply reactive power down to relatively very low voltage. That is, if you plot the reactive power versus the voltage characteristic then the STATCOMs have better reactive power injecting capability and they are also fast.

- Performance better than that of an SVC . Has an internal voltage source, which continues to supply reactive power down to a relatively low system voltage

(d) Synchronous Condenser:

- A synchronous condenser, unlike a SVC has an internal voltage source
  - ☞ continues to supply reactive power down to relatively low voltages
  - ☞ contributes to a more stable voltage performance

(e) Series Capacitors:

Series Capacitors are self-regulating. The reactive power supplied by series capacitors is proportional to the square of Line Current and is independent of bus voltages. Hence they have favourable effect on voltage stability.

- A series capacitor is self-regulating
  - ☞ reactive power depends on the line current and is independent of bus voltages
- Unlike a shunt capacitor, a series capacitor reduces both the characteristic impedance and the electrical length (θ) of the line. As a result
  - ☞ voltage regulation and stability are both significantly improved

4.7 Voltage Collapse

Voltage collapse is the process by which the sequence of events accompanying voltage instability leads to low unacceptable voltage profile in a significant part of a power system. This usually happens when a major contingency occurs in the power system.

Now example of contingency may be that of tripping of a heavily loaded transmission line. The movement this happens, the loading on other transmission lines will increase and the reactive power consumed by these lines will increase as a result, and this will cause reduction in voltage. Now when the reduction in voltage occurs, the immediate thing which will happen is that the under-load tap-changers will come into operation to retain the voltage.

Suppose voltage is dropping and ULTCs start operating and the voltage drop is stopped, and suppose the ULTCs reach their limits, then they will not be in a position to regulate the voltage further. There is a possibility that generators may also reach their field current limits and hence not in a position to further supply reactive power, so they will no more be regulating the terminal voltage.

Then the effectiveness of the shunt capacitors will reduce because when the voltage is low shunt capacitors supply less of reactive power and all these phenomena put together may cause the system to lose voltage stability.

Although sometimes what happens is that, when the voltage drops then some loads start consuming less power because the power consumed by the loads depends upon the voltage. When they consume less power, there is a possibility that that the system will stabilize to a low voltage but at an acceptable level. Voltage may be low but at an acceptable level.

But the sequence of events takes place in a very complex manner, and if in that whole process reactive power sources are weak, we have less of reactive power available, so then voltage may further and further to a very low level and lead to what we call a voltage collapse phenomenon.

Typical scenario of Voltage Collapse

- Heavily loaded System
- Loss of a heavily loaded line
- Reduction in voltage
- Operation of ULTC in substation transformers
- Generators reaching field current limits
- Reduced effectiveness of shunt compensators

4.7.1 Prevention of Voltage Collapse

Voltage collapse could be prevented by employing:

- System Design Measures
- System Operation Measures

4.7.1.1 System Design Measures

Some of the system design measures that could be employed to prevent voltage collapse are,

- Application of reactive power compensating devices
- Control of network voltage and generator reactive power output
- Coordination of protections/controls

- Control of transformer tap-changers
- Under voltage load shedding

4.7.1.2 Application of Reactive Power compensating Devices

Application of reactive compensating devices could involve:

- Ensuring adequate stability margin by proper selection of compensating schemes. The stability margin should be based on the MW and MVAr distances to instability.
- Ensuring that selection of sizes, ratings and locations of compensating devices are based on detailed study covering the most ONEROUS system conditions for which the system is required to operate satisfactorily.

4.7.1.3 Coordination of Protections/Controls

The employment of coordination of protection / controls methods of preventing voltage collapse should be based on the following principles:

- Tripping of equipment to prevent overload conditions should be the last resort.
- Where ever possible, adequate control measures (automatic or manual) should be provided for relieving the overload condition before isolation of the equipment from the system could be considered.

4.7.1.4 Control of Tap-changers

Tap-changers could be controlled either locally or centrally, so as to reduce the risk of voltage collapse.

Where tap changing could be detrimental to the system, the simple method is to block the tap changing action when the source side voltage sags so low and unblock it when the voltage recovers.

4.7.1.5 Under Voltage Load shedding

Under voltage load-shedding could be one of the ways to prevent a voltage collapse situation.

- To cater for unplanned or extreme situations, it may be necessary to use under voltage load-shedding schemes
- Load-shedding provides a low cost means of preventing widespread system collapse.

4.7.1.6 System Operating Measures

System operating measures to avert voltage collapse situations involve:

- Ensuring adequate stability margin
- Ensuring adequate spinning reserve
- And in extreme cases, Operator Action: Operators must be able to recognize voltage stability-related symptoms and take appropriate related remedial actions such as power and voltage transfer controls, and possibly as a last resort, load curtailment.

M05 – ANGLE STABILITY

5.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of angle stability
- Explain power-angle relationship
- State the equal area criterion

5.2 Introduction

Modern power systems are very widely interconnected and while these interconnections result in operating economy and reliability through mutual assistance, they also contribute to the problem of stability inherent in power systems.

This power system stability may be broadly defined as that property of a power system that enables it to remain in state of operating equilibrium under normal operating condition and to regain an acceptable state of equilibrium after being subjected to a disturbance.

5.2.1 Angle Stability

The power system stability problem is generally classified into two main broad categories,

- angle stability and
- voltage stability

The angle stability is further classified into

- small signal angle stability,
- transient stability,
- mid-term stability and
- long-term stability

Voltage Stability on the other hand is further broken into,

- small signal voltage stability and
- transient voltage stability

In this module, we will dwell on angle stability. Voltage stability will be treated in another module.

5.2.2 Rotor Angle Stability

To understand the concept of power system stability, there is the need to define what a Rotor Angle Stability is. Rotor angle Stability is defined as the ability of the interconnected synchronous machines of a power system to remain in synchronism. Here the emphasis is on ability to maintain synchronism. This is the primary requirement for the operation of a power system, where all the machines of the system remain in synchronism. Now to remain in synchronism there must be a torque balance on the rotor. That is, there must be an equilibrium between the torque (T_S) supplied by the prime over and the electromagnetic torque (T_E) developed by the synchronous generator. When the two torques are in equilibrium, the rotor rotates at synchronous speed in the direction of the input torque T_S.

For understanding the basic concept of power system stability and the equation(s) governing its analysis, the principle of rotational dynamics must be explained to develop the equation of motion.

There are two torques which act on the generator rotor, one is the mechanical torque from the prime mover which acts on the system and another is the electrical torque or what is normally referred to as the electromagnetic torque which acts on the rotor. These two torques operate or act on the rotor in opposite directions. Refer to the diagram below Figure 5-1.

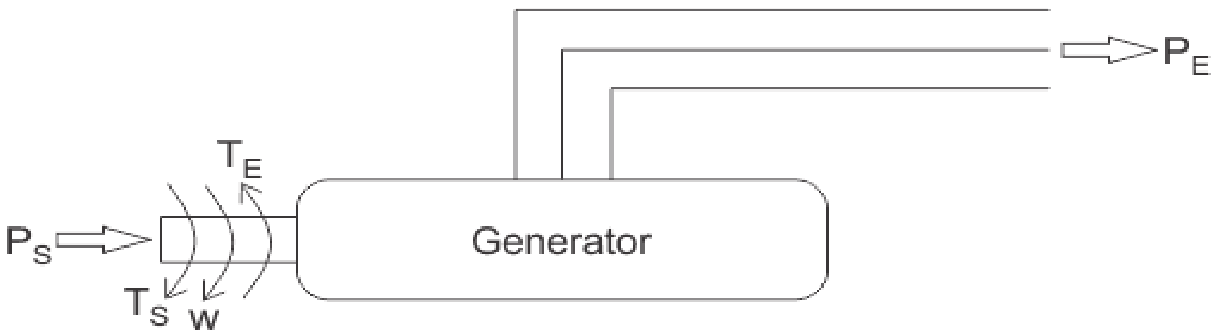


Figure 5-1. The Rotor of Synchronous Generator

The mechanical torque is provided by the prime over and the electrical torque is developed due to the interaction of the magnetic field and the stator currents. Under steady state operating condition, these two torques are equal and the rotor of the synchronous machine rotates in the direction of the mechanical torque at synchronous speed ω_0.

However, when the power system is subjected to a disturbance, there will be a disequilibrium between the two torques, the two torques become unequal and this difference between the supplied input torque T_S and the electrical torque T_E is called accelerating torque T_A.

Assuming that windage and friction torques are negligible, accelerating torque acting on the generator rotor is given by

$T_A = T_S - T_E$

Multiplying both sides by ω, we get

$T_A\omega = T_S\omega - T_E\omega$

Now, torque multiplied by acceleration ω is power. Thus, T x ω = P.

Therefore,

$P_A = P_S - P_E$

In the case of a motor,

$T_A = T_E - T_S$, and

$P_A = P_E - P_S$

In general, the accelerating power is given by

P_A = Input Power – Output Power

Thus,

$P_A = T_A\omega = J\omega\alpha = M\alpha. \quad J\omega = M\frac{d^2\theta}{dt^2}$

Where

- J is the total moment of inertia expressed in kilogram meter square ($Kg\text{-}m^2$).
- M defined as Jω is the angular momentum, and is called the inertia constant of the machine.
- where ω is the synchronous speed of the machine measured in radians per second (rad/s)
- α is the angular acceleration measured in radians per second square (rad/s^2)

Now J is the moment of inertia in $Kg\text{-}m^2$ and ω is the synchronous speed in radians per second, hence this product Jω is called angular momentum (M).

Thus$\frac{d^2\theta}{dt^2}$

$$M\frac{d^2\theta}{dt^2} = P_a$$

$$J\omega \frac{d^2\theta}{dt^2} = P_a$$

$$M\alpha = P_a$$

Where,

- θ = angular displacement (radians)
- $\omega = \frac{d\theta}{dt}$ angular velocity (rad. / sec.)
- $\alpha = \frac{d\omega}{dt} = \frac{d^2\theta}{dt^2}$ angular acceleration

Now let's see how the angular displacement θ relates to rotor angle δ. Consider an object moving at a linear speed of $v_s \pm \Delta v$ whose displacement at any time t is required to be determined. For this purpose, we introduce another object moving with a constant speed of V_s. Then, at any time t, the displacement of the first object is given by $x = v_s t + d$ where d is the displacement of the first object with respect to the second.

Similarly in the case of angular movement, the angular displacement θ, at any time t is given by $\theta = \omega_s t + \delta$

where δ is the angular displacement of the rotor with respect to the rotating reference axis which rotates at synchronous speed ω_s as shown figure 5-2 below.

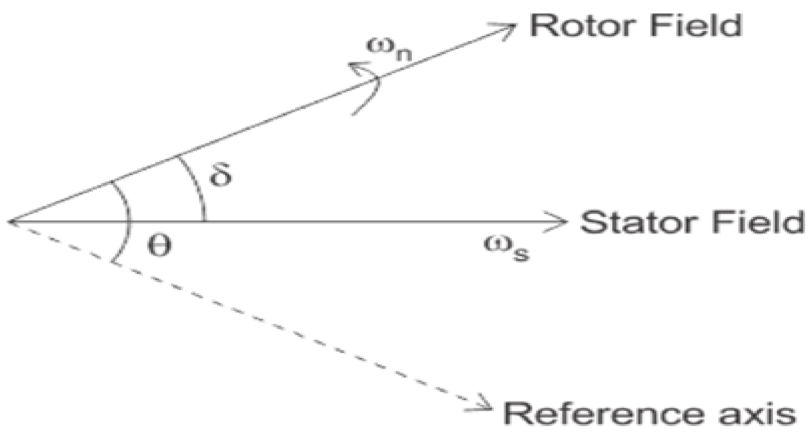


Figure 5-2. Angular Position of Rotor

The angle δ is called the LOAD ANGLE or TORQUE ANGLE.

In view of the above equation, the previous equation could be written as

$$\theta = \omega_s t + \delta$$

$$\frac{d\theta}{dt} = \omega_s + \frac{d\delta}{dt}$$

$$\frac{d^2\theta}{dt^2} = \frac{d^2\delta}{dt^2} = \alpha$$

$\frac{d\theta}{dt}\frac{d\delta}{dt}\frac{d^2\theta}{dt^2} = \frac{d^2\delta}{dt^2}$Therefore the equation $M\frac{d^2\theta}{dt^2} = P_a \frac{d^2\theta}{dt^2}$could be written as

$$M\frac{d^2\delta}{dt^2} = P_A$$

$$\frac{d^2\delta}{dt^2} =$$

Or

$M\alpha = P_A$

The above equation is known as the SWING EQUATION for a synchronous generator. From the swing equation, the SWING CURVE, which is the plot of torque angle (δ) versus time t, could be obtained by solving the swing equation. A typical swing curve is shown in the figure 5-3 below.

Two typical swing curves are shown. Swing curves are used to determine the stability of the system. If the rotor angle reaches a maximum and then decreases, then it shows that the system has transient stability. On the other hand, if the rotor angle increases indefinitely, then it shows that the system is unstable.

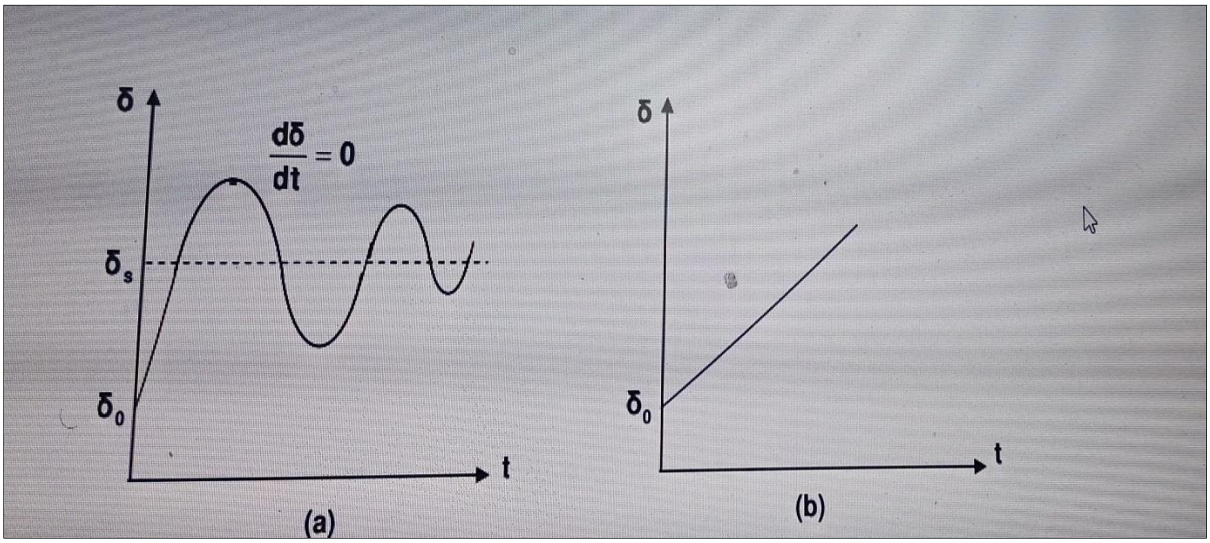


Figure 5-3. Typical Swing Curve: (a) Stable system; (b) Unstable system

Inertia Constant H and Angular Momentum (M)

Because the angular momentum (M) varies over a wide range depending on the type and size of machine, a new constant H, referred to as the Inertia Constant is introduced. Note that we have two main types of synchronous generators, hydro generators and turbo generators and these two machines have widely different values of angular momentum (M) depending on their size. Now to overcome this problem, we define another term called inertia constant which is denoted by the symbol H. This inertia constant H or the constant H is defined as the stored kinetic energy in mega joules at synchronous speed divided by the machine MVA rating. That is

$$H = \frac{Stored\ kinetic\ energy\ at\ synchronous\ speed\ in\ mega\ joules}{Generator\ MVA\ rating}$$

Now if we assume, MVA for the system as the machine rating in MVA, then P_S divided by machine MVA rating (S) becomes the per unit mechanical power, similarly P_E divided by S becomes the per unit electrical power. Therefore, this equation can now be written in terms of power expressed in per unit.

Thus, the swing equation could be written as,

$$H = \frac{1}{2}\frac{J\omega^2}{S} = \frac{M\omega}{2S}\frac{2\mathrm{H}}{\omega}\frac{\mathrm{d}^2\delta}{\mathrm{dt}^2} = \mathrm{P_S} - \quad \mathrm{P_S}$$

Where $M = J\omega$

and S = Generator MVA rating

5.2.3 Small Signal Stability

Now the next important term to consider is Small Signal Stability, defined as the ability of the power system to maintain synchronism under small perturbations. That is, the synchronous machine has the ability to maintain synchronism under small perturbations or small disturbances and this is the primary requirement for stability.

The small disturbances are small variation in loads and generation outputs. For any power system, loads keep on changing continuously and is one example of small disturbance. The second important point here is that the disturbances are considered to be sufficiently small for linearization of the system equations to be permissible for purposes of analysis.

As earlier indicated, the swing equation is a non-linear differential equation, but when we consider small perturbations this equation can be linearized around a nominal operating point.

Once the equation is a linear equation, we can make use of linear control theory. That is, when the differential equation is non-linear it has to be solved by applying numerical techniques to get the closed form solution. However, if the differential equation is linear, we can use a linear control theory to solve the equation and design controllers for the system. Small signal stability is further broken into

- non-oscillatory instability - this occurs because of insufficient synchronizing torque and the other is,
- oscillatory instability which is due to insufficient damping torque or due to unstable control action.

The figure 5-4 below shows the different kinds of situations under small signal stability,

- stable
- non-oscillatory instability and
- oscillatory instability

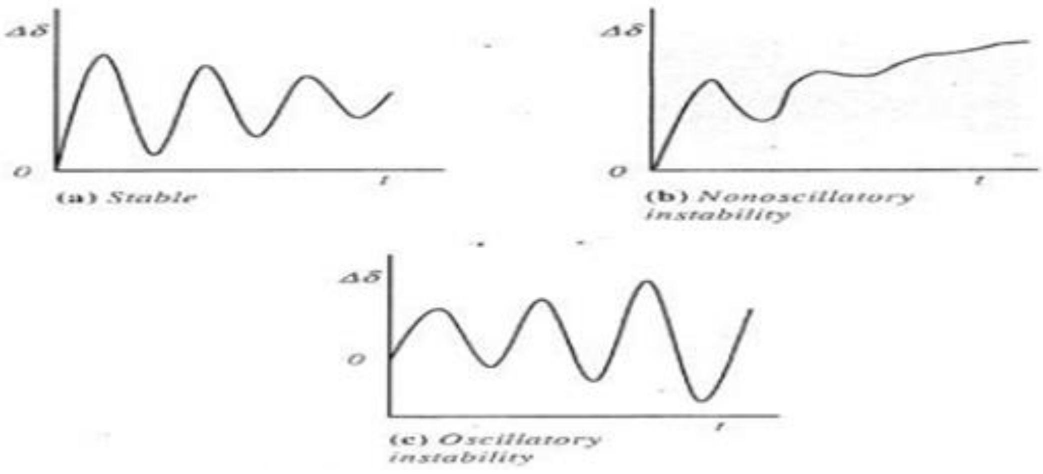


Figure 5-4. Different Situations under Small Signal Stability

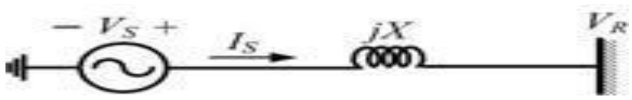
The different modes of oscillations are that lead to these small signal stability situations are,

- local modes,
- inter area modes,
- control modes and
- torsional modes.

The local modes are the ones where synchronous machine(s) located in a power plant oscillate with respect to the rest of the system and the frequency is typically in the range of 0.7 to 2 hertz. Inter-area oscillation on the other hand is where a group of machines of a power system oscillate with another group of machines connected by a weak tie line. One group of machines will form one area and the other group forms another area. When the group of machines are considered the inertia constant H is large and the frequency of oscillation is normally in the range of point 2 to 1 hertz. For control modes, the frequency of the different modes depends upon the actually control phenomena involved therefore, no specific frequency is specified. Torsional modes phenomena on the other hand occur in the steam turbine and the different frequencies which we come across are for typical mass systems and in the range of 16.3, 24.1, 30.3 and 44 hertz.

5.3 Power-Angle Relationship:

Consider the single-machine-infinite-bus (SMIB) system shown below. In this figure, the reactance X includes the reactance of the transmission line and the synchronous reactance or the transient reactance of the generator. The sending end voltage is then the internal emf of the generator. Let the sending and receiving end voltages be given by V_S and V_R



Then the power transfer from the generator bus to the load bus with voltages V_S and V_R respectively is given by,

$$P_e = P_S = P_R = \frac{V_1 V_2}{X} \sin \delta = P_{\max} \sin \delta$$

Where,

$P_{\max}$ $P_{\max} = \frac{V_1 V_2}{X}$ is the maximum power that can be transmitted over the transmission line.

5.3.1 The Power-Angle Curve

The resulting curve of Power (P) versus Rotor angle (δ), referred to as the Power – Angle curve is shown Figure 5-5 below.

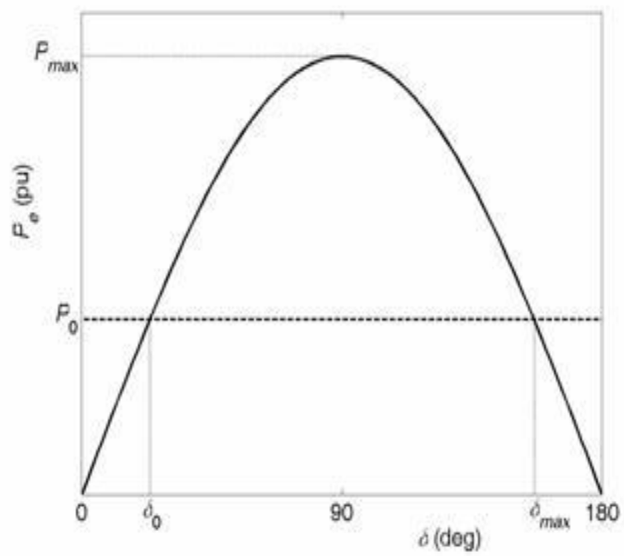


Figure 5-5. Power Angle Curve

From the above power angle curve, we can see that for a given power P_0, there are two possible values of the angle (δ), δ_0 and δmax.

The angles are given by

$$\delta_0 = \sin^{-1}\left(\frac{P_0}{P_{max}}\right)$$

$$\delta_{max} = 180° - \delta_0$$

5.3.2 Transient Stability

Is defined as the ability of the power system to maintain synchronism when subjected to severe transient disturbances.

The word severe transient disturbance is to be carefully understood that the disturbances occur suddenly and they are severe in nature. Examples of these severe disturbances include

- transmission line faults
- sudden large load changes
- loss of generation,
- generating units and
- line tripping.

Transient stability involves non-linear relations whilst the resulting equations for small signal stability could be linearized.

Here the emphasis is that, whenever large disturbances occur in a power system, then the resulting response involves large excursions of rotor angles, the delta (δ) varies over a wide range and therefore the power output is highly non-linear with respect to delta (δ).

This is one important point to note and therefore, transient stability analysis require the solution of non-linear swing equations.

That is, for each operating condition the behaviour of the system is going to be different.

Similarly, the severity of the disturbance, now severity here depends upon the type of fault, location of fault and duration of fault. Similarly, when we talk of large load change, the question is, what is the quantum of load which has come on the system.

Also, when we talk about generator tripping, the question is, what is the amount of generation that has been taken out from the system.

These important issues point to the fact that, the resulting system's stability depends upon the initial operating condition and the severity of the disturbance.

Usually, the system is altered so that the post disturbance steady state operation differs from the system condition prior to the disturbance.

Here, suppose that the system is initially operating in a bulk steady state operating condition. The moment disturbance occurs, there will be a change in the topology of the system and therefore if the system is stable, the new steady state operating condition could be different from the previous one.

Also in any power system, there is probability of occurrence of system faults but statistically, line-to-ground fault has the highest probability of occurrence compared to 3-phase faults which has the minimum probability of occurrence.

This fact is taken into consideration when analysing transient stability of power systems and also when designing the system from operation and planning point of view.

As a result, every power system is designed to be able to withstand the most probable contingencies and not loose synchronism when such contingencies occur.

5.3.3 Forms of Transient Stability

The figure 5-6 below shows the behaviour of a synchronous machine under stable and unstable operating conditions. Now these are shown in the diagram as: (a), (b), and (c).

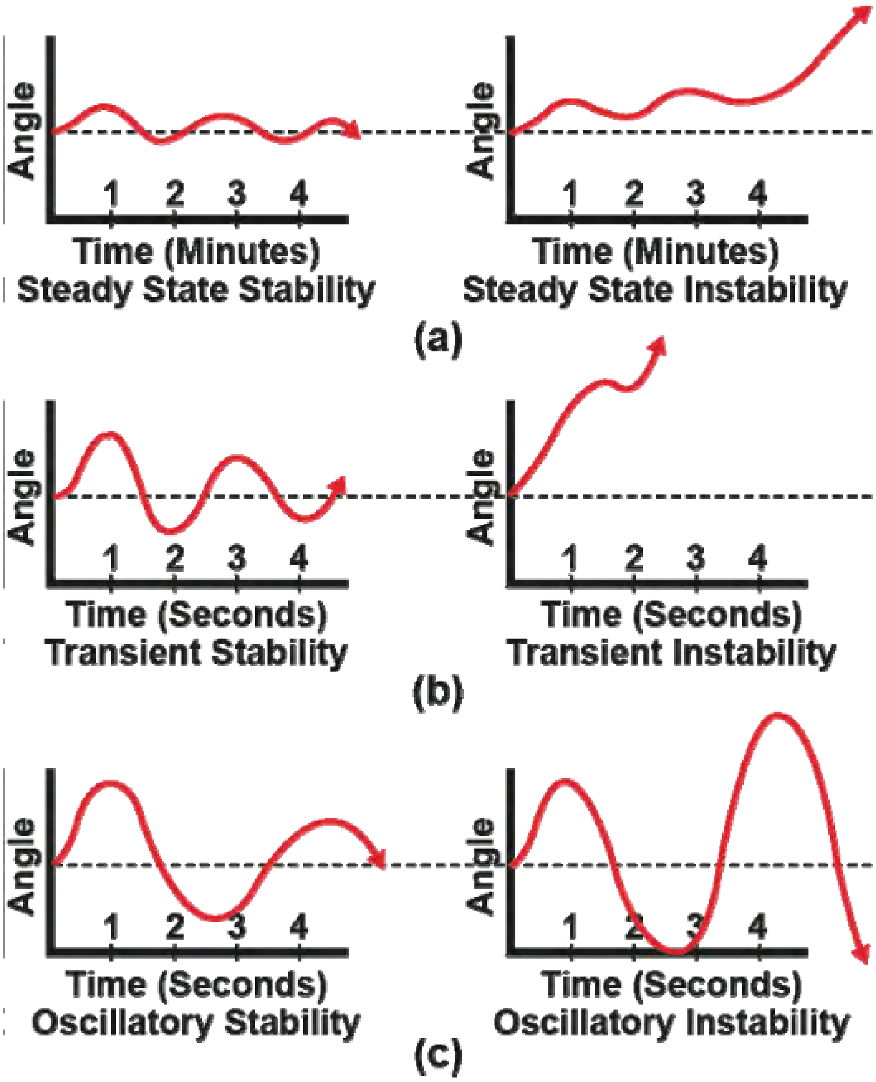


Figure 5-6. Types of Stability and Instability

Figure 5-6 (a) shows that following the disturbance, the power angle increases, attains maximum value then decreases and oscillates with decreasing amplitude - this is a stable case.

Figure 5-6 (b) is the delta increases continuously till the system becomes unstable or till machines lose synchronism.

Figure 5-6 (c) shows a situation where the machine survives the initial swing but the subsequent oscillations increase in amplitude due to insufficient damping torque or improper control action and the resulting system becomes unstable.

The type of instability in (a) is generally called first swing instability and this happens particularly due to insufficient synchronizing power. Figure 5-6 (c) is a case where the power angle delta (δ) increases and attains maximum value but subsequently the magnitude of oscillations grows.

This is the case where the system is stable from the point of view of first swing stability but then becomes unstable due to lack of damping torque and hence the new operating condition is not dynamically (small-signally) stable.

5.3.4 Equal Area Criterion

The accelerating power P_A in the swing equation has a sine term. Therefore the swing equation is a non-linear differential equation and obtaining its solution is not simple. Typically, to analyze the stability of a power system, one will have to solve the swing equation using numerical techniques, but the solution of the swing equation through numerical technique is a time consuming process.

For two machine system and one machine connected to infinite busbar as shown below, it is possible to say whether a system has transient stability or not, without solving the swing equation. Such criterion which decides the stability, makes use of equal area in power angle diagram and hence it is known as EQUAL AREA CRITERION.

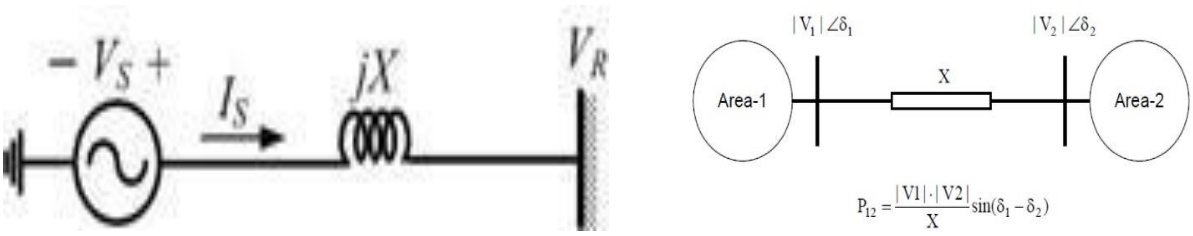


Figure 5-7. Equal Area in Power Angle

Thus the principle by which stability under transient conditions is determined without solving the swing equation, but makes use of areas in power angle diagram, is called the EQUAL AREA CRITERION. The Equal Area Criterion of stability is a graphical method for determining whether disturbed power system will be stable or not. That is, in any stability studies, the primary requirement is to determine for a given operating condition and for a given disturbance whether the system is stable or not. Many times we are also interested in knowing if stable, how much stable and what is the stability margin. The graph showing Equal Area Criterion is shown figure 5-8 below.

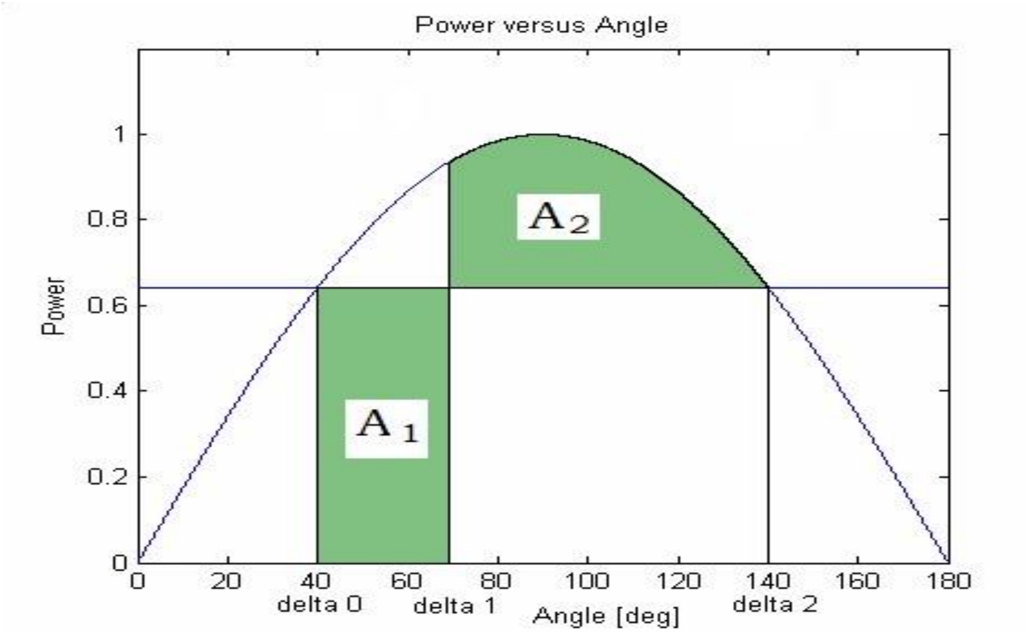


Figure 5-8. Equal Area Criterion

The equal area criterion of stability is a very powerful tool that could be used quickly to determine the stability of the disturbed system.

Therefore, here the applicability of the equal area criteria, under what circumstances of the perturbed system and its limitations would be looked at.

5.4 Equal Area Criterion

For a given power system whose initial operating point has been altered through a major perturbation, it is instructive to be able to use the equal area criterion to assess its stability and the level of stability. The figures below are used to illustrate the transient stability of a disturbed power system and the level of stability. For a power system which has suffered a major disturbance, the resulting system could be either stable, critically stable or unstable.

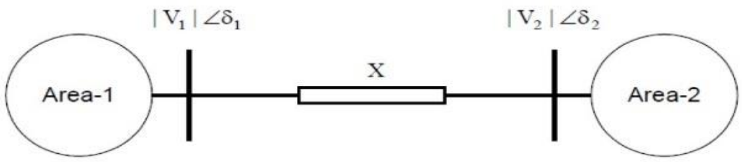
The synchronous machine is operating in steady state delivering a power P_e equal to P_m when a fault occurs in the system. Opening of circuit breakers in the faulted section subsequently clears the fault. The circuit breakers take about 5 or 6 cycles to open and the subsequent post-fault transient lasts for another few cycles. The input power, on the other hand, is supplied by a prime mover that is usually driven by a steam turbine. The time constant of the turbine mass system is of the order of few seconds, while the electrical system time constant is in milliseconds.

Therefore, for all practical purposes, the mechanical power remains constant during this period when the electrical transients occur. The transient stability study therefore concentrates on the ability of the power system to recover from the fault and deliver the constant power Pm with a possible new load angle δ.

Note:

$$P_E = \frac{V_G . V_M}{X} \sin \delta = P_{max} \sin \delta$$

$$Since,\ when\ \delta = 0, maximum\ amplitude = \frac{V_G . V_M}{X}$$



$$P_{12} = \frac{|V1| \cdot |V2|}{X} \sin(\delta_1 - \delta_2)$$

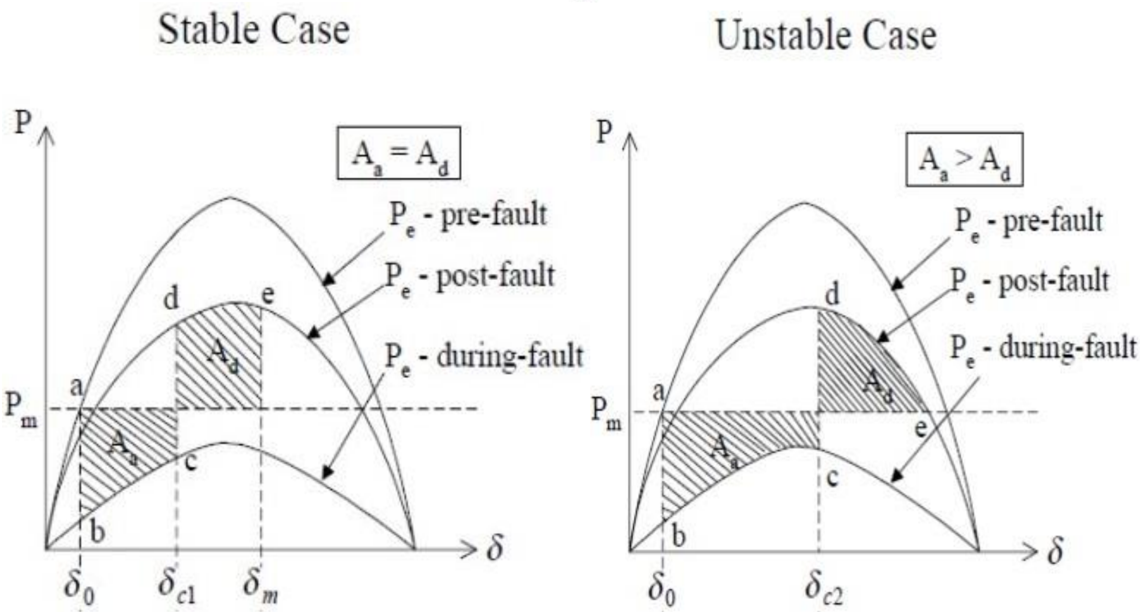


Figure 5-9. Stable and Unstable Case

Where,

$A_a = A_1$ = Area of acceleration

$A_d = A_2$ = Area of deceleration

The A_1 and A_2 are based on solving the two integrals with the indicated limits below.

$$A_1 = \int_{\delta_0}^{\delta_c} (P_m - P_e) d\delta = 0$$

$$A_2 = \int_{\delta_c}^{\delta_m} (P_e - P_m) d\delta = 0$$

$$M d^2\delta / dt^2 = P_a = P_m - P_e$$

If the area of acceleration is larger than the area of deceleration, i.e. A1 > A2, the generator load angle will then cross the point δ_m, beyond which the electrical power will be less than the mechanical power, forcing the accelerating power to be positive.

The generator will therefore start accelerating, before slowing down completely and eventually becoming unstable.

If, on the other hand, A1 < A2, i.e., the decelerating area is larger than the accelerating area, the machine will decelerate completely before accelerating again.

The rotor inertia will force the subsequent acceleration and deceleration areas to be smaller than the first ones and the machine will eventually attain the steady state.

If the two areas are equal, i.e., A1 = A2, then the accelerating area is equal to decelerating area and this defines the boundary of the stability limit.

- The system is stable if $d\delta/dt = 0$
- The system is unstable if $d\delta/dt \geq 0$ for sufficient long time

5.4.1 Transient Stability Limit

Transient stability limit refers to the amount of power that can be transmitted through some point in the power system with stability when the system is subjected to severe aperiodic disturbance.

Here the stability limit is referred to in terms of the amount of power, that is, what is the power in Mega Watts (MW) that can be transmitted and it is with respect to some point in the power system.

5.4.2 Critical Clearing Angle (ΔC)

Now for a given system and for a given initial load, there is a critical clearing angle (δ_c), such that if the actual clearing angle (δ) is smaller than the critical value, then the system is stable and if larger than the critical value the system is unstable.

That is, there is some critical clearing angle (δ_c) and actual clearing angle (δ) such that if the actual (δ) is less than this critical value (δ_c), then the system is stable.

5.4.3 Critical Fault Clearing Time (TC)

Similarly, we define another term - Critical Fault Clearing Time (t_c), again for a given system and a given initial loading condition such that, if the actual fault clearing time (t) is smaller than the critical value (t_c) then the system is stable, but if larger than (t_c) then the system is unstable

The fault clearing time is defined as the sum of the time that the protective relays take to close the circuit breaker trip circuit and the time required for the circuit breaker to interrupt the fault current.

M06 – POWER SYSTEM RESTORATION

6.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of power system restoration
- Explain essential loads for restoration
- State economic dispatch and minimization of unserved energy

6.2 Introduction

Uninterrupted power supply is essential for national productivity, economic growth and social wellbeing of the people. Utilities in charge if power supply must therefore ensure continuous supply at all cost. Power outages which occur must be promptly attended to and supply should be restored within the shortest possible time.

Very severe disturbances may cause power systems to split causing islands or may result in total black out. When black outs occur, the system must be restored within the shortest possible time to minimise the impact on continuity of services. Bigger and well planned power systems are usually stronger and are less prone to blackouts than smaller power systems.

6.3 Purposes of Restoration Following a Blackout

Even though each power blackout and restoration scenario are a unique event, there are certain goals and steps that are common in all restoration procedures. The objective of the restoration procedure following a complete or partial blackout can be described as follows:

- Restore the power system to normal operating condition as quickly as possible
- Synchronise at least one unit at all power generating stations if possible
- Restore essential loads

- Establish all interconnections
- Start economic dispatch
- Minimise the amount of unserved energy

While following this procedure to restore the power grid to normalcy, special attention must be given to frequency balance and voltage control as wide fluctuations in frequency and voltages occur during restoration. Failure to ensure frequency balance and proper voltage control will lead to generator instability and tripping and prolong the restoration process.

6.4 System Assessment Before Restoration

When a power system blackout occurs, the system dispatcher must first assess the extent of the blackout so as to plan the restoration. In the event of a total blackout, two conditions must be satisfied:

- all generating units including embedded generation sources within the control area should have tripped
- all interconnection lines with neighbouring power systems should also have tripped

The above two conditions are necessary to establish a total blackout. Partial blackouts, however, can vary widely in extent. In the event of a partial blackout, a comprehensive assessment of the power grid must be carried out to determine the extent of the blackout before restoration begins.

The boundaries of energised/islanded areas must be clearly identified. The frequency, voltage levels and transmission line loadings within the energised/islanded areas must be assessed. All faulted transmission elements and generation equipment must be identified and isolated from the grid, leaving only healthy transmission equipment and generation facilities to be restored to service.

6.5 Network Preparation Before Restoration

It is very important to prepare the network before restoration to ensure systematic progress and success. During the network preparation the transmission grid is sectionalised into blocks by opening circuit breakers at designated locations on the grid. This ensures that when the restoration begins only small portions of the grid are energised step by step. Energising a large chunk of the power grid at a time causes wide frequency and voltage excursions and may lead to transmission line overloading, over-voltage and generator instability and trips. It is therefore important to proceed at a gradual pace from the beginning till the power grid attains a good level of stability.

To prevent undesired response of the grid to the initial frequency and voltage excursions, under-frequency protection relays should temporarily be defeated while generator voltage regulator should be switched temporarily from automatic control to manual control.

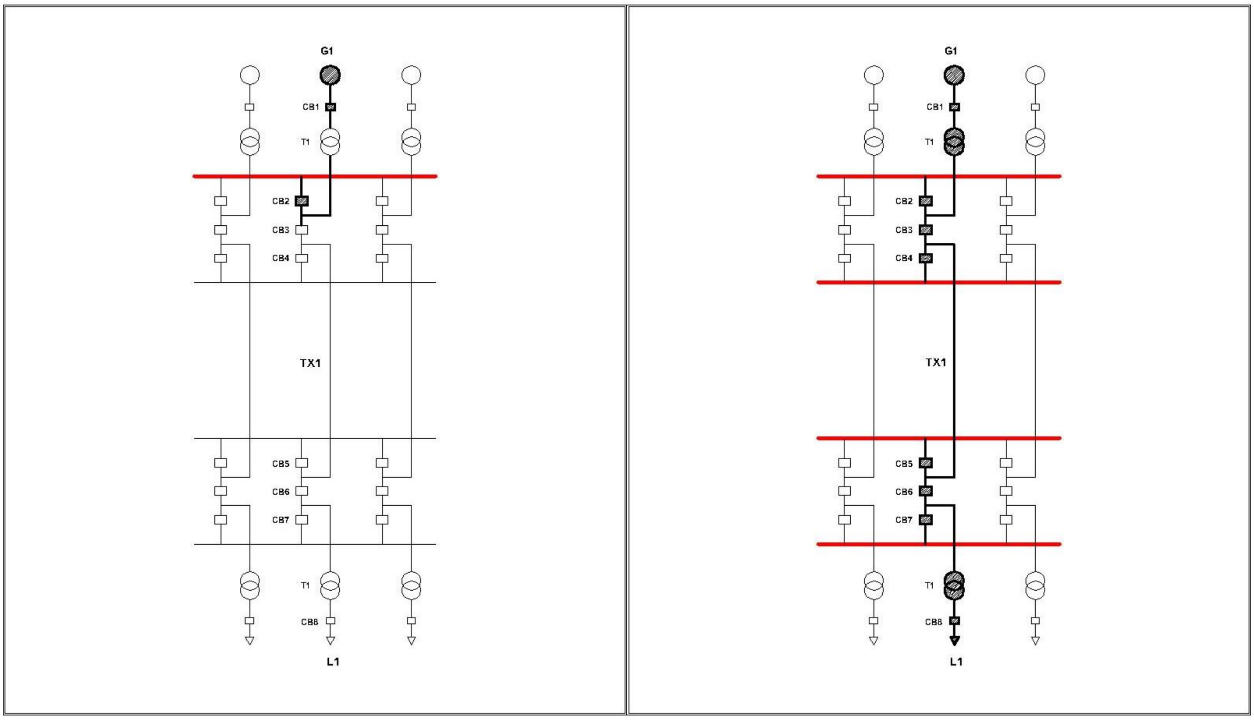
If it is not the desire to import voltage from the neighbouring power systems on the interconnection tie lines to start the restoration process, then all interconnection tie lines should be opened before the start of the restoration and should remain open until the restoration has proceeded successfully and the power grid has become stable. The interconnection tie lines should only be restored when all protective relays which were temporarily defeated have been reactivated and generator voltage regulators have been switched from manual control to automatic control.

Generating units with black start capability are identified and prepared for synchronisation. If no generator with black start capability exists within the boundaries of the control area, then the restoration process can only be started by importing voltage from neighbouring power systems through the interconnection lines.

6.6 Network Energisation

1. Start generator G1 2. Close circuit breakers 1 and 2 to energise the power grid	3. Close circuit breakers 3 – 8 to energise transmission line 1, transformer T1 and pick load L1

Figure 6-1. The First Stages of Network Energisation



1. Start generator G1
2. Close circuit breakers 1 and 2 to energise the generator switchyard
3. Close circuit breakers 3 – 8 to energise transmission line 1, transformer T1 and pick load L1

A generating unit with black start capability is started and synchronised to the power grid to start the restoration process. A transmission line from the generator switchyard is then energised to send voltage to the nearest load centre to supply a load. This is the first and most critical stage of the restoration process. Some power system restoration procedures may however, recommend starting two or more generating units simultaneously before picking the first load. Depending on the size of load to be picked, two or more transmission lines may be energised before picking the load. The start-up can therefore occur in various combinations to achieve the best possible result.

The diagram below shows the first stages of network energisation from the start of the first generating unit to the connection of the first load.

The steps followed in the first stage of the restoration process are:

(a) Start the first generating unit that has black start capability and energise the generator high voltage switchyard

(b) Energise a transmission line from the switchyard and send voltage to the nearest load centre

(c) Restore supply to the load

This stage is highly unstable and is accompanied by wide frequency and voltage excursions. It is very critical to maintain frequency and voltages within acceptable levels. Stability improves as the restoration progresses and more generating units, transmission lines and loads are restored to service.

From the start up through the restoration of the initial loads, the reactive power generated by the transmission lines causes very high voltages on the grid. The excess reactive power must be absorbed by the generating units or some reactive power compensators like shunt reactors and FACTS devices to bring voltages to acceptable levels until adequate loads have been restored to service. For this reason, it is recommended to start the restoration process with hydro power plants which are capable of absorbing the excess reactive power from the grid.

There are two generator control systems which need critical attention and monitoring during the restoration. These are the governor control system which controls load-generation balance and the automatic voltage regulator (or excitation) system which also controls voltage-reactive power balance. Load – generation balance and voltage – reactive power balance must be maintained at all times during the restoration as wide excursions will lead to generator instability and tripping.

All protective relays should be monitored closely during the restoration. Special attention must be paid to generator volts per Hz, out of step, under excitation and over excitation protection relays as these can initiate an undesirable regulator response or generator trip during start up.

Progress is made as more generating units are synchronized, more transmission elements are energized and supply is restored to more loads. As progress is made in the restoration, all generator automatic voltage regulators that were temporarily switched from automatic control to manual control should be switched back to automatic control. Similarly, under frequency relays that were temporarily defeated should be reactivated.

When the system dispatcher is satisfied with the level of stability attained, the tie line interconnections should be restored to begin power exchanges with the neighbouring power systems.

6.7 Power System Restoration Procedure

The procedures established by GRIDCo to follow in the event of a total blackout of the national interconnected transmission system (NITS) are as presented below. Partial blackouts vary widely in the extent. Therefore, following a partial blackout, it is the responsibility of the system dispatcher to adopt the best strategy from these procedures to restore the system to normalcy. The grid map and the single line operating diagram of the NITS are attached in the appendixes herewith for reference in this module.

6.7.1 Stakeholders to be Informed

Following a total system collapse, the system dispatcher at the System Control Centre shall inform all stakeholders of the collapse. The stakeholders informed are:

- The System Control Centre Manager
- All area managers i.e. Akosombo, Volta, Takoradi, Prestea, Kumasi, Techiman and Tamale
- All manned substations and generating stations
- All major load customers i.e. VALCO, ECG, NEDCO and direct load customers e.g. mining companies
- The dispatch centres of the neighbouring interconnected power systems

6.7.2 The Sectionalisation Process

- The system dispatcher at the System Control Centre shall open all feeder circuit breakers and then proceed to sectionalise the power system
- The importance of sectionalisation is to prevent high voltage build up due to Ferranti effect and also prevent picking large load blocks of the grid during the restoration
- The sectionalisation process is carried out as follows:
  (a) At Akosombo: request Akosombo GS personnel to open all switchyard circuit breakers
  (b) At Asiekpe: open Asiekpe-Lome lines
  (c) At Volta: open all Volta switchyard circuit breakers
  (d) At Tafo: Open Tafo-Akwatia line

(e) Request CIE and CEB to open the respective interconnection tie lines at their end

(f) At Kumasi: Open Kumasi-Techiman, Kumasi-Kenaysi and Kumasi-New Obuasi lines

(g) At Aboadze: Open Aboadze-Tarkwa and Aboadze-Volat lines

(h) At Takoradi: Open Tarkwa-Takoradi line

(i) At Prestea: Open Prestea-Rivieara, Prestea-Bogoso lines

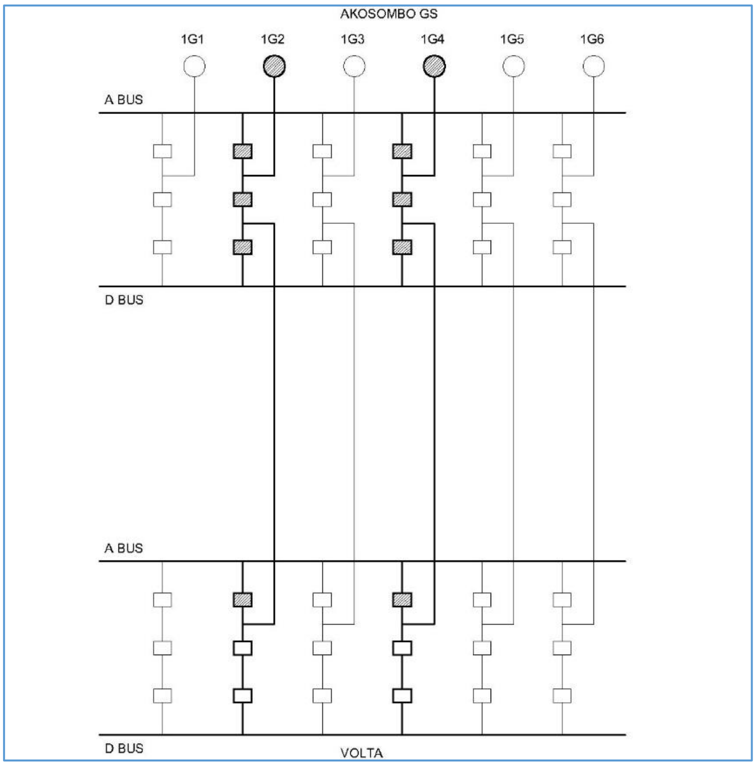
(j) At Obuasi: Open Obuasi-Kenyasi line

6.7.3 The Restoration Process

- Having completed the sectionalisation, the system dispatcher at the System Control Centre shall confirm to Akosombo GS of readiness to receive power into the grid
- This is because Akosombo GS generating units have black start capability and the units are also big enough in size to initiate the restoration process
- The restoration procedure is carried out as follows:

(a) At Akosombo

The system dispatcher at the System Control Centre shall request Akosombo GS to synchronise two (2) generating units to the A bus and then energise the corresponding Akosombo – Volta transmission lines by closing the middle circuit breakers of the units synchronized and the associated D bus circuit breakers



- Akosombo GS units #2 and #4 synchronised
- The associate A bus, middle and D bus circuit breakers are closed
- Associated Akosombo - Volta transmission lines #2 and #4 are energised
- Volta substation A bus is energised

Figure 6-2. Sequence of energisation of Akosombo – Volta Transmission Lines

- Also energise Akosombo – Kpong, Kpong – Kpone and Kpone – Volta transmission lines

(b) At Volta

The system dispatcher at the System Control Centre shall close the circuit breakers of the bays whose lines are on potential from Akosombo

- Energise New Tema, Sunon Asogli, Smelter II – Smelter and Smelter II – Karpower transmission lines to restore supply to Tema loads and also send voltage to all the thermal power plants in the Tema enclave
- Restore supply to Tema customers: Enclave Power, VALCO & ECG
- Monitor generation–load balance, frequency, voltages, generating units and transmission line loadings at all times
- Request generating plants in the Tema enclave to prepare all available generating units for synchronisation
- Pick Volta – Achimota and Volta – Accra East transmission lines to restore supply to Accra East, Achimota, Mallam, Winneba, Cape Coast, Takoradi, Esiama and Aboadze

- Request Kpong GS and power plants within the Tema enclave to synchronise generating units progressively as supply is restored to loads at Accra East, Achimota, Mallam, Winneba, Cape Coast, Takoradi, Esiama
- The amount of load to be supplied shall depend on the generating units that are synchronised from Akosombo GS, Kpong GS and the thermal units within the Tema enclave

(c) At Akosombo

- Energise transmission lines to restore power supply to Tafo, Nkawkaw, Konongo, Anwomaso and Kumasi
- Restore supply to loads progressively as generating units are synchronised
- To the extent possible, generating units being synchronised should be sufficiently spread out over the grid to avoid over-concentration of generating units in one area of the power grid causing congestion problems

(d) At Takoradi

- Energise transmission lines to restore supply to Tarkwa, New Tarkwa, and Prestea

(e) At Kumasi

- Energise transmission lines to restore supply to New Obuasi, Obuasi, Kenyasi, Dunkwa, Bogoso and Asawinso and close the southern loop

(f) All remaining healthy transmission lines shall be energised to restore supply to substations and loads within the southern loop

(i) The interconnection lines to La Côte d'Ivoire (CIE) and Togo – Benin (CEB) shall be restored to service at this stage

(j) **At Kumasi**

- Energise transmission lines to restore supply to Techiman, Sunyani and Bui and the rest of the northern part of the power grid

6.8 Challenges Encountered During Restoration

The challenges that may be encountered during restoration include the following:

- Supervisory Control and Data Acquisition (SCADA) or communication network may be lost during restoration. This can pose a very serious challenge and may prolong the restoration process

- Some circuit breakers may leak air/gas during the power outage period. These breakers may not close when a command is issued. This can also pose a very serious challenge and may prolong the restoration process
- During light load period, e.g. Sunday off-peak period, supply may be restored to a load centre but due to light loading, high voltage can persist and can cause delays in the restoration process

6.9 Conclusion

- The restoration procedures should be updated at all times and be current with the power grid
- All new equipment added to the power grid should be included and old equipment de-commissioned from the grid should also be removed from the procedures
- Failure to update the procedures will cause unexpected or undesired results during the restoration
- Experience gained from every restoration should be documented for future learning

3. METERING AND INSTRUMENTATION

Ghana Grid Company Limited

M01 – BURDEN AND SATURATION CHARACTERISTIC OF INSTRUMENT TRANSFORMER

1.1 Objectives

By the end of this module the student should be able to

- explain the functions and operations of current transformers
- explain the functions and operations of voltage transformers
- distinguish between voltage and current transformers
- combine current and voltage transformer
- list and explain name plate data of instrument transformers
- CT ratio selection

1.2 Introduction

An instrument transformer is a transformer intended to supply measuring instruments, billing meters, protection relays and other similar devices (IEC 60044 - 1). Protective relays require accurate reproduction of the normal, tolerable, and intolerable conditions in the power system for correct sensing and operation. The quality of instrument transformers will directly affect the overall accuracy and performance of the metering, monitoring and protection systems connected to them.

The primary of an instrument transformer is connected to the process and so the inputs are the actual current or voltage in the high voltage system. Our wish is that the secondary output is an exact reproduction of the primary quantity with a constant scale factor. It is however impossible to achieve this since the instrument transformer is usually loaded with instruments, relays and connecting cables.

The main functions of the instrument transformer are to:

- Isolate the measuring circuit from the High Voltage System.
- Convert the current and voltage to standard values reasonable for instruments, equipment and protective relays.
- Protect equipment, especially meters, from the destructive effects of the short circuit currents.

Instrument transformers are used to measure the following power system quantities:

- Current, voltage, power (Active, Reactive and Apparent) for system monitoring and control.
- Energy for billing metering purposes.
- Current, voltage, power, frequency, etc. to control the state of an equipment.

- Current, voltage, power, frequency, etc. to determine faults which are disconnected as quickly as possible.

1.3 Instrument Transformers

1.3.1 Constructions of Instrument Transformers

The theory of transformer holds for both the current and inductive voltage transformers. It is the same equilibrium between current, magnetic flux and voltage. In our analysis we will use the schematic diagram in Figure 1-1 below.

The primary current is divided into two components namely the magnetizing current, I_o, which sets up the magnetic flux that induces the voltage in the secondary winding. The other component, $-N_sI_s/N_p$, balances the secondary ampere windings.

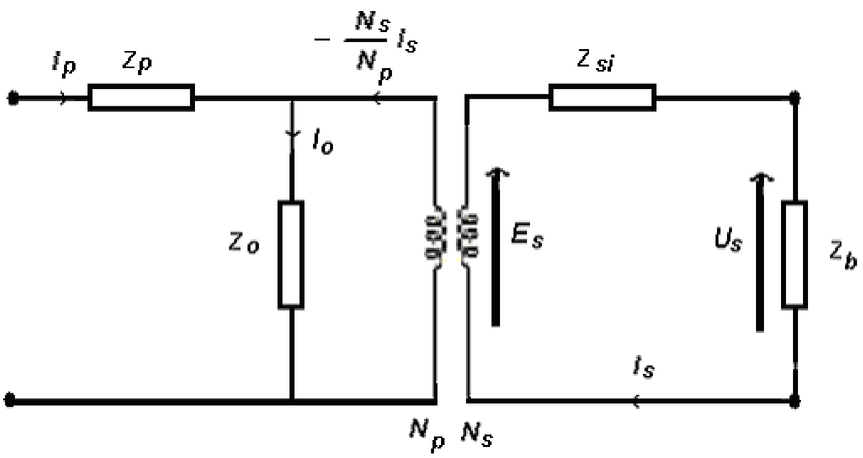


Figure 1-1. Equivalent Circuit of a Transformer

Different demands are made of the CT and VT and so they have different constructions. This is because the CT is a series component whilst the VT is a parallel component.

1.3.1.1 Construction of The CT

One can mention two types of load that are usually connected to the CT:

- Instruments and meters
- Protective relays

These two loads make different demands on the CT and are normally not connected to the same core. It is therefore usual for CTs to have at least two cores – metering and protection.

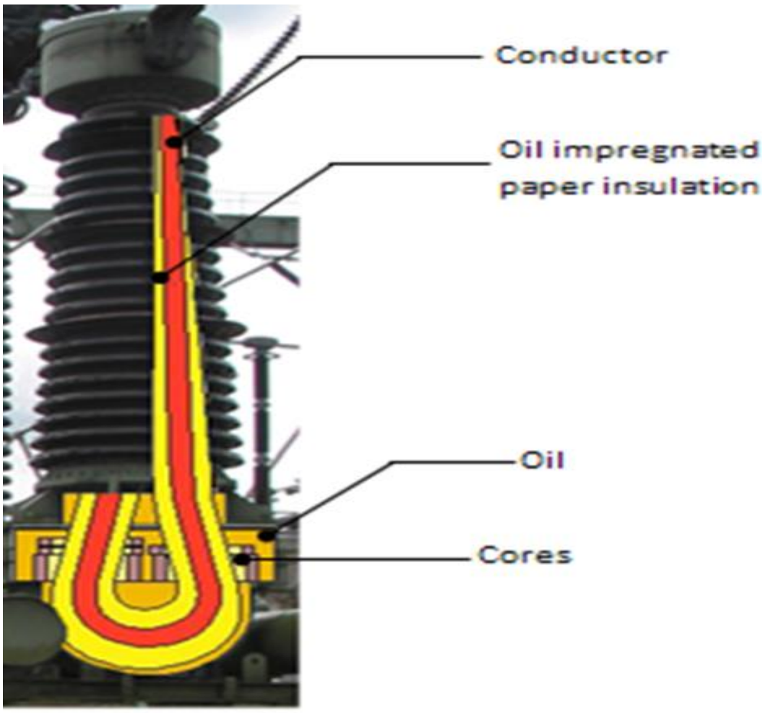


Figure 1-2. High Voltage CT and the CT Construction

The insulation used during the manufacture of CTs depends on the voltage. There are three main types of insulation in use for high voltage CTs namely:

- Dry insulation – epoxy insulated CTs for voltages up to 36kV.
- Oil/Paper insulation – this is the classic insulation material for higher voltage CTs
- Pressurised gas insulation – this is a recent development, the gas insulate CTs that are in pressurized gas insulated switching equipment.

1.3.1.2 Construction Of The VT

Measuring instruments and protection demand different saturation characteristics and so a VT is usually manufactured with at least two secondary windings with a common primary winding and steel (iron) core. One core may be connected open delta for ground fault detection and is under normal symmetrical conditions not loaded. Therefore even though the two cores are magnetically linked they do not disturb each other. There are two types of VTs.

- Inductive voltage transformers - with pure magnetic connection between primary and secondary windings.

- A capacitor voltage transformer is a voltage divider and the secondary voltage is taken out via an inductive transformer over the last capacitor.

Insulation is mainly the same as in the CT - epoxy insulation for low and medium voltages, oil and paper insulation for higher voltages and pressured gas insulation for pressured gas insulated equipment. In Figure 1-3 are the pictures of a voltage transformer and a capacitor voltage transformer.

(A) Capacitor voltage transformer (CVT) (B) Voltage transformer (VT)

Figure 1-3. A capacitor voltage transformer and a voltage transformer

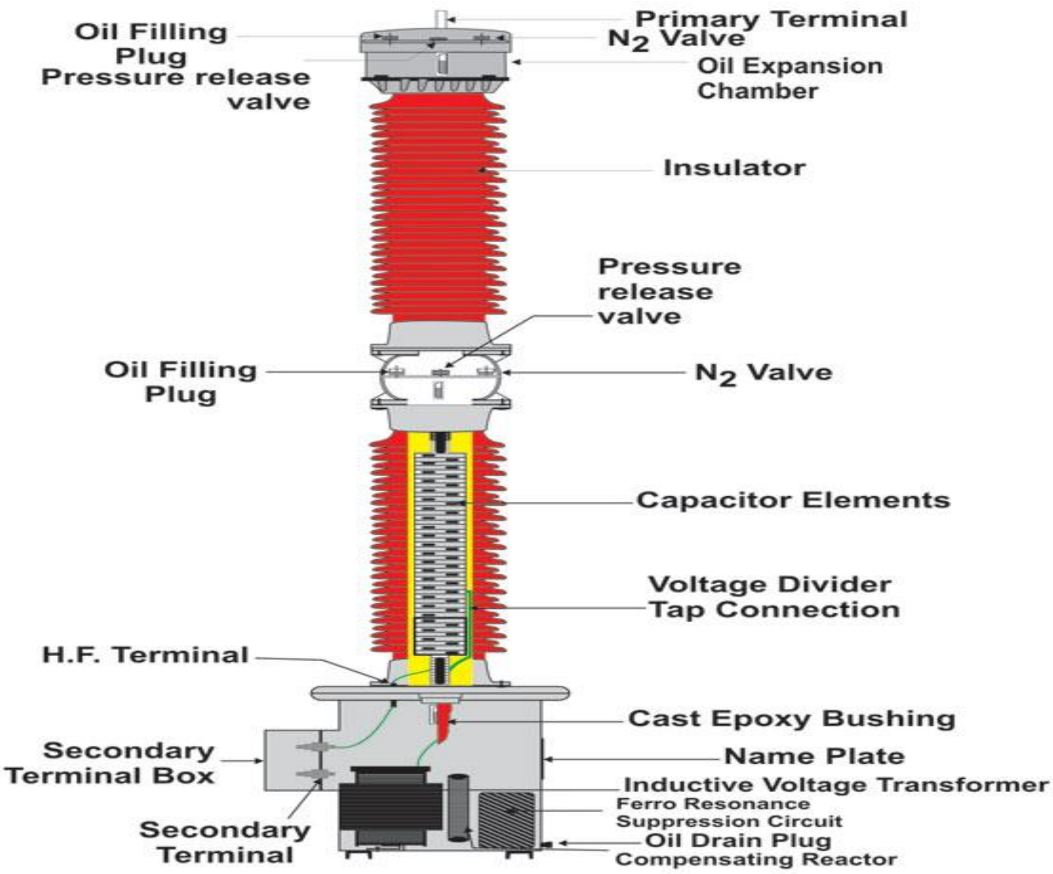


Figure 1-4. The construction of a capacitor voltage transformer

1.3.2 Definitions of CT Quantities

1.3.2.1 Rated Primary Current

The value of the primary current on which the performance of the transformer is based.

1.3.2.2 Rated Secondary Current

The value of the secondary current on which the performance of the transformer is based. Standard values are: 1 and 5A.

1.3.2.3 Rated Turns Ratio

The ratio of the rated primary current to the rated secondary current.

1.3.2.4 Rated Continuous Thermal Current

The value of the current which can be permitted to flow continuously in the primary winding, the secondary winding being connected to the rated burden, without the temperature rise exceeding the values specified.

1.3.2.5 Rated Short-time Thermal Current

The r.m.s. value of the primary current which a transformer will withstand for one second without suffering harmful effects, the secondary winding being short-circuited.

1.3.2.6 Rated Dynamic Current

The peak value of the primary current which a transformer will withstand, without being damaged electrically or mechanically by the resulting electromagnetic forces, the secondary winding being short-circuited

1.3.2.7 Burden

The impedance of the secondary circuit in ohms and power-factor. The burden is usually expressed as the apparent power in voltamperes absorbed at a specified power-factor and at the rated secondary current

1.3.2.8 Rated Burden

The value of the burden on which the accuracy requirements of this specification are based.

1.3.2.9 Rated Output, SN

The value of the apparent power (in voltamperes at a specified power-factor) which the transformer is intended to supply to the secondary circuit at the rated secondary current and with rated burden connected to it.

1.3.2.10 Current Error

The error which a transformer introduces into the measurement of a current and which arises from the fact that the actual transformation ratio is not equal to the rated transformation ratio

$$current\ error = \frac{K_n I_s - I_p}{I_p} \quad (\%)$$

Where

K_n is the rated transformation ratio;
I_p is the actual primary current;
I_s is the actual secondary current when I_p is flowing, under the conditions of measurement.

1.3.2.11 Phase displacement

The difference in phase between the primary and secondary current vectors, the direction of the vectors being so chosen that the angle is zero for a perfect transformer. The phase displacement is said to be positive when the secondary current vector leads the primary current vector. It is usually expressed in minutes or degrees.

1.3.2.12 Composite Error

Under steady-state conditions, the r.m.s. value of the difference between:

a) the instantaneous values of the primary current, and

b) the instantaneous values of the actual secondary current multiplied by the rated transformation ratio, the positive signs of the primary and secondary currents corresponding to the convention for terminal markings. The composite error ε_c is generally expressed as a percentage of the r.m.s. values of the primary current according to the formula:

$$\varepsilon_c = \frac{100}{I_p}\sqrt{\frac{1}{T}\int_o^T (K_n i_s - i_p)^2\, dt} \quad (\%)$$

where

K_n is the rated transformation ratio;
I_p is the r.m.s. value of the primary current;

i_p is the instantaneous value or the primary current;
i_s is the instantaneous value of the secondary current;
T is the duration of one cycle

1.3.3 Burden of Instrument Transformers

Instrument transformers transform primary quantities by the turns ratio to provide secondary current or voltage to feed protective relays or metering equipment.

The total impedance of the loads connected to current or voltage transformers are referred to as the burden. The burden consists of the impedances of the following:

- secondary winding of the instrument transformer
- interconnecting leads
- relay, meter and/or other connected devices

The burdens are usually expressed in volt-amperes at a specified current or voltage. Thus for instrument transformers, if Z_S is the total burden impedance:

CTs:

$$VA = IZ_s \times I = I^2 Z_s \qquad \Rightarrow Z_s = \frac{VA}{I^2}$$

VTs:

$$VA = IZ_s \times I = \frac{V}{Z_s} \cdot Z_s \cdot \frac{V}{Z_s} \qquad \Rightarrow Z_s = \frac{V^2}{VA}$$

Where

VA = rating of CT / VT
I or *V* = amperes or volts at which the burden was measured or specified
Z_S = total burden impedance

1.3.4 Selection of CT Ratio

The major criterion for the selection of CT ratio is almost invariably the maximum load current. In other words, the CT ratio should be selected such that the CT secondary current at maximum load should ***not*** exceed the continuous current rating or the thermal limits of the connected relay or metering equipment.

This is particularly applicable to phase-relays where the load current flows through the relays.

This criterion applies indirectly to the ground relays - (even though they do not receive load currents) - because they are generally connected to the same set of CTs as the phase relays.

The conventional practice over the years has been to select the CT ratio such that the secondary current is just under 5A for the maximum load.

1.4 Mode of Operation of The CT

1.4.1 Equivalent Circuit

The primary current in a power transformer is determined by the load at the secondary side. In a current transformer on the other hand, the primary current is completely independent of the conditions at the secondary side. We can therefore regard the primary current as a constant current source. For an ideal CT:

$$I_p N_p = I_s N_s \quad (1)$$

Equation (1) holds when

- The secondary winding is short-circuited.
- The secondary winding has zero resistance.
- There is no field leakage i.e., there is no net magnetic flux in the core.
- The field set up by the secondary windings is equal and opposite that set up by the primary windings i.e. ampere winding balance.

In practice the secondary winding has a resistance and it would be loaded with indicating meters, energy meters, or protective relays - not to mention connecting cables. One therefore needs a voltage to drive the current through the secondary winding and connected load. This means there must be a net magnetic flux in the core. The needed magnetizing current is from the primary current. The primary current is therefore decomposed into a magnetising component (that sets up the flux in the core) and a component that balances the secondary ampere windings. There is therefore an inherent error in a practical CT. We start with the usual T-equivalent scheme for transformers. For a CT the primary series impedance is not considered since it does not influence the primary current. We therefore use the schematic diagram shown in Figure 1-5 below.

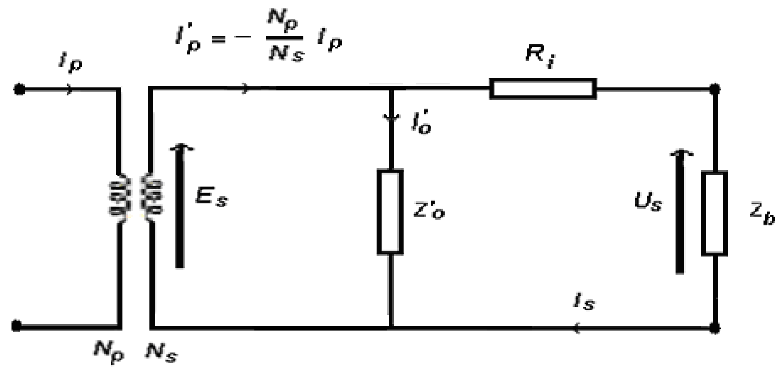


Figure 1-5. Equivalent circuit of a current transformer

Since the secondary winding is evenly distributed along the core, the leakage reactance of the secondary winding is negligible. The series impedance is therefore represented by the winding resistance.

In drawing the phasor diagram it is assumed that the currents and voltages are pure sine waves. The magnetising current is however nowhere near a sine wave because of the hysteresis loop of the iron core.

As long as the core does not saturate the magnetizing ampere windings would be much lower than the primary ampere windings.

The magnetising ampere winding is the sum of the primary and secondary ampere windings. The secondary current will therefore not be a pure sine wave. The deviation from the sine wave will be very little and the secondary current is usually assumed to be a pure sine wave.

1.4.2 CT Performance

The performance is determined by the highest current that can be reproduced, without saturation, to cause large ratio errors.

There are several methods for determining CT performance. Influence of the core magnetic materials and magnetisation curves.

It has been shown that the errors of a current transformer (c.t.) result from the core exciting current, so it is obviously of first importance when considering the performance of a CT to be able to calculate or measure the exciting current.

The excitation or magnetisation characteristics of a CT depend on the cross-sectional area and length of magnetic path of the core, the number of turns in the windings and the magnetic characteristics of the core material.

Figure 1-6 shows typical magnetisation curves for three core materials commonly employed in instrument transformers, namely:

- (a) hot-rolled non-oriented silicon steel,
- (b) cold-rolled oriented silicon steel,
- (c) nickel-iron.

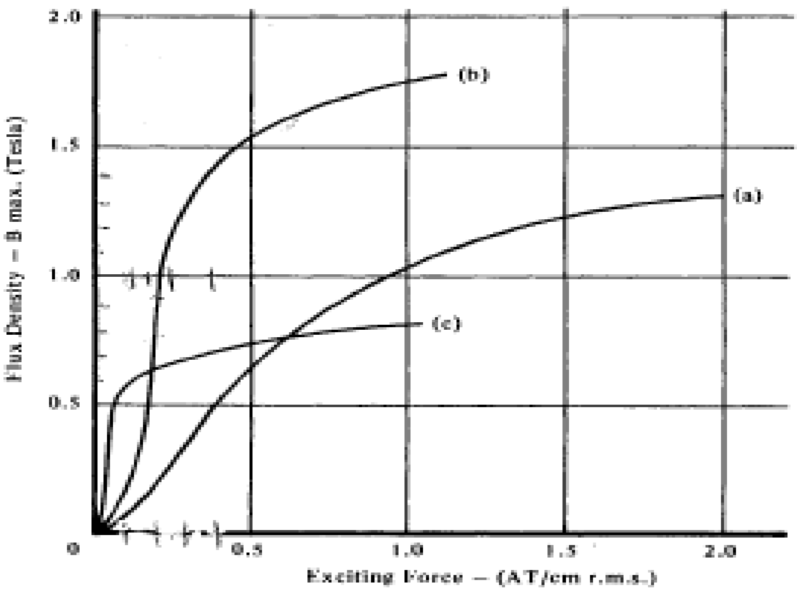


Figure 1-6. 50 Hz magnetisation curves

The curves show the exciting force (m.m.f.) in r.m.s. AT/cm (ampere-turns per cm length of magnetic path) against peak flux density *Bmax* in tesla of net-sectional core area. It will be seen that at low flux densities (a) has the lowest permeability and *(c)* the highest permeability, whereas *(b)* comes in between but has an outstandingly high permeability at high flux densities. A characteristic lying between those of the individual materials can be obtained by building composite cores of two or more materials.

The core maximum flux density B_{max} can be calculated from the fundamental transformer equation quoted below:

$$E_s = \frac{2\pi}{\sqrt{2}} * f * N_s * A_{Fe} * B_{\max} = 4.44\ N_s A_{Fe} B_{\max} f \qquad \text{(A)}$$

The secondary voltage can be determined by the following equation.

$$E_s = |R_i + Z_b| * I_s = Z_s I_s \approx Z_s I'_p \qquad \text{(B)}$$

The approximation gives a small current error of about 1%. The maximum flux density can therefore be derived as

$$B_{\max} = \frac{E_s}{4.44\, N_s A_{Fe} f} \qquad \text{(C)}$$

To calculate the performance of the CT, the following steps are followed:

- With the known maximum fault current, the secondary current can be determined using the CT ratio and assuming no saturation.
- This current multiplied by the total burden Z_S as defined by the Equation gives E_S.
- Thirdly, determine whether the CT can produce this voltage without saturation.

Three approaches are available:

- using Equation (C) above
- using CT characteristic curves
- using the CT accuracy classes

The first two approaches provide accurate data for analysis, while the third approach gives the area of operation.

- Using the formula one needs to know the cross-sectional area of the iron core, which is sometimes difficult to obtain, as well as its saturation flux density.
- CT magnetizing curves are usually plotted in secondary volts versus secondary excitation currents. For the required magnitude of secondary voltage, the degree of saturation can be seen from the curve.
- There are two standard CT classes (ANSI/IEEE): class T for which performance is not easy to calculate and so manufacturer's test curves must be used and class C for which performance can be calculated. The class designation is followed by a number indicating the secondary terminal voltage that the transformer can

deliver to a rated burden at 20 times rated secondary current without exceeding 10% ratio correction.

For relaying the voltage classes are 100, 200, 400 and 800 corresponding to standard burdens B-1, B-2, B-4, and B-8 respectively. These burdens are at 0.5 power factor. The burden numbers are in ohms, obtained by dividing the voltage rating by 20 times the rated secondary current. Thus with the 800V rating and its associated B-8 burden: 8Ω x 5A x 20 = 800V.

1.4.3 Simple Transient-State Theory

When a system fault occurs the fault current almost invariably contains a transient DC component, and for certain balanced schemes of protection it is desirable that the CTs should maintain their turns ratio under such fault conditions. Figure 1-7 shows the currents, induced e.m.f. and core flux conditions in an ideal CT with a 1/1 turns ratio, as indicated in the simplified equivalent circuit where R is the total secondary circuit resistance and L_e the exciting inductance. It will be seen that the maximum flux in the core, due principally to the need for flux to induce the transient unidirectional component of E_s, is several times the alternating flux which would be the only flux required if there were no DC component in the primary current.

It can be shown that when L_e is infinite, the maximum transient flux is governed by the degree of asymmetry of the primary current and by the primary circuit time-constant T_p, in other words, by the area shown shaded in the upper curve.

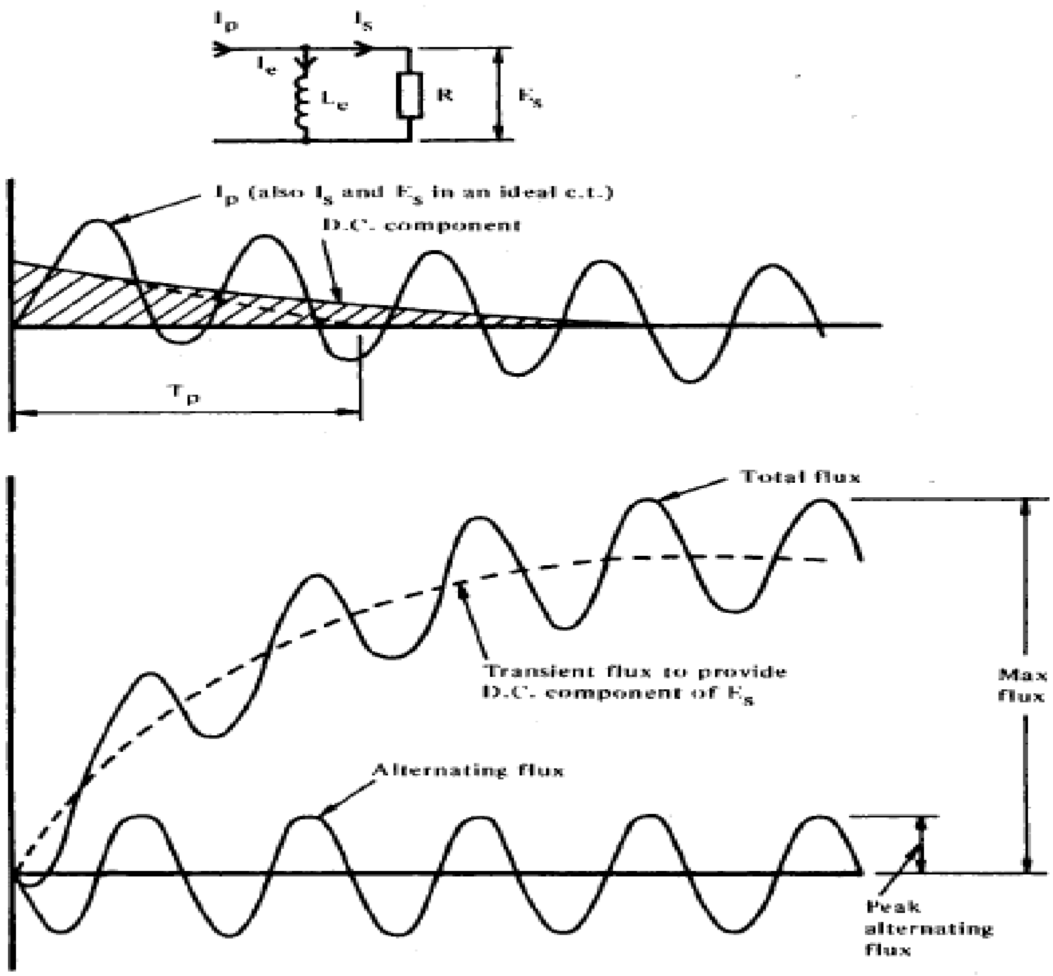


Figure 1-7. Transient current and flux conditions

With maximum asymmetry and a resistive secondary circuit, the ratio of the maximum flux to the peak alternating flux is approximately equal to the *X/R* ratio of the primary circuit, that is, of the power system up to the fault position.

However, when L_e has a finite value, as in practice, the DC component of I_s becomes less than that of I_p by the amount of the DC component of I_e. Thus the DC component of E_s and the unidirectional flux required to produce it are reduced.

For the CT to maintain accurate AC transformation under such conditions, its core section must be large enough to accommodate the total flux without saturation of the core material.

A practical method of determining the required core section is to calculate the secondary e.m.f. corresponding to the steady-state maximum fault current and to multiply this e.m.f. by the system *X/R* ratio to give the required knee-point e.m.f. of the

CT. A total flux excursion corresponding to a knee-point e.m.f. derived in this way is in practice not attained because

- (a) the maximum theoretical magnitude of DC component of the fault current is never attained
- (b) as already explained, the DC component of exciting current reduces the flux excursion, sometimes by as much as 50% and
- (c) the inductive component of the secondary burden requires no unidirectional e.m.f.

However, the upward swing of the total flux may, in unfavourable circumstances, commence from a remanent flux due to previous magnetisation, thus reducing the flux excursion which the core can accommodate without saturating.

This possibility prevents the designer from reducing the core section to take advantage of the factors *(a), (b) and (c)* above.

The effect of saturation in a CT with insufficient core section is shown in Figure 1-8.

The flux reaches the saturation region during one of the positive excursions of primary current and the saturated exciting inductance *Le* shunts most of the primary current, thus distorting the secondary current I_s to the wave shape shown.

During the negative excursions of current, however, the flux is required to reduce and so the core becomes unsaturated during this negative current and for part of the following positive current excursion before becoming saturated once more, and so on. As the DC component of the primary current decays the negative excursions of the current and flux become greater, and the core eventually runs out of saturation during the complete cycle, when the secondary current becomes normal again.

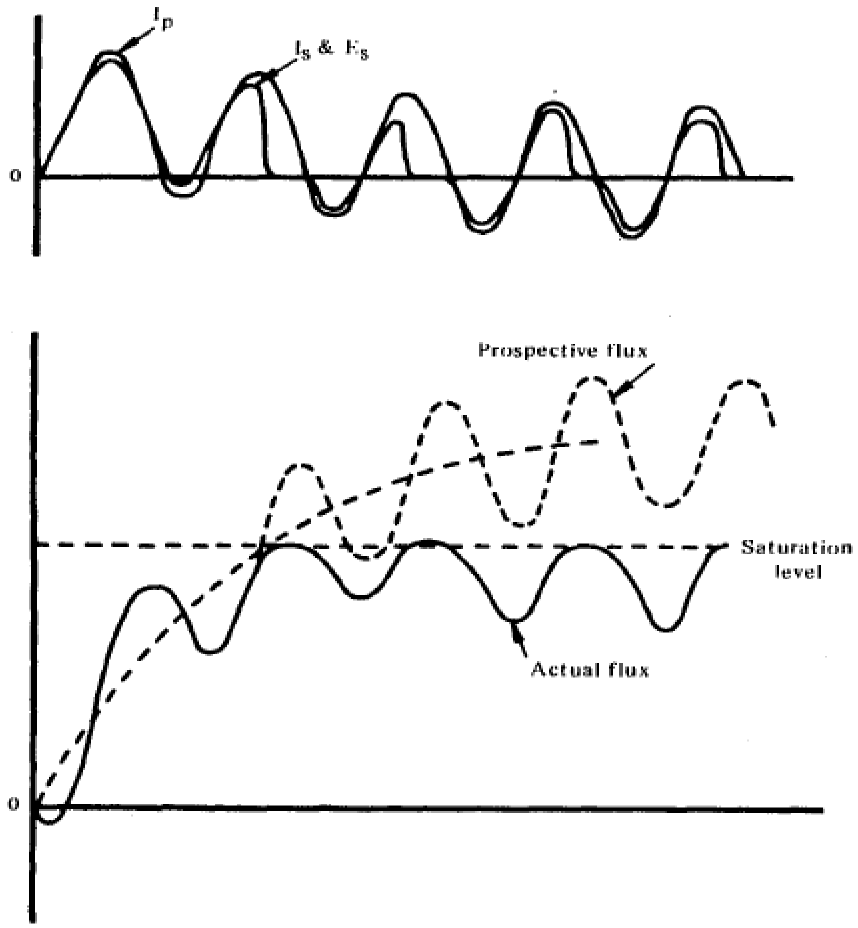


Figure 1-8. Effect of core saturation on flux and secondary e.m.f. and current

1.4.4 Overcurrent Factor

Metering cores feed instruments and meters and must therefore have high accuracy under normal system conditions. During short circuit however, the secondary current must be reduced to prevent damage to the connected instruments. The metering core must therefore be dimensioned to saturate early. For relay cores however, the CT is required to have a high degree of accuracy even for the high short circuit currents that can occur in the primary system. Overcurrent factor is used to state how the CT core is dimensioned with respect to saturation. Overcurrent factor gives the multiple of the primary rated current that drives the CT core to saturation point when rated burden is connected at the secondary.

The overcurrent factor is defined as

F_S = instrument security factor (rated overcurrent factor for metering cores)

ALF = accuracy limit factor (rated overcurrent factor for relay cores)

1.4.4.1 Overcurrent Factor for Metering Cores

At $I_p = F_s.I_{pn}$ the norms require that the current error should be at least 10% when rated burden is connected to the secondary terminal. Neglecting winding resistance, we get

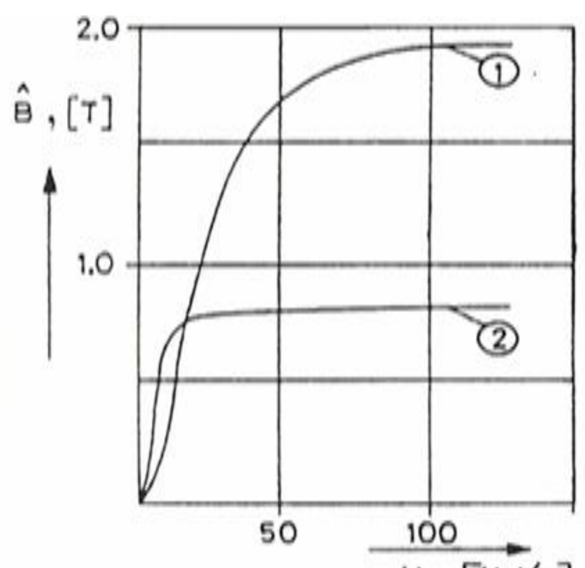
$$F_s \approx \frac{4.44 A_{Fe} B_m f (I_{pn} N_{pn})}{0.9S}$$

S = actual loading in VA.

Overcurrent factor is proportional to the core cross section, saturation flux density and ampere winding, but inversely proportional to the connected load. For metering cores the accuracy requirement conflict with the requirement for a low overcurrent factor. For high ampere winding value i.e. $I_pN_p > 1000$, the conflicting demands do not pose a problem. The wish for a low overcurrent factor, for a given core quality, set an upper boundary for the core cross sectional area. We may therefore have to either reduce the CT rating or use a better core material to satisfy the requirement on accuracy.

It is therefore important at low ampere winding to choose the least possible rating. If the actual burden is lower than that specified, the overcurrent factor will increase by the same proportion. When the actual load is lower than the rated load one may have to connect an extra load in series with the actual load at the secondary terminal to lower the F_s.

From the above discussion, we can see that for a given overcurrent factor, a CT with a Mumetal core will have a better accuracy than one with an oriented steel core. Figure 1-9 shows the magnetizing curves for Mumetal and oriented steel core. Mumetal is more expensive and it is therefore used only when an oriented core cannot satisfy the requirements.



(1) grain oriented steel

(2) Mumetal

Figure 1-9. Magnetising curves for grain oriented electrical steel and Mumetal cores

1.4.4.2 Overcurrent Factor for Relay Cores

The definition of overcurrent factor involves the composite error

$$\varepsilon_c = \frac{100}{I_p}\sqrt{\frac{1}{T}\int_o^T \left(K_n i_s - i_p\right)^2 dt} \qquad (\%)$$

This is actually the rms value of the magnetising current stated in percentage.

$$\varepsilon_c = \frac{I_o}{I_p} * 100 \qquad (\%)$$

There are two classes of relay cores namely 5P and 10P (IEC). The requirement is that the composite error shall be maximum 5% (10%) for 5P (10P) cores at $I_p = I_{pn}.(ALF)$, with rated burden connected to the secondary winding. The composite error takes care of current error, angular displacement and distortion. The composite error requirement for a relay core is because the secondary current must be a guaranteed image of the primary currents with respect to amplitude and curve form.

With similar assumptions as in the case of the metering core we have

$$ALF \approx \frac{4.44 A_{Fe} B_m f \left(I_{pn} N_{pn}\right)}{S}$$

For the relay core, the accuracy and the overcurrent factor requirements are not in conflict with each other. For a relay core one wishes that the overcurrent factor shall be higher than a given value. This can be achieved by increasing the cross section of the core. When the cross section is increased the transformation error reduces. Therefore a relay core usually has very high accuracy under normal system conditions even without winding turns correction.

Overcurrent factor is proportional to the saturation induction. From Figure 1-9 grain oriented electrical steel has a much higher saturation induction than Mumetal, therefore oriented steel are used exclusively for relay cores.

1.4.5 IEC Standard Accuracy Classes

The International Electrotechnical Commission (IEC) specifies the accuracy of CT as for example:

15 VA Class 10 P 20

Where "15" represents the continuous VA burden

"10" represents the accuracy class

"P" stands for protection

"20" represents the accuracy limit factor

Thus for such a 15VA burden CT rated at 5A, the $VA/load$ is 15/5 = 3V, and will have no more than 10% error up to 20 x 3 = 60V secondary.

For a CT designated *30 VA Class 10 P 30*, the $VA/load$ is 30/5 = 6V, and will have no more than 10% error up to 6 x 30 = 180 V secondary.

The permissible burden for such a relay is $Z_b = \frac{VA}{I^2} = \frac{30}{5^2} = \underline{1.2\,\Omega}$

1.4.6 The CT Secondary Voltage at Open Secondary Circuit

When the secondary of a CT is opened the amplitude of the secondary voltage can become several tens of kV. When the secondary winding is opened, the primary ampere winding cannot be balanced and the whole primary current becomes magnetizing current. The core therefore becomes highly saturated for practically the whole half period and the voltage becomes moderate.

The flux will however change rapidly from saturation in one direction to saturation in the other direction. The flux change per unit time will be very high as the current becomes zero and the amplitude of the secondary voltage becomes very high. The secondary voltage becomes highly deformed with one spike voltage per half period as shown in Figure 1-10 below.

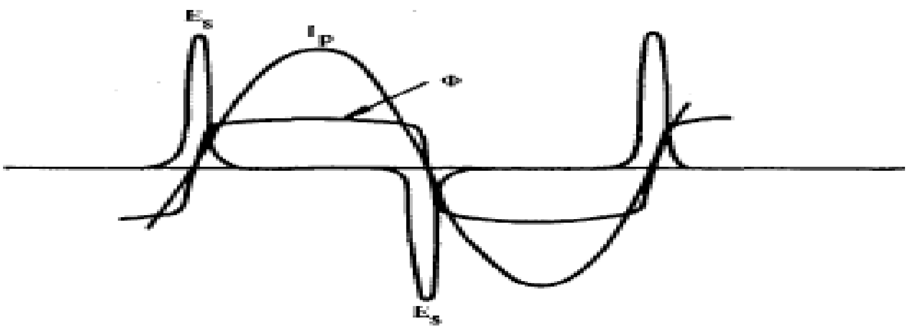


Figure 1-10. CT secondary voltage during open circuit

The voltage spikes can reach dangerously high (fatal) amplitudes and can also damage insulations. One should therefore never use fuses in the secondary circuits of a CT or open the secondary of a CT.

1.5 The Voltage Transformer

1.5.1 Equivalent Circuit and Phasor Diagram

The ideal voltage transformer is similar to a transformer with an open secondary. The primary voltage can be viewed as a constant voltage source. In practical constructions the primary and secondary windings are always wound concentrically around each other to minimize the leakage reactance.

For an ideal transformer

$$\frac{U_p}{U_s} = \frac{N_p}{N_s}$$

(Neglecting voltage drop due to the magnetizing current)

The transformation ratio however deviates from the rated ratio since we need a magnetising current in the primary winding and this leads to a voltage drop in the winding. When the PT is loaded with relays, instruments, meters and connecting cables the load current causes further voltage drops in both the primary and secondary windings. The total voltage drop can be divided into an open circuit voltage drop and a load voltage drop. The schematic diagram of the PT is shown in Figure 1-11.

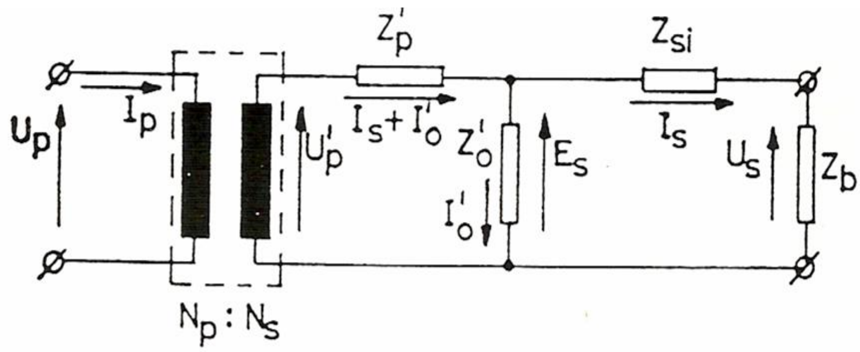


Figure 1-11. Schematic diagram of a PT

The primary impedances are referred to the secondary side. The leakage reactance X_l is divided between the primary and secondary windings. For our example we shall ascribe a leakage reactance of $\frac{3}{4}X_l$ to the primary winding and $\frac{1}{4}X_l$ to the secondary winding.

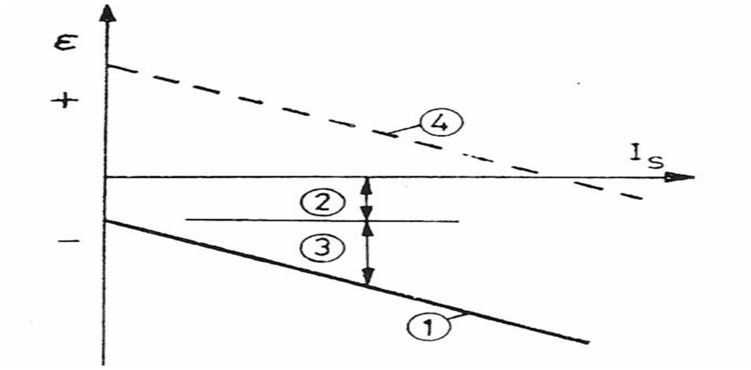
1.5.2 The VT Transformation Error

The transformation error is defined as

$$\varepsilon = \frac{U_s - U'_p}{U'_p} * 100 \qquad (\%)$$

1.5.3 Factors That Affect a VT'S Transformation Error

In a given transformer the flux density will depend only on the voltage. The transformation error will therefore be proportional to the load when the primary voltage remains constant. This is shown below in Figure 1-12.



(1) error curve without correction
(2) open circuit voltage drop
(3) load voltage drop
(4) error curve after winding correction

Figure 1-12. Voltage transformation error at constant primary voltage

The line labelled (1) shows the uncorrected situation where the transformation error is negative. The primary winding will usually consist of 10,000 turns or more. Winding correction is therefore carried out at the primary side. The whole fault curve is lifted up with winding correction as shown by the dashed line.

The open circuit voltage drop is reduced by

- Using thick wires for the primary winding => low R_p
- Reducing the flux density => low I_o
- Reducing leakage reactance

These requirements conflict each other, and one must further make sure that the voltage per turn in the high voltage winding does not become too high. As a compromise, cores with large cross sections are usually used. The induction is held under 0.9T; saturation does therefore not occur at $1.9U_{pn}$. At a flux density below 1T the magnetizing current is low and the number of turns moderate.

To keep the load voltage drop low one must use thick thread for the secondary winding. The ability to carry load could then be high even with low rated burden. The ability to carry load will however be limited by the rated thermal current that has been specified for the secondary winding.

The transformation error depends very little on the voltage. The relative load voltage drop is constant and independent of the voltage because I_s/U'_p is almost constant. The open circuit voltage drop will vary with the voltage according to the core's magnetizing curve but the dependency is low. In the neighbourhood of the rated voltage the error curve will be quite flat.

1.5.4 The VT's Short Circuit Ability

Since a VT must, as an accuracy requirement, be constructed with a very low reactance, the short circuit current is very high. The norms demand that the transformer must tolerate a full short circuit current for only 1s. A VT must therefore always be protected with fuses at the secondary side and the protection must be placed as close to the VT as possible. The short circuit current is low at the primary side. When one uses high voltage fuses at the primary side of the VT it is only to protect the network from a fault within the VT itself.

1.5.5 Transformation Errors - IEC Requirements

The norms require that CTs shall have a guaranteed accuracy when the primary current is held within a specified range of the rated current. The burden can be anything from 25 - 100% of rated burden.

The burden is inductive with a power factor, $cos\varphi_b = 0.8$. The errors shall not be higher than the values specified in Tables 1-1 below.

Class	$\pm\varepsilon_{max}$ (% of calculated value)				$\pm v_{max}$ (centiradians)			
	0.05I							

Class	$\pm\varepsilon_{max}$ (% of calculated value)				$\pm v_{max}$ (centiradians)			
	$\boldsymbol{0.05I_{pn}}$	$\boldsymbol{0.2I_{pn}}$	$\boldsymbol{1.0I_{pn}}$	$\boldsymbol{1.2I_{pn}}$	$\boldsymbol{0.05I_{pn}}$	$\boldsymbol{0.2I_{pn}}$	$\boldsymbol{1.0I_{pn}}$	$\boldsymbol{1.2I_{pn}}$
0.1	0.40	0.20	0.10	0.10	0.45	0.24	0.15	0.15
0.2	0.75	0.35	0.20	0.20	0.90	0.45	0.30	0.30
0.5	1.50	0.75	0.50	0.50	2.70	1.35	0.90	0.90
1.0	3.00	1.50	1.00	1.00	5.40	2.70	1.80	1.80

Table 1-1. IEC's transformation error requirements for Class 0.1-1.0 metering CTs

For Class 3 and Class 5 metering CTs there are no phase displacement requirements but the burden shall be between 50 and 100%.

Class	$\pm\varepsilon_{max}$ (% of calculated value)	
	$0.5I_{pn}$	$1.2I_{pn}$
3	3	3
5	5	5

Table 1-2. IEC current error requirements for Class 3 and Class 5 metering CTs

For protection cores the burden shall be the rated burden.

Class	$\pm\varepsilon_{max}$ (% of calculated value)	$\pm v_{max}$ (centiradians)
	$\boldsymbol{1.0I_{pn}}$	$\boldsymbol{1.0I_{pn}}$
5P	1	1.8
10P	3	-

Table 1-3. IEC transformation error requirements for Class 5P and Class 10P protection CTs

Metering cores of Class 0.2 and Class 0.5 with 5A rated secondary current can have a widened range down to 1% rated current.

The classes are then termed Class 0.2S and Class 0.5S. The burden can be between 25 and 100% of rated burden.

Class	$\pm\varepsilon_{max}$ (% of calculated value)					$\pm v_{max}$ (centiradians)				
	$\boldsymbol{0.01I_{pn}}$	$\boldsymbol{0.05I_{pn}}$	$\boldsymbol{0.2I_{pn}}$	$\boldsymbol{1.0I_{pn}}$	$\boldsymbol{1.2I_{pn}}$	$\boldsymbol{0.01I_{pn}}$	$\boldsymbol{0.05I_{pn}}$	$\boldsymbol{0.2I_{pn}}$	$\boldsymbol{1.0I_{pn}}$	$\boldsymbol{1.2I_{pn}}$
0.2S	0.75	0.35	0.20	0.20	0.20	0.90	0.45	0.30	0.30	0.30

0.5S	1.50	0.75	0.50	0.50	0.50	2.70	1.35	0.90	0.90	0.90

Table 1-4. IEC transformation error requirements for Class 0.2S and Class 0.5S metering CTs

For VTs the IEC requirement is that it shall have a guaranteed accuracy when the primary voltage is between 80 – 100% of rated value. The burden can be anything between 25 - 100% of rated burden. The burden is inductive with a power factor, $cos\varphi_b$ = 0.8. The errors shall not be higher than the values specified in Tables 1-5 and 1-6 below.

Class	$\pm\varepsilon_{max}$ (% of calculated value)	$\pm\nu_{max}$ (centiradians)
0.1	0.1	0.15
0.2	0.2	0.3
0.5	0.5	0.6
1.0	1.0	1.2
3.0	3.0	-

Table 1-5. IEC transformation error requirements for metering VTs

If the VT have two cores both deemed to be continuously rated then each core must satisfy their accuracy requirements when the other core is loaded between 0 and 100% of its rated burden. There are two types of protection VTs classes (3P and 5P) - IEC. The secondary burden shall be between 25 and 100% of rated burden.

Class	$\pm\varepsilon_{max}$ (% of calculated value)		$\pm\nu_{max}$ (centiradians)	
	$0.05U_{pn}$	$f_n\,U_{pn}$	$0.05U_{pn}$	$f_n\,U_{pn}$
3P	3.0	3.0	3.5	3.5
5P	6.0	6.0	7.0	7.0

Table 1-6. IEC transformation error requirements for protection VTs

f_n is termed voltage factor. For an effectively earthed system, f_n = 1.5 with a permissible duration of 30s.

M02 – ENERGY METERS AND 3 PHASE

2.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of power measurement

- Identify STAR and DELTA Connection, Three Phase Power

2.2 Introduction

In a three phase power system, the generator windings are placed 120^0 apart electrically. This arrangement allows a constant power at the output of the generator terminals. Each winding has 2 ends i.e. start and finish and all brought out to the terminal box of the generator. This provides the flexibility to either connect the terminals in two main configurations onto the bus. STAR or WYE and DELTA.

2.3 Star and Delta Connection

In Star connection the ‘start ‘end or ‘finish’ end of the winding is shorted or joined together and a common cable brought out to have a fourth wire. Each phase of the terminal is explicitly labeled A B C or R Y B or L1 L2 L3 and N called neutral.

In Delta connection the ‘finish’ of the next winding is connected to the start of the previous winding to form a series arrangement shaped like triangle but no fourth cable. The terminals are also labeled clearly as A B C or R Y B or L1 L2 L3 etc. with no fourth cable for this arrangement.

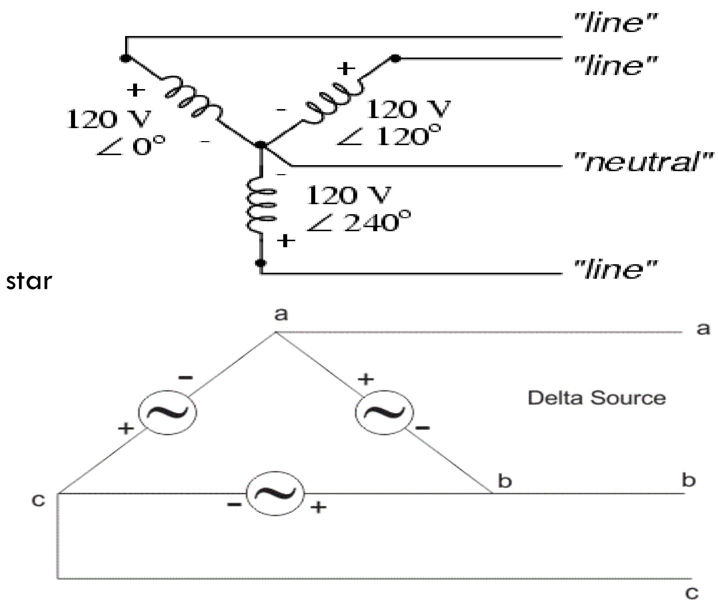


Figure 2-1. Star and Delta Connection

2.4 Voltage and Current Relationship Between Star and Delta

In Star the phase current (I phase) is equal to line current (I line) and phase voltage (V phase) is equal to (V line)/1.732 or square root of 3. This is due to the fact that the windings are electrically placed 120^0 apart.

In Delta the phase voltage (V phase) is equal to the line voltage (V line) and the phase current (I phase) is equal to line current (I Line/1.732) or square root of 3 as explained above.

2.5 Power Measurement

Power is defined as the ability to do work and measured in Watts (W). We use electric power to do many useful work such as heating, cleaning and lighting etc. To measure electric power, two quantities are needed i.e. current flowing through the load and the voltage applied across the load. Power = (I*V) Watts.

However, in some circuits such as inductive loads the current and the voltage do not reach their maximum values at the same time, i.e. they are not in phase with each other, the current delays or (lag) for some time before reaching the maximum and so there is an angle or phase displacement (ϕ) between the voltage and the current.

The cosine value of this phase angle is called power factor. Therefore, Power measured in such circuits is equal to P = (I*V*Cos ϕ) Watts.

2.6 Three Phase Power Measurement

If the applied load is well balanced, the total power for the three phases will be P = (3IVCos ϕ). This also bring another interesting point of power triangle which must be looked into briefly. One arm of the power triangle is called Active or True power, the second one is called Reactive power lastly, Apparent power.

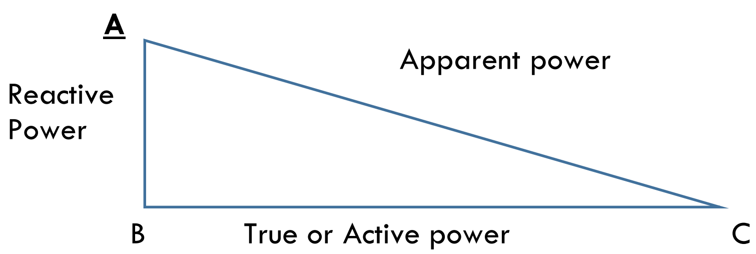


Figure 2-2. Three Phase Power

Active power developed in a three phase system P= 1.732* V*I*Cos ϕ where ϕ is the phase angle between the current and the applied voltage.

Reactive power in a three phase system VAR = 1.732*V*I*Sin ϕ

Apparent power in a three phase system VA = 1.732*V*I power factor dropped.

KVA= KW/Cos ϕ, or square root of the sum of the squares of kW and Kvar or

$\sqrt{(kw^2+kvar^2)}$

Cos ϕ = KW/kVA.

Power in Star or Delta Connection,

$P = 3 \times V_{PH} \times I_{PH} \times \cos\Phi$ or

$P = \sqrt{3} \times V_L \times I_L \times \cos\Phi$

2.7 Methods of Three Phase Power Measurement

Three phase power can be measured using one of the 3 or more different methods depending on the circuit loading conditions.

- By the use of one single phase Watt meter for well-balanced loads.
- By the use of 3 separate Watt meters for both balanced and unbalanced loads.
- 2-element Watt meter.

One single phase Watt meter method

For a well-balanced loads one single phase watt meter can be used to measure a three phase power

The total of the three phase load will be 3*Watt meter reading

when load 1=load 2=load 3.

Three Watt meter method

Three phase power can be measured using 3 individual watt meters where each meter is used to measure the phase power. This can be applied on both balanced and unbalanced loads. The total power will be W1+W2+W3 readings.

The currents and voltages in W1, W2 and W3 are (IR* VRN), (IY*VYN) and (IB* VBN) respectively.

Therefore W1+W2+W3 = (IR x VRN x Cos ϕ 1) + (IYx VYN x Cos ϕ 2) +

(IB x VBN x Cos ϕ 3)

For a balanced load conditions,

VRN = VYN = VBN = *V*, and IR = IY = IB = *I*, and

Cos ϕ 1 = Cos ϕ 2 = Cos ϕ 3 = *Cos ϕ*

then using the italic notation total power (P) = *I* x *V* x *Cos ϕ* Watts.

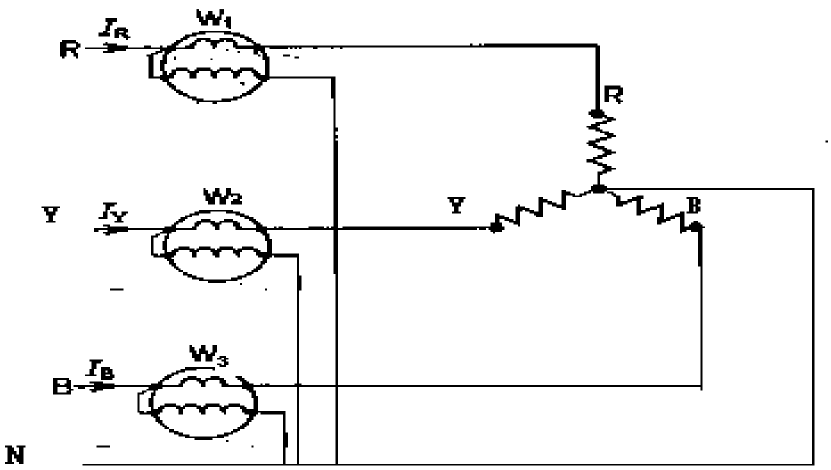


Figure 2-3. 3 element wattmeter analog

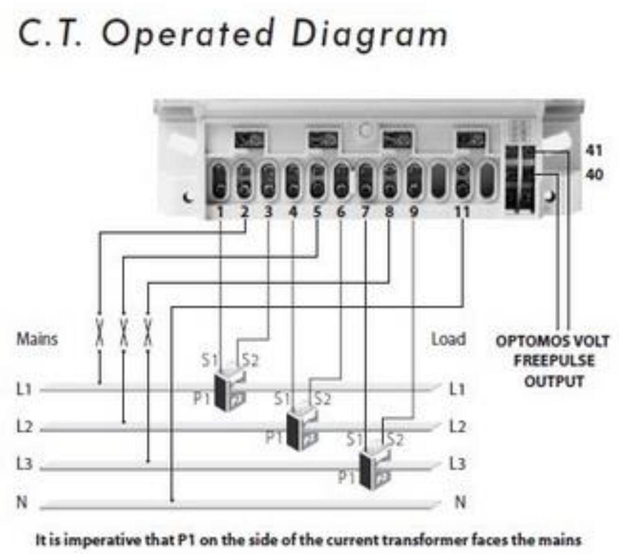


Figure 2-4. digital 3 element meter showing current coils

The electronic solid state meter (unlike the disk-type meter which measures the RMS values) measures instantaneous values of voltage and current, and carries out complex calculations within microseconds. This process is known as digital sampling and quantization of the sinusoidal waveform.

For example a sampling electronic meter measures instantaneous values of current and voltage at approximately 1.4 millisecond intervals. This is equal to 14 samples/cycle in a 50Hz signal wave. The above method of measurement is widely used in the GRIDCo network. Thus all GRIDCo and VRA feeders use the three watt meter method of power measurement

Two Watt meter method

This can also be used in both balanced and unbalanced loads and in circuits where the load current is expected to be high as in delta connected loads

The current in wattmeter W_1 is I_R and the potential is V_{RY}.

In W_2 the current is I_B and the potential is V_{BY}.

The phasor diagram shows that the phasor V_{RY} leads V_R by 30° and

V_{BY} lags 30° behind V_B.

If the load power-factor is cosϕ lagging, then the phase angle between the current and voltage in W_1 is 30 +ϕ, and in W_2 is 30 - ϕ.

Two Watt meter method is sometimes used on industry feeders getting it's supply from Electricity Company of Ghana, (ECG)

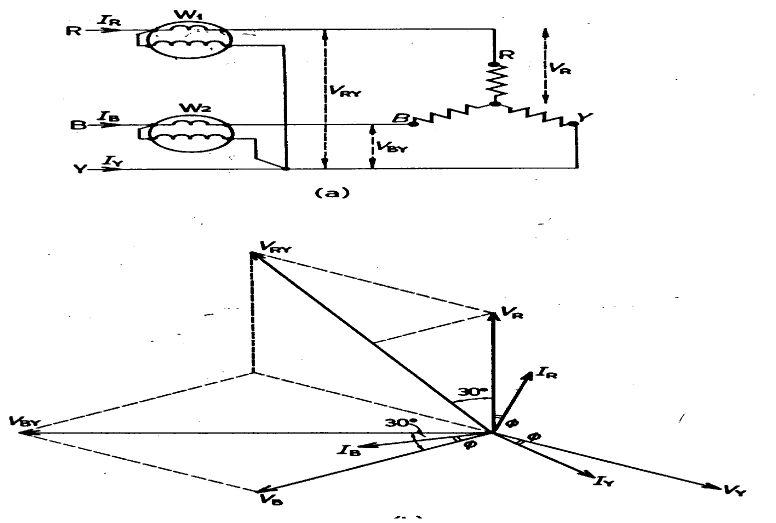


Figure 2-5. 2-element Watt meter with phasor diagram

2.8 Energy Measurement Analog

Energy is the ability to do work or product of power and time usually in hours. This is the amount of power used continuously in one hour, measured in kWh 1 unit of electrical energy.

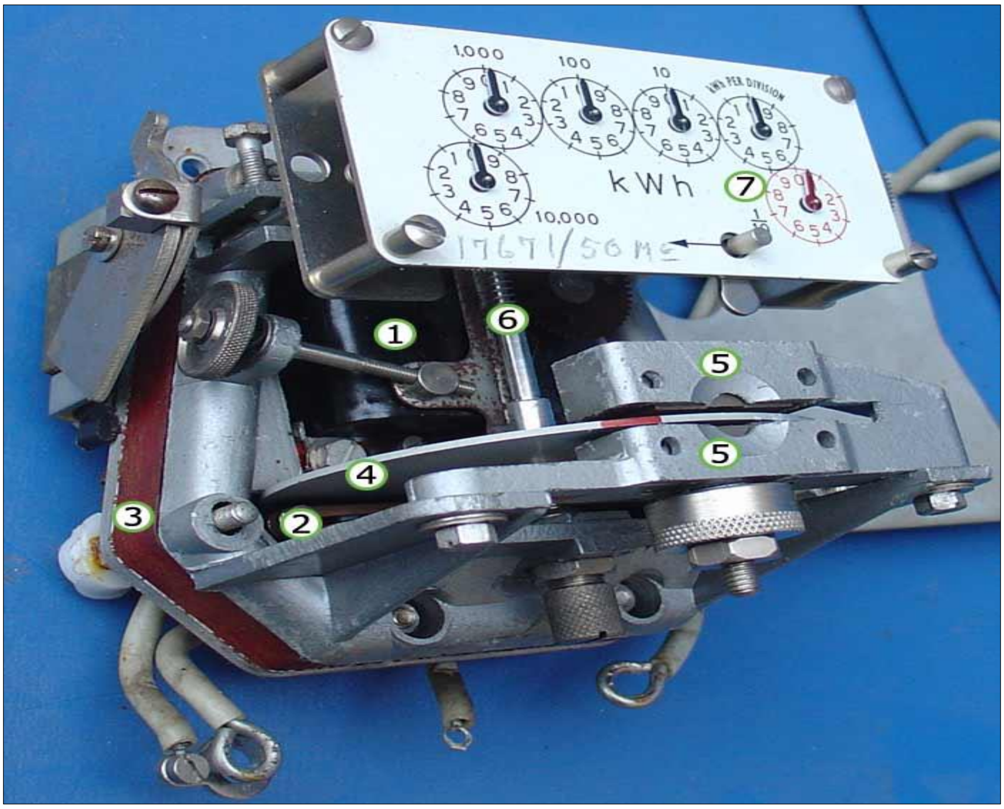


Figure 2-6. Analog Meter

Mechanism of electro-mechanical energy meter.

- 1 - Voltage coil - many turns of fine wire encased in plastic, connected in parallel with load.
- 2 - Current coil - three turns of thick wire, connected in series with load.
- 3 – Stator concentrates and confines magnetic field.
- 4 - Aluminum rotor disc.
- 5 - Rotor brake magnets.
- 6 - Spindle with worm gear.
- 7 - Display dials - note that the 1/10, 10 and 1000 dials rotate clock-wise while the 1, 100 and 10000 dials rotate counter-clockwise.

Figure 2-7. Showing domestic analog meters.

Currently analogue meters have been phased out in the GRIDCo network. Some of these analogue meters are currently in operation in VALCo

2.9 ENERGY MEASUREMENT DIGITAL

Typical digital energy meter showing CT external terminal markings

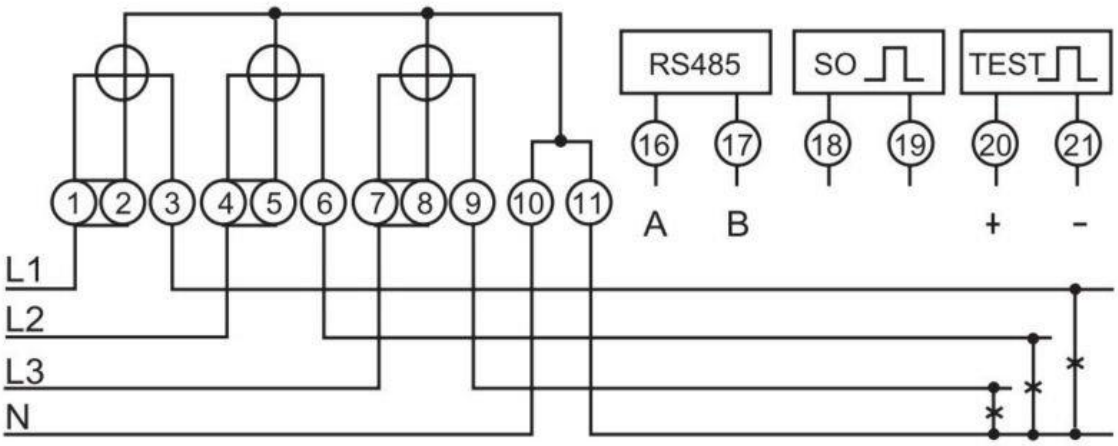


Figure 2-8. CT external Terminal

From the diagram above, the current flowing through the phase “A” or L1 is connected to terminal 1 after passing through the meter current transformer it comes out at terminal 3 before it goes to the load.

The “B” phase or L2 current is also connected to terminal 4 after flowing through the meter current transformer, it comes out at terminal 6 before it goes to the load. The “C” or L3 also at terminals 7 and 9 respectively.

Functional block diagram of digital energy meter

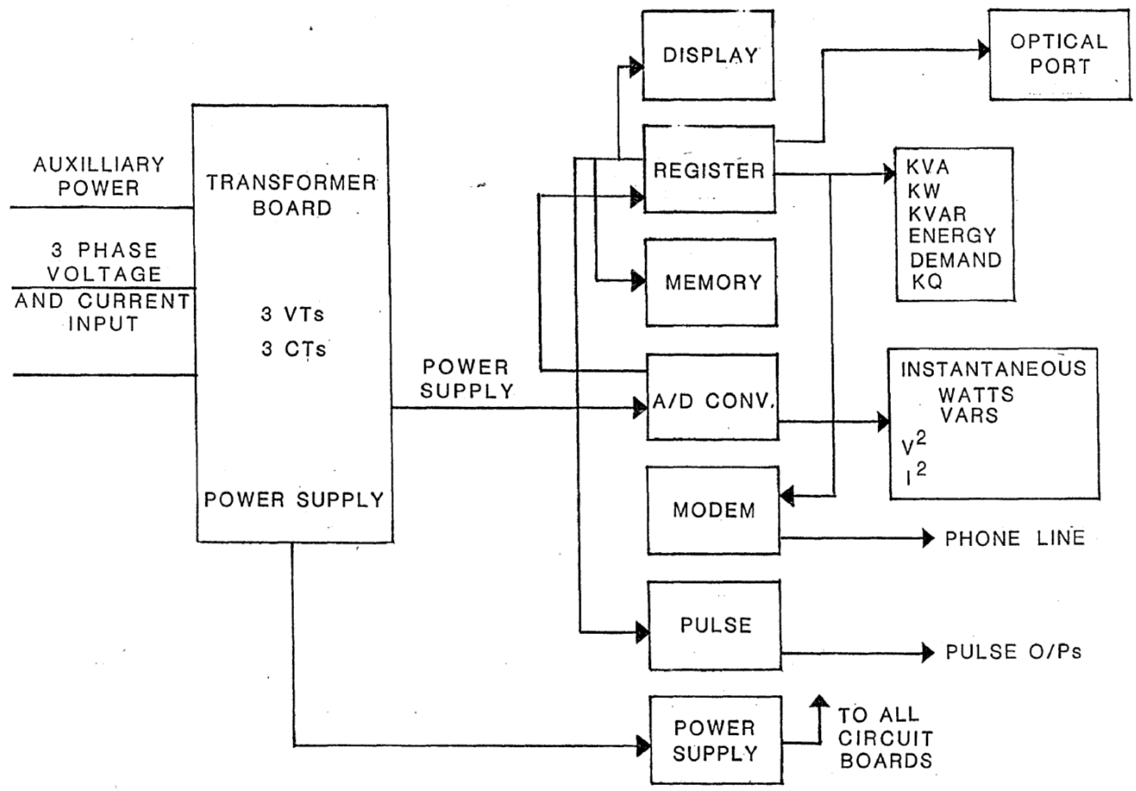


Figure 2-9. Function Block Diagram of Digital Energy Meter

The digital meter has no moving parts. All measurements are carried out by removable electronic circuit boards or modules.

The unit include a transformer module, a power supply module, an analogue to digital conversion module, a register processor module and a pulse output module.

The transformer module contains three voltage and three current transformers to reduce further the incoming signal from the main current transformer (CTS) and potential transformers (PTS).

The analogue to digital converter module has a microprocessor performs the digital sampling and calculates the instantaneous Watts and VARs, volts^2 and amps^2.These instantaneous quantities are transferred to the register microprocessor.

The register controls the whole operation of the meter and calculates the actual kVA, kW, and kVAr from the instantaneous values received. The calculated values are shown on the display module on the meter or transferred directly to a remote location or by a modem over a telephone line to a central station. The register processor module also provides the calculated information to an optical port.

Data captured by the meter remains in the memory bank and can be retrieved via the optical port. This port is also used for the parameterization (programming) of the meter.

Figure 2-10. Digital Billing meter

Advantages:

- 1. The meter is program to perform calculations that resemble either two, or three elements meter installations measurements. It does not have separate internal elements.
- 2. The meter is capable of measuring kwh or kvar flowing in either direction.
- 3. Retrieval of data and programming of the meter is possible via a front port or via a modem port and a telephone line.
- 4. The accuracy of the solid state or digital meter is very high.
  0.1% at rated load and 0.4% at 1% load.
- 5. Testing and calibration of the solid state meter is almost eliminated.
- 6. Accurately measures power and energy with harmonic distorted waveforms.

4. POWER SYSTEM PROTECTION

Ghana Grid Company Limited

M01 – BASIC CONCEPT OF POWER SYSTEM PROTECTION

1.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the fundamentals of protection for power system
- Identify the components of protective systems and relaying principles

1.2 Introduction

A power system is designed to generate sufficient quantity of electric power to meet the present and estimated future demands of the users in a particular area, to transmit it to the areas where it will be used and then distribute it within that area, on a continuous basis.

It is however difficult to meet these objective in the light of the numerous disturbances that confront power systems. The disturbances include: lightning, wind damage, trees falling across lines, vehicles colliding with towers or poles, birds shorting out lines, lines touching each other aircraft colliding with lines, vandalism, small animals entering switchgear, and line breaks due to excessive ice loading

To ensure appreciable return on the large investment in the equipment which make up the power system, pay operating personnel and to keep consumers satisfied with reliable service, the whole system must be kept in operation continuously without major breakdowns. This can be achieved in two ways:

- Implement a system adopting components, which should not fail and require minimal or no maintenance to maintain the continuity of service. By common sense, implementing such a system is neither economical nor feasible, except for small systems.
- Adopt 'normal' system components and put in place the necessary mechanism to foresee and deal with faults rapidly.

The second option of using 'normal' system components and installing protection mechanism is the economically feasible of the two and this option is what has been adopted all over the world.

1.3 Fundamentals of Protection

1.3.1 Basic Requirements of Protective Systems

A protection system or apparatus has three main functions/duties:

- Safeguard the entire system to maintain continuity of supply.
- Minimize damage and repair costs when faults occur.
- Ensure safety of personnel.

These requirements are necessary, firstly for early detection and localization of faults, and secondly for prompt removal of faulty equipment from service. In order to carry out the above duties, protection schemes must possess the following qualities:

- Selectivity: Detect and isolate faulty item only.
- Stability: Leave all healthy circuits intact to ensure continuity or supply.
- Sensitivity: Detect even the smallest fault current or system abnormality and operate correctly at its setting before the fault causes irreparable damage.
- Speed: Operate in a timely manner. The persistence of faults can result in the following:
  - ✓ Increased damage at fault location. Fault energy $= I^2 \times R_f \times t$, where t is fault duration and R_f is fault resistance.
  - ✓ Danger to the operating personnel.
  - ✓ Danger of igniting combustible gas in hazardous areas, such as methane in coal mines which could cause horrendous disaster.
  - ✓ Increased probability of earth faults spreading to healthy phases.
  - ✓ Higher mechanical and thermal stressing power plants. For example, transformer windings suffer progressive and cumulative deterioration under such stresses.
- Dependable: It must trip when called upon to do so.
- Secure: It must not trip when it is not supposed to.

1.3.2 Arc Phenomena

Electric arcs are encountered in a variety of situations in the field of electrical engineering. In some cases, the arcs are unwelcome results of lightning strikes or insulation failures, but in many cases the arcs are deliberately used, and their advantages exploited. For example, electric arcs are used for heating purposes in arc furnaces and arc welding equipment.

Electric arcs are created every time the contacts of a switch or circuit-breaker are opened in order to interrupt current – either a moderate load current or a much higher short-circuits current.

The electric arc is – with the exception of power semiconductors – the only known element that is able to change from a conducting to a non-conducting state in a sufficiently short time.

- **Creation of electric arcs**

An electric arc may be initiated either by an electric flashover between two electrodes which are carrying current, or by the separation of two current carrying contacts.

For example, when the contacts of a circuit-breaker separate, the current through the contacts will continue to flow, driven by the magnetic energy stored in the inductances of the power system.

At the last moment, just before the contacts separate, they touch each other only at a very small surface area. The resulting high current density leads to strong heating, and the contact material will melt and evaporate.

- **Static and dynamic arcs**

Electric arcs may be static or dynamic. A static arc is created practically with dc current in a circuit with a dc voltage source. The arc is created when contacts that are originally closed for current to flow in the circuit are separated from each other. When all transients have died down a stationary arc is produced.

A dynamic arc is created when the current varies with time or where the cooling of the arc varies with time. In a dynamic arc, the voltage over the arc at anytime does not only depend on the instantaneous value of the current but it also depends on the history of the arc, i.e., how much current has flown in the arc before the time of voltage measurement. This is because the conductance of the arc is highly dependent on the arc's temperature and cross-sectional area.

1.3.3 Arc Characteristics

The arc channel between two electrodes (anode and cathode) can be divided into an arc column, a cathode region and an anode region.

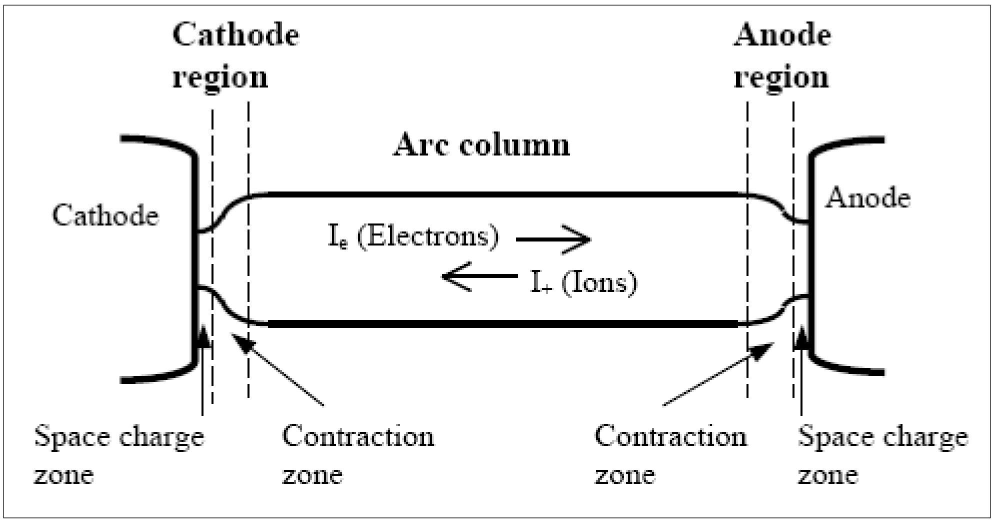


Figure 1-1. The regions of an arc channel

- **The arc column**

The temperature in the arc column is very high. At such high temperatures the gas molecules are largely dissociated into free atoms. The travel velocities of electrons and atoms are so high that ionization takes place when they collide. At the same time, there is also a recombination process where electrons and positively charged ions form neutral atoms. At thermal equilibrium, the rate of ionization is in balance with the rate of recombination. The gas is in plasma state and there is a high amount of free electrons and positive ions.

Although the arc column is strongly ionized, there is no space charge present. There is a balance between the electron charges and the positive ion charges. The electrons have much higher mobility than the positive ions. Therefore almost the entire arc current flow is due to the electrons.

- **The contact regions (anode and cathode)**

The role of the cathode, and the surrounding cathode region, is to emit the current carrying electrons into the arc column. Some electrode materials have such a high boiling temperature that significant thermionic emission of electrons starts already well below the evaporation temperature. Such materials are e.g. carbon, tungsten and molybdenum. In electrode materials with lower evaporation temperature such as copper, the major emission mechanism is field emission, where electrons are emitted due to the high electric field strength close to the surface. Close to the cathode there will be an accumulation of positive ions, arriving from the arc column. Due to this space charge, there will be high electric field strength close to the cathode surface (the cathode drop). This high field strength is essential for efficient (field) emission of electrons into the arc.

The anode mainly serves as a collector of electrons arriving from the cathode. The electrons will arrive at high speed, and deliver all their energy to the anode. The temperature at the anode surface is therefore high. Close to the anode there is a reduction in the number of positive ions, since they tend to drift away to the cathode. The greater number of electrons than positive ions leads to high electric field strength close to the anode surface (the anode drop).

- **Dynamic arcs: conditions at current zero**

In the case of AC arc current, the variation of the current leads to associated dynamic changes in the arc properties. Due to the thermal inertia of the arc plasma, the maximum temperature and stored energy during a current loop occur somewhat later than the peak value of the current. The arc temperature is still high when the current reaches zero. However, at current zero, the power supply to the arc is zero, and there is a possibility of the arc plasma cooling down and hence its disappearance. At current zero there is also the complexity of polarity change, forcing the anode and cathode to change places. When arc persists after current zero, it is attributed to the following:

(a) Thermal reignition

If the arc plasma is still sufficiently ionized at current zero, and if the new cathode emits a sufficient amount of electrons right from the beginning, then the current may pass more or less continuously through zero. The arc channel will pass through a minimum in temperature and stored energy, and then start to heat up again.

(b) Dielectric reignition

If the arc plasma at the moment of current zero is cooled such that it is only weakly ionized, then it may continue to cool down, and the current will be interrupted. However, in practice, the arc channel at current zero may still be comparatively hot and may also contain space charges, and therefore the dielectric withstand capability between the two contacts will be quite low. Due to the voltage that appears between the electrodes there may be a flashover, a new arc will be established, and the arc current starts to flow again.

1.3.4 Recovery Voltage

As soon as an arc is extinguished, a voltage commonly referred to as transient recovery voltage (TRV) builds up between the contacts. The contact system has to withstand this high voltage stress without electrical breakdown in other to sustain the extinguishing of the arc.

Transient recovery voltage is the voltage that appears across current carrying contacts, after current interruption. It is a critical parameter for successful fault interruption. Its characteristics (amplitude and rate of rise) can lead either to a successful current interruption or to a failure (reignition or restrike).

TRV is dependent on the characteristics of the system connected on both terminals of the contacts, and on the type of fault that has to be interrupted (single, double or three-phase faults, grounded or ungrounded fault). The characteristics of the connected system include:

- type of neutral (impedance grounded, ungrounded, solidly grounded, etc.)
- type of load (capacitive, inductive or resistive)
- type of connection (cable or overhead conductor).

The dielectric strength in the space between contacts must build up faster than the TRV for the arc not to re-strike.

1.3.5 DC and AC Arc Interruption

There are two methods by which electric arcs are extinguished. These are: High resistance interruption and Low resistance (or Zero point) interruption.

1.3.5.1 High Resistance Interruption

In this method, arc resistance is made to increase with time so that the current becomes insufficient to maintain the arc (in other words, the voltage drop across it increases to such an extent that the system voltage cannot sustain the arc).

Arc resistance can be increased by:

- Lengthening the arc: Arc resistance is directly proportional to length of arc so to increase resistance, separation between the contacts is increased.

- Cooling the arc: Cooling helps in deionization of arc medium thus increasing arc resistance.
- Reducing cross-section of the arc: When cross-sectional area of arc is reduced, the arc resistance is increased. Allowing the arc to pass through narrow opening can reduce cross-sectional area.
- Splitting the arc: The resistance can be increased by splitting the arc into a number of smaller arcs in series. Each arc experiences the effect of lengthening and cooling. Arc may be split by introducing some conducting plates between the contacts.

Disadvantage of this method is that enormous energy is dissipated in the arc. Hence, high resistance interruption is employed only in dc circuit breakers and low capacity ac circuit breakers.

1.3.5.2 Low Resistance or Zero Point Extinction

This method is employed for arc extinction in ac circuits only. In this method, the arc resistance is maintained low till current zero, during which arc extinguishes naturally and is prevented from restriking (by increasing the dielectric strength of the arc medium) in spite of rising voltage across the contacts.

In ac systems, current drops to zero after every half cycle, during which the arc extinguishes for a brief moment. As already explained, the recovery voltage which will appear across the contacts coupled with the already weak dielectric medium can cause a restrike of the arc. Hence at current zero, the space between contacts which is ionized is deionised so as to prevent a restrike of arc. Deionization is achieved by increasing the dielectric strength on the insulating medium. This can be achieved by employing the following methods.

- Lengthening of the gap: Dielectric strength is directly proportional to length of gap between contacts. So by opening contacts rapidly, dielectric strength can be achieved.
- Increasing the pressure of medium: When pressure increases, density of particles increases, which causes high rate of deionization and hence increases dielectric strength of medium.

- Cooling: Natural recombination of ions occurs rapidly when they are cooled. Therefore cooling the arc can increase dielectric strength.
- Blast effect: If ionized particles are swept away and replaced by unionized particles dielectric strength can be increased. It can be achieved by gas blast directed along the discharge or by forcing oil into the contact space.

1.4 Components Of Protective Systems

1.4.1 Fuses

1.4.1.1 Operating Principle

A fuse acts as both a protective and a disconnecting device (it combines the functions of sensing, comparing and interrupting current). It is the simplest and cheapest form of protection against excessive current. A fuse consists of a metallic element which melts (ruptures) and becomes discontinuous at a relatively high current, thus preventing the further passage of current. It must however, permit the maximum load current to flow continuously without operating or deteriorating. Fuses have the following advantages and disadvantages:

(a) **Advantages**

- Fuses are simple to use.
- Fuses are direct acting.
- Fuses are cheap.
- They do not fail.
- They are very fast at high currents.
- Their operating characteristics can be graded.

(b) **Disadvantages**

- Fuses require replacement after every operation.
- Fuses offer poor protection against low fault currents.
- They are non-directional.
- They have limited voltage breaking capabilities.

1.4.1.2 Fuse Characteristics

- **Rated current:** This is the current that the fuse can carry continuously without damage

- (rupture) or degradation.
- **Minimum fusing current:** This is the minimum current which will cause the fuse to rupture in an 'infinite time'. For a round wire, the appropriate value for fusing current is given by $I = kd^{\frac{3}{2}}$, where k is a constant which depends on the fusible material and d is the diameter of the wire. The value of k for a give d(in cm) are as follows: Copper – 2530, Aluminium – 1870, Tin – 405.5 and Lead – 340.6.
- **Fusing factor:** It is the ratio of the minimum fusing current to the rated current.
- **Minimum breaking current:** It is that current that the manufacturer will guarantee will cause the fuse element to rupture in a 'reasonable time'.
- **Prospective current:** It is the current that will flow through the fuse should the link of the fuse be replaced by zero impedance.
- **Cut-off Current:** The fault current normally has a very large first loop, but the fuse ruptures well before the peak of its loop is reached. The cut-off current is the maximum value actually reached.
- **Pre-arcing time:** It is the interval of time between the beginning of a current large enough to cause a break in the fuse element(s) and the instant when an arc is initiated.
- **Arcing time:** It is the time between the instant of the initiation of an arc to the instant of first arc extinction.
- **Total Operating (or clearing) time**: This is the sum of pre-arching and arcing time.
- The operating time of a fuse is generally quite low (say 0.002sec.) as compared to a circuit breaker (2 or 3 cycles).
- **Let through capacity**(I^2t): It is the amount of energy that the fuse will require before it melts.
- **Pre-arcing I^2t (or melting I^2t):** It is time integral of the square of current passing through the fuse element in pre-arcing time. It is a measure of heating effect in the pre-arcing time.
- **Arcing I^2t I^2t :** It is time integral of the square of current passing through the fuse element in the arcing time.

- **Clearing I^2t or Total I^2t :** The sum of pre-arcing I^2t and arcing I^2t . The various I^2t's and time/current characteristics are required to ensure coordination between fuses or protective devices. They are also required for effective back up protection.
- **Breaking Capacity of fuse:** The rms value of the maximum prospective current that the fuse can clear.

The operating time due to fault current can be of the order of one half-cycle. The fault current is thus cut off by operation of the fuse before the current reaches the maximum prospective value (figure 1-2).

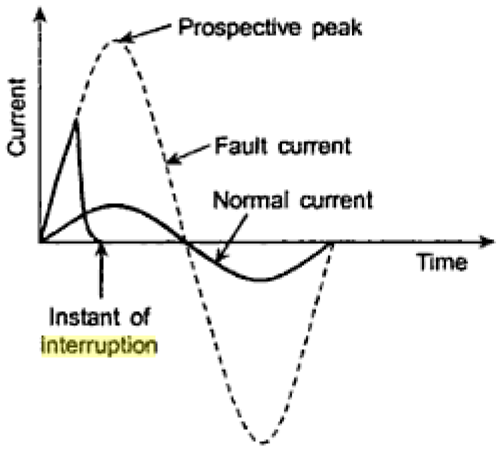


Figure 1- 2. Short-circuit current interrupted by a fuse

Depending on the fault current, the operating time can, however, take some seconds to clear the fault. By suitable design and use of various metallic elements and filler materials (material around the fuse element), different time/current characteristics can be achieved to aid discrimination with other fusses or protective devices. A fuse rating should be selected basically to provide fault protection, rather than overload protection.

1.4.1.3 Types of Fuses

Generally, a fuse has three parts namely: the fuse link (wire), fuse carrier and fuse base. Fuses may be grouped into low voltage fuses and high voltage fuses.

(a) **Low voltage fuses**

- Semi-enclosed

These are rewirable units which are widely used in distribution units. A rewirable unit comprises a removable insulating carrier which holds the fuse element. The fuse element is a finned copper wire. The cooling effect of air increases the fusing current and oxidation causes it to reduce. If accuracy in the value of the fusing current is necessary, then this fuse is most unreliable. They are made up to 500A rated current, but their breaking capacity is low. For example on 415V, circuit breaking capacity is about 4000A. Semi-enclosed fuses are cheap and easy to replace.

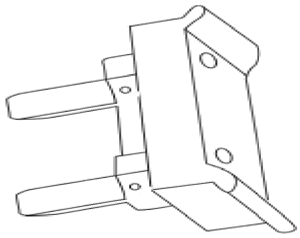


Figure 1-3. A semi-enclosed fuse

- Miniature fuses

These are widely used in equipment for low capacity protection (mainly domestic appliances). They may be filled or unfilled fuselinks.

Figure 1-4. A miniature fuse

- Cartridge fuses

The fuse element is enclosed in a cylinder of hard non combustible material having metal capped ends and is filled with non flammable powder (usually silicon oxide to help extinguish the arc). The fuse elements are made of copper or silver and can be plain strip or tape, constricted or coiled for different applications. The fuse elements may be arranged in parallel to improve heat dissipation. These fuses are generally used in industries.

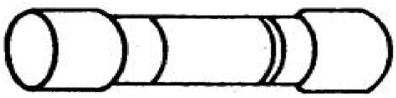


Figure 1-5. A cartridge fuse

For large current ratings and where very large currents have to be interrupted, a high rupturing or breaking capacity (HRC) fuse is used. This is a cartridge fuse in which a silver fuse element is connected between two end-contacts of a ceramic tube filled with a special quartz powder.

When the fuse ruptures, there is a fusion of the silver vapour produced with the filling powder causing globules of high resistance material to be formed in the path of the arc causing it to be extinguished. This is very reliable in performance and very fast in clearing a fault. Current ratings up to 1600A are available and some fuses can interrupt currents up to 100KA.

Figure 1-6. High rupturing capacity fuse

(b) **High voltage fuses**

The length of the fuse element increases in line with the voltage rating of the fuse. Because of this increased length, the fuse element is wound in a helix to keep the length manageable. The number of constrictions is increased to enable the fuse to support high voltage applications.

- Solid-filled fuses

These have similar construction as the low voltage HRC fuses. The material surrounding the fuse element may be sand or powdered boric acid. They are used up to 33KV with breaking capacity of about 8700A at this voltage. Ratings up to 200A at 6.6KV and 11KV and 50A at 33KV are also available.

- Liquid-filled fuses

In liquid-filled construction, the fuse link is enclosed in a tube that is filled with fire-extinguishing fluid such as carbon tetrachloride. The gas formed during arcing is inert and aids in blowing out the arc.

If the pressure becomes excessive, provision is made to have the cap on the outgoing side of the fuse blown off, preventing the rupture of the tube and containing damage to the fuse itself. They may be used in systems up to 132KV or higher. Normal current rating is up to 400A and breaking capacities of 6100A at 33KV.

- Expulsion fuses

The fuse link consists of a fuse element with a cap on one end and a flexible stranded cable on the other. The element is enclosed in an insulating tube usually of fibre. In the open-type, the tube may be made to vent at both ends by having the cap at the top made deliberately weak to blow off when high currents produce high gas pressures. Expulsion fuses have pole mounted holder with a fuse carrier which is by the fuse element.

Figure 1-7. Expulsion fuse

1.4.1.4 Determination of fuse ratings

Fuses can be employed is various sections in a network. The following points must be born in mind when selecting a fuse

- The fuse must be adequately rated to carry the rated current of the circuit.
- The rating must take into account any normal healthy overload conditions, e.g. starting of motors or the switching of capacitors. Fuse must not respond to 6 times the rated motor current for 10secs at starting.
- An allowance must be made if an overload occurs frequently.
- There must be an adequate margin if discrimination between two fuses is required.
- The fuse must protect any equipment which is not rated at the full short-circuit rating of the power system, e.g. contactors, cables and switches.

The fuse rating can be determined using the following rules:

- Rating of fuse closes to load $=1.2\times$ the maximum full load current
- Upstream fuse rating $= 2\times$downstream fuse rating

Whenever a fuse is positioned such that the two formulas can be applied to it, the higher value from the two is used as the rating of the fuse. However, the calculated rating of the fuse may not be available, when this happens; the more appropriate higher or lower fuse is chosen.

1.4.1 Circuit Breakers

1.4.2.1 Operating Mechanism and Arc Interruption

A circuit breaker is designed to protect an electrical apparatus from damage caused by overload or short-circuit. Unlike a fuse, a circuit breaker can be reset (either manually or automatically) to resume normal operation. Circuit breakers may be single-phase (single-pole) or three-phase (three-pole). A circuit breaker generally comprises the following sub-assemblies:

- Poles (set of contacts-one fixed, one moveable);
- Operating mechanism;
- Control cabinet (indoor type breaker); and
- Auxiliaries.

Operating Mechanism

The purpose of the operating mechanism is to change over the circuit breaker state from close to open, or vice versa. In closed position, sufficient pressure must hold the contacts together, overcoming all mechanical and electromagnetic force (caused by current flow).Opening must be fast, such that the operating time between the instant of the trip signal being received to the final contact separation is of the order of 0.03s (i.e.,1.5 cycles in a 50Hz system) in EHV breakers, and about 3 cycles in distribution breakers. The opening is under a relay's trip signal, which energises the CB trip coil from a battery source. The mechanical energy required for the opening operation is obtained by one of the following means:

- Spring charged during closing operation, or, in large breakers, the spring may be kept charged during closed conditions by means of an electric motor;
- Hydraulics pressure energy stored in accumulators; and
- High pressure compressed air stored in auxiliary air vessels-employed in air-blast circuit breakers.

In the first two methods, toggle mechanism or latches are employed for achieving fast operating speed during operation.

Varying types of circuit breakers exist. The type of insulation used in the arcing medium determines the name of the breaker. The medium could be oil, air, vacuum or

SF_6 (Sulphur hexaflouride). The further classification is single break and double break (figure 1-8). In a single break type only the busbar end is isolated but in a double break type, both busbar (source) and cable (load) ends are broken. However, the double break is the most common and accepted type in modern installations.

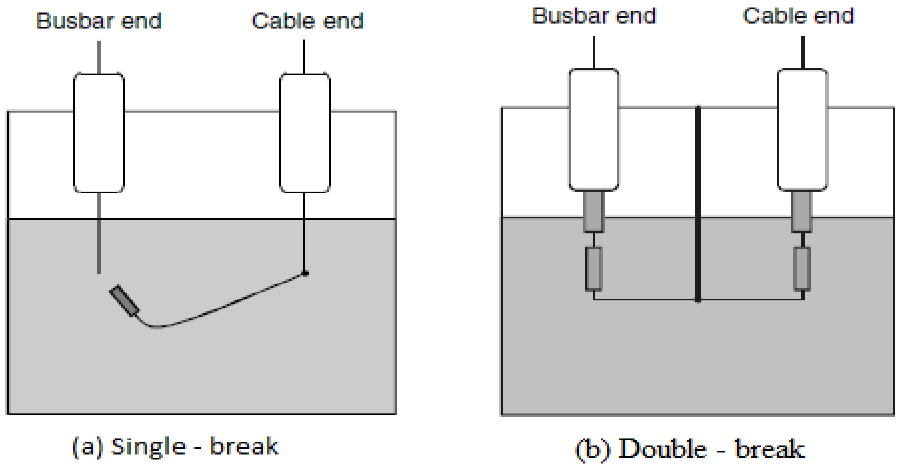


Figure 1-8. Conceptual diagram of single and double-break CBs

1.4.2.2 Air Circuit Breakers

There are two types of circuit breakers which use air as the dielectric medium. They are: Air-breaker circuit breakers and Air-blast circuit breakers.

- **Air-break circuit breakers (ACB)**

These are mostly indoor types. They are used for dc circuits up to 12 kV, and for medium and low voltage ac circuits, usually up to 6.6kV, 400-2400A and rupturing currents of 13-20kA.

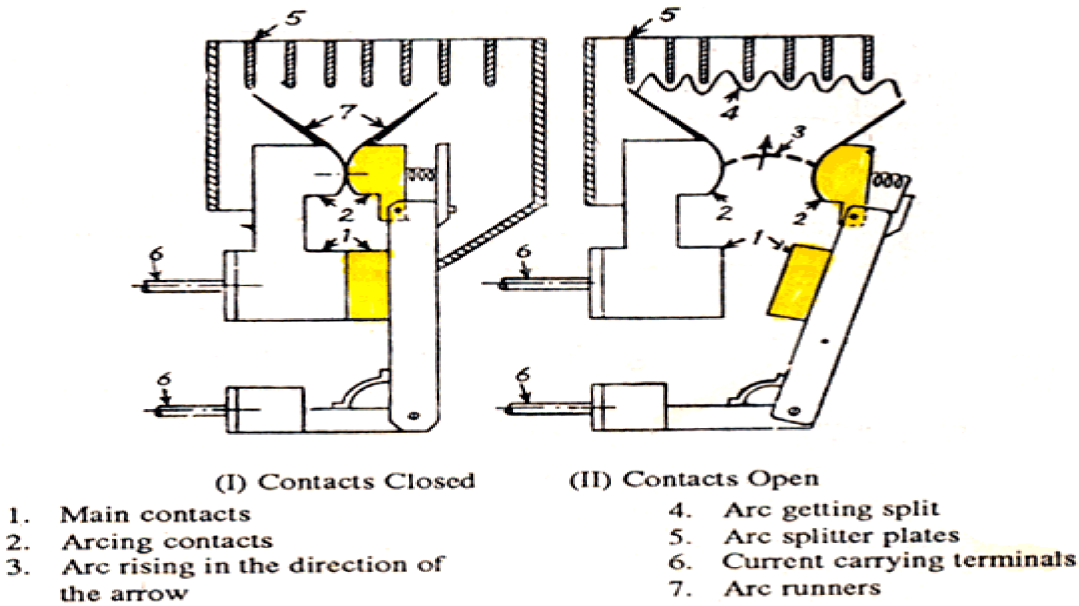


Figure 1-9. Operating principle of air-break circuit breaker

The constructional details of an ACB are shown in figure 1-9. The arc is lengthened in the breaker by the magnetic field and the arc runners, and is finally extinguished by arc splitters. There are two sets of contacts, main and arcing contacts.

The main contacts are first to dislodge while the arcing contacts are still closed under spring pressure. Thus the main contacts do not open any current and have long life. Arcing contacts made of hard copper alloy are easily replaceable.

- **Air-Blast Circuit Breakers (ABCB)**

Blast of air at high speed (supersonic) directed at an arc is very effective in cooling it, and in scavenging the products of ionization after current zero with consequent arc extinction within a cycle.

The high speed air blast is produced by externally generated pressure (inside a pressure vessel), the pressure being of the order of 2-6MN/m^2. The breaker is designed to direct a jet of air derived from the high pressure source to the contact space at the instant of contact separation.

Various possible alternative arrangements for achieving this are shown in figure 10. Of these, the axial blast, possibly using a hollow contact, is preferred for high power circuit breakers, since with the cross blast the arc is lengthened (requiring more breaker space).

Cooling and, therefore, extinguishing takes place at the centre of the arc, which has been removed from the inter-contact space, and the ionized region which is left near each contact facilitates restriking.

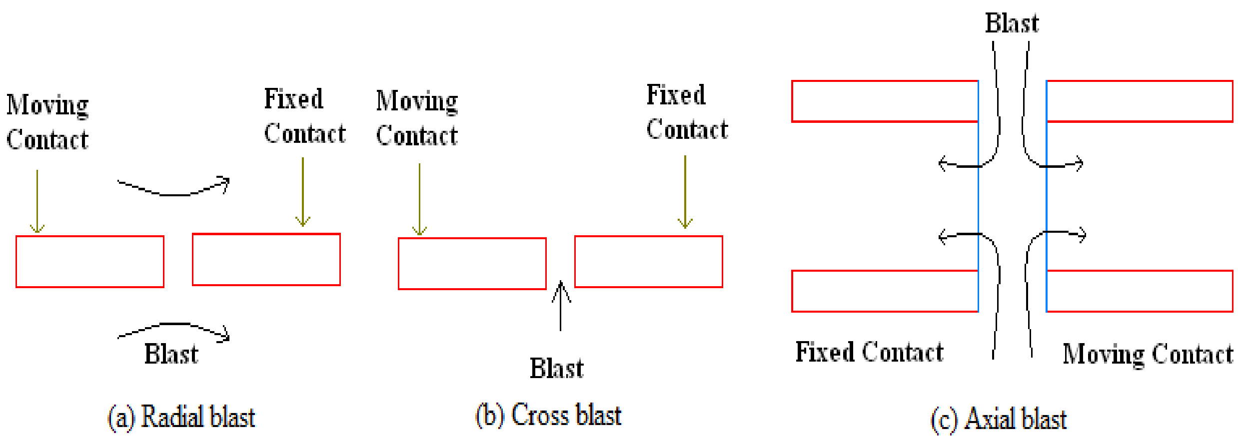


Figure 1-10. Blast alternatives for air-blast circuit breakers

Axial-blast breaker, being highly efficient, may cause chopping to take place at low currents. But since the contact spacing is small (because of high efficiency of the interruption process), voltage surges generated would be limited by restriking.

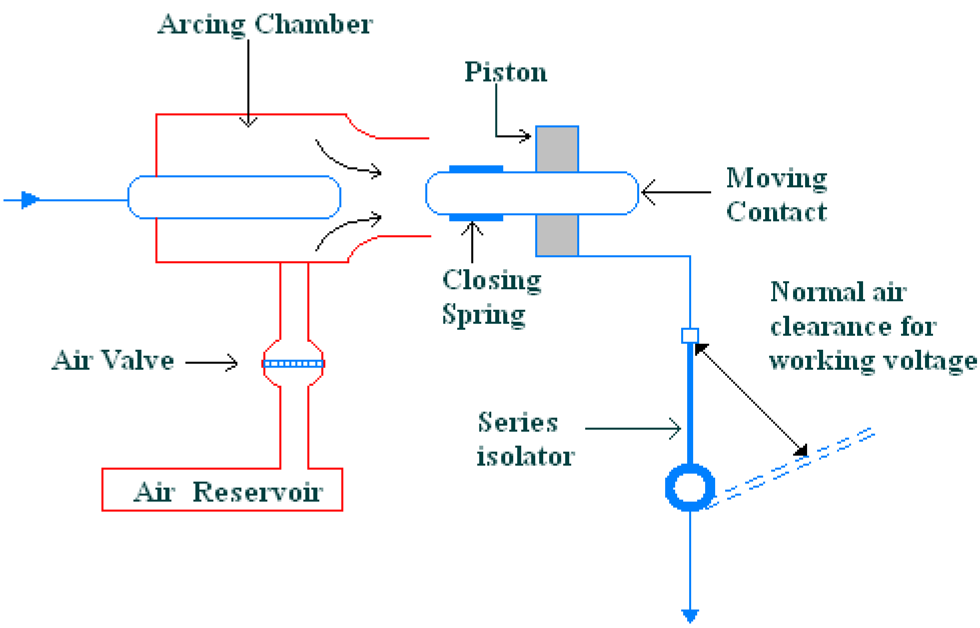


Figure 1-11. Conceptual operation radial-blast circuit breaker

For the circuit-breaker to withstand the recovery voltage after final arc extinction, a series isolating switch is provided, which opens automatically after the arc is extinguished.

This may not be necessary in breakers with pressurized arcing chambers.

The advantages of ABCBs are:

- Reliable operation, because an external source of energy for arc extinction is employed.
- The ABCB's are clean, non-decomposable and non-inflammable.
- Fresh medium is used every time.
- There is faster contact travel because of pneumatic operation, no stored spring energy is needed, and these are suitable for repeated use.
- Small contact travel is involved.

The disadvantages of ABCBs are:

- High air noise while operating, making them unsuitable for urban use.
- Possibility of chopping.
- Independent pressure system needed for ABCB.

1.4.2.3 Oil Circuit Breakers

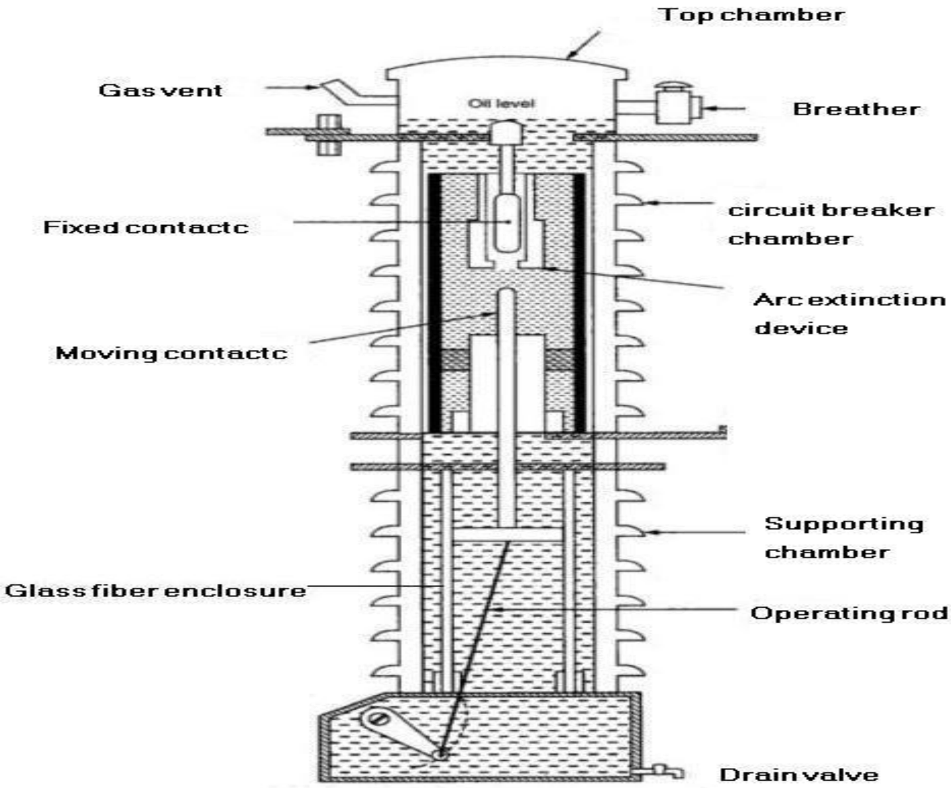


Figure 1-12. Minimum oil circuit breaker

Oil (transformer oil) is employed as arc quenching medium in oil circuit breakers. In earlier designs (i.e. bulk oil breakers), a large oil tank was used for quenching the arc. In modern oil circuit breakers which employ minimum amount of oil, the arc is extinguished in a small arc control device filled with oil. Oil circuit breakers are commonly adopted for the following voltage ratings: 3.6kV, 7.2kV, 12 kV, 36kV, 72.5kV, 145kV, 245kV. In higher voltage ratings, air-blast and SF6 breakers have now taken over.

The arc control devices are based on axial- flow and/or cross-flow principle. For higher current ratings cross-flow principle is preferred. Figure 12 shows the technique of arc quenching in a minimum oil circuit breaker. As the contact separate, the heat of the arc causes the oil to decompose into hydrogen (70%), acetelyn, etc. The gaseous formation causes the pressure inside the arc control device to rise and as a result, the arc is pushed across the side vents, thereby somewhat elongating (cross flow).

As the contacts move further apart lengthening the arc, it gets extinguished. For a given design and speed of contacts, the gas pressure generated is a function of arc current and arcing time, i.e., the arc energy. The time of final extinction of arc, therefore, is a function of arc current in an OCB, wherein smaller currents largely take longer breaking time.

The contacts are allowed to travel well beyond the arc-control device, so that fresh dielectric oil fills the contact space after oil extinction. Other techniques adopted to increase the rate of rise of dielectric strength after final current zero are:

- Flushing of contact space by fresh oil forced into contact space by piston-cylinder arrangement.
- Maintaining oil under pressure by means of inert gas; the pressure reduces the size of air bubbles, thereby increasing its dielectric strength.

The main disadvantages of an OCB are:

- Arc products are inflammable.
- Oil is hygroscopic (has the ability to absorb moisture) and must be sealed air tight in the chamber.
- Dielectric strength of oil is reduced by carbonization during the arcing process. Oil deteriorates over a period of time and must be replaced at regular intervals.

1.4.2.4 Sulphur Hexafluoride Circuit Breakers

Sulfur hexafluoride is an inorganic compound with the formula SF_6. It is a colourless, odourless, non-toxic and non-flammable gas (under standard conditions). Its other properties which make it ideal for circuit breaking are:

- At atmospheric pressure its dielectric strength is two to three times that of air. Because of excellent insulating properties of the gas, reduced electrical clearances are needed.
- Its heat transferability at atmospheric pressure is 2 to 2.5 times that of air; therefore smaller conductor sizes are needed.
- It is chemically stable at temperatures at which oil begins to decompose and oxidize; there are no carbon deposits and tracking.
- It is electronegative; its molecules rapidly absorb free electrons in the arc path forming heavy slow moving negative ions, which are ineffective as current carriers. Hence its superior arc quenching ability.

- Its heat capacity below 6000°K is much larger than that of air and helps in continuous cooling of the arc zone.
- Its arc time constant is a few µs.

With the combination of superior insulating and arc-quenching properties, SF_6 breakers have a very wide range of application: 6.6 KV to 765kV and 20 to 60 kA rupturing capacity. These are becoming increasingly popular.

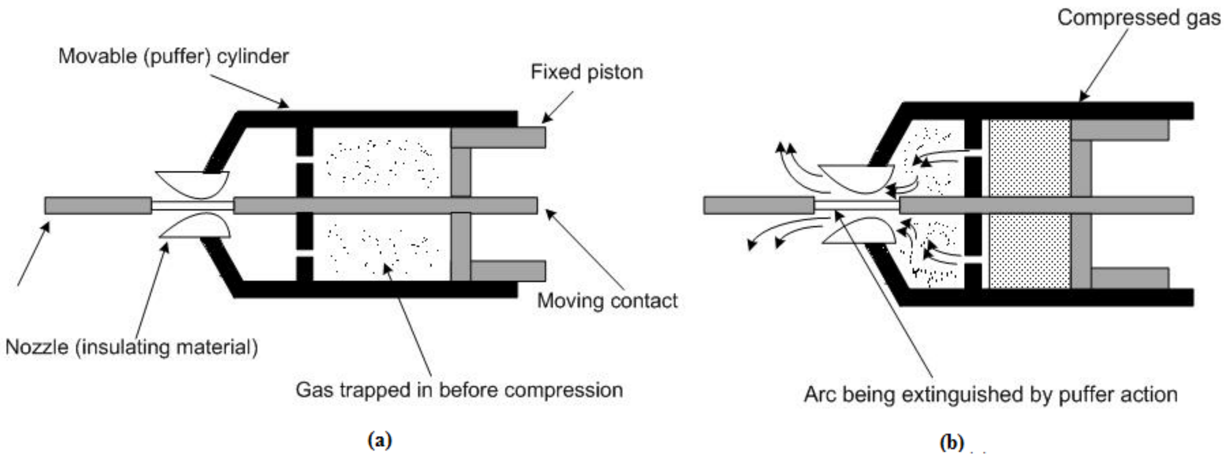


Figure 1-13. Puffer principle

The properties of SF_6 are such that the gas blast speeds need not be as high as in ABCB. The gas is hermetically sealed inside the breaker body at a pressure of about 3atm. High pressure needed to generated the gas blast of sufficient speed is obtained by a puffer mechanism at the time the breaker is open. The puffer mechanism is a piston-cylinder arrangement as illustrated in principle in figure 1-13. While the piston remains stationary, the cylinder is moved at high speed by means of the operating mechanism, creating a high pressure inside the enclosed space. The gas moves out through a convergent-divergent nozzle at high speed into the lower pressure region blowing the arc axially, and thereby quenching it.

The main advantages of SF_6 circuit breakers are:

- Low gas velocity and pressure employed prevent current chopping; capacitive currents are interrupted without restriking.
- There is no short time arc, low contact erosion and no contact replacement.
- No carbon deposition takes place and as such, there is no insulation tracking.
- The smaller sizes of conductors and clearances lead to small overall breaker size; and these have ample overload margin.
- They are not inflammable.

1.4.2.5 Vacuum circuit breakers

Vacuum is a volume of space that is essentially empty of matter, such that its gaseous pressure is much less than atmospheric pressure. Vacuum is a dielectric medium and arc cannot persist in ideal vacuum. Vacuum employed in vacuum circuit breaker is often of the order of 10^{-4} torr.

The separation of current-carrying contacts causes the metal vapour to be released from the contacts giving rise to plasma – electrons and positive metal ions- which fills the space intervening the contacts and maintaining the arc. The vapour density depends upon the current in the arc. In the decreasing phase of the current the rate of release of metal vapour reduces. After the first current zero, the metal vapour quickly disperses and the medium regains its dielectric strength. The arc is thus extinguished in just half a cycle. The contact separation needed is of the order of a few millimetres – least among all circuit breaker types. Up to 10kA, plain-disc contacts are used. Several parallel arcs are formed, each sinking into a hot cathode spot (formed by bombardment by heavy metal ions). These parallel arcs repel each other and quickly get diffused with consequent arc interruption. Above 10kA, these parallel arcs coalesce into a single arc with an extremely hot stationary cathode spot which cannot cool fast enough at current zero to prevent reignition of the arc. It also leads to erosion at a few spots on the contact surfaces reducing their life.

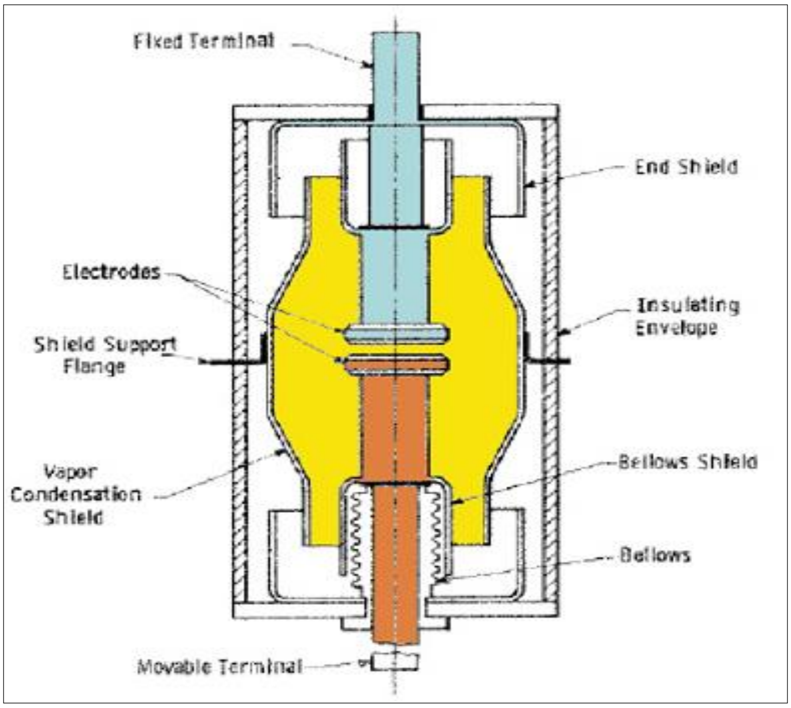


Figure 1-14. Typical vacuum interrupter

To overcome the above problem, special contact geometry is employed, wherein the current path is contrived to achieve self-induced electromagnetic movement of the arc. One type of contact geometry with deep forward curved fingers cut out on the contact surface as illustrated in Figure 1-14 is commonly employed. This causes the root of the arc to keep moving round (retrograde motion), so that the temperature at any one spot cannot rise intolerably, with consequent uniform contact wear and longer life.

The arc time constant is least (a few μs) in vacuum circuit breakers compared to other breaker types. The rapid building up of dielectric strength after final arc extinction (20kV/μs) is a unique feature of VCB's. These are, therefore, ideally suited for capacitor switching-restrike-free performance. The VCB's, because of this feature, tend to chop small currents.

Figure 1-14 shows the constructional details of a VCB. The contacts are enclosed in a sealed glass or ceramic bottle whose space is evacuated to a high degree of vacuum (10^{-4} torr). The moving contact is attached to metal bellows, which permit the movement without loss of vacuum. To prevent the metal vapour from condensing on the bottle or bellows surfaces, metal shields S and T are provided.

They also mask the high internal stress point and produce an almost linear axial grading of the external insulating surfaces. The contact geometry has already been described earlier. The interrupters are sealed for life and have a maintenance-free life of more than 20 years.

The properties required of contact material are:

- good mechanical strength and electrical conductivity;
- good thermal conductivity to assist rapid cooling of the arc;
- sufficient metal vapour from low- current arcing to control current chopping;
- limitation of metal vapour and thermionic emission from high-current arcing, to permit voltage recovery at current zero;
- low weld and cold adhesion strength at the contacting surfaces, to give easy and consistent separation; and
- low and uniform corrosion to give long operating life.

To achieve the above wide-ranging characteristics, metal mixtures evolved from alloys and bulk interspersions, e.g. copper and bismuth, or chromium and copper, are used.

Multi-unit VCB's have been employed at voltages up to 72.5kV. These require smaller space than OCB's and are employed both indoors and outdoors. Their advantages are being increasingly apparent over a widening application range.

1.4.2.6 DC Circuit Breakers

In ac circuit breakers, arc extinction is achieved at the natural current zero of the ac waveform. But in dc circuit breakers, natural zero of voltage and current is not available. Thus for extinction of a dc arc, artificial current zero is required (Low voltage dc arcs can be extinguished using air-break circuit breakers). In HVDC circuits, an artificial current zero has to be created. Such an artificial current zero is possible by connecting an LC circuit in parallel with the circuit breaker; the LC circuit is responsible to produce oscillatory arc current having many artificial current zeros. At one of the artificial current zero, the arc gets extinguished.

Figure 1-15 shows the operating principle of a HVDC circuit breaker. Only vacuum circuit breakers are used in breaking HVDC circuits. The LC circuit along with a switch is connected in parallel with the circuit breaker. The capacitor C used is pre-charged. When the breaker starts opening, the switch in the LC circuit gets closed. Due to the charged capacitor, the discharging current starts flowing in the opposite direction to the load current carried by the circuit breaker. Due to this, arcing current starts oscillating producing many natural zeros. Thus artificial commutation results and arc extinction is achieved. The large transient recovery voltage is the main constraint in HVDC circuit breakers. For successful operation of such a CB, the switch in the LC circuit must be a high speed switch with a very fast response. Such systems are complex and costly.

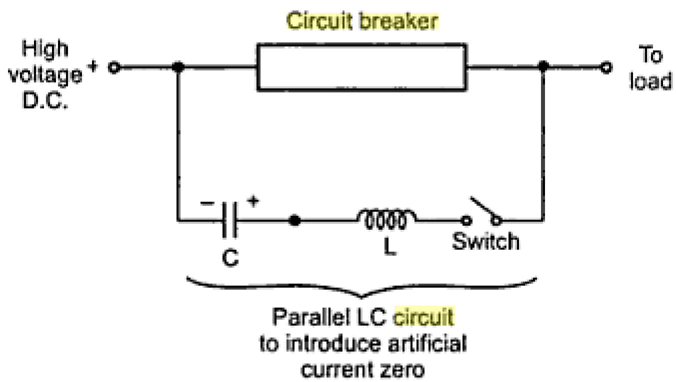


Figure 1-15. Circuit diagram for direct current interruption

1.4.2.7 Testing of Circuit Breakers

Circuit breaker manufacturers perform a number of tests on circuit breakers to ensure that they are of good quality. Some of these manufacturing tests are:

- Mechanical tests
- Insulation tests (power frequency and impulse voltage)
- Temperature rise tests
- Reliability tests under varying stress occurring in actual operation; ambient temperature, vibrations, dust, humidity, repeated operations.
- Short-circuit tests

Electric power engineers on the other hand have several reasons to also maintain and test a circuit breaker. Friction and wear can affect the performance of moving parts. Leaks can occur in the valves and seals used in arc-extinguishing chambers, damping devices, pneumatic and hydraulic operating mechanisms. Faults can occur in electrical control circuits, and the contact surfaces in interrupters and busbar joints can deteriorate, thus increasing the risk of excessive heat generation.

1.4.3 Current Transformers

1.4.3.1 Operating Principle and Applications

All current transformers used in protection are basically similar in construction to standard transformers in that they consist of magnetically coupled primary and secondary windings, wound on a common iron core, the primary winding being connected in series with the transmission line. They must therefore withstand the networks short-circuit current. There are two types of current transformers:

- Wound primary type
- Bar primary type

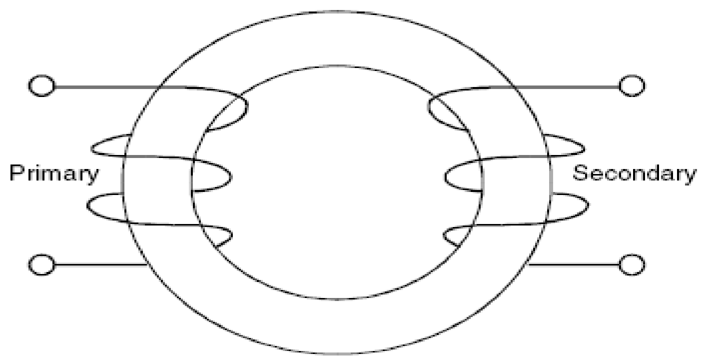


Figure 1-16. Wound primary CT

The wound primary (shown in Figure 1-16) is used for smaller currents, but it can only be applied on low fault level installations due to thermal limitations as well as structural requirements due to high magnetic forces. For currents greater than 100 A, the bar primary type (shown in Figure 1-17) is used.

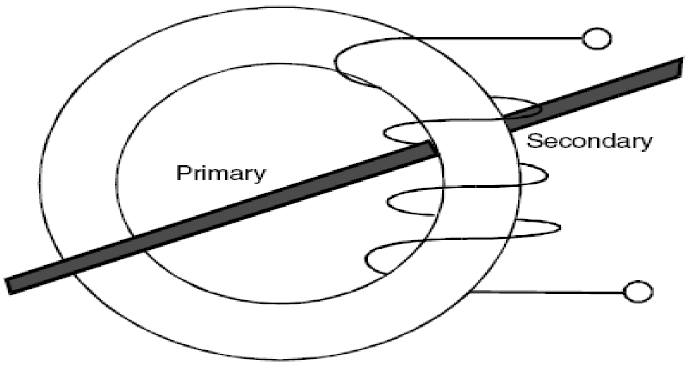


Figure 1-17. Bar primary CT

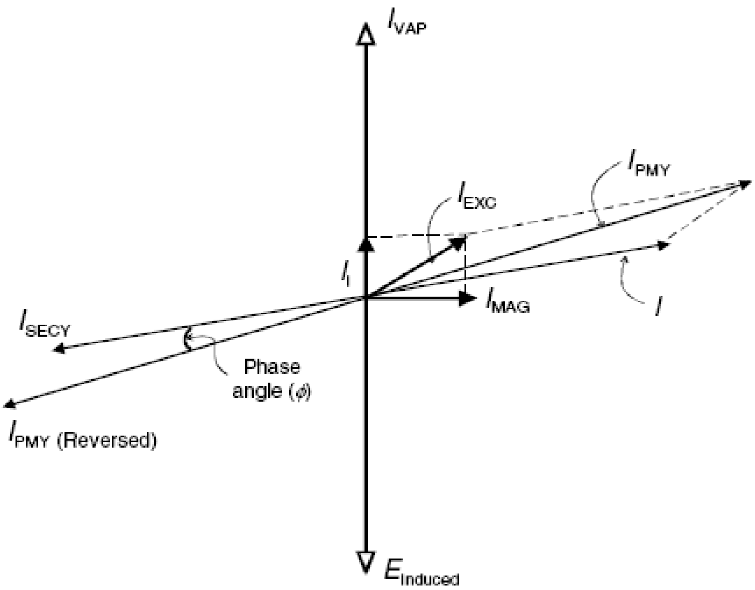


Figure 1-18. Vector diagram for a CT

The basis of both types of CTs is that:

- Amp-turns on the Primary = Amp-turns on the secondary

The primary current contains two components:

- An exciting current, which magnetizes the core and supplies the eddy current and hysteresis losses, etc.
- A remaining primary current component, which is available for transformation to secondary current in the inverse ratio of turns.

The exciting current is not being transformed and is therefore the cause of transformer errors. The amount of exciting current drawn by a CT depends upon the core material and the amount of flux that must be developed in the core to satisfy the output requirements of the CT. This is explained vectorally in Figure 1-18.

1.4.3.2 Characteristics of CTs

(a) Equivalent circuit

The specific performance characteristic of a CT is easily obtained from its equivalent circuit. Figure 1-19 and 1-20 show the equivalent circuit of a CT and the corresponding vector diagram respectively.

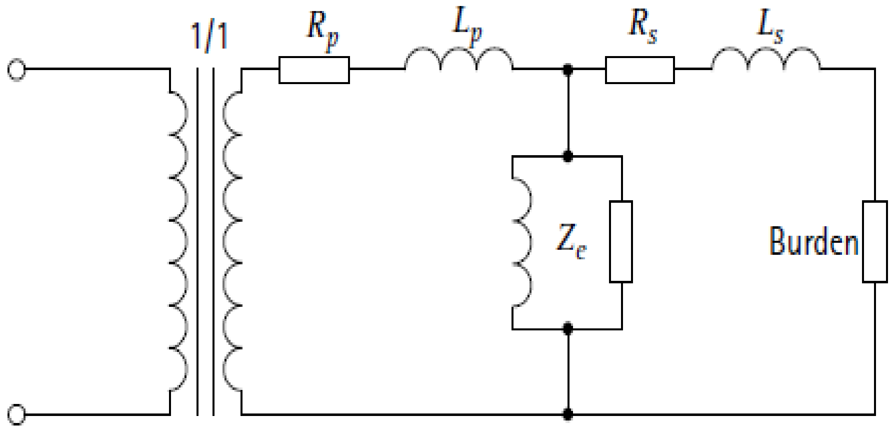


Figure1-19. Equivalent circuit of CT with all values referred to secondary

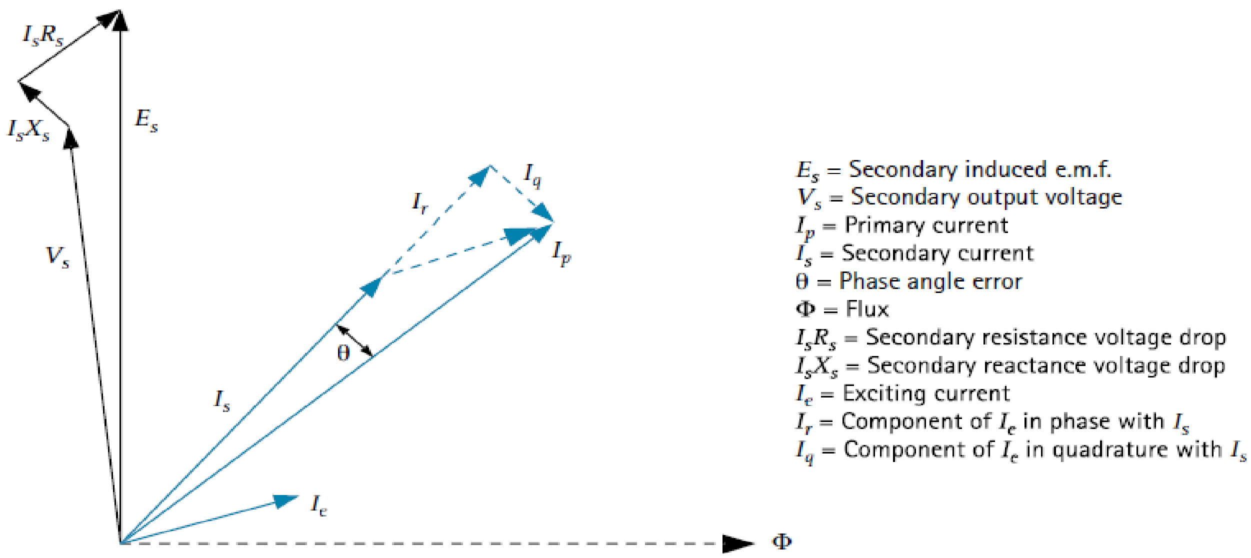


Figure 1-20. Vector diagram of CT

(b) CT errors

Errors arise because of the shunting of the burden by the exciting impedance. This uses a small portion of the input current for exciting the core, reducing the amount passed to the burden. So $I_s = I_p - I_e$, where I_e is dependent on Z_e, the exciting impedance and the secondary e.m.f. E_s, given by the equation $E_s = I_s(Z_s + Z_b)$, where:

Z_s = the self-impedance of the secondary winding, which can generally be taken as the resistive component R_s only.

Z_b = the impedance of the burden

- Current or ratio error

This is the difference in magnitude between I_p and I_s and is equal to I_r, the component of I_e which is in phase with I_s.

- Phase error

Phase error is the difference in phase between the primary and secondary current vectors. The phase displacement is said to be positive when the secondary current vector leads the primary current vector. It is usually expressed in minutes.

The values of the current error and phase error depend on the phase displacement between I_s and I_e, but neither current nor phase error can exceed the vectorial error I_e. For a moderately inductive burden which results in I_s and I_e being approximately in phase, there will be little phase error, and the exciting component will result almost entirely in ratio error. A reduction of the secondary winding by one or two turns is often used to compensate for this.

- Composite error

This is defined in IEC 60044-1 as the rms value of the difference between the ideal secondary current and the actual secondary current.

It includes current and phase errors and the effects of harmonics in the exciting current.

(c) Magnetization curve

It is a graph of magnetizing current versus the open-circuit voltage generated at the terminals of the CT. This curve is the best method of determining a CTs performance.

Due to the non-linearity of the core, it follows the B-H loop characteristic and comprises three regions, namely the initial region, unsaturated region and saturated region (see Figure 1-21).

The transition from the unsaturated region to the saturated region of the open-circuit excitation characteristic (magnetizing curve) is a rather gradual process in most core materials. This transition characteristic makes a CT not to produce equivalent primary current beyond a certain point. This transition is defined by 'knee-point' voltage in a CT, which decides its accurate working range. The 'knee-point' voltage is generally defined as the voltage at which a further 10% increase in volts at the secondary side of the CT requires more than 50% increase in excitation current. For most applications, it means that current transformers can be considered as approximately linear up to this point.

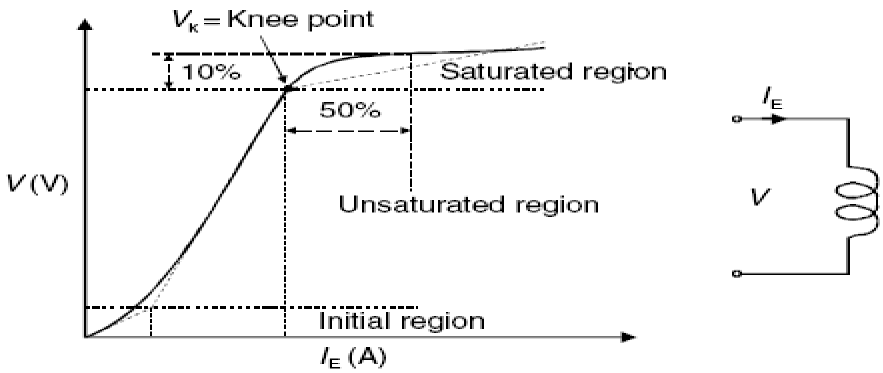


Figure 1-21. Typical CT saturation curve

- Metering CTs

Instruments and meters are required to work accurately up to full-load current, but above this, it is advantageous to saturate and protect the instruments under fault conditions. Hence, it is common to have metering CTs with a very sharp knee-point voltage. A special nickel-alloy metal having a very low magnetizing current is used in order to achieve the accuracy. Figure 1-22 shows the magnetization curve of a metering CT.

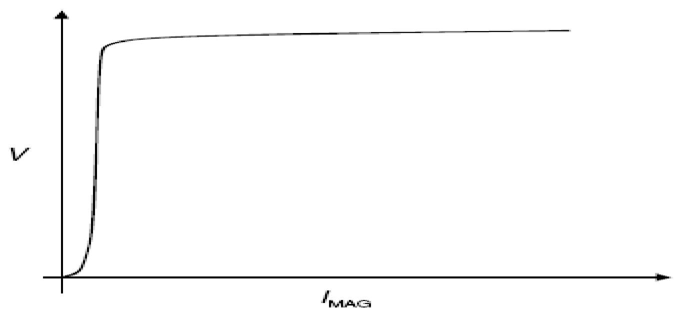


Figure 1-22. Metering CT saturation curve

- Protection CTs

Protective relays are not normally expected to give tripping instructions under normal conditions. On the other hand these are concerned with a wide range of currents from acceptable fault settings to maximum fault currents many times the normal rating. Larger errors may be permitted and it is important that saturation is avoided wherever possible to ensure positive operation of the relays mainly when the currents are many times the normal current (see Figure 1-23).

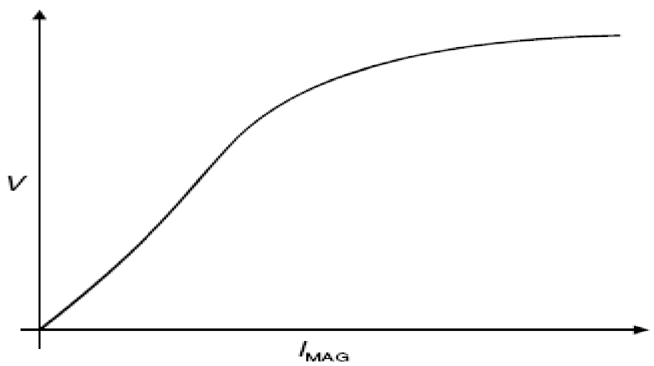


Figure 23. Protection CT saturation curve

(d) Polarity

Polarity in a CT is similar to the identification of +ve and –ve terminals of a battery. Polarity is very important when connecting relays, as this will determine correct operation or not depending on the types of relays. The terminals of CTs are marked P1 and P2 on the primary, and S1 and S2 on the secondary as shown in figure 24. BS 3938 states that at the instant when current is flowing from P1 to P2 in primary, then current, in secondary, current must flow from S1 to S2 through the external circuit.

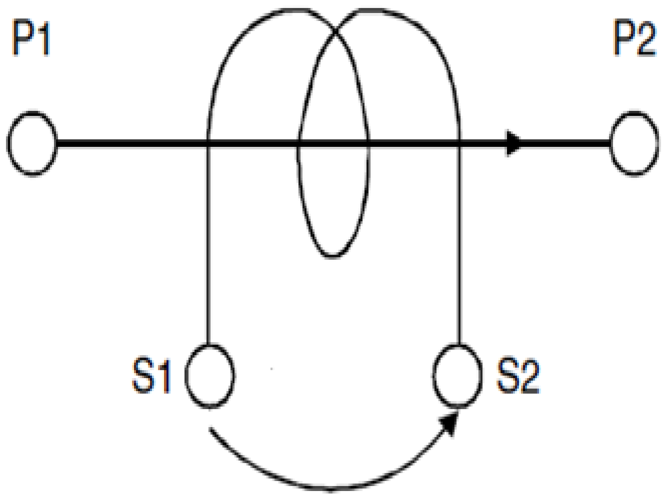


Figure 1-24. Polarity of CTs

1.4.3.3 Selection of CTS

(a) Burden

The burden of a CT is the maximum load (in VA) that can be applied to the CT secondary.

- The CT secondary load = Sum of the VA's of all the loads (ammeter, wattmeter, transducer etc.) connected in series to the CT secondary circuit + the CT secondary circuit cable burden (cable burden = I^2 x R x L, where I = CT secondary current, R = cable resistance per length, L = total length of the secondary circuit cable. If the proper size and short length of wire is used, cable burden can be ignored).
- The CT secondary circuit load should not be more than the CT VA rating. If the load is less than the CT burden, all meters connected to the measuring CT should provide correct reading.

(b) Accuracy class

In the case of metering CTs, accuracy class is typically, 0.2, 0.5, 1 or 3. This means that the errors have to be within the limits specified in the standards for that particular accuracy class. The metering CT has to be accurate from 5% to 120% of the rated primary current, at 25% and 100% of the rated burden at the specified power factor. In the case of protection CTs, the CTs should pass ratio and phase errors at the specified accuracy class which is usually 5P or 10P, as well as composite error at the accuracy limit factor of the CT. Tables 1-1 and 1-2 show accuracy classes for metering and protection CTs respectively.

Accuracy Class	Current Error at Rated Primary Current %	Phase Displacement at Rated Primary Current		Composite Error at Rated Accuracy Limited Primary Current %
		Minutes	Centiradians	
5P 10P	1			5 10

Table 1-1. Accuracy Class and Error for Protection CTs

Class	Percentage Current Error at Percentage of Rated Current Shown Below			Phase Displacement at Percentage of Rated Current Shown Below					
				Minutes			Centiradians		
	10 up to but not incl. 20	20 up to but not incl. 100	100 up to 120	10 up to but not incl. 20	20 up to but not incl. 100	100 up to 120	10 up to but not incl. 20	20 up to but not incl. 100	100 up to 120
0.1	0.25	0.2	0.1	10	8	5	0.3	0.24	0.15
0.2	0.5	0.35	0.2	20	15	10	0.6	0.45	0.3
0.5	1.0	0.75	0.5	60	45	30	1.8	1.35	0.9
1.0	2.0	1.5	1.0	120	90	60	3.6	2.7	1.8

Table 1-2. Accuracy Class and Errors for Measuring CTs

(c) Specification of CTs

A current transformer is normally specified in terms of:

- input / output current ratio
- A rated burden at rated current
- An accuracy class
- An upper limit beyond which accuracy is not guaranteed (known as the accuracy limit factor, ALF), which is more vital in case of protection CTs.

In terms of the specification, a current transformer would, for example, be briefly referred to as 15 VA 5P20 if it were a protection CT or 15 VA Class 0.5 if it is a metering CT. The meanings of these figures are as below:

	Protection	**Metering**
Rated burden	15 VA	15 VA
Accuracy class	5P	0.5
Accuracy limit factor	20	-

Metering CTs

In general, the following applies:

Accuracy class requirement

- 0.2 for precision measurements
- 0.5 for high grade kilowatt hour meters
- 1.0 for commercial grade kilowatt hour meters
- 1.0 or 3 for general industrial measurements

- 3 or 5 for approximate measurements

Burden (depending on pilot lead length)

- Moving iron ammeter: 1-2VA
- Moving coil rectifier ammeter: 1-2.5VA
- Electrodynamic instrument: 2.5-5VA
- Maximum demand ammeter 3-6VA
- Recording ammeter or transducer 1-2.5VA

Protection CTs

In addition to the general specification required for CT design, protections CTs require an Accuracy Limit Factor (ALF). This is the multiple of rated current up to which the CT will operate while complying with the accuracy class requirements.

In general the following applies:

- Instantaneous overcurrent relays & trip coils - 2.5VA Class 10P5
- Thermal inverse time relays - 7.5VA Class 10P10
- Low consumption Relay - 2.5VA Class 10P10
- Inverse definite min. time relays (IDMT) overcurrent - 15VA Class
- 10P10/15
- IDMT Earth fault relays with approximate time grading - 15VA Class
- 10P10
- IDMT Earth fault relays with phase fault stability or accurate time grading required - 15VA Class 5P10

Class PS(X) CTs

Class PS CTs are special CTs used mainly in balanced protection systems (including restricted earth fault) where the system is sensitively dependent on CT accuracy. Further to the general CT specifications, the following data is required:

- V_{kp}- Knee point Voltage
- I_o – Maximum magnetizing current at V_{kp}
- R_s – Maximum resistance of the secondary winding.

1.4.3.4 Connection of CTs

Current transformers for protection are normally provided in groups of three, one for each phase. They are most frequently connected in 'star' as illustrated in Figure 1-25. The secondary currents obtainable with this connection are the three individual phase currents and the residual or neutral current. The residual current is the vector sum of the three-phase currents, which under healthy conditions would be zero. Under earth fault conditions, this would be the secondary equivalent of the earth fault current in the primary circuit.

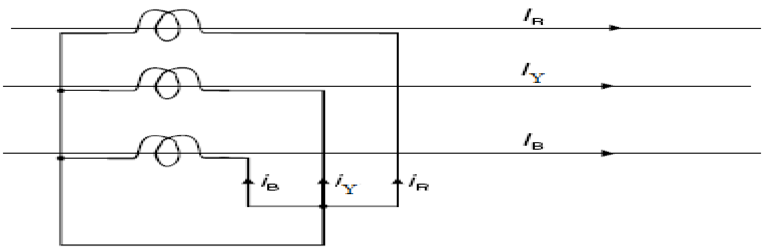


Figure 1-25. Star connection of current transformers

Sometimes, current transformers are connected in 'delta' for the following reasons:

- To obtain the currents I_R-I_Y, I_Y-I_B, I_B-I_R
- To eliminate the residual current from the relays
- To introduce a phase-shift of 30° under balanced conditions, between primary and relay currents (see Figure 1-26).

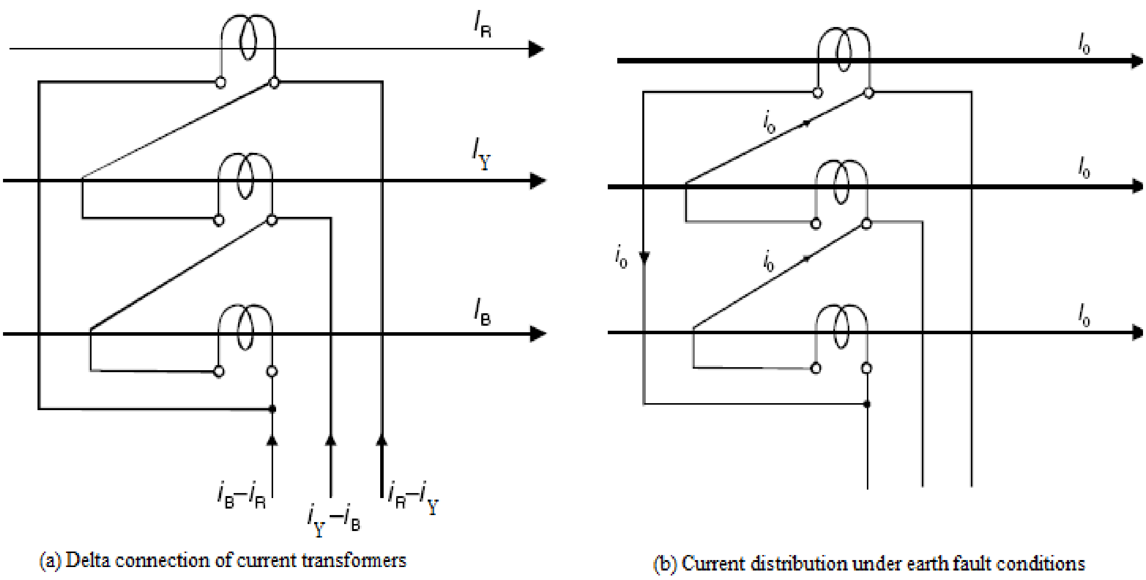


Figure 1-26. Delta connection of CTs

1.4.3.5 Protection of CTs

Current transformers generally work at a low flux density. The core is made of very good metal to give small magnetizing current. On open-circuit, secondary impedance becomes infinite and the core saturates. This induces a very high voltage in the primary up to approximately system volts and the corresponding volts in the secondary will depend on the number of turns, multiplying up by the ratio (i.e. volts/turn × no. of turns). Since CTs normally have much more turns in secondary compared to the primary, the voltage generated on the open-circuited CT will be much more than the system volts, leading to flashovers. Hence as a safety precaution, a current transformer on load should never be open-circuited.

In the light of this the secondary resistance of a CT should always be kept as low as possible. To prevent the secondary circuits from attaining dangerously high potential to earth, the secondary circuits are earthed.

1.4.4 Potential Transformers

1.4.4.1 Operating Principle and Applications

A voltage transformer is an open-circuited transformer whose primary winding is connected across the main electrical system voltage being monitored.

A convenient proportionate voltage is generated in the secondary for monitoring. The most common voltage produced by voltage transformers is 100–120 V (as per local country standards) for primary voltages from 380 V to 800 kV or more. There are basically, two types of voltage transformers used for protection equipment.

- Electromagnetic type (commonly referred to as a VT)
- Capacitor type (referred to as a CVT).

The electromagnetic type is a step down transformer whose primary (HV) and secondary (LV) windings are connected as below (see Figure 1-27).

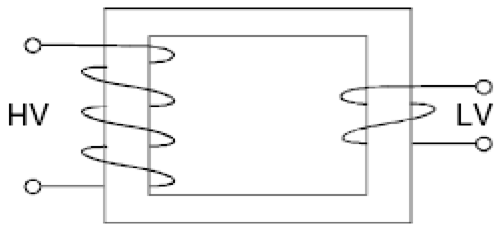


Figure 1-27. Electromagnetic type PT

The number of turns in a winding is directly proportional to the open-circuit voltage being measured or produced across it. This type of electromagnetic transformer is used in systems up to 110/132 kV.

For higher voltages, it is common to adopt the second type namely the capacitor voltage transformer (CVT). Figure 1-28 below gives the basic connection adopted in this type.

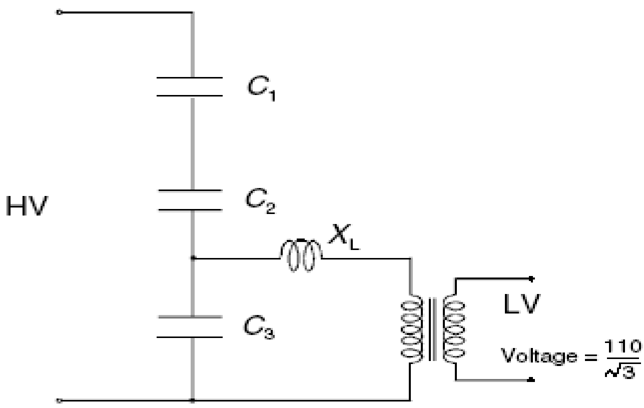


Figure 1-28. Capacitor-type PT

Here the primary portion consists of capacitors connected in series to split the primary voltage to convenient values. The magnetic voltage transformer is similar to a power transformer. The capacitor PT is more commonly used on extra high-voltage (EHV) networks.

The capacitors also allow the injection of a high-frequency signals onto the power line conductors to provide end-to-end communications between substations for distance relays, telemetry/supervisory and voice communications.

1.4.4.2 Characteristics of PTs

(a) Equivalent circuit

Figures 1-29 and 1-30 show the equivalent circuit and vector diagram of a VT.

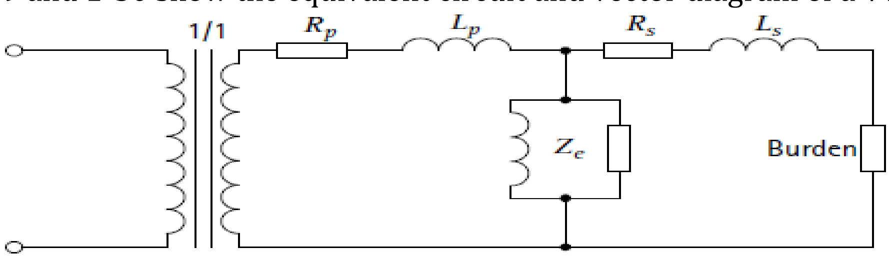


Figure 1-29. Equivalent circuit of a VT

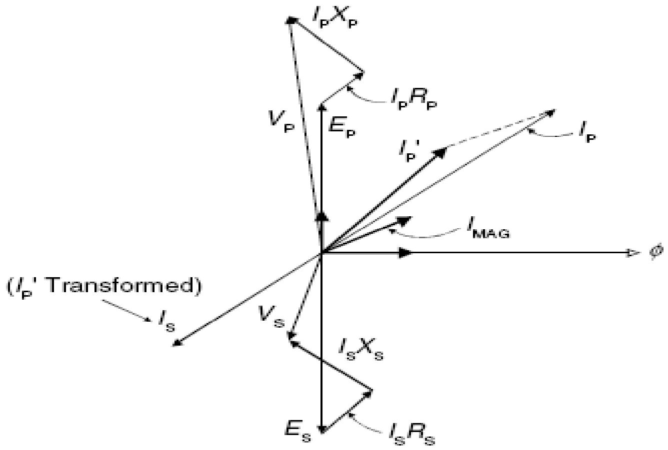


Figure 1-30. Vector diagram of VT

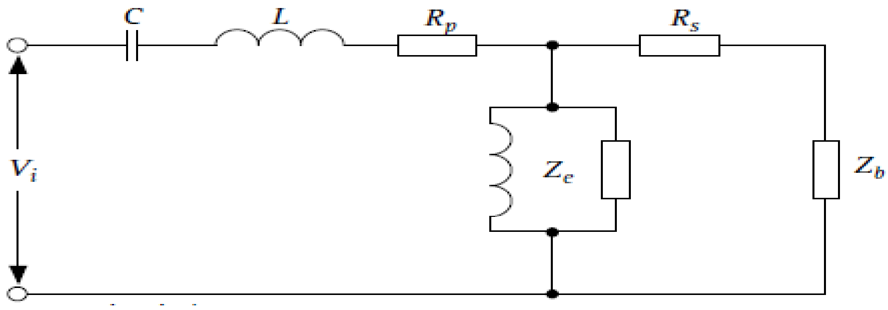


Figure 1-31. Equivalent circuit of a CVT

The equivalent circuit of a CVT is shown in Figure 1-31. The subsequent sessions cover mainly VTs.

(a) Errors

The ratio and phase errors of a VT can be calculated using the vector diagram of Figure 1-30. The ratio error is defined as:

$$\frac{K_n V_s - V_p}{V_p} \times 100\%$$

Where K_n is the nominal ratio, V_p is the primary voltage and V_s is the secondary voltage.

If the error is positive, the secondary voltage exceeds the nominal value. The turns ratio of the transformer need not be equal to the nominal ratio; a small turns compensation will usually be employed, so that the error will be positive for low burdens and negative for high burdens.

The phase error is the phase difference between the reversed secondary and the primary voltage vectors. It is positive when the reversed secondary voltage leads the primary vector. Requirements in this respect are set out in IEC 60044-2.

Voltage factor V_f	Time rating	Primary winding connection/system earthing conditions
1.2	continuous	Between lines in any network. Between transformer star point and earth in any network
1.2	continuous	Between line and earth in an effectively earthed network
1.5	30 s	
1.2	continuous	Between line and earth in a non-effectively earthed neutral system with automatic earth fault tripping
1.9	30 s	
1.2	continuous	Between line and earth in an isolated neutral system without automatic earth fault tripping, or in a resonant earthed system without automatic earth fault tripping
1.9	8 hours	

Table 1-3. Voltage factors and permissible duration of maximum voltage

(b) Voltage factor

Voltage factor V_f is an upper limit of operating voltage, expressed in per unit of rated voltage. This is important for correct relay operation and operation under unbalanced fault conditions or unearthed or impedance earthed systems, resulting in a rise in the voltage on the healthy phases.

Voltage factors, with the permissible duration of the maximum voltage, are given in table 1-3.

1.4.4.3 Selection of VTs

(a) Specification of VTs

Potential transformers are specified in terms of:

- Ratio: input / output voltage ratio
- Tappings: all taps required on each winding
- Burden (VA): total burden of each winding or tapping
- Accuracy class
- Frequency
- Dimensions : maximum limits
- Mounting: required terminations and mounting

- Temperature class : If other than Class B

In addition to the general specification required for VTs, protection VTs require a Rated Voltage Factor (Vf).

(b) Burden of VTs

VT burden is the load in terms of volt-amperes (VA) posed by the devices in the secondary circuit on the VT. This includes the burden imposed by the connecting leads.

(c) Temperature class

This gives an indication of the permissible temperature rise over the specified ambient temperature. Typical classes are E, B and F.

(d) Accuracy class of VTs

Voltage transformers shall be capable to produce secondary voltages, which are proportionate to the primary voltages over the full range of input voltage expected in a system. Voltage transformers for protection are required to maintain reasonably good accuracy over a large range of voltage from 0 to 173% of normal. However, the close accuracy is more relevant for metering purposes, while for protection purposes the margin of accuracy can be comparatively less. Permissible errors vary depending on the burden and purpose of use and typical values as per IEC are given in Table 1-4.

Accuracy is not a major cost-deciding factor for a voltage transformer due to the high efficiency of the transformers, which normally ensures that there is no major voltage drop in the secondary leads. Thus, it is common to select voltage transformers based on the loads (choosing appropriate rated burden). The question of accuracy of VT's used in protection circuits can be ignored and is generally neglected in practice.

		Range		Limits of Errors		
Standard	Class	Burden %	Voltage %	Ratio %	Phase Displacement Min	Application
IEC 186	0.1	25–100	80–120	0.1	5	Laboratory
	0.2	25–100	80–120	0.2	10	Precision metering, revenue metering
	0.5	25–100	80–120	0.5	20	Standard revenue metering
	1.0	25–100	80–120	1.0	40	Industrial grade meters
	3.0	25–100	80–120	3.0	–	Instruments
	3P	25–100	5-V_f*	3.0	120	Protection
	6P	25–100	5-V_f*	6.0	240	Protection

* V_f = Voltage factor

Table 1-4. Accuracy class and errors of VTs

1.4.4.4 Connection of PTs

Electromagnetic voltage transformers may be connected inter-phase or between phase and earth. However, capacitor voltage transformers can only be connected phase-to-earth. Voltage transformers are commonly used in three-phase groups, generally in star–star configuration. With this arrangement, the secondary voltages provide a complete replica of the primary voltages and any voltage (phase-to-phase or phase-to-earth) may be selected for monitoring at the secondary.

It is common to detect earth faults in a three-phase system using the displacement that occurs in the neutral voltage when earth faults take place. The residual voltage (neutral displacement voltage, polarizing voltage) for earth fault relays can be obtained from a VT between neutral and earth, for instance at a power transformer neutral. It can also be obtained from a three-phase set of VTs, which have their primary winding connected phase to earth and one of the secondary windings connected in a broken delta.

1.4.4.5 Protection and Earthing of PTs

Voltage Transformers can be protected by HRC fuses on the primary side for voltages up to 66kV. Fuses do not usually have a sufficient interrupting capacity for use with higher voltages. Practice varies, and in some cases protection on the primary is omitted.

The secondary of a VT should always be protected by fuses or a miniature circuit breaker (MCB). The device should be located as near to the transformer as possible.

A short circuit on the secondary circuit wiring will produce a current of many times the rated output and cause excessive heating. Even where primary fuses can be fitted, these will usually not clear a secondary side short circuit because of the low value of primary current and the minimum practicable fuse rating.

To prevent secondary circuits from reaching dangerous potential, the circuits should be earthed. Earthing is made at only one point of a VT secondary circuit or galvanically interconnected circuits.

A VT with the primary connected phase-to-earth is earthed at the secondary at terminal n. A VT with the primary winding connected across two-phases, shall have that secondary terminal which has a voltage lagging the other terminal by 120° earthed. Windings not under use are also earthed

1.5 Relaying Principles

1.5.1 Relay Technology

1.5.1.1 Electromechanical Relays

These relays were the earliest forms of relay used for the protection of power systems, and they date back nearly 100 years. They work on the principle of a mechanical force causing operation of a relay contact in response to a stimulus.

The mechanical force is generated through current flow in one or more windings on a magnetic core or cores, hence the term electromechanical relay. The principle advantage of such relays is that they provide galvanic isolation between the inputs and outputs in a simple, cheap and reliable form – therefore for simple on/off switching functions where the output contacts have to carry substantial currents, they are still used. Electromechanical relays can be classified into several different types as follows:

- attracted armature
- moving coil
- induction
- thermal
- motor operated
- Mechanical

However, only attracted armature types have significant application at this time, all other types having been superseded by more modern equivalents.

- **Attracted Armature Relays**

These generally consist of an iron-cored electromagnet that attracts a hinged armature when energised. A restoring force is provided by means of a spring or gravity so that the armature will return to its original position when the electromagnet is de-energised. Movement of the armature causes contact closure or opening, the armature either carrying a moving contact that engages with a fixed one, or causes a rod to move that brings two contacts together.

It is very easy to mount multiple contacts in rows or stacks, and hence cause a single input to actuate a number of outputs. The contacts can be made quite robust and hence able to make, carry and break relatively large currents under quite onerous conditions (highly inductive circuits). This is still a significant advantage of this type of relay that ensures its continued use.

The energizing quantity can be either an a.c. or a d.c. current. If an a.c. current is used, means must be provided to prevent the chatter that would occur from the flux passing through zero every half cycle. A common solution to the problem is to split the magnetic pole and provide a copper loop round one half.

The flux change is now phase-shifted in this pole, so that at no time is the total flux equal to zero. Conversely, for relays energized using a d.c. current, remnant flux may prevent the relay from releasing when the actuating current is removed. This can be avoided by preventing the armature from contacting the electromagnet by a non-magnetic stop or constructing the electromagnet using a material with very low remnant flux properties.

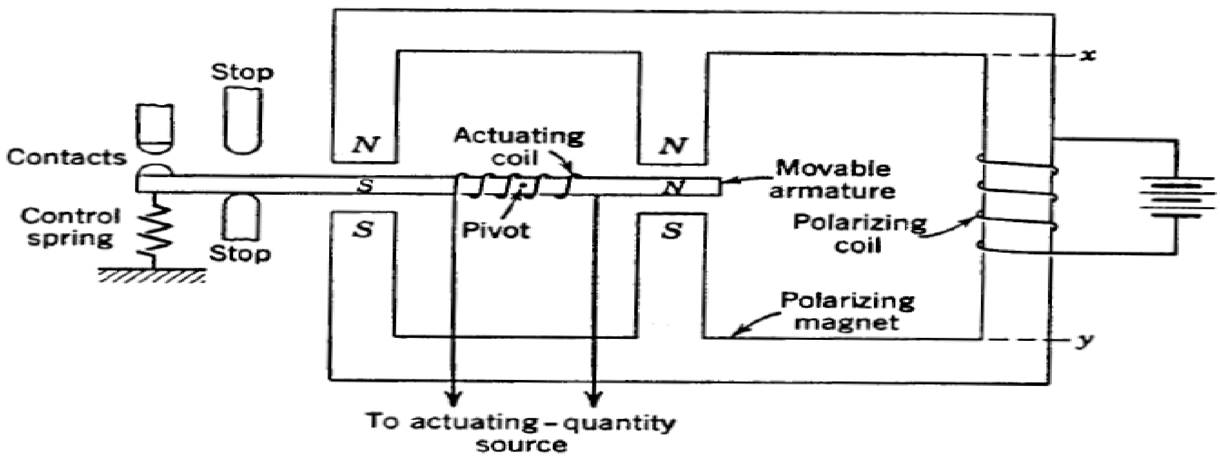


Figure 1-32. Attracted armature relay

Operating speed, power consumption and the number and type of contacts required are a function of the design. The typical attracted armature relay has an operating speed of between 100ms and 400ms, but reed relays (whose use spanned a relatively short period in the history of protection relays) with light current contacts can be designed to have an operating time of as little as 1msec. Operating power is typically 0.05-0.2watts, but could be as large as 80watts for a relay with several heavy-duty contacts and a high degree of resistance to mechanical shock.

Some applications require the use of a polarised relay. This can be simply achieved by adding a permanent magnet to the basic electromagnet. Both self-reset and bi-stable forms can be achieved. One possible example of use is to provide very fast operating times for a single contact, speeds of less than 1ms being possible.

1.5.1.2 Static Relays

The term ‘static’ implies that the relay has no moving parts. This is not strictly the case for a static relay, as the output contacts are still generally attracted armature relays. In a protection relay, the term ‘static’ refers to the absence of moving parts to create the relay characteristic.

Introduction of static relays began in the early 1960’s. Their design is based on the use of analogue electronic devices instead of coils and magnets to create the relay characteristic. Early versions used discrete devices such as transistors and diodes in conjunction with resistors, capacitors, inductors, etc., but advances in electronics enabled the use of linear and digital integrated circuits in later versions for signal processing and implementation of logic functions.

While basic circuits may be common to a number of relays, the packaging was still essentially restricted to a single protection function per case, while complex functions required several cases of hardware suitably interconnected.

User programming was restricted to the basic functions of adjustment of relay characteristic curves. They therefore can be viewed in simple terms as an analogue electronic replacement for electromechanical relays, with some additional flexibility in settings and some saving in space requirements. In some cases, relay burden is reduced, making for reduced CT/VT output requirements.

A number of design problems had to be solved with static relays. In particular, the relays generally require a reliable source of dc power and measures to prevent damage to vulnerable electronic circuits had to be devised. Substation environments are particularly hostile to electronic circuits due to electrical interference of various forms that are commonly found (e.g. switching operations and the effect of faults).

While it is possible to arrange for the dc supply to be generated from the measured quantities of the relay, this has the disadvantage of increasing the burden on CTs or VTs, and there will be a minimum primary current or voltage below which the relay will not operate. This directly affects the possible sensitivity of the relay.

So provision of an independent, highly reliable and secure source of relay power supply was an important consideration. To prevent maloperation or destruction of electronic devices during faults or switching operations, sensitive circuitry is housed in a shielded case to exclude common mode and radiated interference.

The devices may also be sensitive to static charges, requiring special precautions during handling, as damage from this cause may not be immediately apparent, but become apparent later in the form of premature failure of the relay. Therefore, radically different relay manufacturing facilities are required compared to electromechanical relays. Calibration and repair is no longer a task performed in the field without specialised equipment.

1.5.1.3 Digital Relays

Digital protection relays introduced a step change in technology. Microprocessors and microcontrollers replaced analogue circuits used in static relays to implement relay functions. Early examples began to be introduced into service around 1980, and, with improvements in processing capacity, can still be regarded as current technology for many relay applications. However, such technology has almost been completely superseded by numerical relays.

Compared to static relays, digital relays introduce A/D conversion of all measured analogue quantities and use a microprocessor to implement the protection algorithm. The microprocessor may use some kind of counting technique, or use the Discrete Fourier Transform (DFT) to implement the algorithm. However, the typical microprocessors used have limited processing capacity and memory compared to that provided in numerical relays. The functionality tends therefore to be limited and restricted largely to the protection function itself. Additional functionality compared to that provided by an electromechanical or static relay is usually available, typically taking the form of a wider range of settings, and greater accuracy. A communications link to a remote computer may also be provided.

The limited power of the microprocessors used in digital relays restricts the number of samples of the waveform that can be measured per cycle. This, in turn, limits the speed of operation of the relay in certain applications. Therefore, a digital relay for a particular protection function may have a longer operation time than the static relay equivalent. However, the extra time is not significant in terms of overall tripping time and possible effects of power system stability.

1.5.1.4 Numerical Relays

The distinction between digital and numerical relay rests on points of fine technical detail, and is rarely found in areas other than Protection. They can be viewed as natural developments of digital relays as a result of advances in technology. Typically, they use a specialized digital signal processor (DSP) as the computational hardware, together with the associated software tools. The input analogue signals are converted into a digital representation and processed according to the appropriate mathematical algorithm. Processing is carried out using a specialised microprocessor that is optimised for signal processing applications, known as a digital signal processor or DSP for short. Digital processing of signals in real time requires a very high power microprocessor.

In addition, the continuing reduction in the cost of microprocessors and related digital devices (memory, I/O, etc.) naturally leads to an approach where a single item of hardware is used to provide a range of functions ('one-box solution' approach). By using multiple microprocessors to provide the necessary computational performance, a large number of functions previously implemented in separate items of hardware can now be included within a single item. Numerical relays have the following advantages over static relays:

- Several setting groups
- Wider range of parameter adjustment
- In-built remote communications
- Internal Fault diagnosis
- Power system measurements
- Distance to fault locator
- Disturbance recorder
- Auxiliary protection functions (broken conductor, negative sequence, etc.)
- CB monitoring (state, condition)
- User-definable logic
- In-built backup protection functions
- Consistency of operation times - reduced grading margin

Because a numerical relay may implement the functionality that used to require several discrete relays, the relay functions (overcurrent, earth fault, etc.) are now referred to as being 'relay elements', so that a single relay (i.e. an item of hardware housed in a single case) may implement several functions using several relay elements. Each relay element will typically be a software routine or routines.

The argument against putting many features into one piece of hardware centres on the issues of reliability and availability. A failure of a numerical relay may cause many more functions to be lost, compared to applications where different functions are implemented by separate hardware items. Comparison of reliability and availability between the two methods is complex as interdependency of elements of an application provided by separate relay elements needs to be taken into account.

With the experience gained with static and digital relays, most hardware failure mechanisms are now well understood and suitable precautions taken at the design stage. Software problems are minimised by rigorous use of software design techniques, extensive prototype testing and the ability to download amended software into memory (possibly using a remote telephone link for download). Practical experience indicates that numerical relays are at least as reliable and have at least as good a record of availability as relays of earlier technologies.

1.5.1.5 Signalling and Intertripping

Unit protection schemes formed by a number of relays located remotely from each other, and some distance protection schemes; require some form of communication between each location in order to achieve a unit protection function. This form of communication is known as protection signalling. Additionally communications facilities are also required when remote operation of a circuit breaker is required as a result of a local event. This form of communications is known as intertripping. The communication messages involved may be quite simple, involving instructions for the receiving device to take some defined action (trip, block, etc.), or it may be the passing of measured data in some form from one device to another (as in a unit protection scheme). Various types of communication links are available for protection signalling, for example:

- private pilot wires installed by the power authority
- pilot wires or channels rented from a communications company

- carrier channels at high frequencies over the power lines
- radio channels at very high or ultra high frequencies
- optical fibres

Whether or not a particular link is used depends on factors such as:

- the availability of an appropriate communication network
- the distance between protection relaying points
- the terrain over which the power network is constructed
- the cost involved.

Protection signalling is used to implement unit protection schemes, provide teleprotection commands, or implement intertripping between circuit breakers.

(a) Private pilot wires and channels

Pilot wires are continuous copper connections between signalling stations, while pilot channels are discontinuous pilot wires with isolation transformers or repeaters along the route between signalling stations. They may be laid in a trench with high voltage cables, laid by a separate route or strung as an open wire on a separate wooden pole route.

Distances over which signalling is required vary considerably. At one end of the scale, the distance may be only a few tens of metres, where the devices concerned are located in the same substation. For applications on EHV lines, the distance between devices may be between 10-100km or more. For short distances, no special measures are required against interference, but over longer distances, special send and receive relays may be required to boost signal levels and provide immunity against induced voltages from power circuits, lightning strikes to ground adjacent to the route, etc. Isolation transformers may also have to be provided to guard against rises in substation ground potential due to earth faults.

The capacity of a link can be increased if frequency division multiplexing techniques are used to run parallel signalling systems, but some Utilities prefer the link to be used only for protection signalling. Private pilot wires or channels can be attractive to a utility running a very dense power system with short distances between stations.

(b) Power line carrier communication techniques

Where long line sections are involved, or if the route involves installation difficulties, the expense of providing physical pilot connections or operational restrictions associated with the route length require that other means of providing signalling facilities are required. Power Line Carrier Communications (PLCC) is a technique that involves high frequency signal transmission along the overhead power line. It is robust and therefore reliable, constituting a low loss transmission path that is fully controlled by the Utility. High voltage capacitors are used, along with drainage coils, for the purpose of injecting the signal to and extracting it from the line. Injection can be carried out by impressing the carrier signal voltage between one conductor and earth or between any two phase conductors. The basic units can be built up into a high pass or band pass filter.

High noise levels arise from lightning strikes and system fault inception or clearance. Although these are of short duration, lasting only a few milliseconds at the most, they may cause overloading of power line carrier receiving equipment. Signalling systems used for intertripping in particular must incorporate appropriate security features to avoid maloperation. The most severe noise levels are encountered with operation of the line isolators, and these may last for some seconds. Although maloperation of the associated teleprotection scheme may have little operational significance, since the circuit breaker at one end at least is normally already open, high security is generally required to cater for noise coupled between parallel lines or passed through line traps from adjacent lines.

(c) Radio channels

At first consideration, the wide bandwidth associated with radio frequency transmissions could allow the use of modems operating at very high data rates. Protection signalling commands could be sent by serial coded messages of sufficient length and complexity to give high security, but still achieve fast operating times. In practice, it is seldom economic to provide radio equipment exclusively for protection signalling, so standard general-purpose telecommunications channel equipment is normally adopted.

Typical radio bearer equipment operates at the microwave frequencies of 0.2 to 10GHz. Because of the relatively short range and directional nature of the transmitter and receiver aerial systems at these frequencies, large bandwidths can be allocated without much chance of mutual interference with other systems.

Radio systems are well suited to the bulk transmission of information between control centres and are widely used for this. When the route of the trunk data network coincides with that of transmission lines, channels can often be allocated for protection signaling. More generally, radio communication is between major stations rather than the ends of individual lines, because of the need for line-of-sight operation between aerials and other requirements of the network. Roundabout routes involving repeater stations and the addition of pilot channels to interconnect the radio installation and the relay station may be possible, but overall dependability will normally be much lower than for PLCC systems in which the communication is direct from one end of the line to the other.

Radio channels are not affected by increased attenuation due to power system faults, but fading has to be taken into account when the signal-to-noise ratio of a particular installation is being considered. Most of the noise in such a protection signaling system will be generated within the radio equipment itself.

A polluted atmosphere can cause radio beam refraction that will interfere with efficient signaling. The height of aerial tower should be limited, so that winds and temperature changes have the minimum effect on their position.

(d) Optical fibre channels

Optical fibers are fine strands of glass, which behave as wave guides for light. This ability to transmit light over considerable distances can be used to provide optical communication links with enormous information carrying capacity and an inherent immunity to electromagnetic interference.

A practical optical cable consists of a central optical fiber which comprises core, cladding and protective buffer coating surrounded by a protective plastic oversheath containing strength members which, in some cases, are enclosed by a layer of armouring.

To communicate information, a beam of light is modulated in accordance with the signal to be transmitted. This modulated beam travels along the optical fibre and is subsequently decoded at the remote terminal into the received signal. On/off modulation of the light source is normally preferred to linear modulation since the distortion caused by non-linearities in the light source and detectors, as well as variations in received light power, are largely avoided.

Optical fibre communications are well established in the electrical supply industry. Albeit optical fibres can be laid in cable trenches, there is a strong trend to associate them with the conductors themselves by producing composite cables comprising optical fibres embedded within the conductors, either earth or phase.

For overhead lines use of OPGW (Optical Ground Wire) earth conductors is very common, while an alternative is to wrap the optical cable helically around a phase or earth conductor. This latter technique can be used without restringing of the line.

1.5.2 Relaying Schemes

1.5.2.1 Overcurrent Relays

Overcurrent 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 on 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 overcurrent relay, and it is in wide use for protection of radial low-voltage distribution 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. Overcurrent protection should not be confused with 'overload' protection, which normally makes use of relays that operate in a time related in some degree to the thermal capability of the plant to be protected. Overcurrent protection, on the other hand, is directed entirely to the clearance of faults, although with the settings usually adopted some measure of overload protection may be obtained.

- **Co-ordination procedure**

Correct overcurrent relay application requires knowledge of the fault current that can flow in each part of the network. Since large-scale tests are normally impracticable, system analysis must be used. The data required for a relay setting study are:

- a one-line diagram of the power system involved, showing the type and rating of the protection devices and their associated current transformers
- the impedances in ohms, per cent or per unit, of all power transformers, rotating machines and feeder circuits
- the maximum and minimum values of short circuit currents that are expected to flow through each protection device
- the maximum load current through protection devices
- the starting current requirements of motors and the starting and locked rotor/stalling times of induction motors
- the transformer inrush, thermal withstand and damage characteristics
- decrement curves showing the rate of decay of the fault current supplied by the generators
- performance curves of the current transformers

The relay settings are first determined to give the shortest operating times at maximum fault levels and then checked to see if operation will also be satisfactory at the minimum fault current expected. It is always advisable to plot the curves of relays and other protection devices, such as fuses, that are to operate in series, on a common scale. It is usually more convenient to use a scale corresponding to the current expected at the lowest voltage base, or to use the predominant voltage base. The alternatives are a common MVA base or a separate current scale for each system voltage. The basic rules for correct relay co-ordination can generally be stated as follows:

- whenever possible, use relays with the same operating characteristic in series with each other
- make sure that the relay farthest from the source has current settings equal to or less than the relays behind it, that is, that the primary current required to operate the relay in front is always equal to or less than the primary current required to operate the relay behind it.

Principles of Time/Current grading

Among the various possible methods used to achieve correct relay co-ordination are those using either time or overcurrent, or a combination of both. The common aim of all three methods is to give correct discrimination. That is to say, each one must isolate only the faulty section of the power system network, leaving the rest of the system undisturbed.

(a) Discrimination by time

In this method, an appropriate time setting is given to each of the relays controlling the circuit breakers in a power system to ensure that the breaker nearest to the fault opens first. A simple radial distribution system is shown in Figure 1-33, to illustrate the principle.

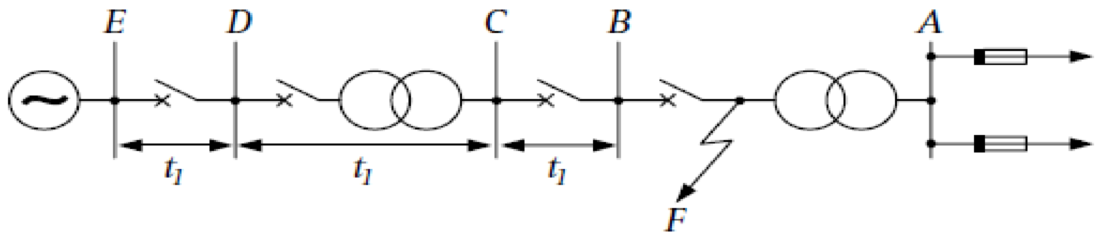


Figure 1-33. Radial system with time discrimination

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

It is the time delay element, therefore, which provides the means of discrimination. The relay at B is set at the shortest time delay possible to allow the fuse to rupture for a fault at A on the secondary side of the transformer. After the time delay has expired, the relay output contact closes to trip the circuit breaker. The relay at C has a time delay setting equal to $t_1$seconds, and similarly for the relays at D and E. If a fault occurs at F, the relay at B will operate in t seconds and the subsequent operation of the circuit breaker at B will clear the fault before the relays at C, D and E have time to operate. The time interval t_1 between each relay time setting must be long enough to ensure that the upstream relays do not operate before the circuit breaker at the fault location has tripped and cleared the fault.

The main disadvantage of this method of discrimination is that the longest fault clearance time occurs for faults in the section closest to the power source, where the fault level (MVA) is highest.

(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 of current such that only the relay nearest to the fault trips its breaker. Figure 1-34 illustrates the method.

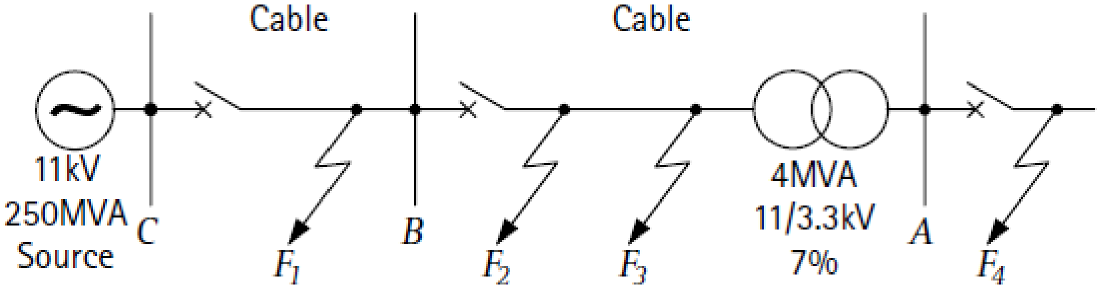


Figure 1-34. Radial system with current discrimination

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

$$I = \frac{V_{ph}}{Z_s + Z_{L1}}$$

Where $$Z_s = source\ impedance = \frac{11^2}{250} = 0.485\Omega$$

$$Z_{L1} = cable\ impedance\ between\ C\ and\ B = 0.24\Omega$$

$$Z_{L2} = cable\ impedance\ between\ B\ and\ 4MVA\ transformer = 0.04\Omega$$

Hence, $$I = \frac{11000/\sqrt{3}}{0.725} = 8800A$$

So, a relay controlling the circuit breaker at C and set to operate at a fault current of 8800A would in theory protect the whole of the cable section between C and B. However, there are two important practical points that affect this method of co-ordination:

(a) it is not practical to distinguish between a fault at F_1 and a fault at F_2, since the distance between these points may be only a few metres, corresponding to a change in fault current of approximately 0.1%

(b) in practice, there would be variations in the source fault level, typically from 250MVA to 130MVA. At this lower fault level, the fault current would not exceed 6800A, even for a cable fault close to C. A relay set at 8800A would not protect any part of the cable section concerned.

Discrimination by current is therefore not a practical proposition for correct grading between the circuit breakers at C and B. However, the problem changes appreciably when there is significant impedance between the two circuit breakers concerned.

Consider the grading required between the circuit breakers at C and A in Figure 1-34. Assuming a fault at F4, the short-circuit current is given by:

$$I = \frac{V_{ph}}{Z_s + Z_{L1}}$$

Where $Z_s = \text{source impedance} = 0.485\Omega$

$$Z_{L1} = \text{cable impedance between C and B} = 0.24\Omega$$

$$Z_{L2} = \text{cable impedance between B and 4MVA transformer} = 0.04\Omega$$

$$Z_T = \text{transformer impedance} = 0.07\left(\frac{11^2}{4}\right) = 2.12\Omega$$

Hence, $I = \dfrac{11000/\sqrt{3}}{2.885} = 2200A$

For this reason, a relay controlling the circuit breaker at B and set to operate at a current of 2200A 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 2200A, that is 2860A, for the relay at B. Now, assuming a fault at F_3, at the end of the 11kV cable feeding the 4MVA transformer, the short-circuit current is given by:

$$I = \frac{11/\sqrt{3}}{Z_s + Z_{L1} + Z_{L2}}$$

Thus assuming a 250MVA source fault level,

$$I = \frac{11/\sqrt{3}}{0.485 + 0.24 + 0.04} = 8300A$$

Alternatively, assuming a 130MVA source fault level,

$$I = \frac{11/\sqrt{3}}{0.93 + 0.24 + 0.04} = 5250A$$

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

- **Discrimination by both time and current**

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

It is because of the limitations imposed by the independent use of either time or current co-ordination that the inverse time overcurrent relay characteristic has evolved. With this characteristic, the time of operation is inversely proportional to the fault current level and the actual characteristic is a function of both 'time' and 'current' settings. Figure 1-35 illustrates the characteristics of two relays given different current/time settings.

For a large variation in fault current between the two ends of the feeder, faster operating times can be achieved by the relays nearest to the source, where the fault level is the highest. The disadvantages of grading by time or current alone are overcome.

The selection of overcurrent relay characteristics generally starts with selection of the correct characteristic to be used for each relay, followed by choice of the relay current settings. Finally the grading margins and hence time settings of the relays are determined. An iterative procedure is often required to resolve conflicts, and may involve use of non-optimal characteristics, current or time grading settings.

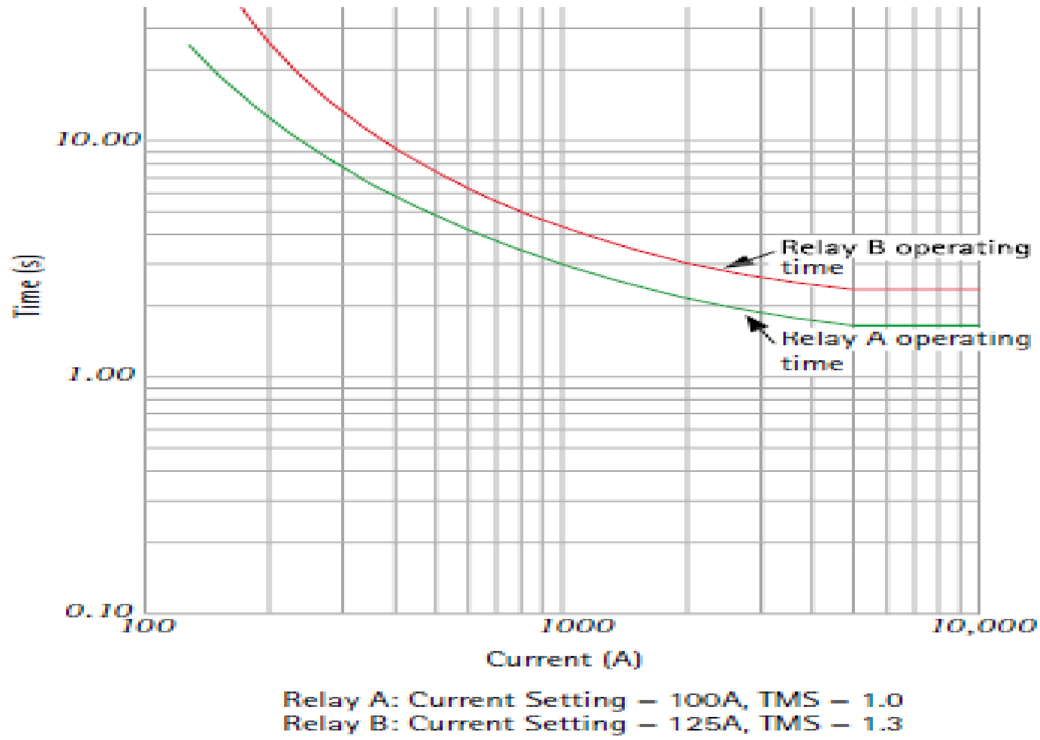


Figure 1-35. Relay characteristic for different settings

- **Standard IDMT overcurrent relays**

The current/time tripping characteristics of IDMT relays may need to be varied according to the tripping time required and the characteristics of other protection devices used in the network. For these purposes, IEC 60255 defines a number of standard characteristics as follows:

- Standard Inverse (SI)
- Very Inverse (VI)
- Extremely Inverse (EI)
- Definite Time (DT)

Relay Characteristic	Equation (IEC 60255)
Standard Inverse (SI)	$t = TMS \times \frac{0.14}{I_r^{0.02} - 1}$
Very Inverse (VI)	$t = TMS \times \frac{13.5}{I_r - 1}$
Extremely Inverse (EI)	$t = TMS \times \frac{80}{I_r^2 - 1}$
Long time standard earth fault	$t = TMS \times \frac{120}{I_r - 1}$

Table 1-5. Relay characteristics to IEC 60225

- **Important terminologies regarding relays**

(a) Pickup current - It is the minimum current in the relay coil at which the relay starts to operate. When the current in the relay is less than the pick-up value the relay does not operate and the breaker controlled by it remains in the closed position. When the relay coil current is equal to or greater than the pickup value, the relay operates to energize the trip coil that opens the circuit breaker.

(b) Current setting – It is often desirable to adjust the pickup current to any value. This is known as current setting and is usually achieved by the use of tappings on the relay coil. The taps are brought out to a plug bridge, which permits the altering of the number of turns on the relay coil, this changes the torque on the disc and hence the time of operation of the relay.

$$Pickup current = Rated\ secondary\ current\ of\ CT \times Current\ setting$$

(c) Plug setting multiplayer (PSM) – It is the ratio of fault current in the relay coil to the pickup current.

$$PSM = \frac{Fault\ current\ in\ relay\ coil}{pickup\ current}$$

(d) Time-setting multiplier – A relay is generally provided with control to adjust the time of operation. This adjustment is known as time setting multiplier. The time setting dial is calibrated from 0 to 1 in steps of 0.05. These figures are multipliers to be used to convert the time derived from the time/psm curve into the actual operating time. The actual time of operation is calculated by multiplying the time setting multiplier with the time obtained from the time/psm curve of the relay.

(e) Time/ PSM – It is the curve between time of operation and plug setting multiplier of a relay.

1.5.2.2 Distance Relays

Distance protection, in its basic form, is a non-unit system of protection offering considerable economic and technical advantages. Unlike phase and neutral overcurrent protection, the key advantage of distance protection is that its fault coverage of the protected circuit is virtually independent of source impedance variations.

Distance protection is comparatively simple to apply and it can be fast in operation for faults located along most of a protected circuit. It can also provide both primary and remote back-up functions in a single scheme. It can easily be adapted to create a unit protection scheme when applied with a signaling channel. In this form it is eminently suitable for application with high-speed autoreclosing, for the protection of critical transmission lines.

(a) Basic operating principle of distance relays

Since the impedance of a transmission line is proportional to its length, for distance measurement it is appropriate to use a relay capable of measuring the impedance of a line up to a predetermined point (the reach point). Such a relay is described as a distance relay and is designed to operate only for faults occurring between the relay location and the selected reach point, thus giving discrimination for faults that may occur in different line sections.

The basic principle of distance protection involves the division of the voltage at the relaying point by the measured current. The apparent impedance so calculated is compared with the reach point impedance. If the measured impedance is less than the reach point impedance, it is assumed that a fault exists on the line between the relay and the reach point.

The reach point of a relay is the point along the line impedance locus that is intersected by the boundary characteristic of the relay. Since this is dependent on the ratio of voltage and current and the phase angle between them, it may be plotted on an R/X diagram. The loci of power system impedances as seen by the relay during faults, power swings and load variations may be plotted on the same diagram and in this manner the performance of the relay in the presence of system faults and disturbances may be studied.

(b) Relay performance

Distance relay performance is defined in terms of reach accuracy and operating time. Reach accuracy is a comparison of the actual ohmic reach of the relay under practical conditions with the relay setting value in ohms. Reach accuracy particularly depends on the level of voltage presented to the relay under fault conditions. The impedance measuring techniques employed in particular relay designs also have an impact. Operating times can vary with fault current, with fault position relative to the relay setting, and with the point on the voltage wave at which the fault occurs. Depending on the measuring techniques employed in a particular relay design, measuring signal transient errors, such as those produced by capacitor voltage transformers or saturating CTs, can also adversely delay relay operation for faults close to the reach point. It is usual for electromechanical and static distance relays to claim both maximum and minimum operating times. However, for modern digital or numerical distance relays, the variation between these is small over a wide range of system operating conditions and fault positions.

- **Zones of protection**

Careful selection of the reach settings and tripping times for the various zones of measurement enables correct coordination between distance relays on a power system. Basic distance protection will comprise instantaneous directional Zone 1 protection and one or more time delayed zones.

Digital and numerical distance relays may have up to five zones, some set to measure in the reverse direction. Typical settings for three forward-looking zones of basic distance protection are given in the following sub-sections. To determine the settings for a particular relay design or for a particular distance teleprotection scheme, involving end-to-end signaling, the relay manufacturer's instructions should be referred to.

- **Zone 1 setting**

  Electromechanical/static relays usually have a reach setting of up to 80% of the protected line impedance for instantaneous Zone 1 protection. For digital/numerical distance relays, settings of up to 85% may be safe. The resulting 15-20% safety margin ensures that there is no risk of the Zone 1 protection over-reaching the protected line due to errors in the current and voltage transformers, inaccuracies in line impedance data provided for setting purposes and errors of relay setting and measurement. Otherwise, there would be a loss of discrimination with fast operating protection on the following line section. Zone 2 of the distance protection must cover the remaining 15-20% of the line.

- **Zone 2 setting**

  To ensure full cover of the line with allowance for the sources of error already listed in the previous section, the reach setting of the Zone 2 protection should be at least 120% of the protected line impedance. In many applications it is common practice to set the Zone 2 reach to be equal to the protected line section

+50% of the shortest adjacent line. Where possible, this ensures that the resulting maximum effective Zone 2 reach does not extend beyond the minimum effective Zone 1 reach of the adjacent line protection. This avoids the need to grade the Zone 2 time settings between upstream and downstream relays. In electromechanical and static relays, Zone 2 protection is provided either by separate elements or by extending the reach of the Zone 1 elements after a time delay that is initiated by a fault detector. In most digital and numerical relays, the Zone 2 elements are implemented in software.

Zone 2 tripping must be time-delayed to ensure grading with the primary relaying applied to adjacent circuits that fall within the Zone 2 reach. Thus complete coverage of a line section is obtained, with fast clearance of faults in the first 80-85% of the line and somewhat slower clearance of faults in the remaining section of the line.

- **Zone 3 setting**

  Remote back-up protection for all faults on adjacent lines can be provided by a third zone of protection that is time delayed to discriminate with Zone 2 protection plus circuit breaker trip time for the adjacent line. Zone 3 reach should be set to at least 1.2 times the impedance presented to the relay for a fault at the remote end of the second line section.

  On interconnected power systems, the effect of fault current infeed at the remote busbars will cause the impedance presented to the relay to be much greater than the actual impedance to the fault and this needs to be taken into account when setting Zone 3. In some systems, variations in the remote busbar infeed can prevent the application of remote back-up Zone 3 protection but on radial distribution systems with single end infeed, no difficulties should arise.

(c) Distance relay characteristics

Some numerical relays measure the absolute fault impedance and then determine whether operation is required according to impedance boundaries defined on the R/X diagram. Traditional distance relays and numerical relays that emulate the impedance elements of traditional relays do not measure absolute impedance. They compare the measured fault voltage with a replica voltage derived from the fault current and the zone impedance setting to determine whether the fault is within zone or out-of-zone. Distance relay impedance comparators or algorithms which emulate traditional comparators are classified according to their polar characteristics, the number of signal inputs they have, and the method by which signal comparisons are made. The common types compare either the relative amplitude or phase of two input quantities to obtain operating characteristics that are either straight lines or circles when plotted on an R/X diagram. At each stage of distance relay design evolution, the development of impedance operating characteristic shapes and sophistication has been governed by the technology available and the acceptable cost. Since many traditional relays are still in service and since some numerical relays emulate the techniques of the traditional relays, a brief review of impedance comparators is justified.

- **Amplitude and Phase comparison**

Relay measuring elements whose functionality is based on the comparison of two independent quantities are essentially either amplitude or phase comparators. For the impedance elements of a distance relay, the quantities being compared are the voltage and current measured by the relay. There are numerous techniques available for performing the comparison, depending on the technology used. They vary from balanced-beam (amplitude comparison) and induction cup (phase comparison) electromagnetic relays, through diode and operational amplifier comparators in static-type distance relays, to digital sequence comparators in digital relays and to algorithms used in numerical relays.

Any type of impedance characteristic obtainable with one comparator is also obtainable with the other. The addition and subtraction of the signals for one type of comparator produces the required signals to obtain a similar characteristic using the other type. For example, comparing V and I in an amplitude comparator results in a circular impedance characteristic centred at the origin of the R/X diagram. If the sum and difference of V and I are applied to the phase comparator the result is a similar characteristic.

- **Plain impedance characteristic**

This characteristic takes no account of the phase angle between the current and the voltage applied to it; for this reason its impedance characteristic when plotted on an R/X diagram is a circle with its centre at the origin of the co-ordinates and of radius equal to its setting in ohms. Operation occurs for all impedance values less than the setting, that is, for all points within the circle. The relay characteristic, shown in Figure 1-36, is therefore non-directional, and in this form would operate for all faults along the vector AL and also for all faults behind the busbars up to impedance AM.

It is to be noted that A is the relaying point and RAB is the angle by which the fault current lags the relay voltage for a fault on the line AB and RAC is the equivalent leading angle for a fault on line AC. Vector AB represents the impedance in front of the relay between the relaying point A and the end of line AB. Vector AC represents the impedance of line AC behind the relaying point. AL represents the reach of instantaneous Zone 1 protection, set to cover 80% to 85% of the protected line.

A relay using this characteristic has three important disadvantages:

- It is non-directional; it will see faults both in front of and behind the relaying point, and therefore requires a directional element to give it correct discrimination.
- It has non-uniform fault resistance coverage.
- It is susceptible to power swings and heavy loading of a long line, because of the large area covered by the impedance circle.

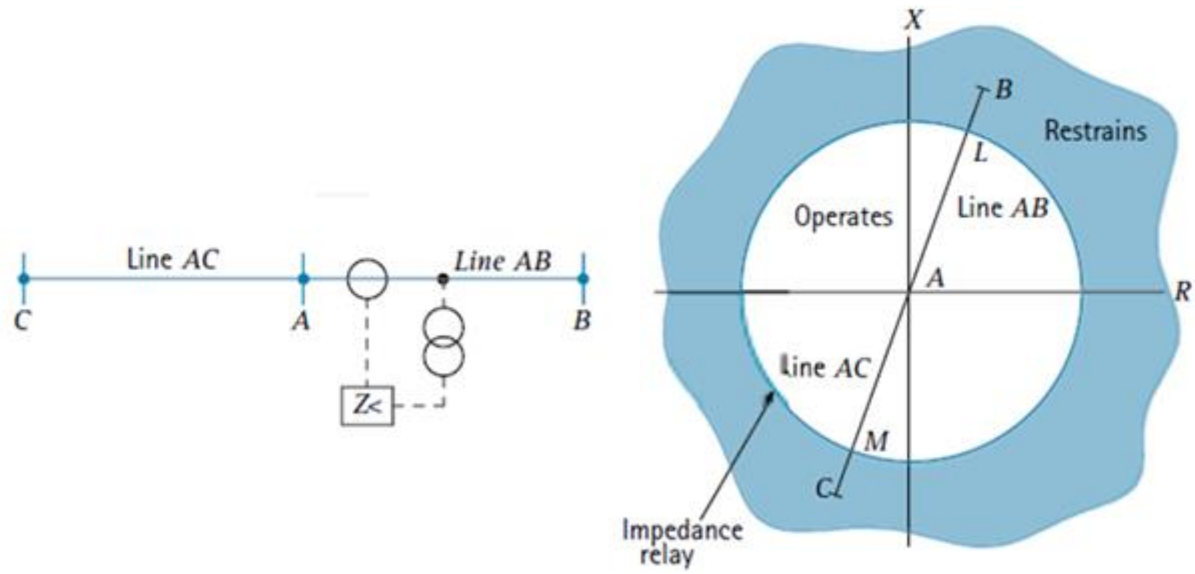


Figure 1-36. Plain impedance characteristic

Directional control is an essential discrimination quality for a distance relay, to make the relay non-responsive to faults outside the protected line. This can be obtained by the addition of a separate directional control element. The impedance characteristic of a directional control element is a straight line on the R/X diagram, so the combined characteristic of the directional and impedance relays is the semi-circle APLQ shown in Figure 1-37.

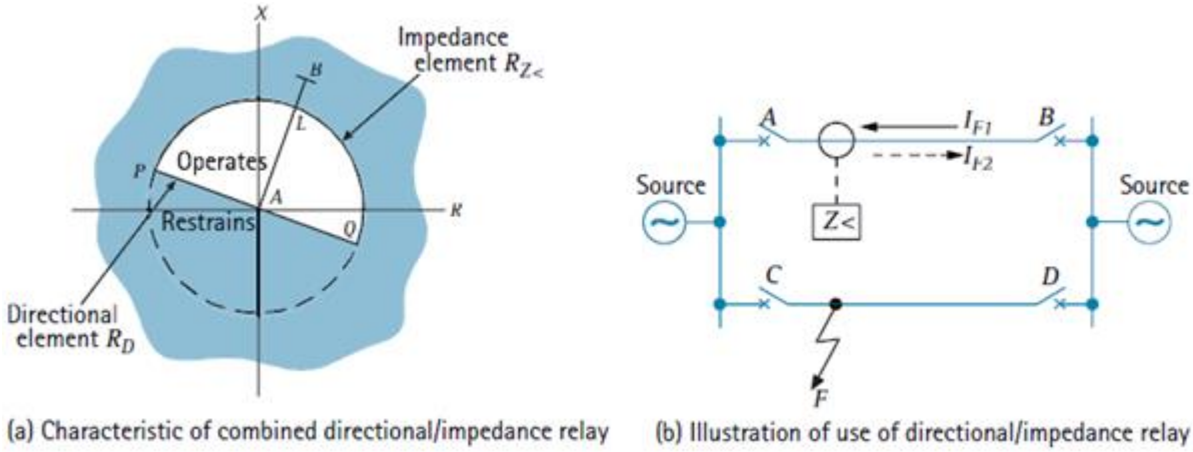
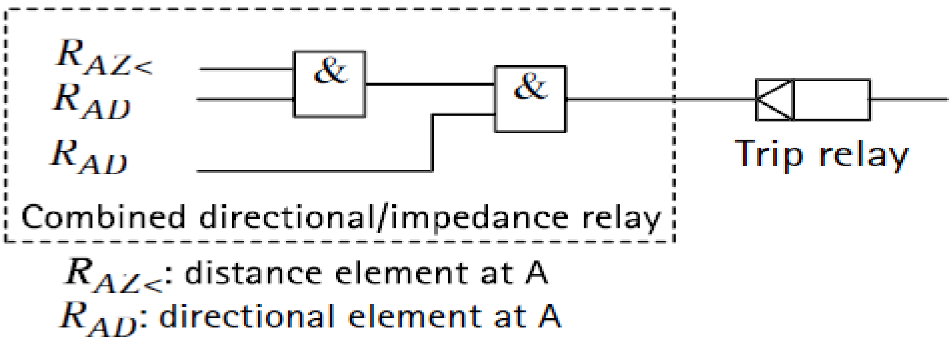


Figure 1-37. Combined characteristic of directional and impedance relays

If a fault occurs at F close to C on the parallel line CD, the directional unit RD at A will restrain due to current I_{F1} (see Figure below). At the same time, the impedance unit is prevented from operating by the inhibiting output of unit RD. If this control is not provided, the under impedance element could operate prior to circuit breaker C opening. Reversal of current through the relay from I_{F1} to I_{F2} when C opens could then result in incorrect tripping of the healthy line if the directional unit RD operates before the impedance unit resets. This is an example of the need to consider the proper co-ordination of multiple relay elements to attain reliable relay performance during evolving fault conditions.



Logic for directional and impedance elements at A

- **Self-polarised mho relay**

The mho impedance element is generally known as such because its characteristic is a straight line on an admittance diagram. It cleverly combines the discriminating qualities of both reach control and directional control, thereby eliminating the ‘contact race' problems that may be encountered with separate reach and directional control elements. This is achieved by the addition of a polarising signal. Mho impedance elements were particularly attractive for economic reasons where electromechanical relay elements were employed.

As a result, they have been widely deployed worldwide for many years and their advantages and limitations are now well understood. For this reason they are still emulated in the algorithms of some modern numerical relays.

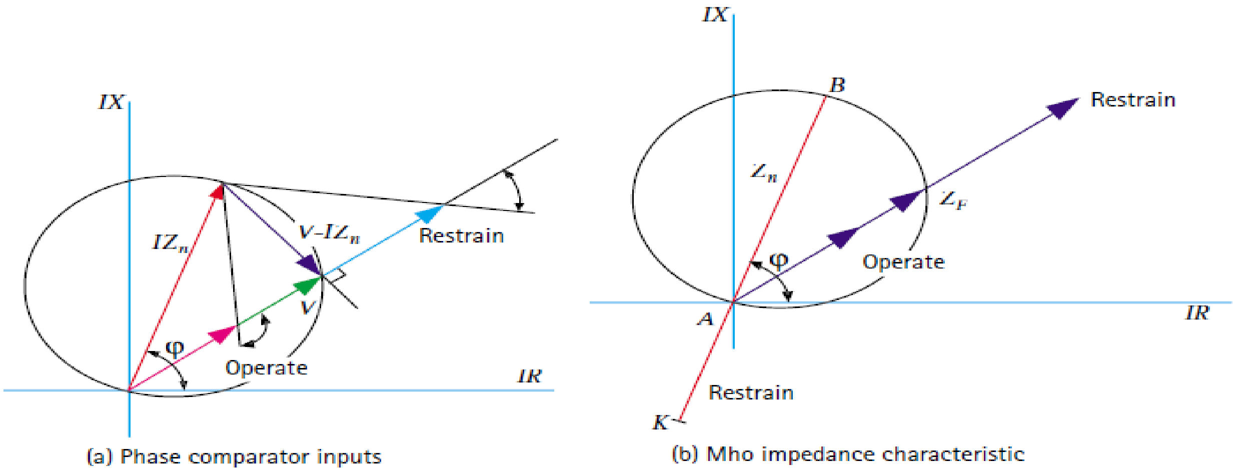


Figure 1-38. Characteristic of mho impedance relay

The characteristic of a mho impedance element, when plotted on an R/X diagram, is a circle whose circumference passes through the origin, as illustrated in figure 1-38. This demonstrates that the impedance element is inherently directional and such that it will operate only for faults in the forward direction along line AB.

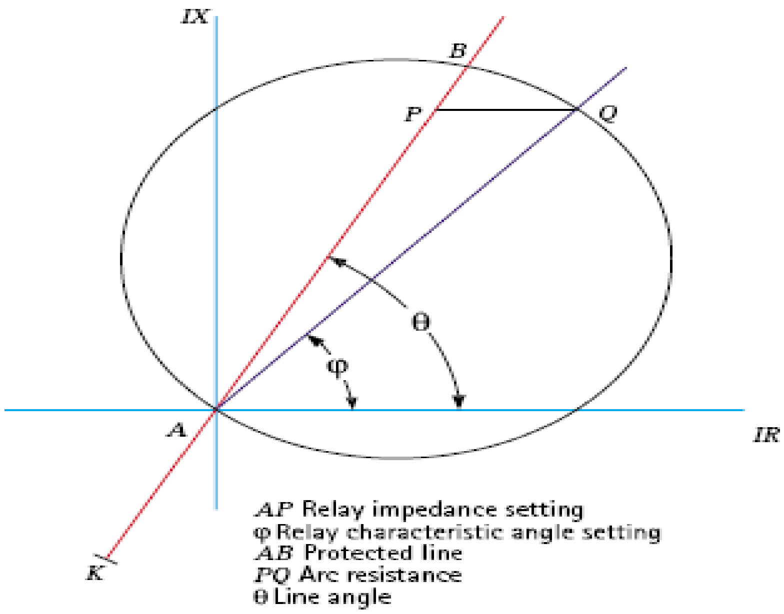


Figure1- 39. Mho relay characteristic with increased arc resistance coverage

The impedance characteristic is adjusted by setting Z_n, the impedance reach, along the diameter and, the angle of displacement of the diameter from the R axis. Angle is known as the Relay Characteristic Angle (RCA). The relay operates for values of fault impedance ZF within its characteristic.

It will be noted that the impedance reach varies with fault angle. As the line to be protected is made up of resistance and inductance, its fault angle will be dependent upon the relative values of R and X at the system operating frequency. Under an arcing fault condition, or an earth fault involving additional resistance, such as tower footing resistance or fault through vegetation, the value of the resistive component of fault impedance will increase to change the impedance angle. Thus a relay having a characteristic angle equivalent to the line angle will under-reach under resistive fault conditions.

It is usual, therefore, to set the RCA less than the line angle, so that it is possible to accept a small amount of fault resistance without causing under-reach. However, when setting the relay, the difference between the line angle θ and the relay characteristic angle must be known. The resulting characteristic is shown in figure 1-39 where AB corresponds to the length of the line to be protected. With set less than θ, the actual amount of line protected, AB, would be equal to the relay setting value AQ multiplied by cosine (θ-).

4.5.2.3 Differential Relays

Differential protection, as its name implies, compares the currents entering and leaving the protected zone and operates when the differential between these currents exceeds a pre-determined magnitude. This type of protection can be divided into two types, namely: balanced current and balanced voltage.

(a) Balanced circulating current system

The principle is shown in figure 1-40. The CTs are connected in series and the secondary current circulates between them. The relay is connected across the midpoint thus the voltage across the relay is theoretically nil, therefore no current through the relay and hence no operation for any faults outside the protected zone.

Similarly under normal conditions the currents, leaving zone A and B are equal, making the relay to be inactive by the current balance. Under internal fault conditions (i.e. between the CTs at end A and B) relay operates.

This is basically due to the direction of current reversing at end B making the fault current to flow from B to A instead of the normal A to B condition in the earlier figure (see figure 1-41).

The current transformers are assumed identical and are assumed to share the burden equally between the two ends. However, it is not always possible to have identical CTs and to have the relay at a location equidistant from the two end CTs. It is a normal practice to add a resistor in series with the relay to balance the unbalance created by the unequal nature of burden between the two end circuits. This resistor is named as 'stabilizing resistance'.

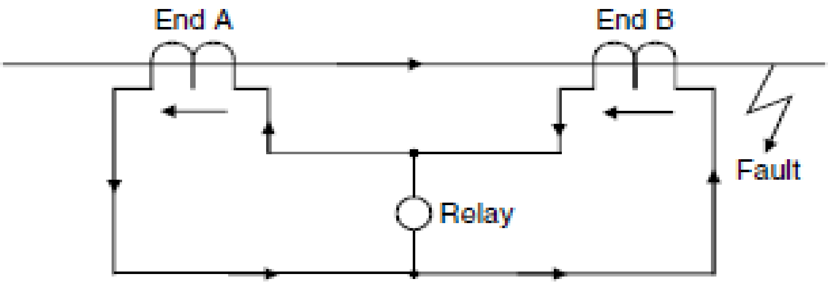


Figure 1-40. Balanced circulating current scheme, external fault (stable)

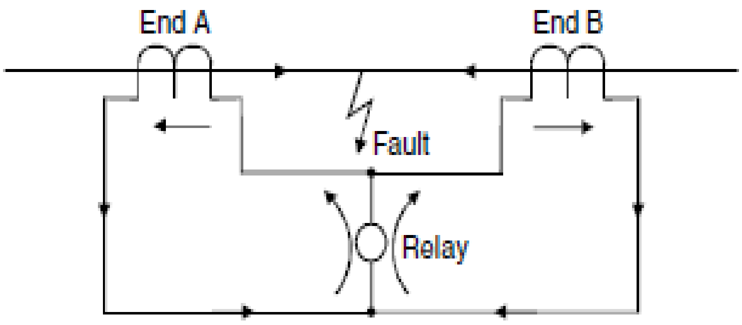


Figure 1-41. Balanced circulating current scheme, internal fault (operate)

(b) Balanced voltage system

As the name implies, it is necessary to create a balanced voltage across the relays in end A and end B under healthy and out-of-zone fault conditions. In this arrangement, the CTs

are connected to oppose each other (see figure 1-42). Voltages produced by the secondary currents are equal and opposite; thus no currents flow in the pilots or relays, hence stable on through-fault conditions. Under internal fault conditions relays will operate (see figure 1-43).

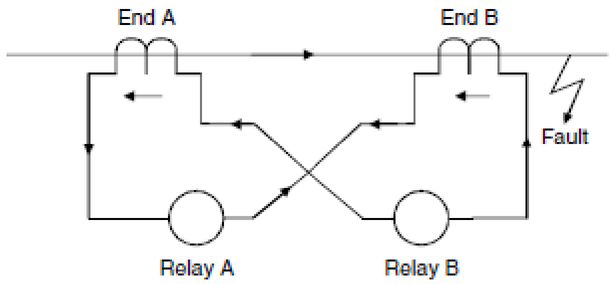


Figure 1-42. Balanced voltage scheme, external fault (stable)

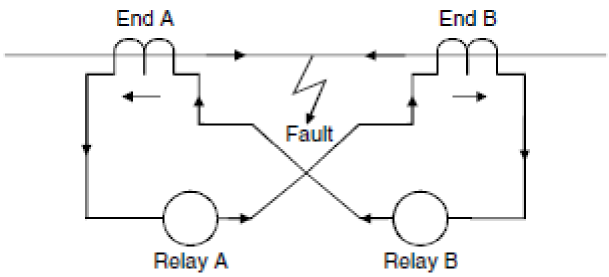


Figure 1-43. Balanced voltage scheme, internal fault (operate)

The balanced or circulating current systems are invariably used for generator, transformer and switchgear main protection where it is convenient to readily access the midpoint of the pilots. This is because both sets of CTs are mounted in the same substation and a single relay is used to detect the fault condition within the protected zone.

On the other hand, balanced voltage systems are used mainly on feeder protection where the CTs are mounted in different substations, which are some distance apart. As there are two relays involved, one at each end, they can each be mounted in their respective substation. Although similar, the various forms of differential protection differ considerably in detail. The differences are concerned with the precautions taken to ensure stability – i.e. to ensure that the protection does not operate incorrectly for a through fault.

- **Percentage differential relays**

The disadvantage of the current differential protection is that current transformers must be identical; otherwise there will be current flowing through the current relays for faults outside of the protected zone or even under normal conditions. Sensitivity to the differential current due to the current transformer errors is reduced by percentage differential relays.

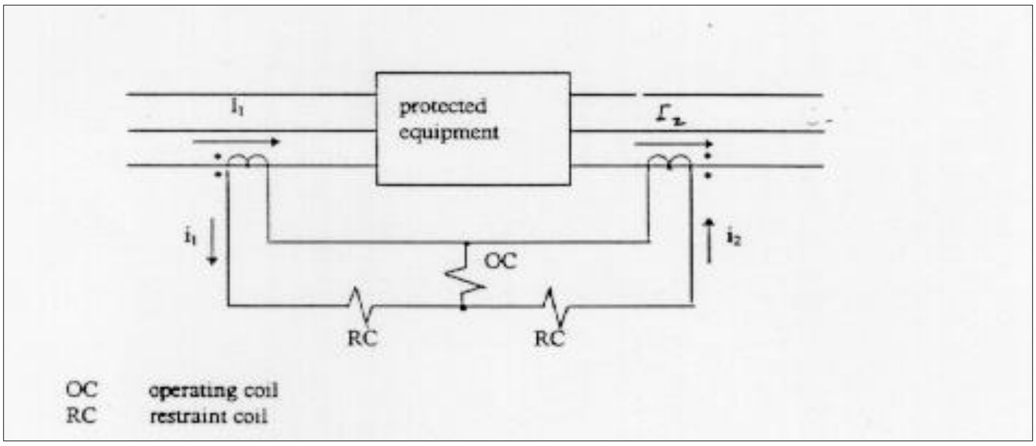


Figure 1-44. Percentage Differential Relay

In percentage differential relays, the current from each current transformer flows through a restraint coil. The purpose of the restraint coil is to prevent undesired relay operation due to current transformer errors. The operating coil current | i_1 - i_2 | required for tripping is a percentage of the average current through the restraint coils. It is given by:

$$|i_1 - i_2| \geq k\left|\frac{i_1 + i_2}{2}\right| = k|i_{average}|$$

where k is the proportion of the operating coil current to the restraint coil current. For example if k = 0.1, the operating coil current must be more than 10% of the average restraint coil current in order for the relay to operate.

4.5.2.4 Autoreclosers

Faults on overhead lines can be categorized into (a) transient (or temporary) faults and (b) permanent faults. 80-90% of faults on any overhead line network are transient in nature. The remaining 10%-20% of faults are either semi-permanent or permanent.

Transient faults are commonly caused by lightning and temporary contact with foreign objects. The immediate tripping of one or more circuit breakers clears the fault. Subsequent re-energisation of the line is usually successful. A small tree branch falling on the line could cause a semi-permanent fault. The cause of the fault would not be removed by the immediate tripping of the circuit, but could be burnt away during a time-delayed trip. HV overhead lines in forest areas are prone to this type of fault.

Permanent faults, such as broken conductors, and faults on underground cable sections, must be located and repaired before the supply can be restored. Use of an auto-reclose scheme to re-energise the line after a fault trip permits successful re-energisation of the line. Sufficient time must be allowed after tripping for the fault arc to de-energise prior to reclosing otherwise the arc will re-strike.

Such schemes have been the cause of a substantial improvement in continuity of supply. A further benefit, particularly to EHV systems, is the maintenance of system stability and synchronism.

(a) Application of autoreclosing

The most important parameters of an auto-reclose scheme are:

- dead time
- reclaim time
- single or multi-shot

These parameters are influenced by:

- type of protection
- type of switchgear
- possible stability problems
- effects on the various types of consumer loads

The weighting given to the above factors is different for HV distribution networks and EHV transmission systems.

(b) Autoreclosing on HV distribution networks

On HV distribution networks, auto-reclosing is applied mainly to radial feeders where problems of system stability do not arise, and the main advantages to be derived from its use can be summarised as follows:

- reduction to a minimum of the interruptions of supply to the consumer
- instantaneous fault clearance can be introduced, with the accompanying benefits of shorter fault duration, less fault damage, and fewer permanent faults

As 80% of overhead line faults are transient, elimination of loss of supply from this cause by the introduction of auto-reclosing gives obvious benefits through:

- improved supply continuity
- reduction of substation visits

Instantaneous tripping reduces the duration of the power arc resulting from an overhead line fault to a minimum. The chance of permanent damage occurring to the line is reduced. The application of instantaneous protection may result in non-selective tripping of a number of circuit breakers and an ensuing loss of supply to a number of healthy sections. Auto-reclosing allows these circuit breakers to be reclosed within a few seconds. With transient faults, the overall effect would be loss of supply for a very short time but affecting a larger number of consumers.

If only time-graded protection without auto-reclose was used, a smaller number of consumers might be affected, but for a longer time period. When instantaneous protection is used with autoreclosing, the scheme is normally arranged to inhibit the instantaneous protection after the first trip. For a permanent fault, the time-graded protection will give discriminative tripping after reclosure, resulting in the isolation of the faulted section. Some schemes allow a number of reclosures and time-graded trips after the first instantaneous trip, which may result in the burning out and clearance of semi-permanent faults.

Further benefit of instantaneous tripping is a reduction in circuit breaker maintenance by reducing pre-arc heating when clearing transient faults. When considering feeders that are partly overhead line and partly underground cable, any decision to install auto-reclosing would be influenced by any data known on the frequency of transient faults. When a significant proportion of faults are permanent, the advantages of auto-reclosing are small, particularly since reclosing on to a faulty cable is likely to aggravate the damage.

(c) Autoreclosing on EHV transmission lines

The most important consideration in the application of auto-reclosing to EHV transmission lines is the maintenance of system stability and synchronism. The problems involved are dependent on whether the transmission system is weak or strong. With a weak system, loss of a transmission link may lead quickly to an excessive phase angle across the CB used for re-closure, thus preventing a successful re-closure.

In a relatively strong system, the rate of change of phase angle will be slow, so that delayed auto-reclose can be successfully applied. An illustration is the interconnector between two power systems as shown in figure 1-45. Under healthy conditions, the amount of synchronising power transmitted, P, crosses the power/angle curve OAB at point X, showing that the phase displacement between the two systems is θ_0.

Under fault conditions, the curve OCB is applicable, and the operating point changes to Y. Assuming constant power input to both ends of the line, there is now an accelerating power XY. As a result, the operating point moves to Z, with an increased phase displacement, θ_1, between the two systems. At this point the circuit breakers trip and break the connection. The phase displacement continues to increase at a rate dependent on the inertia of the two power sources.

To maintain synchronism, the circuit breaker must be reclosed in a time short enough to prevent the phase angle exceeding θ_2. This angle is such that the area (2) stays greater than the area (1), which is the condition for maintenance of synchronism.

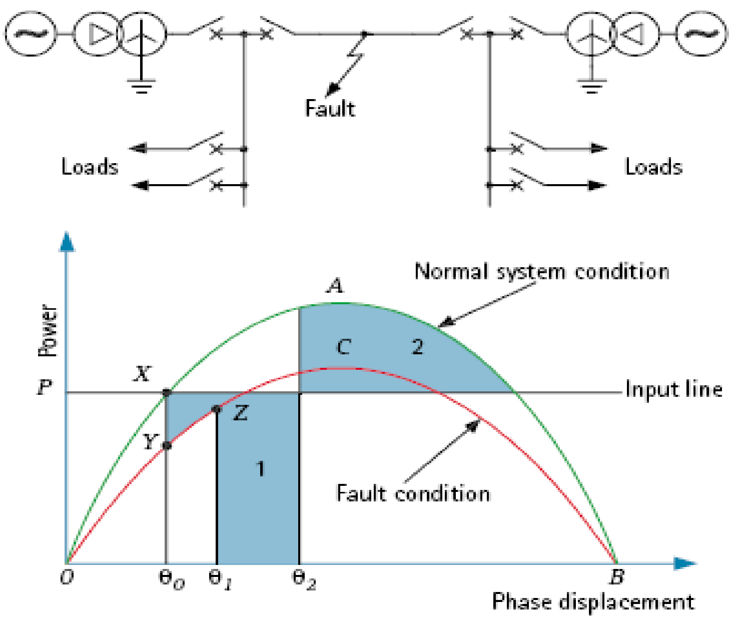


Figure 1-45. Effect of high-speed three-phase autoreclosing on system stability of a weak system

This example, for a weak system, shows that the successful application of auto-reclosing in such a case needs high-speed protection and circuit breakers, and a short dead time.

On strong systems, synchronism is unlikely to be lost by the tripping out of a single line. For such systems, an alternative policy of delayed autoreclosing may be adopted. This enables the power swings on the system resulting from the fault to decay before reclosure is attempted.

M02 – FAULT CHARACTERISTICS AND CALCULATIONS

2.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of fault characteristics and Calculations
- Explain types of fault and fault calculation methods

2.2.1 Introduction

Power systems are subject to many kinds of faults. The principal types are: three-phase with and without earth connection; phase-to-phase (two-phase); phase-to earth (single-phase); and double phase-to-earth (phase-phase-earth). Faults sometimes occur simultaneously at separate points on the system and on different phases (cross-country faults).

Sometimes they are accompanied by a broken conductor, or may even take the form of a broken conductor without earth connection. All of these appertain to lines and feeders, but the principal ones are common to all kinds of plant.

2.3 Faults

2.3.1 Nature and Causes of Faults

The nature of a fault is simply defined as any abnormal condition which causes a reduction in the basic insulation strength between phase conductors, or between phase conductors and earth or any earthed screens surrounding the conductors.

In practice, a reduction is not regarded as a fault until it is detectable; that is, until it results either in an excess current or in a reduction of the impedance between conductors, or between conductors and earth, to a value below that of the lowest load impedance normal to the circuit.

Pollution is commonly caused by deposited soot or cement dust in industrial areas, and by salt deposited by wind-borne sea-spray in coastal areas. Other causes of faults are:

- on overhead lines—trees, flying objects, birds, aircraft, lightning, fog, ice and snow loading, punctured or broken insulators, open-circuit conductors, abnormal loading

- in machines, cables and transformers—failure of solid insulation because of moisture, mechanical damage, accidental contact with earth or earthed screens, flashover in air caused by overvoltage, abnormal loading. All incidents arising from these causes are so-called 'primary' or 'system' faults.

Another kind of fault is the 'non-system' fault, so called because it defines an operation of protection which results in the tripping of circuit breakers without an accompanying fault on the primary system.

Such non-system faults may be the result of defects in the protection, for example incorrect settings, faulty or incorrect connection, or they may result from human error in testing or maintenance work.

For the purposes of statistical analysis, a fault (covering both 'system' and 'nonsystem' faults) is arbitrarily defined as:

- any abnormal event causing or requiring the automatic tripping of a circuit breaker, or,
- any operation in error of a circuit breaker or isolator.

2.3.2 Frequency of Occurrence of Faults

Most faults in an electrical utility system with a network of overhead lines are one-phase-to-ground faults resulting primarily from lightning-induced transient high voltage and from falling trees and tree limbs.

In the overhead systems, momentary tree contact caused by wind is another major cause of faults. Ice, freezing snow, and wind during severe storms can cause many faults and much damage.

These faults include the following, with approximate percentages of occurrence:

Single-phase-to-ground:	(70 – 80)%
Phase-to-phase-to-ground:	(17 – 10)%
Phase-to-phase:	(10 – 8)%
Three-phase:	(3 – 2)%

Series unbalances, such as a broken conductor or a blown fuse, are not too common, except perhaps in the lower-voltage system in which fuses are used for protection.

2.3.3 Objectives of Fault Calculations

An essential part of the design of a power supply network is the calculation of the system voltages and currents which flow in the components when faults of various types occur. The magnitude of the fault currents gives the engineer the current settings for the protection to be used and the ratings of the circuit breakers. The idea is to be able to rescue the system from the abnormal conditions within minimum time. The main objectives of fault calculations can be summarised as follows:

- To determine maximum and minimum three-phase short-circuit currents.
- To determine the unsymmetrical fault current for single and double line-to-earth, line-to-line faults and open-circuit faults.
- Investigation of the operation of protective relays.
- Determination of rated rupturing capacity of breakers.
- To determine fault-current distribution and busbar-voltage levels during faults.

2.3.4 Types of Fault

Electrical failure generally implies one or the other (or both) of two types of failure, namely insulation failure resulting in a short-circuit condition or conducting path failure resulting in an open-circuit condition. The principal types of fault are listed and classified in Table 2-1 below.

Short-circuited phases	Three-phase fault clear of earth Three-phase-to-earth fault Phase-to-phase fault Single-phase-to-earth fault Two-phase-to-earth fault Phase-to-phase plus single-phase-to earth fault
Open-circuited phases	Single-phase open-circuit Tow-phase open-circuit Three-phase open-circuit
Simultaneous faults	A combination of two or more faults at the same time, the faults being of similar or dissimilar type and occurring at the same or different locations. Typical examples are the cross-country earth-fault and the open circuit with earth fault condition
Winding faults	Winding-to-earth short-circuit Winding-to-winding short-circuit Short-circuited turns Open-circuited winding

Table 2-1. Types of fault

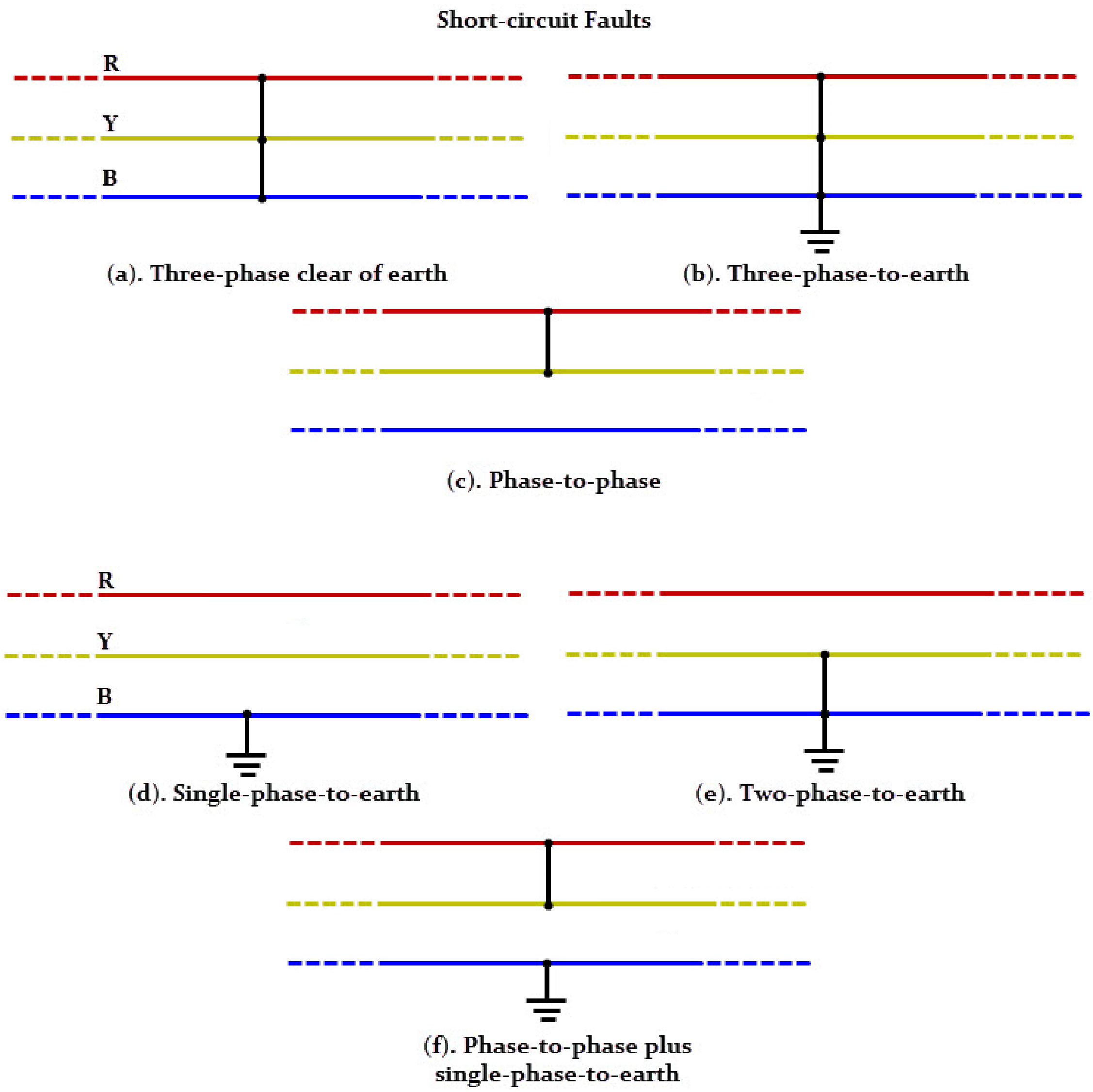


Figure 2-1. Short-circuited-phase faults

Short-circuited phases*:* Faults of this type are caused by insulation failure between phase conductors or between phase conductors and earth, or both, the result being the short-circuiting of one or more phases to earth or to one another, or both. The full range of possible fault conditions of this type is illustrated in Figure 2-1. The three-phase fault, which may be to earth or clear of earth, is the only balanced or symmetrical short-circuit condition, the presence or absence of the earth connection being normally of little or no significance unless the fault occurs simultaneously with a second unbalanced fault involving earth. The three-phase short-circuit is commonly used as a standard fault condition as, for example, in the determination of system fault-levels, these levels being normally quoted as three-phase short-circuit values.

Open-circuited phases: This type of fault, illustrated in Figure 2-2, is the failure of one or more phases to conduct. The more common causes of this type of fault are joint failures on overhead lines and cables, and the failure of one or more phases of a circuit-breaker or isolator to open or close. The single-phase and two-phase conditions are of particular interest because they both tend to produce unbalance of the power system currents and voltages with consequent risk of damage to rotating plant.

Simultaneous faults: *A* simultaneous fault condition, sometimes termed a multiple fault condition, is defined as the simultaneous presence of two or more faults of similar or dissimilar types at the same or different points on the power system. Such conditions may result from a common cause, from different but consequential causes or, extremely rarely, from quite separate and independent causes.

Winding faults: The types of fault which can occur on machine and transformer windings are illustrated in Figure 2-3 and consist mainly of short-circuits, from one phase winding to earth, from one phase winding to another or from one point to another on the same phase winding. The last mentioned condition is known as a short-circuited turns fault, and is of particular interest from the protection standpoint in that the fault current in the short-circuited turns may be very large and that in the remainder of the winding very small. The open-circuited winding condition is quite rare in practice and is usually the result of damage to the winding as a consequence of a preceding winding short-circuit at or near the point of fault.

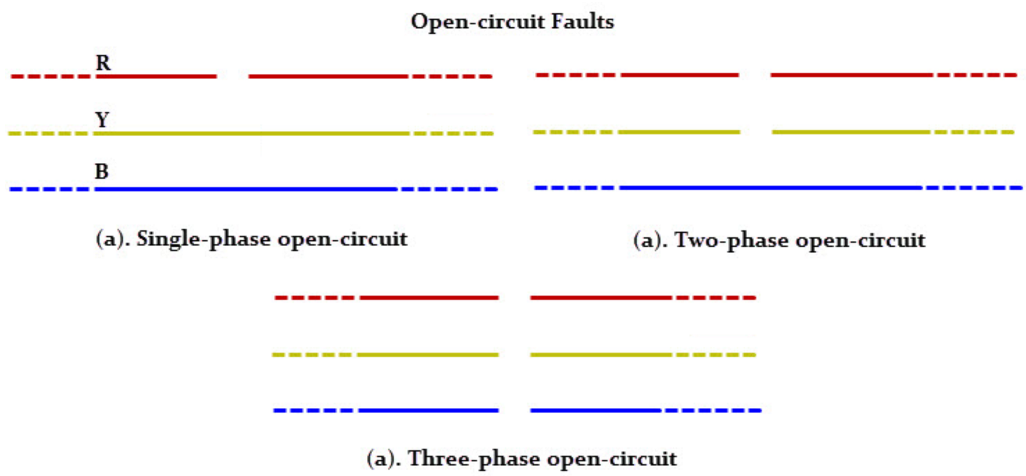


Figure 2-2. Open circuit faults

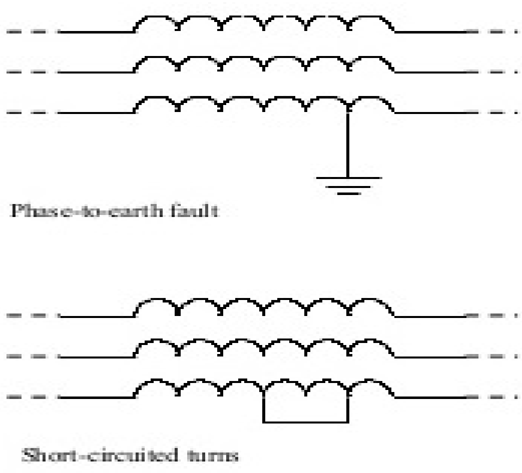


Figure 2-3. Winding faults

2.3.5 Categories of Faults

- **Changing–fault conditions:** The types of faults which have been mentioned above can all be regarded as fixed fault conditions, in that the type of fault remains unchanged for the duration of the fault. The great majority of fault conditions are of this type but there are others, known as changing-fault conditions, in which the type of fault changes during the course of the fault. Such changing-fault conditions can result from a number of causes, the most common being the spreading of a fault arc, or of the ionised gases from a fault arc, to other phases and even to other circuits. A typical example is a single-phase-to-earth fault which develops into a two-phase-earth fault and possibly, later, into a three-phase fault. The analysis of a changing fault condition presents no particular difficulty, since the condition can be considered as a succession of fixed fault conditions, each of which can be analysed individually.
- **Symmetrical faults:** These are faults which affect all phases equally, i.e. three-phase-to-earth and three-phase clear of earth.
- **Unsymmetrical faults**: These are faults which produce varying effects on some or all phases, i.e. phase-phase fault, double-phase-to-earth fault and single-phase-to-earth fault
- **Permanent faults:** Faults which do not die out on their own. Such fault occurs when for example a tree falls on a transmission line.
- **Transient faults:** Faults which die out on their own. For example, a short-circuit caused by wind.

2.3.6 Factors Affecting Fault Severity

The severity of a power system fault condition may be assessed in terms of the disturbance produced and the damage caused, the magnitude of the fault current and its duration being of particular interest, especially in relation to the design and application of power system protection.

The factors which affect fault severity must therefore be given due consideration in all aspects of power system analysis in order to ensure results which are truly representative of the conditions which can occur in practice. The factors which normally require to be considered are:

- **Source conditions:** These relate to the amount and disposition of all connected generation (including all other power sources such as interconnections with other systems), the two extremes of minimum and maximum connected plant being of particular interest. The minimum and maximum plant conditions are normally those corresponding to the conditions of minimum and maximum connected load.
- **Power system configuration:** This is determined by the items of plant, namely generators, transformers, overhead-line and cable circuits etc., assumed to be in service for the particular condition being investigated and by such other factors as have a bearing on the topology of the equivalent system network. The system configuration may change during the course of a fault with consequent changes in the magnitude and distribution of the fault current, typical causes being the sequential tripping of the circuit-breakers at the two ends of a faulted transmission line and the sequential clearance of multiple fault conditions
- **Neutral earthing:** Faults which involve the flow of earth current (for example a single-phase or two-phase fault to earth, a single-phase or two-phase open-circuit) may be influenced considerably by the system neurtral-earthing arrangements, particularly by the number of neurtral earthing points and the presence or absence of neutral earthing impedances. Power systems may be single-point or multiple-point earthed and such earthing may be direct (that is, solid earthing) or via impedance. Earthing impedance can be used to limit the earth-fault current to a very low and even negligibly small value, as in the case of a system earthed through a Petersen coil.

- **Nature and type of fault**: From what has already been said, it will be evident that the type of fault and its position in the power system may have a considerable effect on the magnitude and distribution of the system fault current this being particularly the case in respect of earth-faults as compared with phase faults, open-circuits as compared with short-circuits and faults within machine and transformer windings as compared with similar faults at winding phase-terminals. Similarly, the effects of a given fault condition may be considerably modified by the simultaneous presence of one or more other fault conditions as, for example, in the combination of a short-circuit and an open-circuit phase condition. A further factor which may require consideration is the possible effect of fault impedance (for example, fault-arc resistance and the ohmic resistance of any metallic or non-metallic fault path, etc), this being of particular importance in matters relating to the design and application of distance protection.

2.4 Basic Principles of Network Analysis

2.4.1 Fundamental Network Laws

The great majority of fault calculations are concerned with the behaviour of the power system under steady-state conditions or conditions which, from the point of view of analysis, may be regarded as steady-state conditions. It can also usually be assumed that all the power system currents and voltages vary sinusoidally with time at a common constant frequency and can therefore be treated as vector quantities and be expressed, together with the power system impedances and admittances, in complex-number form. The relationship between the currents, voltages and impedances in any linear network is governed by the three basic network laws, namely Ohm's Law and the two laws of Kirchhoff, a formal statement of these laws in terms of vector quantities being given below.

Ohm's Law: Ohm's Law states that the vector voltage drop V produced by a vector current I flowing through a complex impedance Z is given by the vector equation

$$V=IZ$$

An alternative form is

$$I= VY$$

where Y is the reciprocal of Z and is the complex admittance. The law is illustrated In Figure 2-4 from which it will be noted that the sense of the voltage-drop V is in opposition to that of the current I.

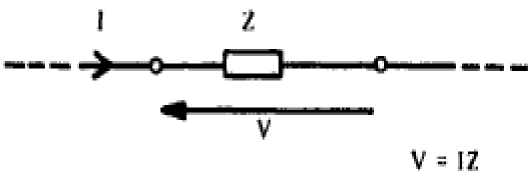


Figure 2-4. Ohm's Law

Kirchhoff's First Law: Kirchhoff's First Law states that the vector sum of all the currents entering any junction or node in a network is zero or, stated in equation form

$$\sum_i I_i = 0$$

where I_i is the vector current flowing into the node from branch i, the summation extending over all the branches connected to the node. Outflowing currents with respect to the node are simply treated as negative inflowing currents.

The law, also known as the Junction Law is illustrated in Figure 2-5.

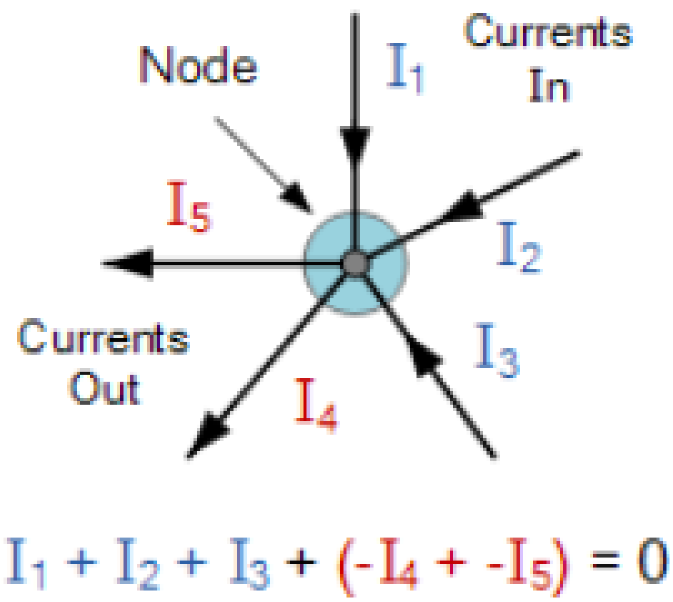
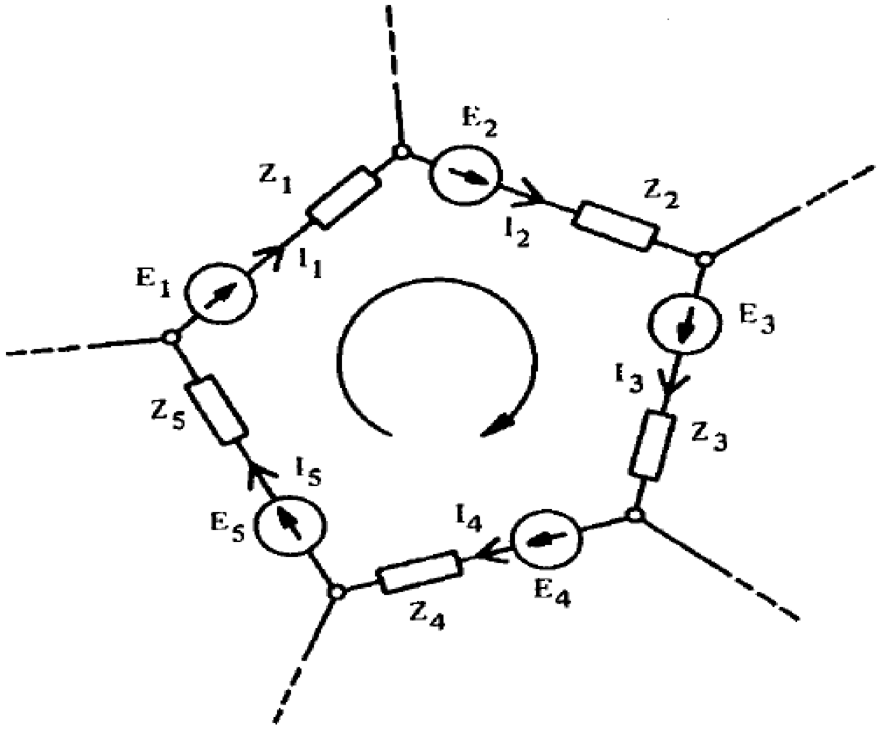


Figure 2-5(a). Kirchhoff's First Law



$$E_1 + E_2 + E_3 + E_4 + E_5 = I_1Z_1 + I_2Z_2 + I_3Z_3 + I_4Z_4 + I_5Z_5$$

Figure 2-5(b). Kirchhoff's Second Law

Kirchhoff's Second Law: Kirchhoff's Second Law states that the vector sum of all the driving voltages (that is source voltages) acting round any closed path or mesh in a network is equal to the vector sum of the voltage drops in the impedances of the component branches of the path. Thus, in equation form

$$\sum_i E_i = \sum_i I_i Z_i$$

where E_i is the vector driving voltage in branch i, I_i the vector current in the branch and Z_i the complex impedance of the branch, the summation extending over all the component branches of the path or mesh.

The driving voltages and currents must all be measured in the same direction round the path. Expressed in another way, the law simply states that the vector sum of all the voltages (that is driving voltages and voltage drops) acting round a closed path or mesh is zero, conditions being specified.

2.4.2 Network Analysis Methods

Fault calculation is a matter of network analysis and can be achieved by a number of alternative methods, namely:

- direct solution of the network equations obtained from the mesh-current or nodal-voltage methods,
- solution by network reduction and back-substitution and,
- solution by simulation using a fault calculator or network analyser.

The choice of method will normally depend on the size and complexity of network and on the amount of information required from the analysis, a further important factor being the availability of suitable computing facilities. Direct solution of the network equations is now commonly employed using suitable digital-computer facilities and appropriate computer programs, such use of the computer making it possible to study a wide range of system and fault conditions speedily and economically, particularly in the case of the larger networks. Solution by network reduction using manual (that is slide rule or desk-calculator computation) is widely used for such problems as involve, or can be represented by, a network of limited size and complexity, there being a large number of fault calculations which fall into this class.

2.4.3 Network Theorems and Reduction Formulas

Combination of series branches: Taking first the general case of any number of branches connected in series, any given branch *i* comprising a driving voltage E_i and series impedance Z_i, the equivalent single branch comprises a driving voltage E_r in series with an impedance Z_r where

$$E_r = \sum_{i}^{n} E_i = E_1 + E_2 + \cdots + E_n$$

and

$$Z_r = \sum_{i}^{n} Z_i = Z_1 + Z_2 + \cdots + Z_n$$

and *n* is the number of branches. The driving voltages are all measured in the same direction with respect to the end nodes of the series combination. These rules, applied to the combination of three series-connected branches, are illustrated in Figure 2-6.

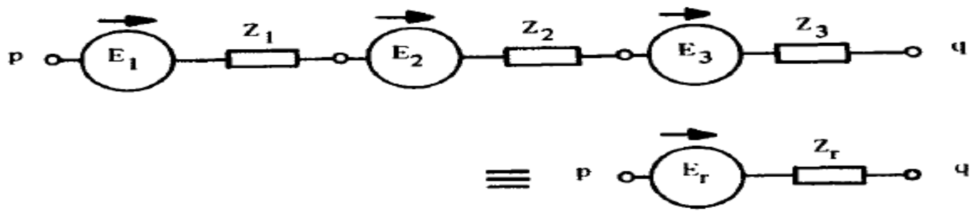


Figure 2-6. Combination of series branches

Combination of parallel branches: Taking, again, the general case of any number of branches but now connected in parallel, any given branch *i* comprising a driving voltage E_i and series admittance Y_i (that is series impedance $1/Y_i$), the equivalent single branch comprises a driving voltage E_r in series with an admittance Y_r (that is, an impedance $1/Y_r$), where,

$$E_r = (1/Y_r) \sum_i E_i Y_i = (1/Y_r)(E_1 Y_1 + E_2 Y_2 + \dots + E_n Y_n)$$

$$Yr = \sum_i^n Y_i = Y_1 + Y_2 + \cdots + Y_n$$

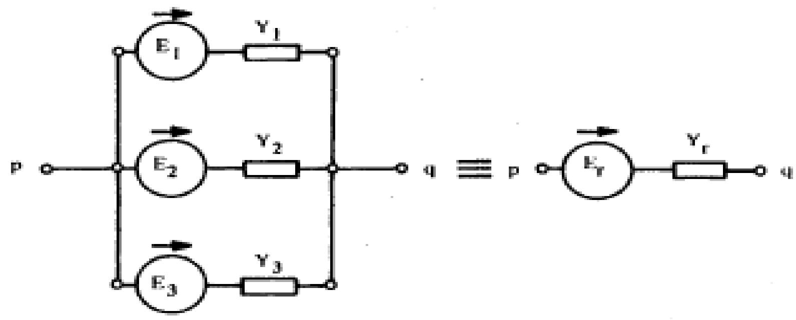


Figure 2-7. Combination of parallel branches

The driving voltages are all measured in the same direction with respect to the common nodes of the parallel combination. These rules, applied to the combination of three parallel-connected branches, are illustrated in Figure 2-7.

Star-to-delta transformation: The star-to-delta transformation permits any set of three star-connected branches with isolated star-point to be replaced by an equivalent set of three delta-connected branches. Thus, let *a*, *b* and *c* denote the three terminals of the star and its equivalent delta, and let the star-connected branches comprise driving voltages E_a, E_b, and E_c and impedances Z_a, Z_b and Z_c respectively, the voltages being measured in the direction away from the star point. Then denoting the driving voltages and impedances of the equivalent delta-connected branches by E_{ab}, E_{bc} and E_{ca} and Z_{ab}, Z_{bc} and Z_{ca} respectively, the latter values are given in terms of the former by the equations

$E_{ab} = E_a - E_b + IZ_{ab}$

$E_{bc} = E_b - E_c + IZ_{bc}$

$E_{ca} = E_c - E_a + IZ_{ca}$

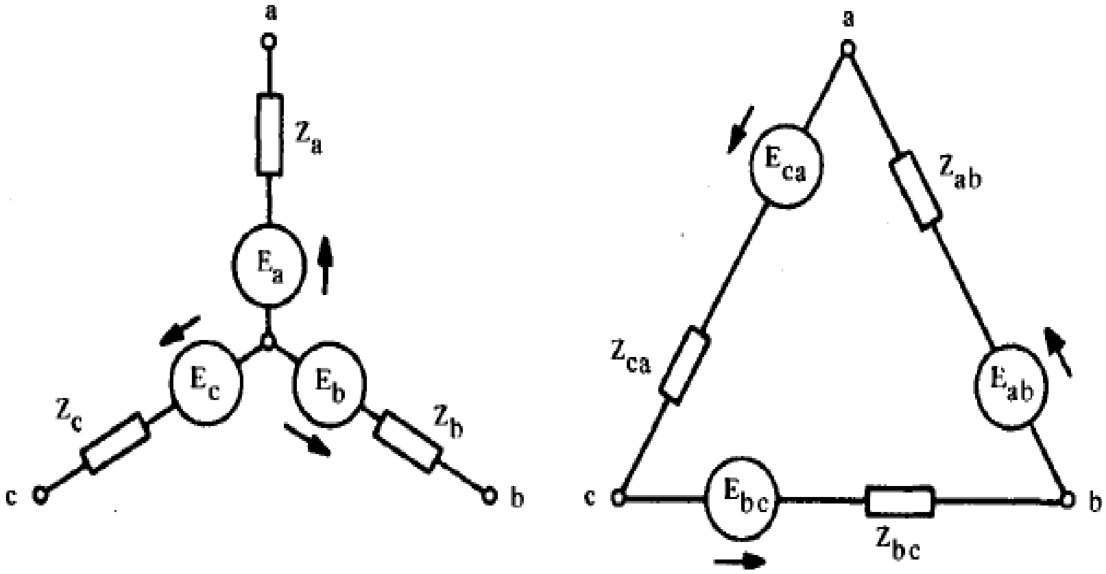


Figure 2-8. Star and delta circuits

$$Z_{ab} = \frac{Z_a Z_b + Z_b Z_c + Z_c Z_a}{Z_a}$$

$$Z_{bc} = \frac{Z_a Z_b + Z_b Z_c + Z_c Z_a}{Z_b}$$

$$Z_{ca} = \frac{Z_a Z_b + Z_b Z_c + Z_c Z_a}{Z_c}$$

Where I, equal to $(E_{ab} + E_{bc} + E_{ca})/(Z_{ab}+Z_{bc}+Z_{ca})$, is any arbitrary chosen current assumed to be circulating in an anticlockwise direction through the branches of the delta. It is normally convenient to assume this current to be zero. The driving voltage E_{ab}, E_{bc} and E_{ca} act from *b* to *a*, *c* to *b*, and *a* to *c*, respectively, in the branches concerned. These rules are illustrated in Figure 2-8.

Delta-to-Star transformation: The delta-to star-transformation permits any set of three delta-connected branches to be replaced by an equivalent set of three star connected branches with isolated star point, the relationships between the star and delta quantities, using the nomenclature of the previous section, being given by the equations

$$E_a - E_b = E_{ab} - I\, Z_{ab}$$
$$E_b - E_c = E_{bc} - I\, Z_{bc}$$
$$E_c - E_a = E_{ca} - I\, Z_{ca}$$

And

$$Z_a = \frac{Z_{ab}Z_{ca}}{Z_{ab}+Z_{bc}+Z_{ca}}$$

$$Z_b = \frac{Z_{bc}Z_{ab}}{Z_{ab}+Z_{bc}+Z_{ca}}$$

$$Z_c = \frac{Z_{ca}Z_{bc}}{Z_{ab}+Z_{bc}+Z_{ca}}$$

where I equals to $(E_{ab} + Ebc + E_{ca})/(Z_{ab}+Z_{bc}+Z_{ca})$ is the current circulating in an anticlockwise direction through the branches of the delta.

It should be noted that any one of the driving voltages E_a, E_b and E_c can be chosen quite arbitrarily, this value being then used to determine the remaining two driving voltages.

It is normally convenient to arrange that the sum of the three driving voltages is equal to zero, in which case

$$E_a = ⅓[\, E_{ab} - E_{ca} - I(\, Z_{ab} - Z_{ca})]$$

$$E_b = ⅓[\, E_{bc} - E_{ab} - I(\, Z_{bc} - Z_{ab})]$$

$$E_c = ⅓[\, E_{ca} - E_{bc} - I(\, Z_{ca} - Z_{bc})]$$

where I as already stated is given by

$$I = \frac{E_{ab}+E_{bc}+E_{ca}}{Z_{ab}+Z_{bc}+Z_{ca}}$$

For the special case in which $E_{ab} + E_{bc} + E_{ca} = 0$, giving $I=0$, the star driving voltages then become

$$E_a = ⅓(\, E_{ab} - E_{ca})$$

$$E_b = ⅓(\, E_{bc} - E_{ab})$$

$$E_c = ⅓(\, E_{ca} - E_{bc})$$

The transformation rules are as illustrated by the circuit shown in Figure 2-8.

Combination of equal driving-voltages: If two or more branches have a common node and identical driving-voltages with respect to this node, then the individual branch driving-voltages can all be removed and replaced by a single external driving voltage connected to the common node, the latter driving voltage being equal to the common value of the original branch driving-voltages. The theorem is illustrated in Figure 2-9 and follows readily from the fact that equipotential points can be joined together without any resultant change in the electrical state of the network.

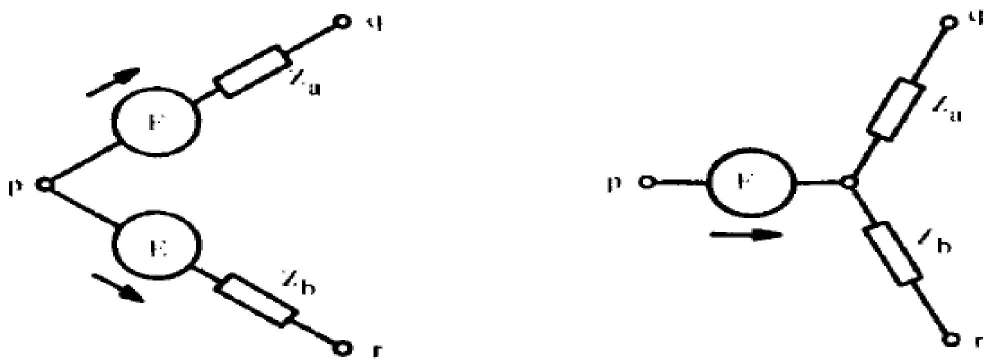
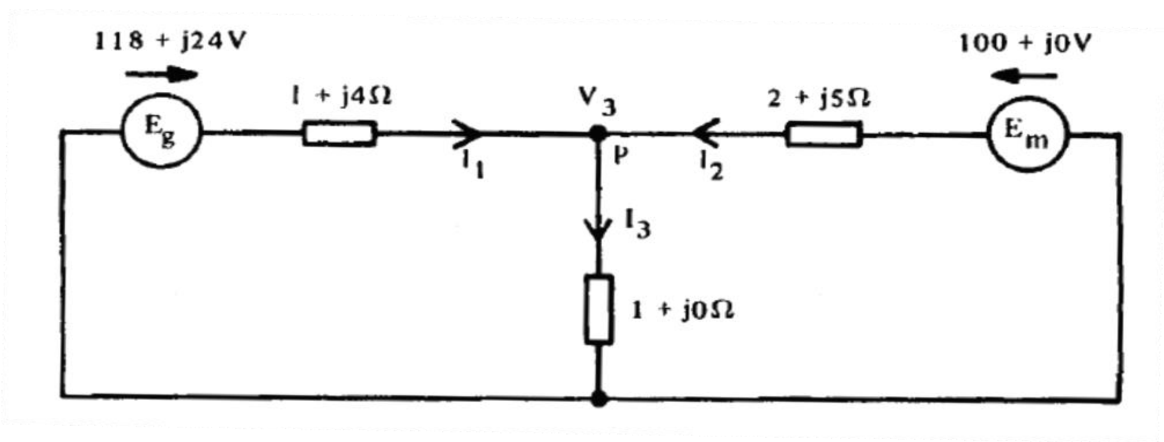


Figure 2-9. Combination of equal driving voltages

The theorem is particularly useful in power system analysis in the reduction of a multiple-source network to its single-source equivalent.

Superposition Theorem: The Superposition Theorem, applicable to any linear network, states that the current which flows in any branch of a network as a result of the simultaneous action of several driving voltages is equal to the vector sum of the currents which would flow in the branch in question with each driving voltage acting individually and all the remaining driving voltages equal to zero, that is, short-circuited. The theorem is illustrated in Figure 2-10 using a simple two machine problem.



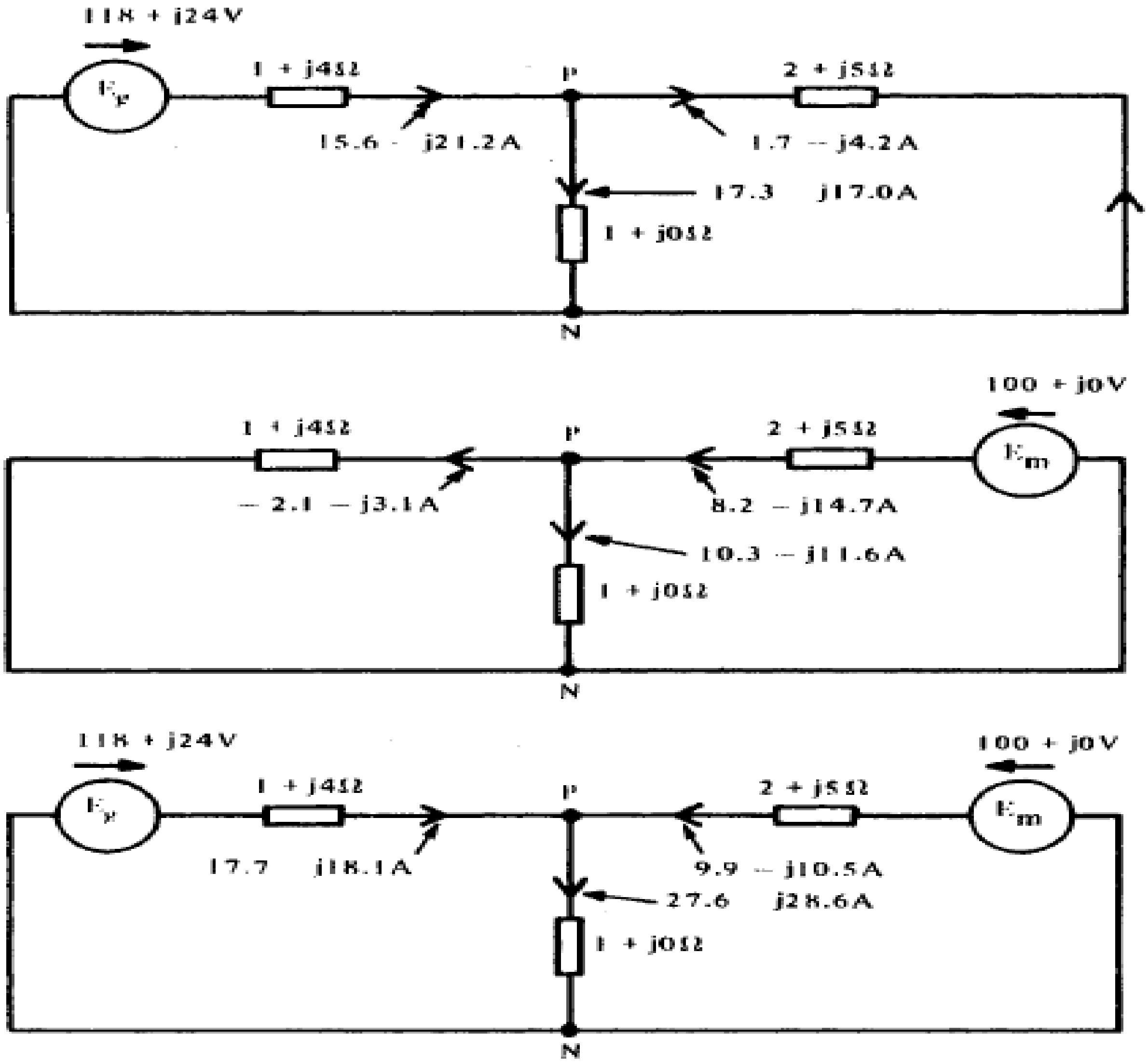


Figure 2-10. Illustration of the superposition theorem

Thevenin's Theorem: Thevenin's Theorem, similarly applicable to any linear network, states that any such network containing driving voltages, as viewed from any two terminals, can be replaced by a single driving voltage acting in series with a single impedance.

The value of this driving voltage is equal to the open-circuit voltage between the two terminals, and the series impedance is the impedance of the network as viewed from the two terminals with all the driving voltages equal to zero, that is short-circuited.

The theorem is illustrated in Figure 2-11 and its application to the simple two-machine circuit of the above Figure 2-10 is shown in Figure 2-12.

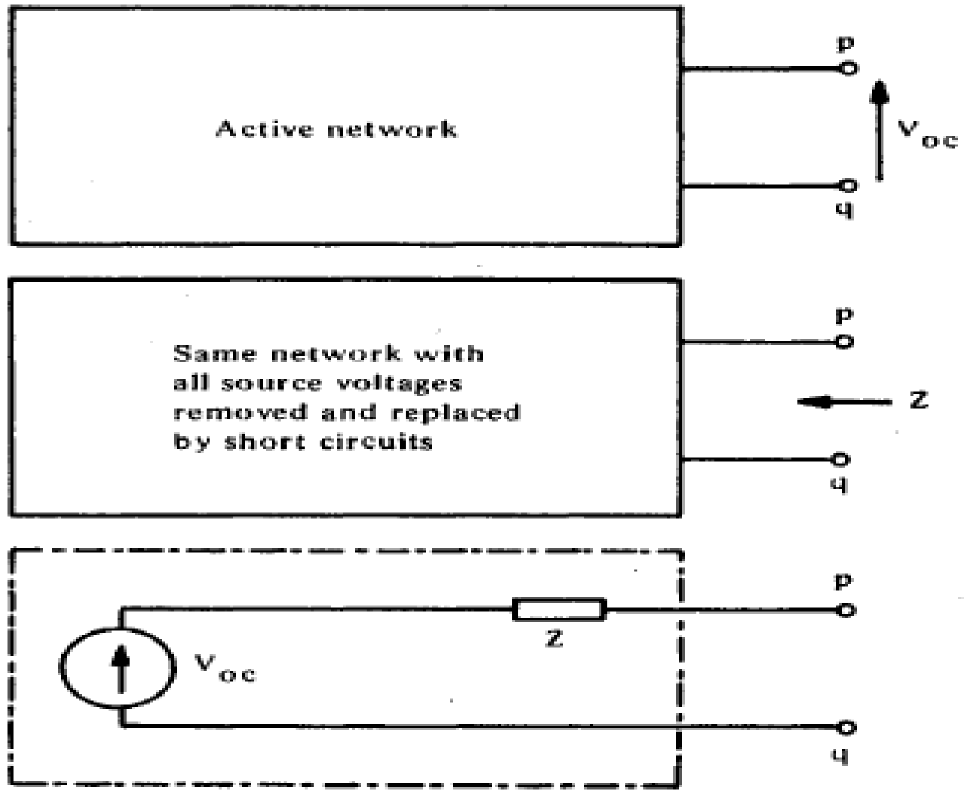


Figure 2-11. Thevenin's Theorem

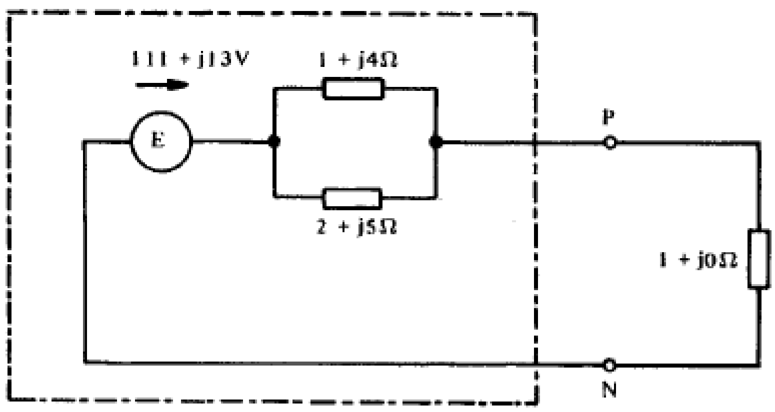


Figure 2-12. Thevenin's Theorem applied to the example of Figure 2-11

Norton's Theorem: Norton's Theorem is the dual of Thevenin's Theorem and states that any linear network containing driving voltages, as viewed from any two terminals, can be replaced by a single driving current shunted by an impedance. The value of this driving current is equal to the short-circuit current which will flow between the two terminals when connected together, and the shunt impedance is the impedance of the network as viewed from the two terminals with all the driving voltages equal to zero, that is short-circuited.

The theorem is illustrated in Figure 2-13 and its application to the simple two-machine circuit of Figure 2-10 is shown in Figure 2-14. It is important to note that the driving current is constant in value irrespective of the voltage across it, just as a given driving voltage is constant in value irrespective of the current through it.

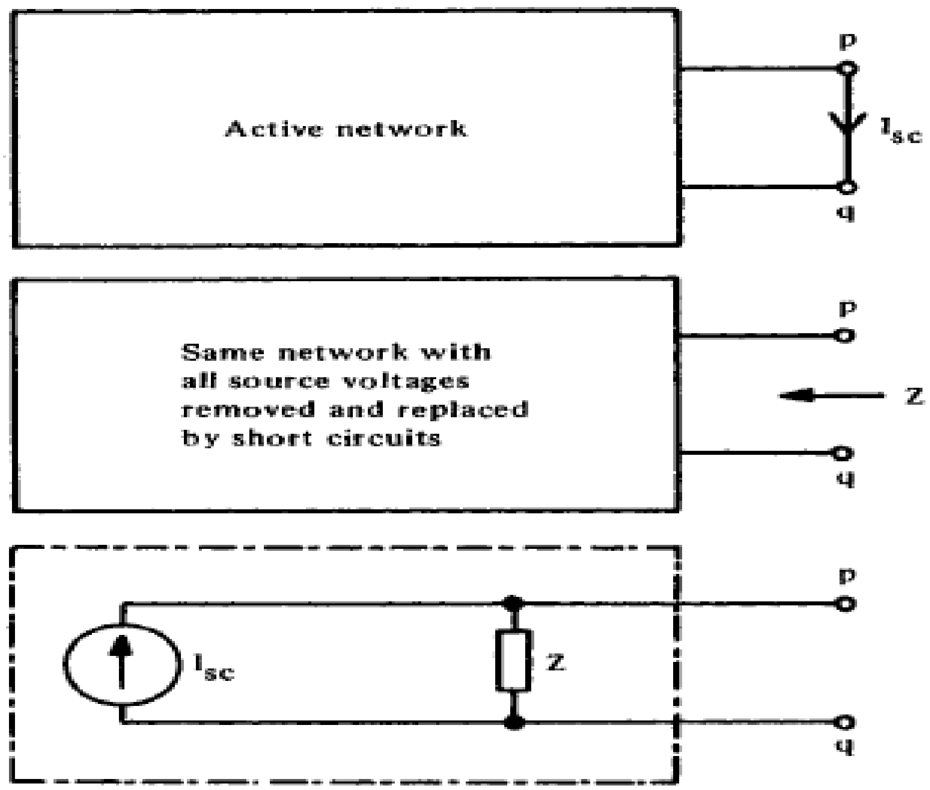


Figure 2-13. Norton's Theorem

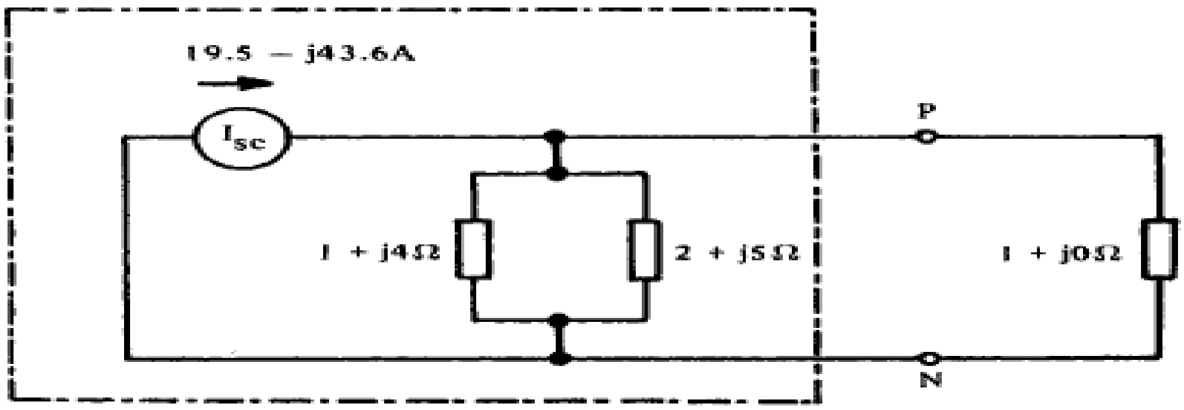


Figure 2-14. Norton's Theorem applied to the example of Figure 2-10

A constant driving current can be regarded in physical terms, as the current produced by an infinite voltage acting in series with an infinite impedance, the ratio of the voltage to the impedance being the required driving current.

2.5 Per Unit Notation

Power transmission lines are operated at voltage levels where the kilovolt (kV) is the most convenient unit for expressing voltage. Because of the large amount of power transmitted, kilowatts (kW) or megawatts (MW) and kilovoltamperes (kVA) or megavoltamperes (MVA) are the common terms for expressing power.

In the analysis of power networks, however, instead of using actual values of these quantities, it is usual to express them as fractions (per unit) or percentage of reference (or base) quantities. The **base** or **reference value** may be arbitrarily chosen, but usually **rated** or **full-load quantities** (rated voltage, rated kilovoltamperes, etc.) are chosen as base values. The per-unit value of any quantity is defined as the ratio of the quantity to its base value (expressed as a decimal). The ratio in percent is 100 times the value in per unit.

Thus we express per unit as

$$pu = \frac{actual\ value\ in\ any\ \ unit}{base\ or\ reference\ value\ in\ same\ unit}$$

Both the per-unit and percent methods of calculation are simpler than the use of actual amperes, ohms and volts quantities.

2.5.1 Advantages of PU Method

- It represents results in more meaningful data when the relative magnitudes of similar circuit quantities can be compared directly.
- It facilitates solution of circuits at different voltage level and power ratings.
- It is independent of voltage changes and phase shift through 'impedance'.
- Manufacturers quote pu impedance values on the base of ratings on equipment nameplates.
- Per unit impedance of any transformer is the same when referred to either the primary or the secondary side.
- Per unit values of similar power equipment lie within narrow ranges and it is relatively easy to select.
- The use of √3 is eliminated in 3-phase calculations, simplifying the calculations.

- The product of two quantities expressed in per unit is expressed in per unit itself.
- The driving or source voltage usually can be assumed to be 1.0pu for fault and voltage calculations.
- There is less chance of confusion between single-phase and three-phase power or between line-to-line and line-to-neutral voltage.
- Per unit impedance of a transformer in a three-phase system is the same regardless of the type of winding connections.

2.5.2 Base Quantities

We can select a base for per unit calculations from any of the following parameters:

Base Current, I_{base}, Base Voltage, V_{base},

Base Impedance, Z_{base}, Base Apparent power, S_{base}, etc.

Per unit current $I_{pu} = \dfrac{I_{actual}}{I_{base}}$

Per unit voltage $V_{pu} = \dfrac{V_{actual}}{V_{base}}$

Per unit rating $kVA_{pu} = \dfrac{kVA_{actual}}{kVA_{base}}$

The table below shows base parameters for single and three-phase systems.

For single-phase	For three-phase
$V_{base,\Phi}=V_{LN}$ (kV)	$V_{base} = V_{LL} = \sqrt{3}V_{base,\Phi} = \sqrt{3}V_{LN}$ (kV)
$I_{base,\phi} = \dfrac{kVA_{base,\phi}}{kV_{base,\phi}}$	$I_{base} = I_{base,\phi} = \dfrac{kVA_{base,\phi}}{kV_{base,\phi}} = \dfrac{\frac{1}{3}kVA_{base}}{kV_{base}/\sqrt{3}} = \dfrac{kVA_{base}}{\sqrt{3}kV_{base}} = S_{base}/\sqrt{3}V_{base}$ (A)

$Z_{base} = \frac{V_{base,\phi}}{I_{base,\phi}} = \frac{kV_{base}}{I_{base} \times 10^3} = \frac{kV_{base}}{kVA_{base} \times 10^3 / kV_{base}}$	$Z_{base} = \frac{V_{base,\phi}}{I_{base,\phi}} = \frac{kV_{base}/\sqrt{3}}{1000 \times kVA_{base} / \sqrt{3}\,kV_{base}}$
$Z_{base} = \frac{(kV_{base})^2}{MVA_{base}}$	$Z_{base} = \frac{(kV_{base})^2}{MVA_{base}}$ (Ω)
$S_{base,\Phi}$= $kVA_{base,\phi}$ =rated phase kVA	S_{base}= rated 3-phase kVA = 3 $kVA_{base,\phi}$ =√3$V_{base}I_{base}$

Table 2-2. Base parameters for single and three-phase systems

It can be seen from Table 2-2 that the base impedances for single-phase and three-phase systems are similar, and without the factor of √3.

Per unit impedance $Z_{pu} = \frac{Z_{actual}}{Z_{base}} = Z_{actual} \times \frac{MVA_{base}}{(kV_{base})^2}$

2.5.3 Conversion of Impedance to New Base

Let subscript 1 and 2 represent original and new bases respectively.

$$Z_{pu1} = Z_{actual} \times \frac{MVA_{base1}}{(kV_{base1})^2} \qquad \text{(a)}$$

$$Z_{pu2} = Z_{actual} \times \frac{MVA_{base2}}{(kV_{base2})^2} \qquad \text{(b)}$$

Dividing Equation (b) by (a) and rearranging

$$Z_{pu2} = Z_{pu1} \times \frac{MVA_{base2}}{MVA_{base1}} \times \left(\frac{kV_{base1}}{kV_{base2}}\right)^2$$

or

$$Z_{pu\,new} = Z_{pu\,old} \times \frac{MVA_{newbase}}{MVA_{old\,base}} \times \left(\frac{kV_{old\,base}}{kV_{newbase}}\right)^2$$

In most problems, the values of the units are given with respect to a base voltage and a base MVA or kVA.

2.5.3.1 Referring a Transformer's Impedance to a New Base

Consider the simple three-phase circuit shown in Figure 2-15 below.

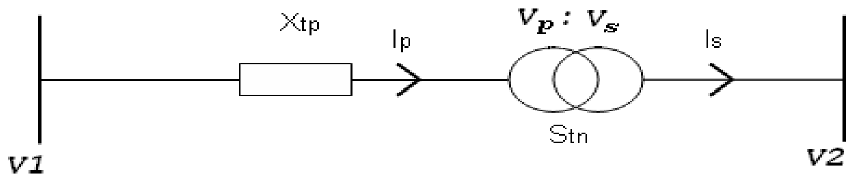


Figure 2-15. Simple three-phase circuit

We choose the rating of the transformer as base MVA, S_{tn}.

V_1 and V_2 are rated voltages for the two buses.

From Figure 2-15 the short circuit impedance of the Transformer (measured on the primary side) is X_{tp}.

For an ideal transformer

$$I_1 N_1 = I_2 N_2 \qquad \text{(a)}$$

$$\frac{V_1}{N_1} = \frac{V_2}{N_2} \qquad \text{(b)}$$

Dividing Equation (b) by Equation (a) we get

$$Z_1 = \left(\frac{N_1}{N_2}\right)^2 Z_2$$

Therefore measured on the secondary side the impedance will be.

$$X_{ts} = X_{tp}\left(\frac{Vs}{Vp}\right)^2$$

2.6 Analysis of Balanced Three Phase Faults

A three-phase fault is a condition of either: (a) all three phases of the system are short circuited to each other or (b) all three phases of the system are earthed as show in Figure 2-16. The three-phase short-circuit can normally be regarded as the most severe condition from the point of view of fault severity, and it is accordingly the maximum possible value of the three-phase fault level which normally determines the required short-circuit rating of power system switchgears.

During a three-phase fault, the reactance of a generator is a time varying quantity. It is X_d'' in the sub-transient period (one to three cycles), X_d' in the transient period (up to about 30 cycles), and the synchronous reactance X_d after that.

The purpose of a study determines the one used. It must be kept in mind that the sub-transient currents can be very large due to the small size of X_d''.

Due to symmetry, the three phase currents during a symmetrical fault can be solved using ordinary circuit theory.

If the fault has zero impedance to ground, it is called a solid fault or bolted fault (all three lines shorted to ground with zero impedance).

2.6.1 Modelling of System Components

The main components of power systems which are considered are:

(a) Synchronous machine

It is represented by a constant voltage source behind transient or subtransient reactance. Normally, both generator and motor subtransient reactance is used to determine the momentary current flowing on occurrence of a short-circuit.

(b) Transformers

All transformers are considered to be at their normal tap

(c) Lines

Line charging capacitances and other shunt connections to earth are neglected. This is due to the fact that voltages dip very low and currents drawn by them are small in comparison to fault current.

If the resistances of the lines are smaller than the reactances by a factor of six or more, the resistances are neglected to obviate the need for complex arithmetic.

(d) Loads

Normally, loads are neglected for the same reason given for case (c).

2.6.2 Single Fault Representation of Balanced Three-Phase Faults

In a balanced three phase circuit, since the information relating to one single phase gives the information relating to the other two phases as well, it is sufficient to do calculations in a single phase circuit.

Figure 2-16 shows one single phase 'AN' of the three phase circuit 'ABC N'. Since the system is balanced, there is no current in the neutral, and there is no potential drop across the neutral wire. Thus the star point 'S' of the system would be at the same potential as the neutral point 'N'.

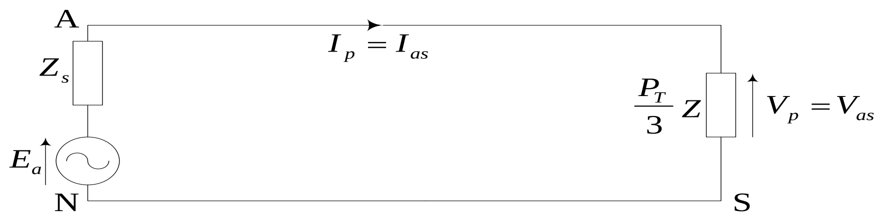


Figure 2-16. Single phase circuit

Also, the line current is the same as the phase current, the line voltage is √3 times the phase voltage, and the total power is 3 times the power in a single phase.

$I = I_p = I_L$, $V = V_p = V_L / \sqrt{3}$ and $S = S_p = S_T / 3$

Working with the single phase circuit would yield single phase quantities, which can then be converted to three phase quantities using the above conversions.

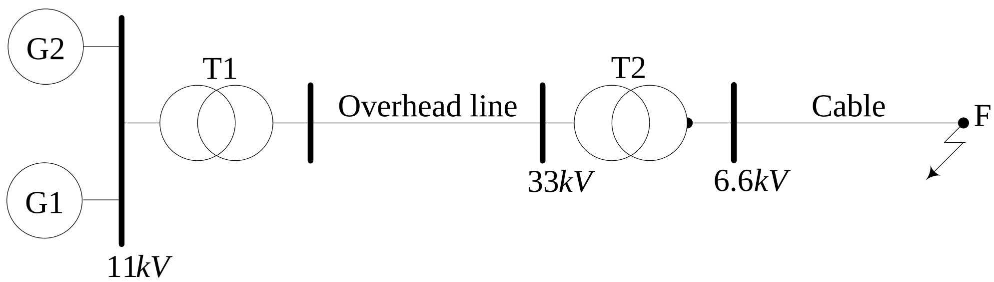
2.6.3 Calculation of Three-Phase Short-Circuit Quantities

Two conditions will be studied.

Case 1: **System is unloaded** (i.e. generators are not loaded)

Example

In the radial network shown in the figure below, a three-phase fault occurs at point F. Determine the fault current and the line voltage at the $11kV$ bus under fault conditions.



Generator 1: $10MVA$, 15% reactance

Generator 2: $10MVA$, 12.5% reactance

Transformer 1: $10MVA$, 10% reactance

Overhead line: $L = 30km$, $Z = (0.27 + j0.36)\Omega/km$

Transformer 2: $5MVA$, 8% reactance

Cable: $L = 3km$, $Z = (0.135 + j0.08)\Omega/km$

Solution

Selecting a system base of $100MVA$ and base voltages of $11kV$ in generators, $33kV$ for overhead line and $6.6kV$ for cable, and using the formula: $X_{pu(new)} = X_{pu(old)} \times \frac{S_{base(new)}}{S_{base(old)}}$

Reactance of generator 1 $= \frac{j0.15 \times 100}{10} = j1.5pu$

Reactance of generator 2 $= \frac{j0.125 \times 100}{10} = j1.25pu$

Reactance of transformer 1 $= \frac{j0.1 \times 100}{10} = j1pu$

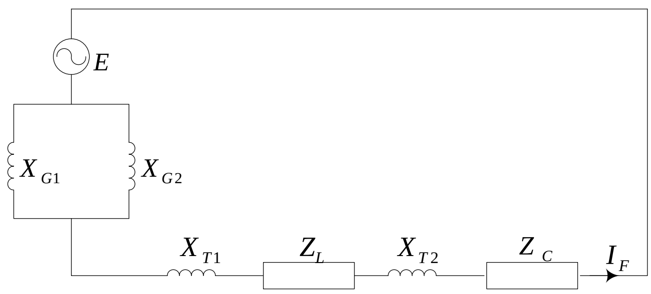
Reactance of transformer 2 $= \frac{j0.08 \times 100}{5} = j1.6pu$

Overhead line impedance $= Z(\Omega) \times \frac{S_{base}}{V_{base}^2} = 30 \times (0.27 + j0.36) \times \frac{100 \times 10^6}{(33 \times 10^3)^2}$

$= (0.744 + j0.99)pu$

Cable impedance $= 3 \times (0.135 + j0.08) \times \frac{100 \times 10^6}{(6.6 \times 10^3)^2} = (0.93 + j0.55)pu$

The equivalent circuit is shown below



Total impedance, $Z_T = X_{G1} // X_{G2} + X_{T1} + Z_L + X_{T2} + Z_C$

$= j1.5 // j1.25 + j1 + (0.744 + j0.99) + j1.6 + (0.93 + j0.55)$

$= 1.674 + j4.82$

$= 5.1\angle 70.8^0$

$$I_F = \frac{E}{Z_T} = \frac{1\angle 0^0}{5.1\angle 70.8^0} = 0.196\angle -70.8^0\ pu$$

$$I_{base} = \frac{S_{base}}{\sqrt{3}V_{base}} = \frac{100\times10^6}{\sqrt{3}\times6.6\times10^3} = 8750A \therefore I_{F(actual)} = I_{pu}\times I_{base} = 0.196\times8750 = 1715\ A$$

Total impedance between F and $11kV$ bus,

$$= j1+(0.93+j0.55)+j1.6+(0.744+j0.99)$$

$$Z = 1.674+j4.14$$

$$= 4.43\angle76.8^0$$

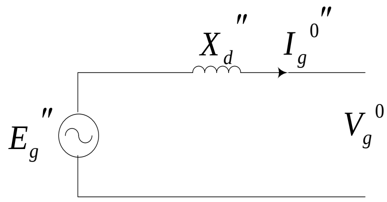
Voltage at $11kV$ bus $= I_F\times Z = 0.196\angle-70.8^0\times4.43\angle76.8^0 = 0.88\angle6^0\ pu$

$$= 0.88\times11kV = 9.68kV$$

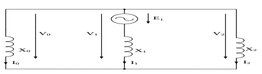
Case 2: **System is loaded**

The voltage behind the sub-transient reactance for the generator is obtained as

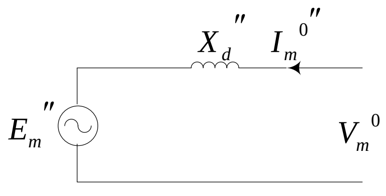
$$E_g'' = V_g^0 + jI_g^0 X_d''$$



and for synchronous motors, the voltage behind the subtransient and transient reactances are given respectively by:



$$E_m' = V_m^0 - jI_m^0 X_m'$$

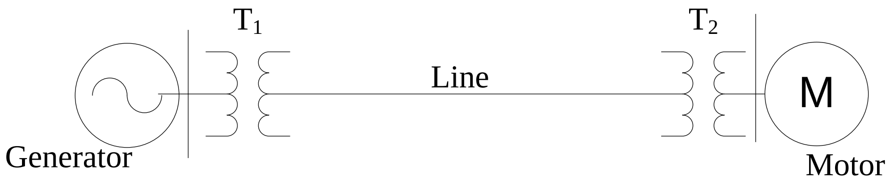


Where V^0 and I^0 are the respective prefault bus voltages and currents.

In the above examples, the bus voltages were used to represent the synchronous machines. These voltages according to the above equations for E_g'' and E_m'' or E_m' are the voltages behind the subtansient or transient reactances when the synchronous machines are not loaded. i.e. $I_g^0 = I_m^0 = 0$.

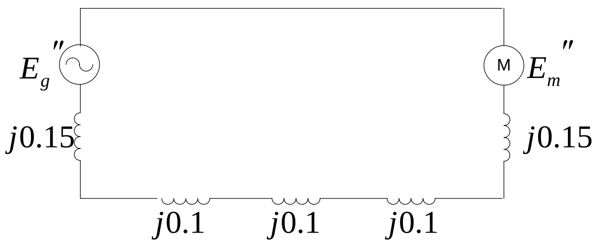
Example

A synchronous generator rated 25MVA and a synchronous motor each rated 25MVA, 11kV having 15% subtransient reactance are connected through transformers and line as shown in the figure below. The transformers are rated 25MVA, 11/66kV and 66/11kV with leakage reactance of 10% each. The line has a reactance of 10% on a base of 25MVA, 66kV. The motor is drawing 15MW at 0.8pf leading and a terminal voltage of 10.6kV when a symmetrical 3-phase fault occurs at the motor terminals. Find the subtransient current in the generator, motor and fault path.



Solution

The prefault circuit is shown below



$V_m^{\,0} = 10.6kV$

$= \dfrac{10.6}{11} = 0.9636pu$ at a base voltage of $11kV$

Load $= 15MW$, $0.8pf$ leading

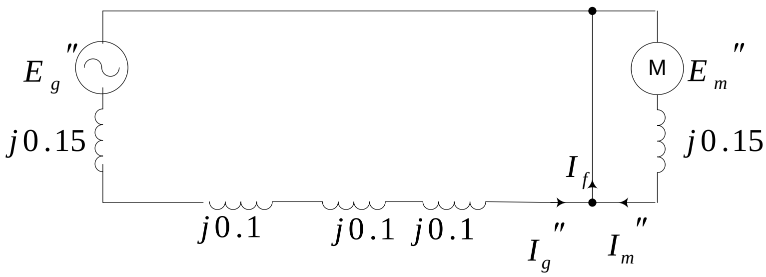
$= \dfrac{15}{25} = 0.6pu$, $0.8pf$ leading at a base of 25MVA

Prefault current, $I^0 = \dfrac{P}{V\cos\theta}\angle\cos^{-1}\theta = \dfrac{0.6}{0.9636\times 0.8}\angle\cos^{-1}0.8 = 0.7783\angle 36.9^0$

$$\begin{aligned}
E_g'' &= V_m^{\,0} + jX_d I^0 \\
&= 0.9636\angle 0^0 + j(0.15+0.1+0.1+0.1)\times 0.7783\angle 36.9^0 \\
&= 0.7536 + j0.28
\end{aligned}$$

$$E_m{}^0 = V_m{}^0 - jX_m I^0$$
$$= 0.9636\angle 0^0 - j0.15 \times 0.7783\angle 36.9^0$$
$$= 1.0337 - j0.0934$$

The post fault circuit is shown below



Applying Kirchhoff's voltage law,

$$I_g'' = \frac{E_g''}{(j0.15 + j0.1 + j0.1 + j0.01)} = \frac{0.7536 + j0.28}{j0.45}$$
$$= 0.6222 - j1.674$$

$$I_m'' = \frac{E_m''}{X_m} = \frac{1.0337 - j0.0934}{j0.15} = -0.6224 - j6.8915$$

$$I_f = I_g'' + I_m'' = (0.6222 - j1.674) + (-0.6224 - j6.8915) = -0.0002 - j8.5653$$

2.7 Method of Symmetrical Components

A power system is normally treated as a balanced three-phase network. In general, when a fault occurs, the symmetry of a balanced network is upset, resulting in unbalanced currents and voltages appearing in the network.

The exception to this rule is the three-phase fault, which because it involves all three phases equally at the same time and location, is described as a symmetrical fault. These unsymmetrical fault conditions can be analysed using the symmetrical component theory.

The symmetrical components method formulates a system of three separate phasor systems which when superimposed give the true unbalance conditions in the circuit. It must be emphasised that the three phasor systems are essentially artificial and used merely as an aid to calculation. The various sequence-component voltages and currents do not exist as physical entities in the network.

The method postulates that a three-phase unbalanced system of voltages and currents may be represented by the following three separate system of phasors:

- a balanced 3-phase system (equal in magnitude but 120° degrees apart) in the normal a-b-c sequence, called the positive phase sequence (pps) system.
- a balanced 3-phase system of reversed sequence i.e. a-c-b called the negative phase sequence (nps) system.
- three phasors equal in magnitude and phase revolving in the positive phase rotation called the zero phase sequence (zps) system.

It is common practice to assign 1, 2, and 0 to the pps, nps and zps components respectively.

Figure 2-17 shows a phase diagram representation of phase-sequence components

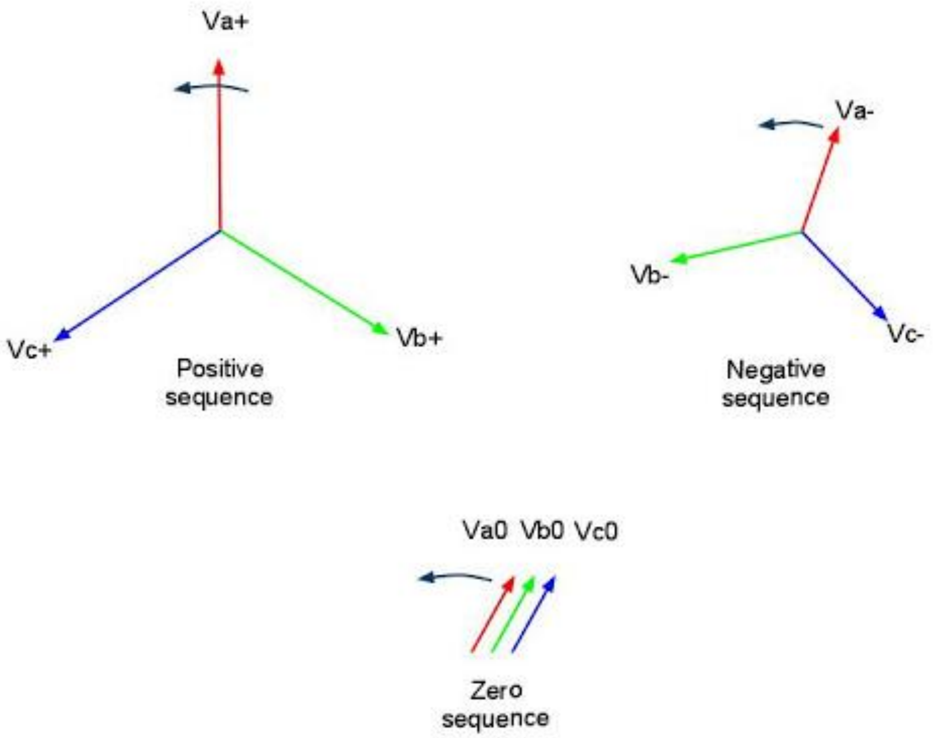


Figure 2-17. Phase diagram representation of phase-sequence components

If

$$V_{a0} = V_{b0} = V_{c0}$$

$V_{a1} = V_1$, then

$V_{b1} = V_1 \angle 240^0$, and

$V_{c1} = V_1 \angle 120^0$

Similarly, if

$V_{a2} = V_2$, then

$V_{b2} = V_2 \angle 120^0$, and

$V_{c2} = V_2 \angle 240^0$

It is normal practice to take the a-phase as reference and express the other two phases in terms of the a-phase quantities. Thus:

$$\mathrm{V_a = V_{a0} + V_{a1} + V_{a2} = V_0 + V_1 + V_2}$$

(Phase 'a' voltage is the sum of the phase 'a' voltage of all the three separate phasors)

$$\mathrm{V_b = V_{b0} + V_{b1} + V_{b2} = V_0 + h^2 V_1 + h V_2}$$

$$\mathrm{V_c = V_{c0} + V_{c1} + V_{c2} = V_0 + h V_1 + h^2 V_2}$$

where,

$h = 1\angle 120^0 = -0.5 + j0.866 = -\frac{1}{2} + j\frac{\sqrt{3}}{2}$ and

$h^2 = 1\angle 240^0 = -0.5 - j0.866 = (-\frac{1}{2} - j\frac{\sqrt{3}}{2})$

In a matrix form, we can write Equation 5.1 as:

$$\begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & h^2 & h \\ 1 & h & h^2 \end{bmatrix} \begin{bmatrix} V_0 \\ V_1 \\ V_2 \end{bmatrix}$$

$$\begin{bmatrix} V_0 \\ V_1 \\ V_2 \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & h^2 & h \\ 1 & h & h^2 \end{bmatrix}^{-1} \begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & h & h^2 \\ 1 & h^2 & h \end{bmatrix} \begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix}$$

Similarly,

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & h^2 & h \\ 1 & h & h^2 \end{bmatrix} \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix}$$

and
$$\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & h^2 & h \\ 1 & h & h^2 \end{bmatrix}^{-1} \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & h & h^2 \\ 1 & h^2 & h \end{bmatrix} \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix}$$

Note the new positions of h and h^2 in the matrices.

Additionally, $\mathrm{h^3 = 1} = 1\underline{/360^0}$

$\mathrm{1 + h + h^2 = 0}$, and

$\mathrm{h + h^2 = -1}$

2.7.1 Representation of Plants in the Phase-Sequence Networks

In order to apply symmetrical components to a power system, the various components of the power system (generators, transformers, lines, etc) must be given impedances which reflect the three phasor systems. For example, a generator must have a pps impedance, nps impedance and zps impedance in other for it to be factored into a fault analysis using the method of symmetrical components.

2.7.1.1 The Synchronous Machine

The pps impedance Z_1 of the stator winding is the normal transient or sub-transient value, the latter being about $\frac{1}{10}$th of the synchronous impedance of the machine. The nps impedance Z_2 is normally quite close to the pps impedance under fault conditions.

The zps impedance Z_0 depends upon the nature of the connection between the star point of the windings and the earth. Resistors or reactors are frequently connected between the star point and earth for reasons usually connected with protective gear and the limitation of over-voltages. Figure 2-18 shows the connection of earthing impedance.

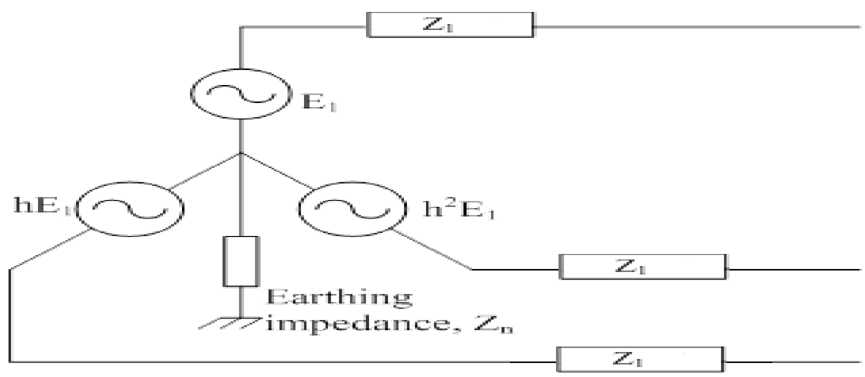


Figure 2-18. Earthing impedance connection to a synchronous machine

Normally, the only voltage sources appearing in the sequence networks are the pps voltages, as the generators only generate pps emfs. This is because it is the pps whose sequence is the same as that of a generator.

Whenever earthing impedance is present, three times (3X) its value is added in series with the zero sequence impedance. The sequence networks representing a synchronous generator are thus shown in Figure 2-19.

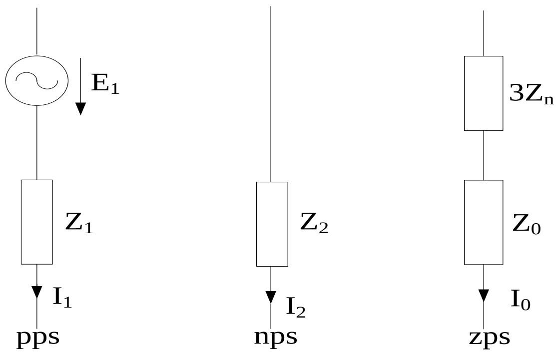


Figure 2-19. Symmetrical components of a synchronous machine

2.7.1.2 Lines and Cables

The pps and nps impedances are the normal balanced values. The zps impedance depends upon the nature of the return path through the earth. It is also modified by the presence of an earth wire on the tower which protects the lines against lightning surges. The following rough guide to the value of Z_0 may be used. The zero-sequence impedance is generally greater than the positive (and negative) sequence impedance being usually in the order of two to three times the positive-sequence value in the case of overhead-line circuits. Typically for an underground cable pps and nps impedances are identical but the ratio $Z_0 / Z_1 = 3-5$ for a 3-cored cable and 1 – 1.25 for a single core cable.

2.7.1.3 Transformers

The pps and nps impedance are the normal balanced ones. The zps connection of transformers is however complicated and depends on the connection of the winding. Table 2-3 presents the zero-sequence representation of transformers for various winding arrangements. Zero-sequence currents in the windings on one side of a transformer must produce the corresponding ampere-turns in the other. The table can be understood by first understanding Figure 2-20. Although in practice, a number of different connections are used, the most common type is the delta-star connection. In such an arrangement, if there are zps currents present, then they simply circulate around the delta winding and cannot flow in the lines (or other plant) outside it. This is so because of the absence of a neutral on the delta side. Zero sequence currents will flow only when there is a connection to earth. The following simple rule can be followed to represent zero sequence networks:

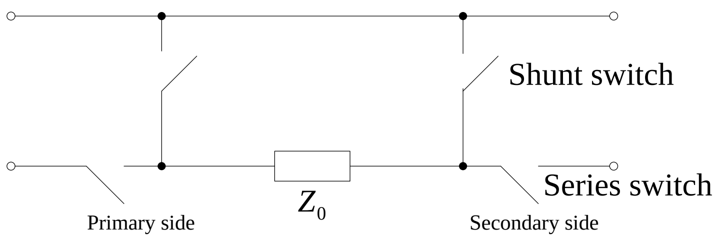


Figure 2-20. Zero sequence representation

Close the **shunt switch** on a side, if the connection on that side is **delta**. Close the **series switch** on a side if the connection on that side is **star earthed**. Otherwise, leave the switches open. It must be noted that on the primary side the series switch is before the shunt but on the secondary side, the series is after the shunt. Additionally, for generators and motors, a side is closed when it is star earthed and opened when is star clear of earth.

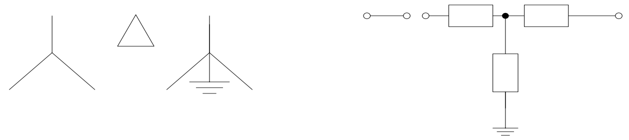
CONNECTION OF WINDINGS *Primary* *Secondary*	REPRESENTATION PER PHASE	COMMENTS
		Zero-sequence currents free to flow in both primary and secondary circuits
		No path for zero-sequence currents in primary circuits
		Single-phase currents circulate in the delta but not outside it
		No flow of zero-sequence currents possible
		No flow of zero-sequence currents possible
		Tertiary winding provides path for zero-sequence currents

Table 2-3. Zero-sequence representation of various transformers

2.7.2 Analysis of Various Faults

In general, we can say that the three sequence networks are as shown in Figure 2-21 in which the sequence impedances are the total impedances which can comprise generators, lines and transformers.

Depending upon the type of fault, the three networks can then be connected in order to determine the fault currents, voltages, etc.

The impedances Z_0, Z_1 and Z_2 are the total impedances obtained from the respective sequence networks.

You may have realised that you have not been introduced to how to produce the pps and nps networks as well as finding their impedances.

This is because the pps and nps networks are the normal one-line diagrams. Their sequence impedances are found the same way you will find the total zero sequence impedance from a zps network. The figures below illustrates the application of nps, pps and zps

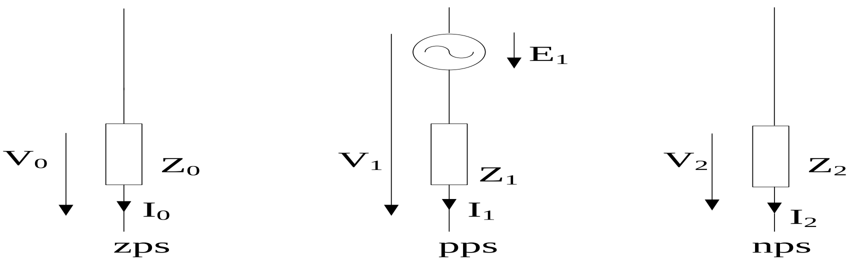


Figure 2-21. Unsymmetrical fault components

The following sections develop circuit models for the various fault cases. Each time such a fault occurs, reproduce the appropriate model and substitute the values.

2.7.2.1 Single-Phase-Earth Faults

Consider an a-phase-earth fault at point F on a single-end-fed system as shown in Figure 2-22.

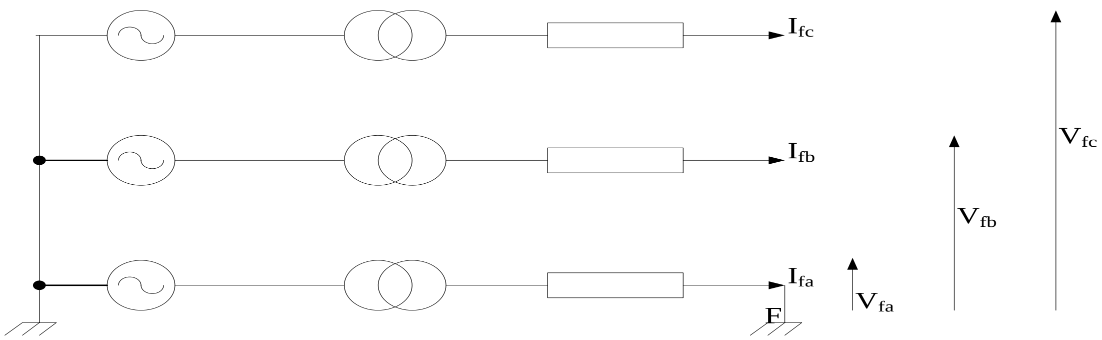


Figure 2-22. A single-phase-earth fault

For this fault, the constraints are:

$V_{fa} = 0, I_{fb} = I_{fc} = 0$

Note: the subscripts 'f' are just being used to denote the fact that the values being sought for are faulted values.

$V_{fa} = 0$ because the voltage at the fault point is the same as earth voltage which is zero.

$I_{fb} = I_{fc} = 0$ since phase b and c will not be feeding any fault. It must however be noted that the load currents in these phases will not be zero.

It is just that these load currents do not have any fault component in them.

Using equation below, i.e. from

$$\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & h & h^2 \\ 1 & h^2 & h \end{bmatrix}\begin{bmatrix} I_a \\ I_b = 0 \\ I_c = 0 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} I_a \\ I_a \\ I_a \end{bmatrix}.$$

we get

$$I_{f0} = I_{f1} = I_{f2} = \tfrac{1}{3} I_{fa}$$

Once again note that the presence or absence of the subscript 'f' does not change anything.

This result shows that all the sequence networks are in series since they have the same current (i.e. $I_{f0} = I_{f1} = I_{f2} = \tfrac{1}{3} I_{fa}$). The network connection diagram is thus:

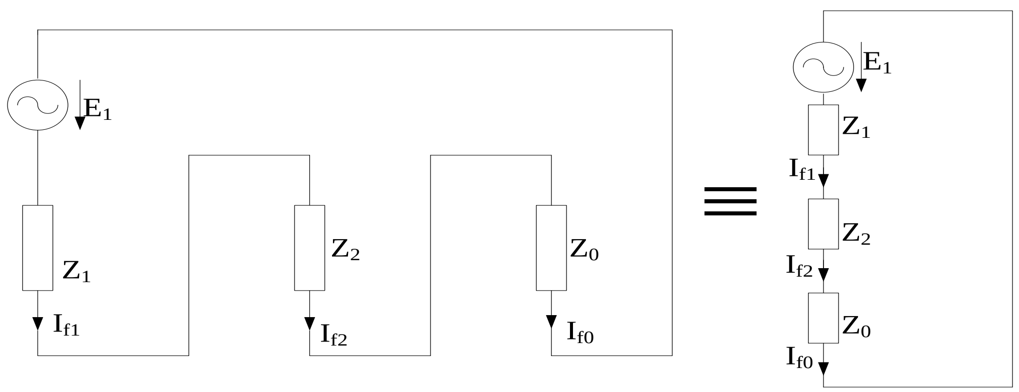


Figure 2-23. Sequence network representation of single-phase-earth faults

From Figure 2-23, it can be seen that the fault current is given by (by applying Kirchhoff's voltage law):

$$I_{fa} = 3I_{f0} = 3I_{f1} = 3I_{f2} = \frac{3E_1}{Z_0 + Z_1 + Z_2}$$

The fault point voltages can be likewise obtained. Figure 2-23 is thus the model for single-phase to earth faults.

2.7.2.2 Phase-Phase Fault

Consider a b-c phase fault as shown in Figure 2-24.

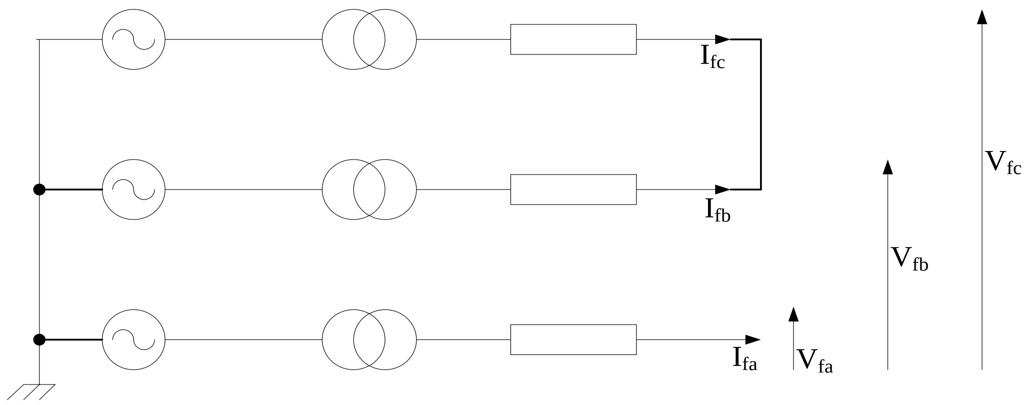


Figure 2-24. Phase-phase fault

For this fault, the constraints are:

$I_{fa} = 0$, $I_{fb} = -I_{fc}$

Since the fault is not linked to earth,

$I_{f0} = V_{f0} = 0$.

From the matrix relationship of the above equation, we get

$$I_{f1} = \tfrac{1}{3}\left(hI_{fb} + h^2 I_{fc}\right) = \tfrac{1}{3}\left(h - h^2\right)I_{fb}$$

$$I_{f2} = \tfrac{1}{3}\left(h^2 I_{fb} + hI_{fc}\right) = -\tfrac{1}{3}\left(h - h^2\right)I_{fb}$$

i.e. $I_{f1} + I_{f2} = 0$

Also

$$V_{fb} = h^2 V_{f1} + hV_{f2}$$

$$V_{fc} = hV_{f1} + h^2 V_{f2}$$

And since for this fault $V_{fb} = V_{fc}$, it thus follows that $V_{f1} = V_{f2}$.

The network connection is thus:

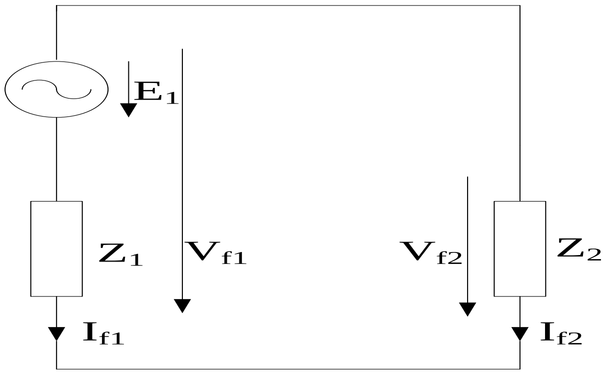


Figure 2-25. Sequence network connection of phase-phase fault

It should be noted that for this fault condition, the zps quantities are zero and this is true for any fault clear of earth.

2.7.2.3 Double-Phase-Earth Fault

Consider a b-c-earth fault as shown in Figure 2-26.

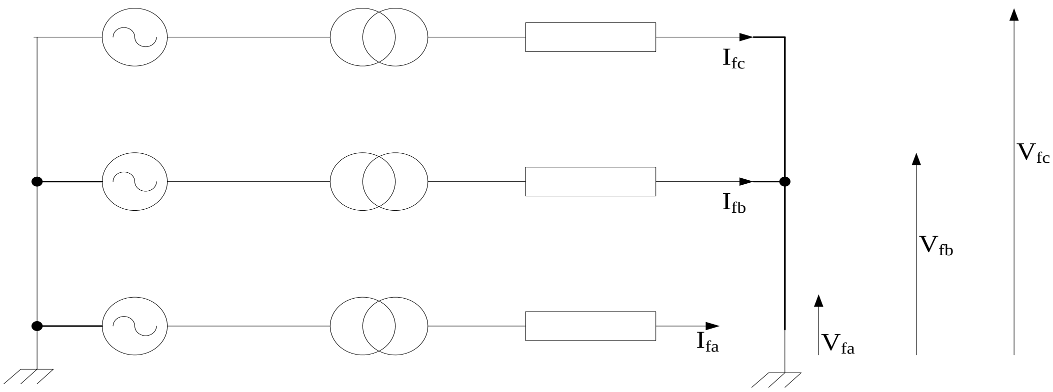


Figure 2-26. Double-phase-earth fault

Here, the constraints are: $I_{fa} = 0$, $V_{fb} = V_{fc} = 0$.

Again, using the matrix relationship of Equation, we get

$$V_{f0} = V_{f1} = V_{f2} = \frac{V_{fa}}{3}$$

From the above Equation, it can also be shown that

$$I_{f0} + I_{f1} + I_{f2} = 0$$

The required sequence network is thus:

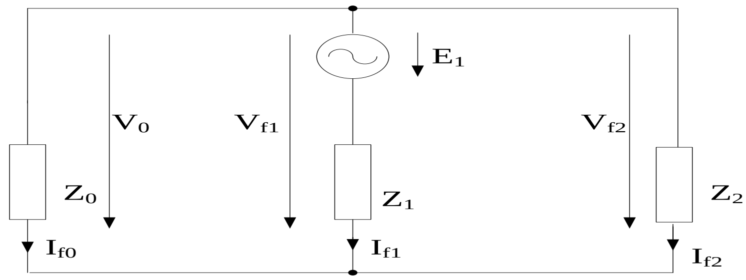


Figure 2-27. Sequence network connection of double-phase-earth fault

2.7.2.4 Three-Phase-Earth Fault

Consider the faulted system as shown in Figure 2-28.

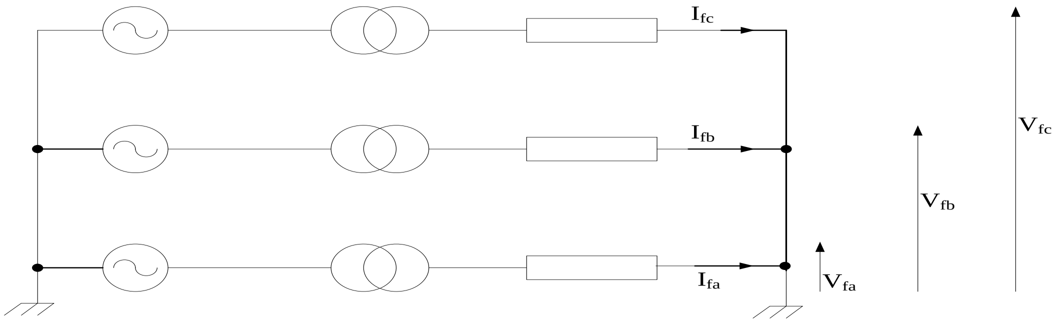


Figure 2-28. Three-phase to earth fault

For this fault, the constraints are:

$$V_{fa} = V_{fb} = V_{fc} = 0 \text{, and}$$

$$I_{fa} + I_{fb} + I_{fc} = 0$$

By using the above constraints in conjunction with the matrix relationships, it can be shown that

$$V_{f0} = V_{f1} = V_{f2} = 0, \quad I_{f0} = I_{f2} = 0 \text{ and } I_{f1} = I_{fa}$$

It can thus be seen that for this type of fault, only the pps network exist and this is true because as mentioned before, this is a symmetrical fault. The network is thus:

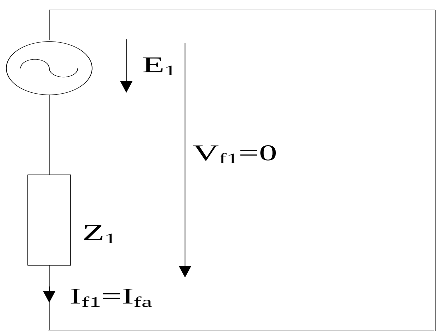


Figure 2-29. Sequence network connection of three-phase fault

M03 – SUBSTATION PROTECTION SYSTEM

3.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of substation protective system
- Explain kinds of power system protection, protective relay and protection components

3.2 Introduction

The primary objective of all power systems is to maintain a very high level of continuity of service, and when intolerable conditions occur, to minimize the outage times. Power system protection and control plays a significant role in ensuring the supply of reliable high quality electricity to customers who demand uninterrupted electrical power supply. Progress in design and development of protection technology has necessarily had to keep pace with advances in the design of primary plant, such as generators, transformers, switchgear, overhead lines and underground cables.

3.3 Electrical Power System

An electric power system is a network of electrical components used in the supply, transmission, distribution and consumption of electricity. The electrical power system consists of four basic subsystems, namely:

- Generation
- Transmission
- Distribution and
- Load

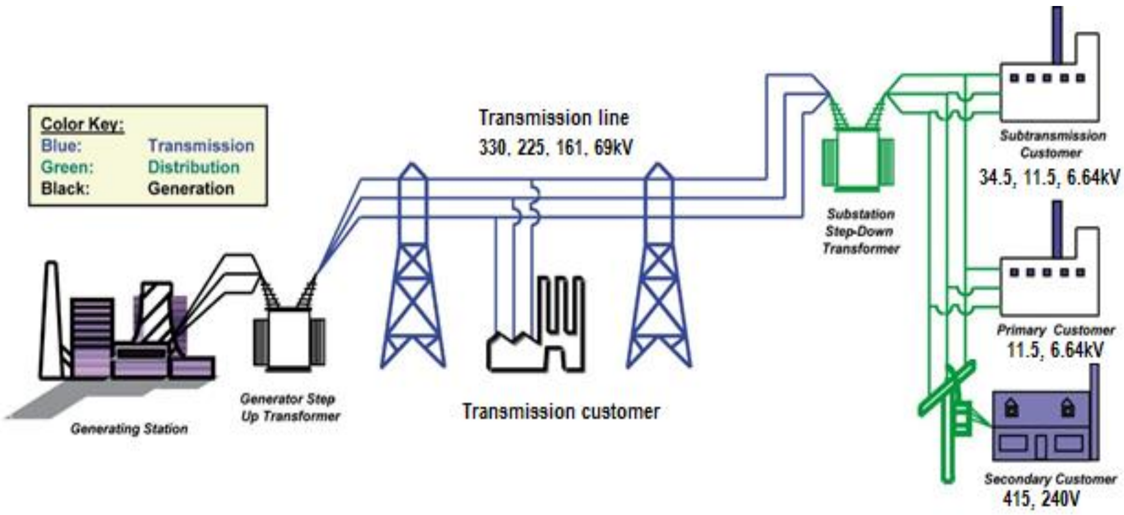


Figure 3-1. Simplified diagram of an electric power system

At a Ghanaian generation substation (such as Akosombo, Aboadze or Bui) , a unit transformer steps up the generation voltage from about 13.8kV to the transmission voltage of 161kV. Power is transmitted to bulk substations where transformers step down the voltage to the sub-transmission level (34.5 kV). At the distribution substation, the power transformers step down the voltage to the distribution level (11.5kV and 6.64kV). Finally the distribution transformer effects the final voltage transformation to the load voltage of 240/415V. Some typical transmission line and substation layouts are given below.

3.3.1 System Layout

Power system arrangements can have implications for protection. The following power system arrangements can be found:

- (a) Radial lines
  - Tamale – Yendi (TM3YD), Dunkwa – Ayanfuri D3AR, Ayanfuri – Asawinso (AR1AS)
- (b) Parallel lines
  - Akosombo – Volta lines (A2V, A3V, A4V, A5V and A6V)
  - Akosomo – Tafo lines (A7F, A11F)
- (c) Ring systems
  - Northern Loop (Techiman – Kintampo – Buipe – Tamale – Bolgatanga – Tumu- Wa – Sawla – Bui - Tehiman
- (d) Combinations of *(a), (b)* and *(c).*

Arrangement *(a)* does not satisfy the requirements of a duplicate supply, unless there is a source of generation at each end. Arrangement *(b)* provides a satisfactory duplicate supply. Arrangement *(c)* is, in effect, a logical extension of the idea of two parallel feeders. In its simplest form it provides a duplicate supply to every substation, provided that the ring is closed. When the ring is open the system reverts to one of two radial feeders.

In the more complex form of Figure 3-2 with interconnecting lines and multiple power sources more sophisticated forms of protection are needed than would be acceptable for the simple ring system if the aims of the protection are to be fulfilled. In this form can be discerned also combinations of (a), *(b)* and *(c).* The interconnected power system is the form suited to a transmission system.

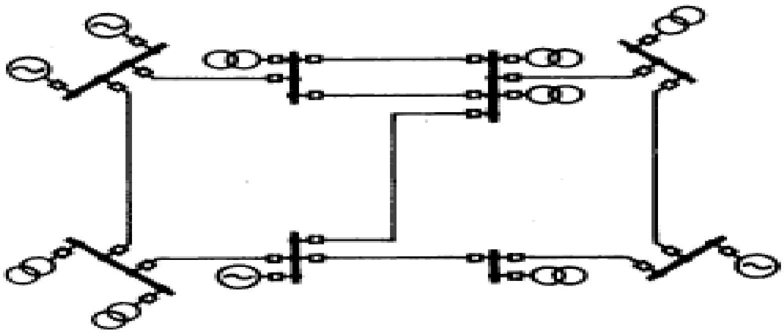


Figure 3-2. Interconnected power system

3.3.2 Substation Layout

Substations differ greatly in size, construction cost and complexity. The layout of a substation depends on the capacity and the importance of the substation to the power system. Substation layout affects the complexity of protection needed to adequately protect the substation equipment. The following substation layouts are found in the Ghanaian National Interconnected Power System.

- Single Bus System
- Single Bus with Bus Tie Breaker System
- Double Bus Bar Single Breaker System
- Main and Transfer Bus System
- Double Breaker Double Bus System
- Breaker and a Half Bus System
- Ring Bus System

3.4 Power System Protection

3.4.1 Definition of Protection

The IEEE defines a protective relay as "a relay whose function is to detect defective lines or apparatus or other system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action" (IEEE 100). The function of protective equipment is not the 'preventive' one as its name could imply, in that it takes action only after a fault has occurred.

It is fair to say that without discriminative protection it would be impossible to operate a modern power system. The protection is needed to remove as speedily as possible any element of the power system in which a fault has developed.

So long as the fault remains connected, the whole system may be in jeopardy from *three main effects of the fault*, namely:

- A risk of individual generators in a power station, or groups of generators in different stations, to lose synchronism and fall out of step with consequent splitting of the system;
- A risk of damage to the affected plant and healthy plant.
- The risk of loss of power supply to a large area leading to loss of production and interruption of vital processes.

It is the function of the protective equipment, in association with the circuit breakers, to avert these effects.

3.4.2 Factors That Affect Power System Protection

The ultimate aim of a power system is to provide 100 percent continuity of supply. This cannot be achieved by the protection alone, in addition, the power system must be so designed that there are duplicate or multiple outlets from power sources to load centers, and at least two sources of supply to each distributing station.

If full advantage is to be taken of their provision, the protection system must possess some basic attributes as presented below.

3.4.2.1 Qualities of Protection System

There are five basic attributes protection systems should possess. These are Reliability, Selectivity, Speed of operation, Simplicity and Economics.

3.4.2.1.1 Reliability

Reliability has two aspects: *dependability* and *security*. Dependability is defined as "the degree of certainty that a relay or relay system will operate correctly" (IEEE C37.2).

Security "relates to the degree of certainty that a relay or relay system will not operate incorrectly" (IEEE C37.2).

In other words, dependability indicates the ability of the protection system to perform correctly when required, whereas security is its ability to avoid unnecessary operation during normal day-to-day operation, and faults outside the designated zone of operation.

3.4.2.1.2 Selectivity

Relays have an assigned area known as the primary protection zone, but they may properly operate in response to conditions outside this zone. This is designated as the backup or overreached zone. Selectivity is the process of applying and setting the protective relays that overreach other relays such that they operate as fast as possible within their primary zone, but delay operation in their backup zone. This is necessary to permit the primary relays assigned to this backup or overreached area time to operate. Selectivity or relay coordination is important to assure maximum service continuity with minimum system disconnection.

3.4.2.1.3 Speed

It is desirable that a protection relay isolates a trouble zone as rapidly as possible. Zero-time or very high-speed protection, although inherently desirable, may result in an increased number of undesired operations. As a broad generality, the faster the operation, the higher the probability of incorrect operation. Time, generally a very small amount, remains one of the best means of distinguishing between tolerable and intolerable transients.

3.4.2.1.4 Simplicity

A protective relay system should be kept as simple and straightforward as possible while still accomplishing its intended goals. Each added unit or component, which may offer enhancement of the protection, but is not necessarily to the basic protection requirements, should be considered very carefully. Each addition provides a potential source of trouble and added maintenance.

3.4.2.1.5 Economics

It is fundamental to obtain the maximum protection for the minimum cost, and cost is always a major factor. The lowest-priced, initial cost protective system may not be the most reliable one; furthermore, it may involve greater difficulties in installation and in operation, as well as higher maintenance costs. Protection "costs" are considered "high" when considered alone, but they should be evaluated in the light of the much higher cost of the equipment they are protecting and the cost of an outage or loss of the protected equipment through improper protection.

3.4.2.1.6 Summary

It would indeed be utopian if all five basic objectives could be achieved to their maximum level. Thus, the protection engineer must maximize these as a group for the protection problem at hand and for the requirements of the system.

3.4.2.2 Location of Current Transformers and Circuit Breakers

Protection can be applied only where there are circuit breakers to enable isolation of the trouble area and where current and voltage transformers, when required, are available to provide information about faults and trouble in the power system. In particular, the boundary of a protection system depends on the location of the current transformer feeding the protection.

3.4.2.3 System Grounding

3.4.2.3.1 Neutral-Grounding Methods

Fault detection invariably relies on the presence of a significant amount of fault current; and this requirement is usually met as far as faults between phases are concerned. The exceptions concern earth-faults alone, the reason being that the value of the earth-fault current is governed by the method adopted of earthing the power-system star (neutral) point.

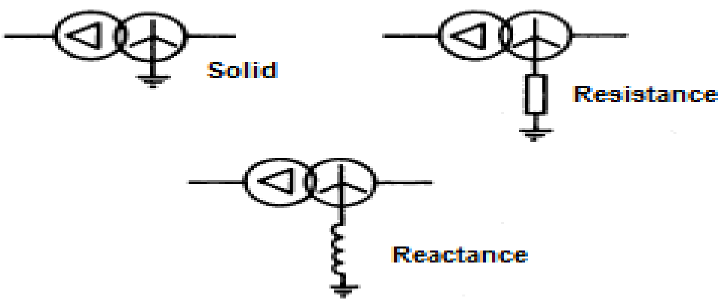


Figure 3-3. Neutral earthing methods

The methods commonly used in neutral earthing, shown in Figure 3 are:

- Solid-earthing in which the only impedance between the neutral and earth is that represented by the earthing conductor itself and the resistance between the earth-plate (or rods) and earth. An internationally accepted definition of a solidly earthed system is 'an effectively-earthed' system. which is defined as one 'in which, during a phase-to-earth fault, the voltage-to-earth of any sound phase does not exceed 80 per cent of the voltage between phases of the system.'

- Resistance-earthing, in which a resistor is interposed between the star-point and earth. This is also known as 'non-effective' earthing, the converse of effective earthing.
- Reactance-earthing (also non-effective), in which a reactor is used instead of a resistor. The reactance (like the resistance of the resistor) is chosen to suit the requirements of the protection, or to control inductive interference, which is the predominant requirement.
- Arc-suppression (Petersen) coil earthing, in which a reactor is used but its reactance is adjusted to match, more or less exactly, the value of the capacitance to earth of two phases with the third phase connected solidly to earth.
- Earthing through a combination of arc suppression coil and resistor, in which a persistent earth-fault on one phase is 'suppressed' by the coil. As it is not desired that the fault should remain indefinitely on the system, after a delay, adjustable up to 30 s, the coil is automatically shunted by a resistor of low value which permits adequate earth-fault current to now to operate orthodox discriminative protection.

3.4.3 Necessity for Back-Up Protection

There are two reasons for applying back-up protection to the elements of a power system. One is the obvious one of 'backing-up' the main protection to ensure that in the event of its failure, the fault will be cleared with complete discrimination, or at least with the minimum of dislocation of supply or of circuits. The second is to cover those parts of a protected circuit (or element) which are not covered by the main protection by reason of the location of the current or the voltage transformers.

To understand this function of back-up protection it is necessary to explain that with every protective installation there is associated a 'protected zone' which is defined, for a unit system, as the zone lying between the two or several sets of current transformers which together with the relays constitute the protective system; and, for a non-unit system, the zone lying between the current transformers and the point or points on the protected circuit beyond which the system is unable to detect the presence of a fault. Figures 3-4 and 3-5 illustrate this.

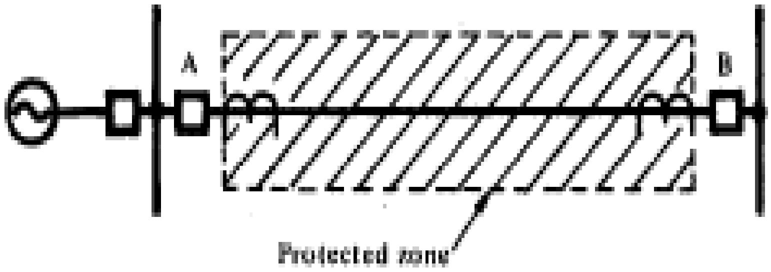


Figure 3-4. Protected zone of a unit system of protection

Thus faults that occur between the current transformers and circuit breaker, for example, in Figure 3-4, are outside the zone of the circuit protection and can be dealt with either by the busbar protection, or by back-up protection.

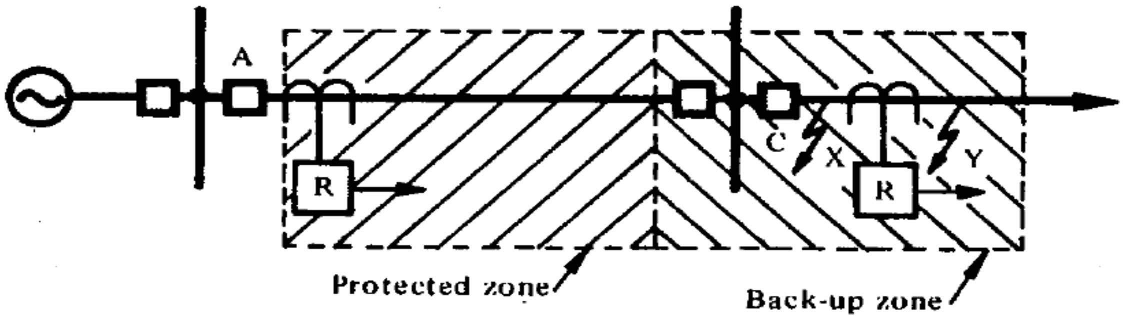


Figure 3-5. Protected and back-up zones of a protection (distance protection)

The latter in performing that function would be acting as 'remote back-up'. This is exemplified in Figure 3-5 in which the back-up protection at A acts as back-up for a fault at X, or a fault at Y, not cleared for any reason by the circuit breaker at C.

A fault between A and B (Figure 3-4) not cleared for any reason by the 'main protection' must also be cleared at A (assuming for simplicity a single infeed) by back-up protection. In this instance the latter would be acting as 'local back-up'.

3.4.4 Methods of Discrimination

In providing selective fault clearance a protective relay needs to be provided with information to enable it to discriminate between fault conditions within its legitimate zone of operation for which tripping is required, and external faults and healthy load currents for which tripping is not required.

Generally where only local information is used some element of time delay must be included to provide discrimination between adjacent protection systems whereas, when comparison is made of both local and remote quantities the protection covers one discrete unit of the power system and can provide rapid and wholly discriminative fault clearance.

Some basic methods of discrimination may now be considered.

3.4.4.1 Discrimination by Time

In this the basic idea is to add time lag features to the controlling relays of a number of circuit-breakers in the power system so that the breaker or breakers nearest to a fault on the system always trips first.

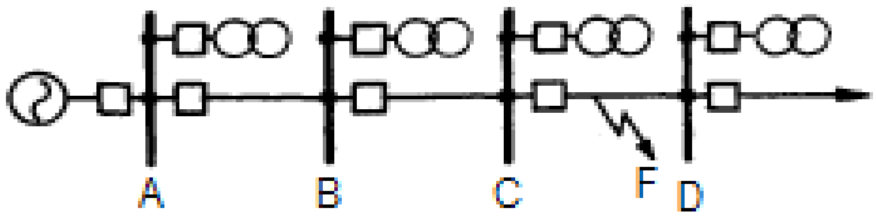


Figure 3-6. Simple radial system with single infeed at station A and a fault F on feeder CD

Figure 3-6, which shows a simple radial line passing through transformer stations A, B, C and D, at each of which the outgoing line has a circuit breaker.

Suppose that we are able to add time lag features to the protection systems such that after these recognise the existence of a fault the tripping is delayed thus:

D-no added delay,

C-0.4 s added delay,

B-0-8 s added delay,

A-1.2 s added delay.

Consider the effect of a fault, F, in the line section CD. The breaker at C will open after 0.4s, and will disconnect the fault before the breakers at A and B can trip. Supply is thus maintained to A, B and C. This is known as time discrimination.

An interval of the order 0.4s is necessary to give the circuit-breaker and its protective relays time to operate fully before the next breaker with the longer time can receive an impulse to trip.

3.4.4.2 Discrimination by Current Magnitude

Discrimination can be obtained by recognising the fact that faults in different parts of a power system will cause fault currents of different magnitude on account of the differing impedances between the source and the points of fault.

This with the protective relays of the various circuit-breakers set to trip at suitably tapered current values, will ensure that the breakers near to the fault will trip and will leave others traversed by the same fault current undisturbed.

Thus, supply will be maintained to those parts of the system which are healthy.

3.4.4.3 Discrimination by Time and Direction

Consider Figure 3-7 where all the relays operate with the time lags shown, but only with fault power flowing through the relays in the direction shown by the arrows.
Trial of the effects of faults anywhere on the ring main show that a fault occurring on any section of ring main will be discriminatively cleared by the relays, and there will be no loss of supply.

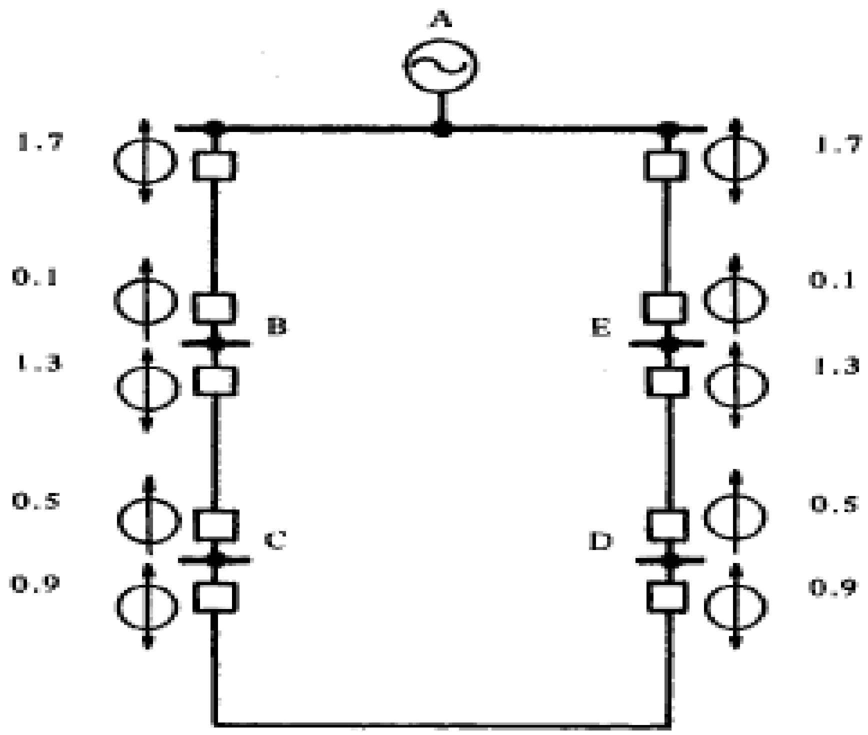


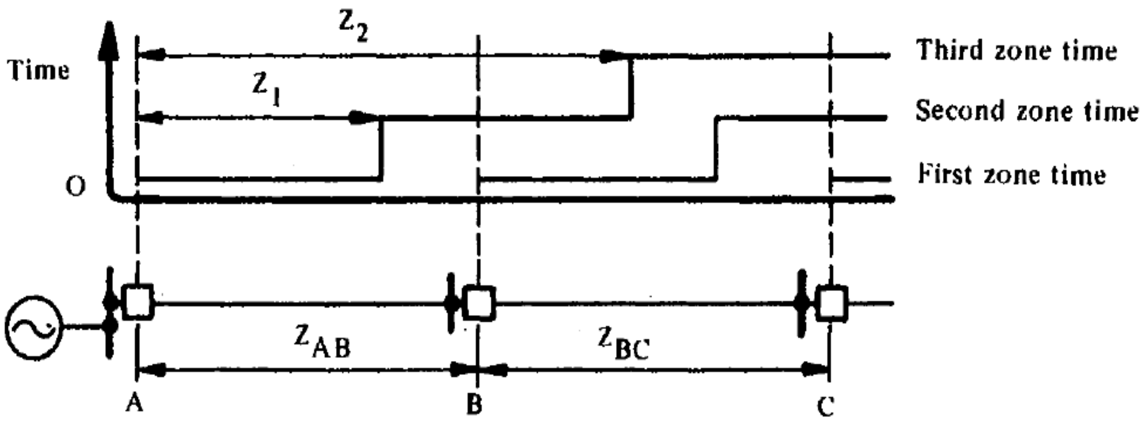
Figure 3-7. Combined directional and non-directional time-graded protection applied to a ring main system

3.4.4.4 Discrimination by Distance Measurement

The limitations in the methods of discrimination can be reduced if the relays which control circuit-breakers are made such that they will measure the distance from the circuit-breaker location to the fault.

If this distance is less than that to the next circuit breaker out from the source, the fault is within the section controlled by the breaker concerned, and this will trip.

3.4.4.5 Time as an Addition to Distance Discrimination



Z_{AB}, Z_{BC} – feeder impedances
Z_1, Z_2 – zone 1 and zone 2 reach of distance protection

Figure 3-8. Time distance characteristic of three-zone distance protection scheme

The addition of time as a factor will often extend the usefulness of distance discrimination. The system is similar to that of Figure 3-6, the stations A, B and C and the intervening lines being the same in both drawings. Distance relays are located at A, B and C and they control the circuit-breakers there. The relay at A is intended to detect faults in the feeder AB and would be set to measure the distance A to B, or more specifically the impedance Z_{AB}. Taking account of practical accuracy limits in the relay the zone of instantaneous response (known as first zone, Z_1) is set to *80-85% of* Z_{AB}.

If a fault should occur beyond Z_1 up to the circuit breaker at B, a second time lag step (about 0.4 sec) in the relay at A will then operate, thus clearing the fault after a short time lag. The distance relays at B and C have similar time lag 'second zones' and Figure 3-8 suggests even a third zone to provide 'additional' back up for a situation where the relays at stations B and C fail to operate.

3.4.4.6 Current Balance Methods

For practical power system is invariably more complex than those so far considered. Satisfactory discrimination can be provided by a protection system which makes a comparison between currents at each end of the protected circuit and the simplest and most widely used form in that of current balance protection.

This is illustrated in its basic form in Figure 3-9 which shows current transformers at both ends of the protected circuit connected so that for through load or through fault conditions current circulates between the interconnected CTs.

The relay is normally connected across equipotential points and therefore does not operate. For an internal fault the balance is disturbed and the out of balance current will operate the relay to trip the associated circuit breaker.

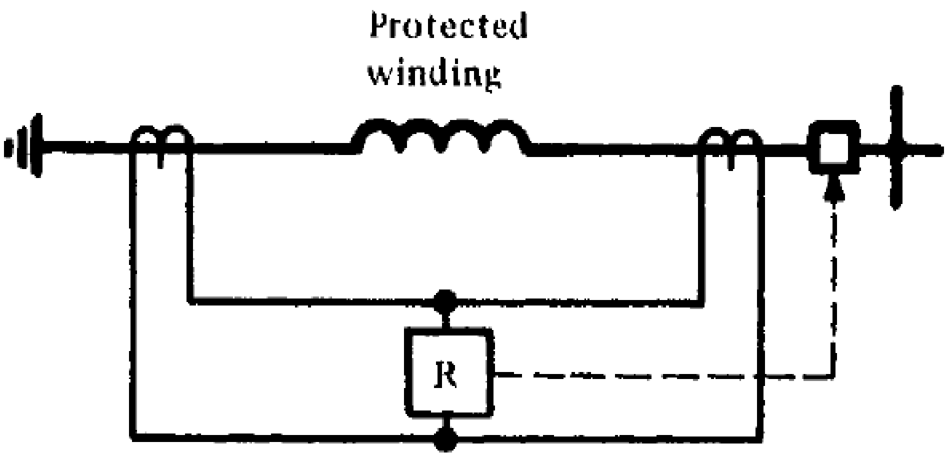


Figure 3-9. Current-balance system using circulating current principle

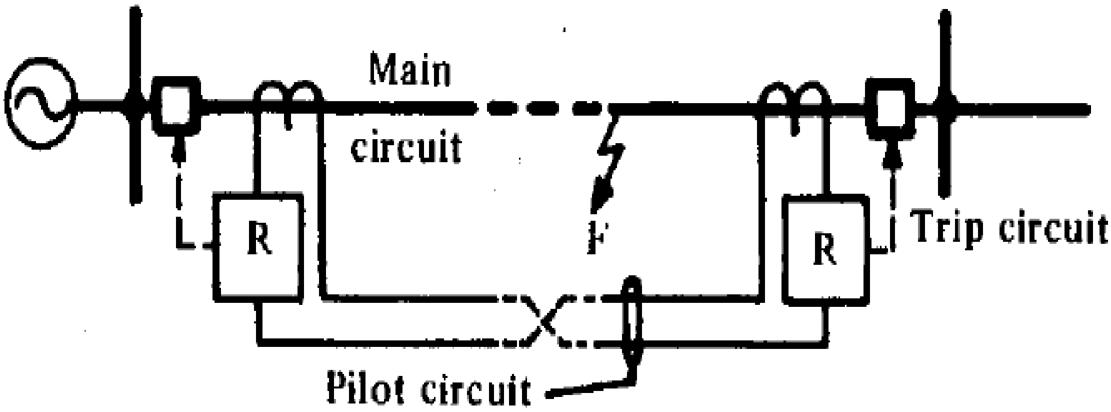


Figure 3-10. Principle of opposed voltage feeder protection

3.4.4.7 Opposed Voltage Protection

Figure 3-10 shows a protective scheme for a single feeder. This, like the scheme of Figure 3-9, relies on the fact that, provided there is no fault on the feeder, the currents entering and leaving it must be equal in phase and magnitude. Balance is therefore between circuit ends, and to accomplish this, an auxiliary circuit is required, connected as shown. In the case illustrated the current transformers are of a special type, designed to produce a secondary voltage linearly proportional to the primary current. With no fault on the feeder these secondary voltages will be equal and opposite, so that no current flows in the relays, which are in series with the pilot circuit. A fault at F will disturb the balance between ends, the current transformer secondary voltages will no longer balance, and current will flow in the relays, which, on closing their contacts, will trip the circuit-breakers at the two ends.

3.4.4.8 Phase-Comparison Method

In situations where the means of communication between circuit ends is unable to provide a linear transmission of current amplitude information, a comparison between relative phase angles is often possible. The most widely used protection of this kind is the phase-comparison carrier current protection system in which alternate half cycles of current at each end of the protected circuit are modulated with a carrier signal and transmitted over the power line, for comparison against the locally derived signal. The comparator will have an angular setting, i.e. it will operate when the phase angle between the two currents exceeds a predetermined value.

3.4.4.9 Distance Protection with Signalling Channel

The basic form of three zone distance protection has the disadvantage of low speed (Zone 2) fault clearance for faults within the last 20% of the protected feeder. Where high speed fault clearance is necessary over the whole feeder this delayed tripping can be eliminated by the use of an instruction signal. The scheme adopted in the Ghanaian system, shown in Figure 3-11(a) is to make the tripping conditional. In this case operation of Zone 2 at the circuit end nearest to the fault sends an 'acceleration' signal to the remote end which in effect, short circuits the time lag associated with an independent Zone 2 relay.

Tripping is thus dependent upon two criteria:

- receipt of a signal from the remote end of the circuit to advise that tripping has taken place there.
- operation of an independent Zone 2 at the local end to confirm that a fault still persists on the protected line.

If this method is inverted we have the arrangement shown in Figure 11(b) where the distance relay now has an instantaneous zone *(Z_2)* which extends beyond the protected feeder and the signal transmitted at the remote end is used to block its tripping circuit under through fault conditions. The high speed block initiation relay (HSS) is directional and operate only for faults outside the protected feeder (i.e. it has a reversed reach).

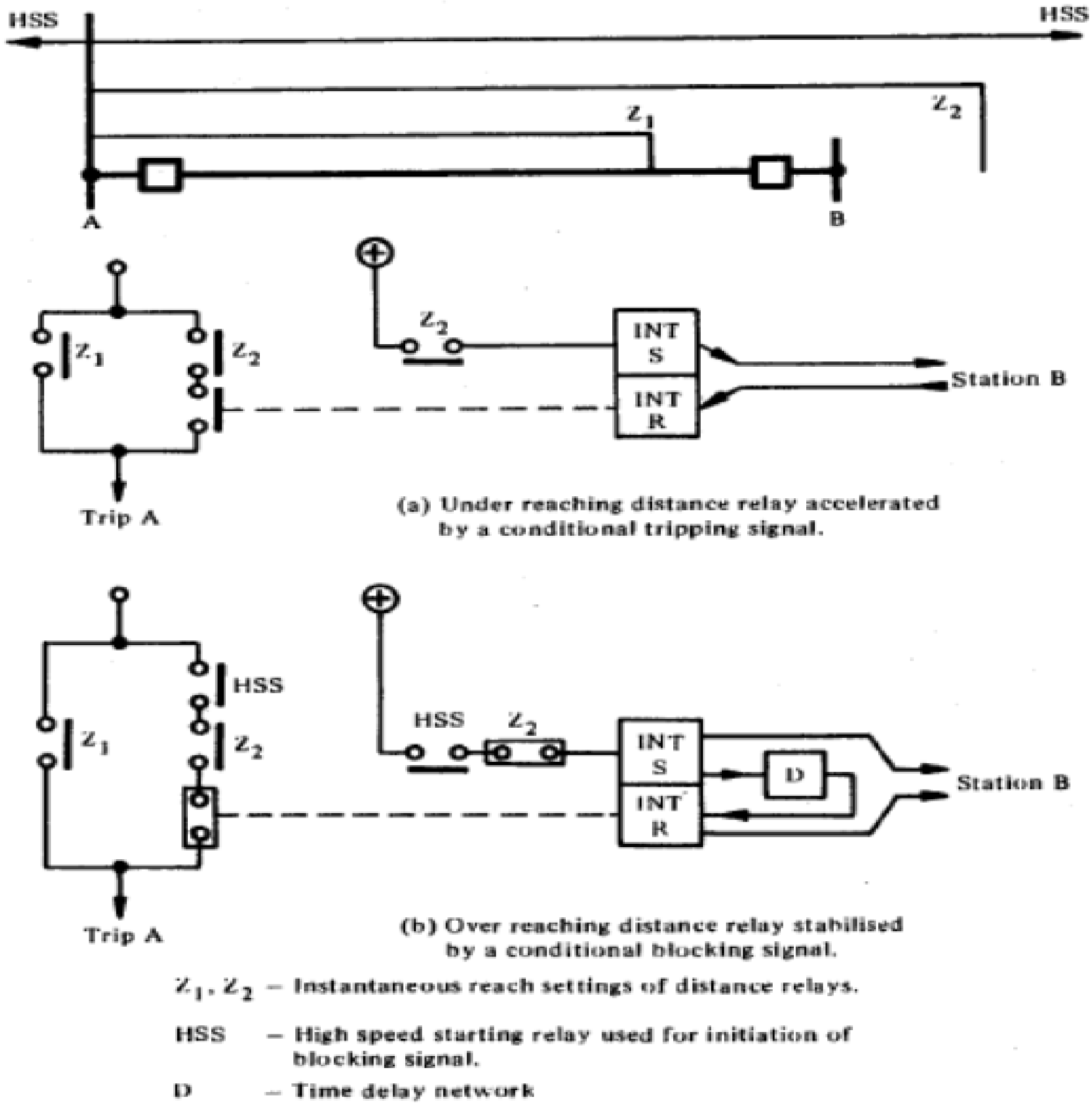


Figure 3-11. Showing two methods of using a communication channel to accelerate distance protection

Tripping at end A is prevented by relay R which is operated, via the signalling channel from relay S at end B. End B does not wish to trip because Z_2 is not operated (the fault is 'behind' the relay).

3.5 Basic Relay Design Principles

The design techniques used to provide relays for the protection of electric power systems has progressed from electromechanical to solid state to numerical in a relatively short period. The several steps in this progression were as follows:

- Electromechanical: all analogue measurements, comparison, tripping and so forth.
- Solid state: analogue or operational amplifiers, solid-state operate element, thyristor, or contact output.
- Numerical: analogue/digital and microprocessor, contact output

All types are in service, but the microprocessor designs are widely offered today. The basic protection characteristics are essentially the same for both electromechanical and solid-state relays.

Thus, a review of the characteristics for the electromechanical relays provides a background for the modern units.

3.5.1 Time Overcurrent/Overvoltage Relay

One typical type of a time-overcurrent type relay is illustrated in Figure 3-12 below. Alternating current applied to the main coil produces magnetic flux, most of which passes through the air gap and disk to the magnetic keeper.

This returns through the disk to the two side legs of the electromagnet. The shorted turns of the lag coil on one side-leg causes a time and phase shift in the flux through that side of the disk to produce rotation of the disk.

This rotation is damped by a permanent magnet. The spiral spring provides reset of the contacts after the operating quantity is removed or reduced below pickup value.

Contacts attached to the disk shaft can be normally open or closed in the de-energized state. This combination produces fast operation at high current and slow operation at low current; hence, an inverse time characteristic.

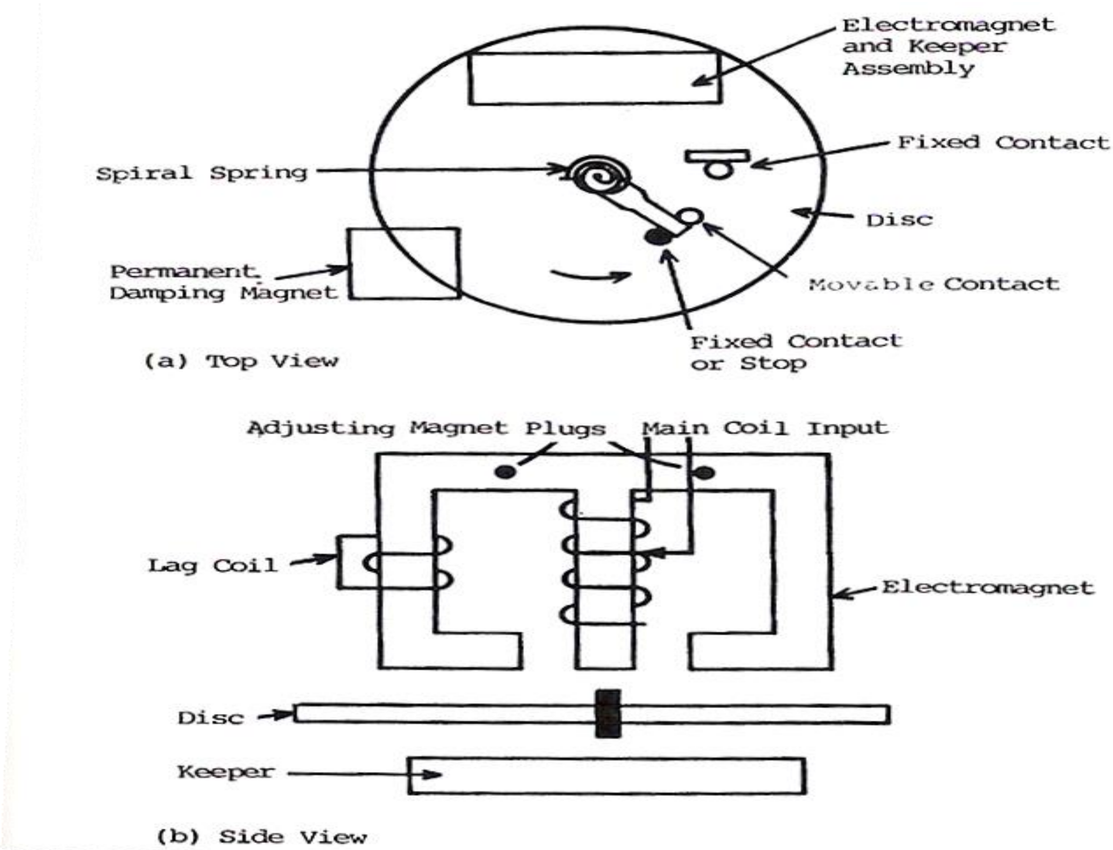


Figure 3-12. Typical induction disk inverse-type overcurrent relay

The design of an overvoltage relay is similar to that of the induction disc overcurrent relay described above.

3.5.2 Instantaneous Current/Voltage Relay

Such relays are used in many areas of protection, such as overcurrent or over- or under-voltage units, to trip directly or as fault detectors. Typical types in general use are the clapper or telephone relay in Figure 3-13 and induction cup or induction cylinder relay in Figure 3-14.

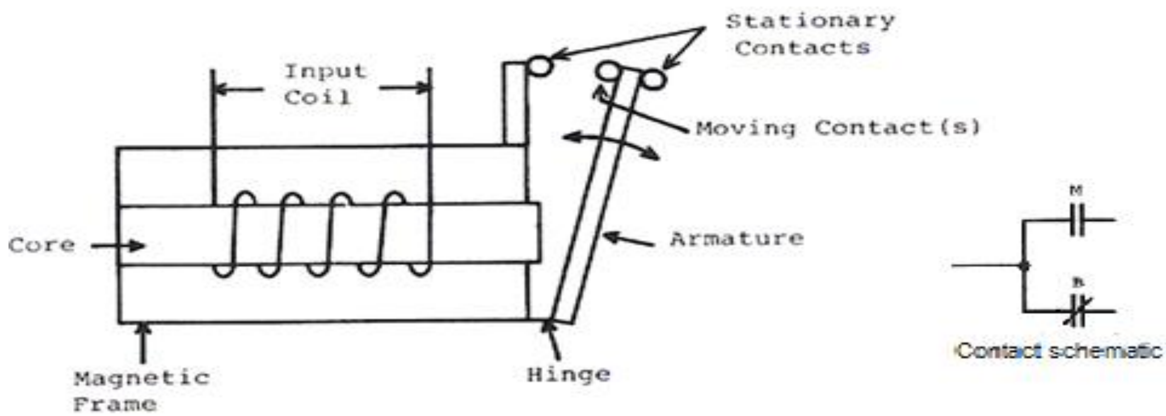


Figure 3-13. Typical electromechanical clapper or telephone relay

For the telephone relay current or voltage applied to the coil produces flux, which attracts the armature. Contacts on the moving member are thus operated. Multiple contacts are possible on the telephone relay. The ac types have taps or other means to change the pickup value.

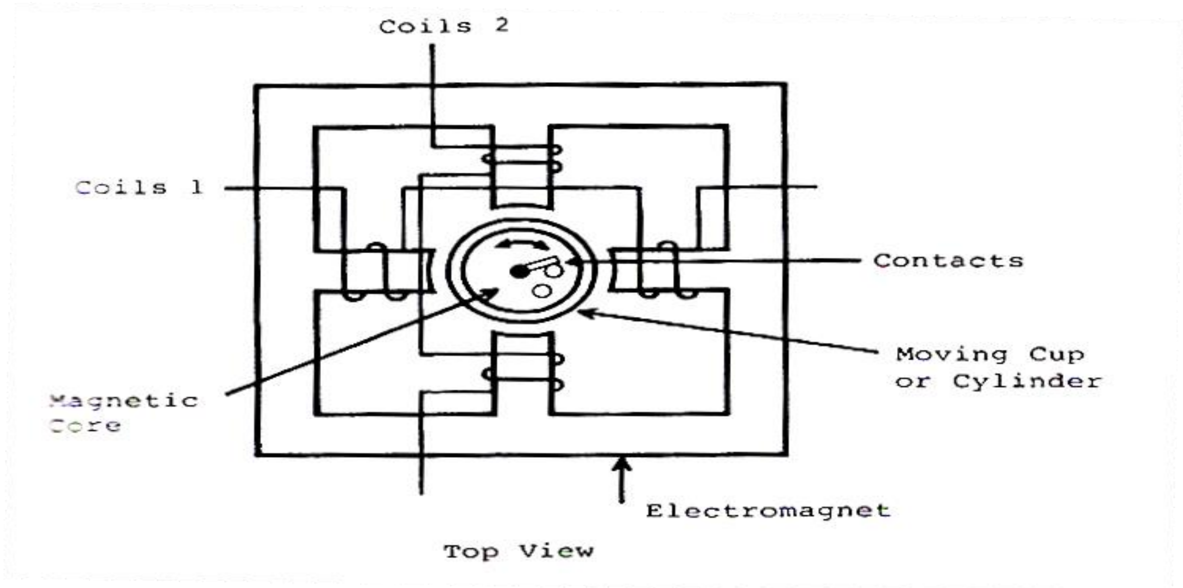


Figure 3-14. Typical electromechanical induction cup or cylinder relay

The ac induction cup or induction cylinder unit of Figure 3-14 is basically a ‘two-phase motor’, with the two coils wound as shown on the four poles of the electromagnet. In the center is a magnetic core and around or over this is the moving cup or cylinder, with the moving contacts and spring to provide reset. When the fluxes of coils 1 and 2 are in phase, no rotational torque exits. As an instantaneous overcurrent unit, a phase shift is designed in one coil circuit, such that an operating torque is produced when the current is higher than the pickup value. The rotation is limited to a few millimetres, enough to close the contacts.

3.5.2.1 Directional-Sensing Power Relays

The induction cup and induction cylinder units are used to indicate the direction of power flow and magnitude. The operating current is passed through one set of windings and a reference voltage or current through the other. When the phase relations are favourable, the unit operates. Because these units, as directional units, are very sensitive, they are used in almost all applications with fault-sensing units, such as the time-overcurrent or instantaneous overcurrent units. Other types have tapped windings to operate when the power level exceeds a preset value.

3.5.3 Polar Unit

The polar unit is a dc unit operating from ac quantities through a full wave-rectifier. It provides very sensitive, high-speed operation, with very low-level inputs. As shown in Figure 3-15, an electric coil is wound around a hinged armature with contacts in the center of a magnetic structure with nonmagnetic spacers in the rear. A permanent magnet bridges this structure to polarize the two halves. Two adjustable magnetic shunts bridge the spacers to vary the magnetic flux paths.

With the coil de-energised and balanced air gaps (Figure 3-15a), the armature is not polarized, and contacts will float in the center. Now adjusting the gaps to provide unbalance, some of the flux is shunted through the armature (Figure 3-15b). Thus the contacts can be either held open or closed. Energizing the coil with dc magnetizes the armature either north or south increasing or decreasing any prior armature polarization.

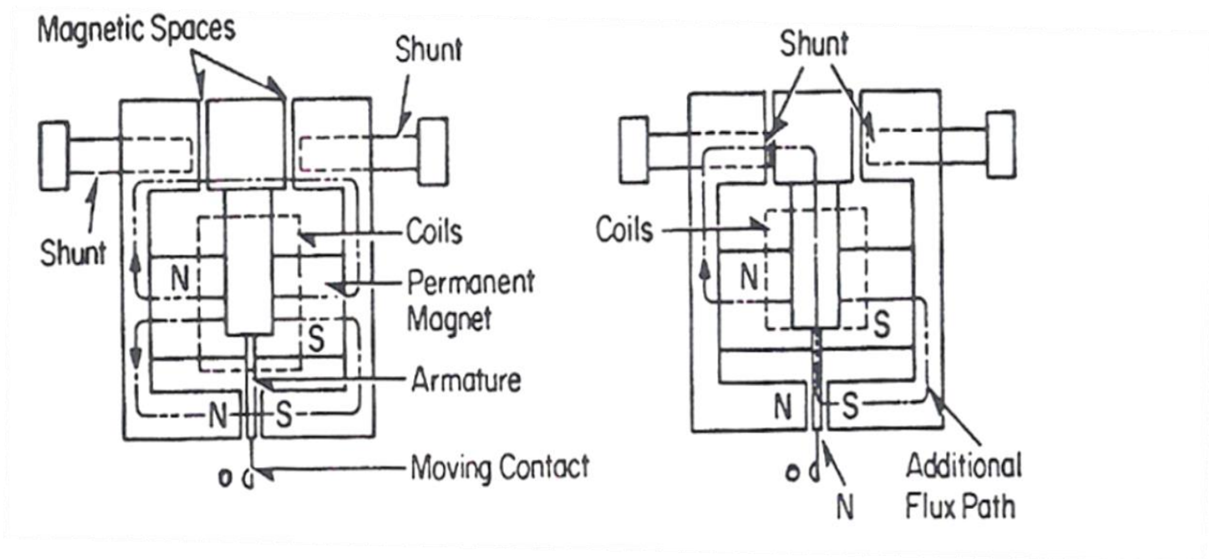


Figure 3-15. The dc polar unit: (a) balanced air-gaps (b) unbalanced air-gaps

In Figure 3-15b the armature is shown polarized N before energisation so the armature will move to the right and the contacts open. Direct current in the coil, to overcome prior polarization and to make the contact end a south pole, results in contact movement to the left and contact closure. The contact action can be gradual or quick, depending on the adjustments. The left gap controls the pickup value, and the right gap the reset value. Two coils, one an operating and the other a restraint, are used in some applications. Examples are the electromechanical pilot wire and differential relays.

3.5.3.1 The Current Differential Relay

The best protection technique is that known as differential protection. Electrical current entering a protected zone is compared with current leaving the zone by the use of current transformers (CTs). If the net between the currents is essentially zero, it is assumed that no fault or intolerable problem exists. However, if the net is not zero, an internal problem exists and the differential current can operate associated relays.

Differential protection is universally applicable to all parts of the power system: generators, motors, buses, transformers, lines, capacitors, reactors, and sometimes combinations of these. As the protection of each part of the power system is discussed, invariably, differential protection is the first consideration, and often it is the choice for the primary protection.

3.5.3.1.1 The Differential Principle

The differential protection technique is illustrated in Figure 3-16, and for simplicity, only two circuits to the protection zone are shown. The sum of the current flowing in essentially equals the sum of the currents flowing out during normal operation.

For normal operation and all external faults (through fault condition), the secondary current in Figure 3-16a in the protective relay is the difference in the exciting currents of the differentially connected current transformers. Per unit current distribution is shown.

For example, I_p is the primary current in the lines entering or leaving the protected area. I_p - I_e is the secondary ampere current and is equal to primary current divided by the current transformer ratio minus the secondary exciting current.

Even with exactly the same ratio and type of current transformer, the relay current I_{op} will be small, but never zero. This is because of the losses within the protected area and the small differences between the similar CTs. This assumes that no current transformer significantly saturates for the maximum symmetrical ac through currents.

Figure 3-16b shows that the differential relay operating current essentially is the sum of the input currents feeding the fault. This is total fault current on a secondary ampere basis.

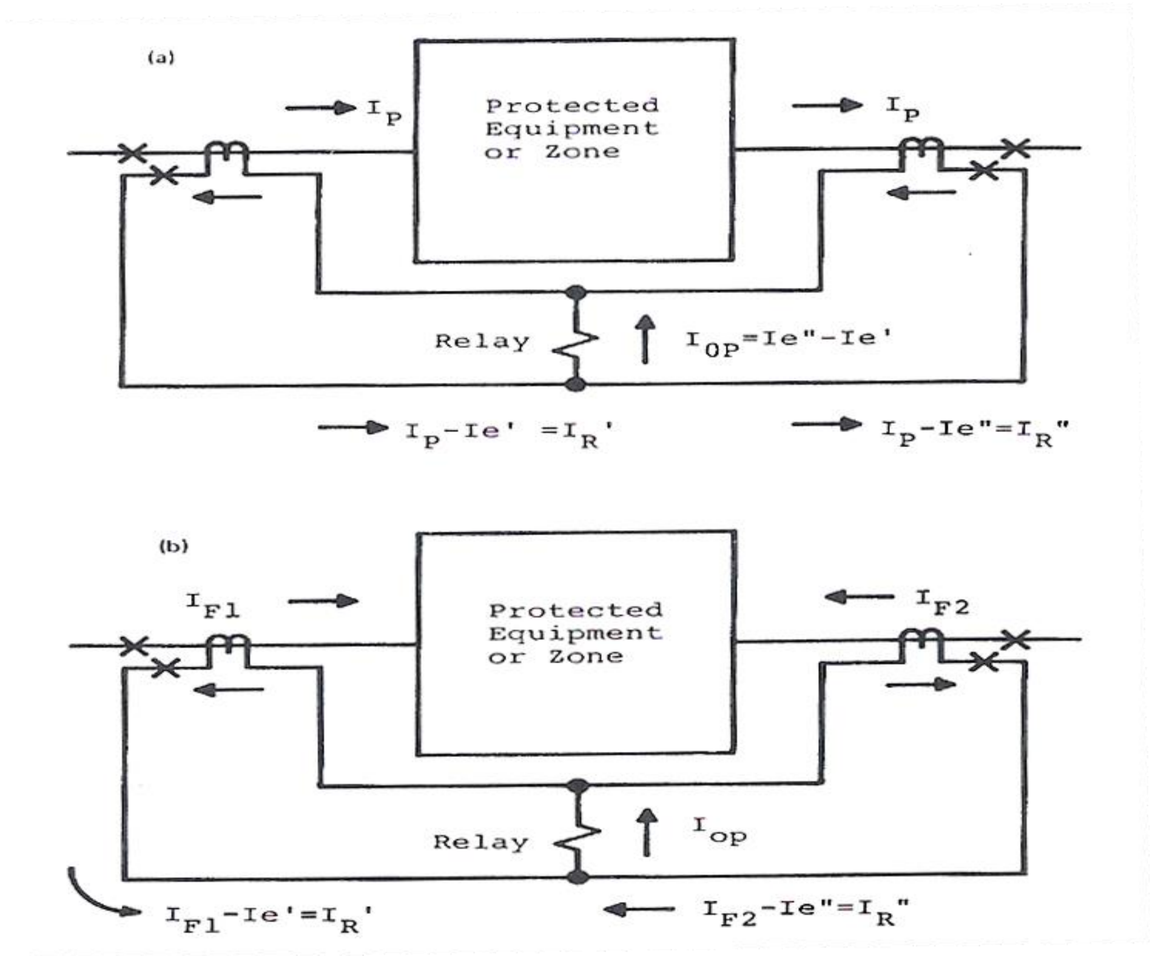


Figure 3-16. Basic current differential scheme

(a) normal conditions; $I_{op} = I''_e - I'_e$, (b) internal fault $I_{op} = I_{F1} + I_{F2} - (I''_e + I'_e)$

To provide high sensitivity to light internal faults with high security (high restraint) for external faults, most differential relays are of the percentage differential type. Figure 3-17 is a simplified schematic of this type of relay for two circuits. The secondary of the CTs are connected to restraint windings *R*. Currents in these inhibit operation. Associated with these restraint windings is the operating winding *OP*. Current in this winding tends to operate the relay.

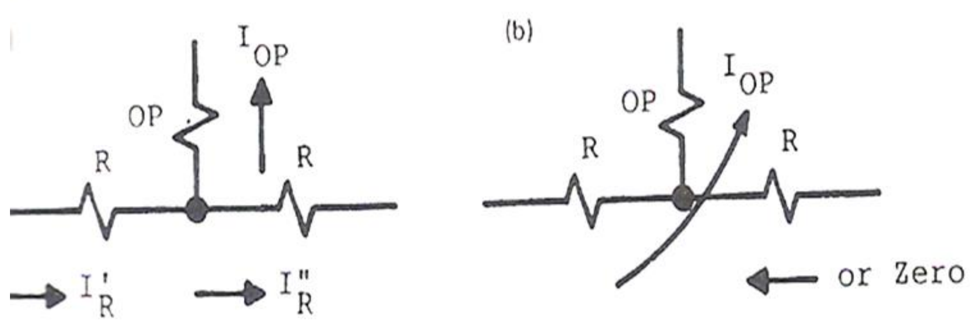


Figure 3-17. Percentage differential relay (a) external faults; (b) internal faults

At low through currents the percentage is low because at these levels the current transformer performance is usually quite reliable. At high through-fault currents, where the CT performance may not be as dependable, a high-percentage characteristic is provided (Figure 3-18). This gives increased sensitivity with higher security.

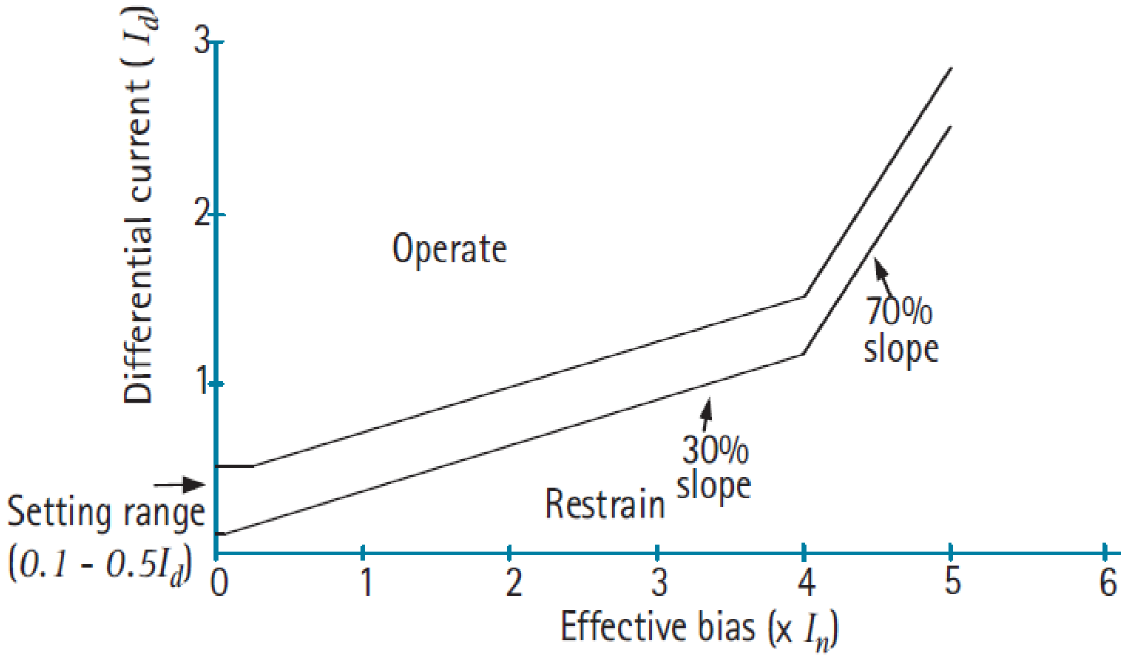


Figure 3-18. Percentage differential relay characteristic

For lines where the terminals and CTs are separated by considerable distances, it is not practically possible to use differential relays as described in the foregoing. Still the differential principle provides the best protection and is still widely used.

This is true particularly at the higher voltages. A communication channel such as a pilot wire, fiber-optic cable, power line carrier, audio tones over wire, or microwave is used for information comparison between the various terminals.

3.5.4 Distance Relays

Fundamentally, distance relays compare the power system voltage and current. They operate when the ratio is less than a preset value.

For balanced conditions and for phase faults, the ratio of the voltage to current applied to the relay is the impedance of the circuit, because $V/I = Z$. Thus, these relays are set as a function of the fixed impedance of the power system for the zone they are to protect.

3.5.4.1 Balanced Beam Type

An early design provides a good basic understanding of the principle and appreciation of common terms currently used. This early type is illustrated in Figure 3-19. A balanced beam has a voltage energized electromagnet to restrain its movement and a current-operated electromagnet to close its contacts.

By design and setting, the voltage-restraint force can be made to equal the current-operating force for a solid zero-voltage three-phase fault at the set point shown as nZ_L. This threshold point is known as the 'balance point', 'operating threshold', or 'decision point' of the unit.

For a fault between the relay and point *n,* the current *I* will be larger and *V* will decrease or remain approximately the same relative to the values for the fault at *n.* Thus, the increased current causes the beam to tip at the left end to close the contacts.

For an external fault to the right of point *n,* the current will be less than for the fault at *n,* and the voltage will be higher. Thus, the torque or pull of the voltage coil is greater than that of the current coil for restraint or no operation.

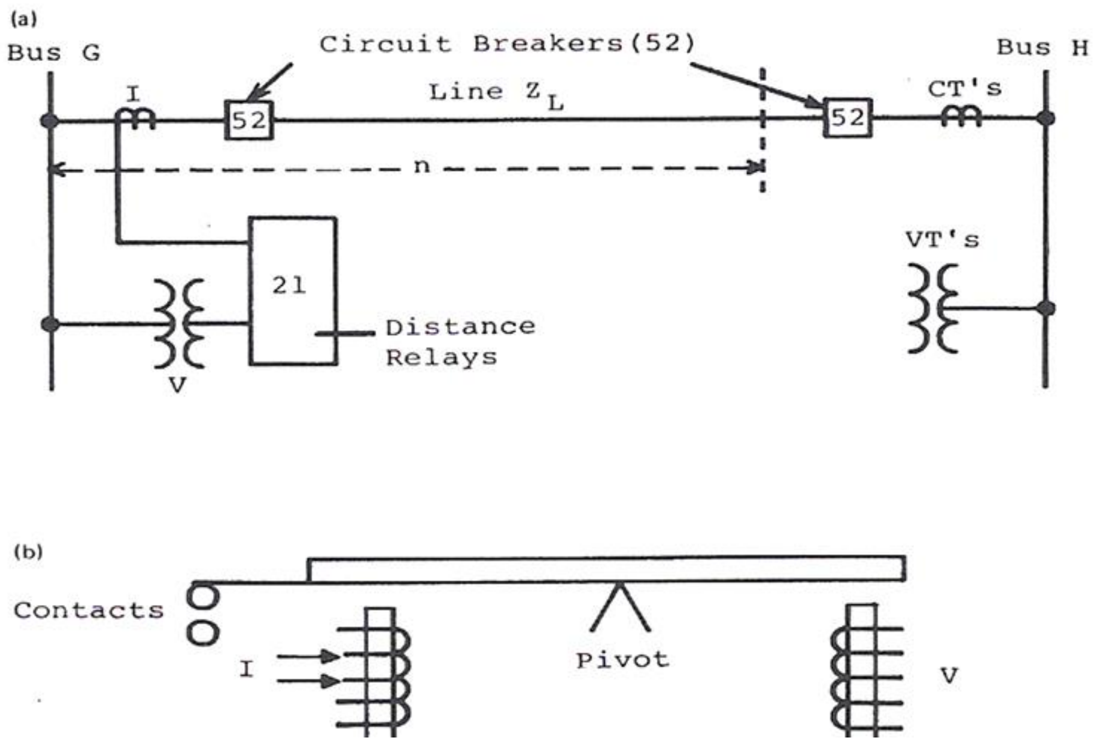


Figure 3-19. Distance relay operating principles – the balanced-beam operation unit: (a) distance relay to line GH; (b) simplified explanation diagram

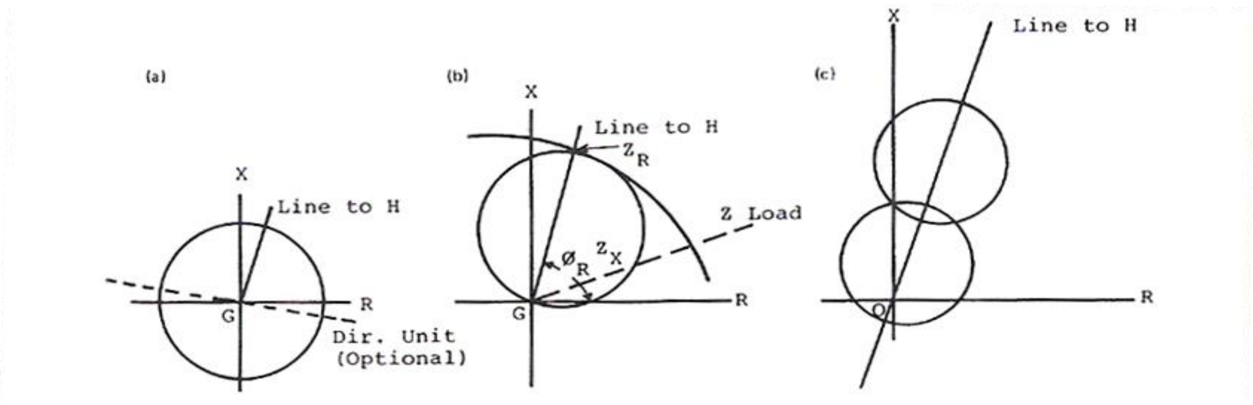
With the solid three-phase fault at the balance point *n,* the voltage at *n* will be zero. Then the voltage at the relay location will be the drop along the circuit, or InZ_L. Dividing this voltage by the current, the unit responds to impedance:

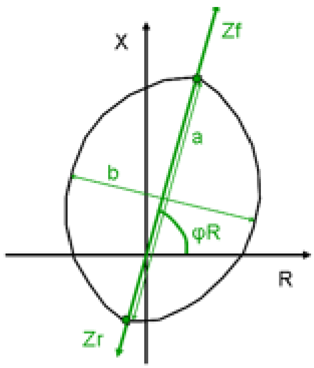
$$Z_n = \frac{V}{I} = \frac{I\ nZ_L}{I} = nZ_L$$

Thus, the setting and operation are a function of the impedance from the relay voltage measurement point to the balance or set point. By using line-to-line voltages and line-to-line currents the reach of the phase-type relays is the same for three-phase, phase-to-phase, and two-phase-to-ground faults. Because the current cancels in the above Equation, this reach is fixed for a given setting over a very wide range of fault currents, thereby providing a fixed reach with instantaneous protective relays not possible with an overcurrent instantaneous relay.

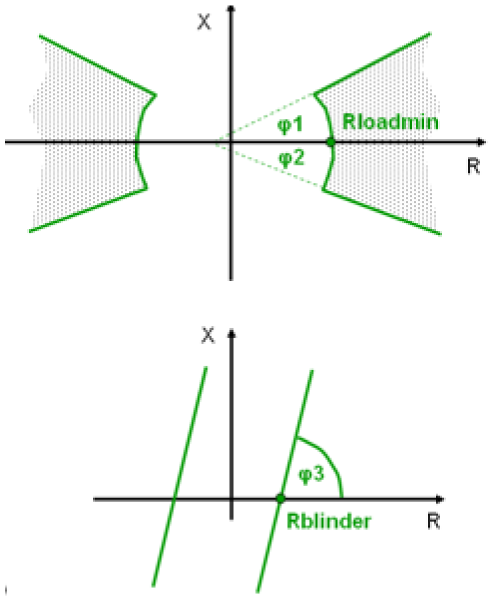
3.5.4.2 The R-X Diagram

The characteristics of distance relays are shown most conveniently on an impedance *R-X* diagram, where the resistance *R* is the abscissa and the reactance *X* is the ordinate. Typical characteristics on these axes are shown in Figure 3-20. For any given discussion the origin is the relay location, with the operating area generally in the first quadrant. Whenever the ratio of the system voltage and current falls within the circle shown, or in the cross-hatched area, the unit operates. The elementary type discussed in Figure 3-19 provided an impedance characteristic such as that shown in Figure 3-20a. This obsolete design was independent of the phase relation of the voltage and current, thereby operating in all four quadrants. Thus, a separate directional-sensing unit was necessary to prevent operation for faults in the system to the left of bus G.

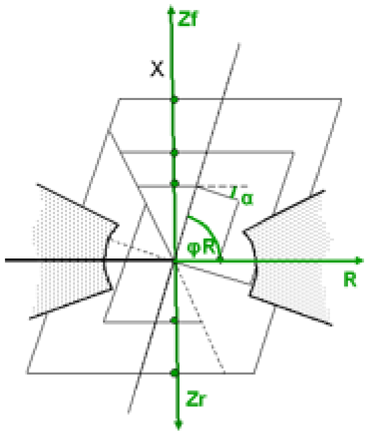




(d)



(e)



(f)

Figure 3-20. Distance relay characteristics on the R-X diagram:
(a) Impedance;(b) mho; (c) offset mhos; (d) lens;
(e) simple blinders; (f) reactance.

3.5.4.3 The Mho Characteristic

The circle through the origin (see Figure 3-20b) is known as a mho unit and is in wide use for line protection. It is directional and is more sensitive to currents lagging at about 60°-85° than to loads that are near a 0° to 30° lagging current.

The equation of the mho circle through the origin is

$$Z = \frac{Z_R}{2} - \frac{Z_R \angle \phi}{2}$$

$Z_R/2$ is the offset from the origin, $Z_R \angle \phi$ is the radius from the offset point. When the offset is along the *X* axis and ϕ is 0°, relative to the *R* axis, Z = 0. When ϕ is 180°, Z = Z_R. When the mho circle is tilted, as in Figure 20b, ϕ is the angle of ϕ_R of the offset.

$$Z_X = Z_R \cos(\phi_R - \phi_X)$$

where Z_X is the impedance from the origin to any point on the circle at angle ϕ_X, and Z_R is the relay reach at ϕ_R.

The primary protection of a line such as GH in Figure 3-19 requires two or more distance units. This is shown in Figure 3-21 for station G, using three mho units. Zone 1 unit operates instantaneously and is commonly set for nZ_{GH} where n is less than 1, (usually ~0.8). Zone 2 unit is set with n greater than 1 or about 1.5, depending on the system to the right of station H. A time-coordinating delay is required for zone 2 because it overreaches bus H

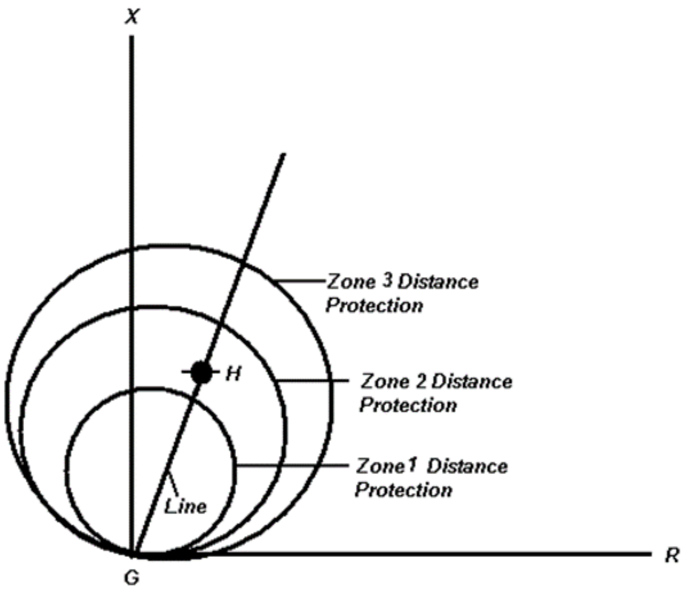


Figure 3-21. Distance mho units applied at G for the primary protection of line GH of Figure 3-19

A third zone, zone 3, is used in the hope of providing remote backup protection for the line(s) to the right on station H.

Sometimes zone 3 at G is set to look backward from, or to the left of, station G.

This can be used for backup or as a carrier-start unit in pilot relaying. In these applications, the zone 3 mho-type unit, with offset to include the origin, should be used.

This characteristic is the lower mho unit in Figure 3-20c.

This assures operation for close-in faults, for which the voltages are very low or zero. The mho relays can be either single-phase or polyphase types.

3.5.4.4 Single-Phase Mho Units

For the single-phase types, three mho units (circles through the origin as in Figure 3-21b) are required for a protective zone.

All three units operate for three-phase faults, but for phase-to-phase and double-phase-to-ground faults, only one unit operates.

Thus,

The A unit energized by I_{ab}, and V_{ab} operates for *ab* and *ab- gnd* faults

The B unit energized by I_{bc}, and V_{bc} operates for *bc* and *bc- gnd* faults

The C unit energized by I_{ca}, and V_{ca} operates for *ca* and *ca-gnd* faults.

The B and C units will not operate for the *ab* faults, the A and C units will not operate for the *bc* faults, and the A and B units will not operate for the *ca* faults.

This can be seen for the *bc* faults from Figure 3-22d and 3-22e. The fault current I_{bc} is large and the fault voltage V_{bc} is small to provide low impedance for operation.

However, for the *bc* faults I_{ab} and I_{ca} are small, whereas V_{ab} and V_{ca} are large for a large apparent impedance.

These impedances will be outside the operating circles for the A and C units. Similar conditions apply for the *ab* and *ca* faults.

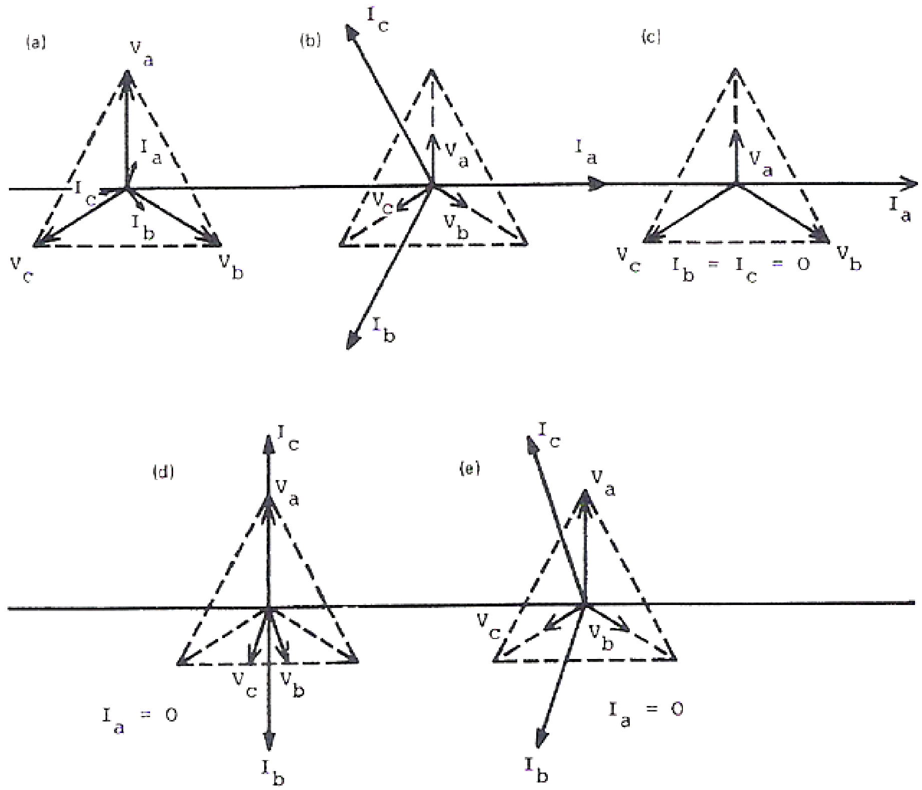


Figure 3-22. Typical current and voltage phasors for common shunt faults: The fault currents are shown at 90° lagging (Z = X). During faults load is neglected

(a) normal balanced system; (b) three-phase faults;

(c) a-phase-Grd fault; (d) bc faults; (e) bc-Grd faults.

3.5.4.5 Polyphase Mho Units

The polyphase type has two units for a zone protection as shown in Figure 3-20b:

- A mho circle through the origin, operating for three-phase faults; and
- A phase-to-phase unit, with a large operating circle partly shown as an arc. This unit does not operate on balanced conditions (load, swings, and such), nor for faults behind the relay (third and fourth quadrants).

3.5.5 Numerical Relays

Numerical relays provide greater flexibility, more adjustable characteristics, increased range of settings, high accuracy, reduced size, and lower costs, along with many ancillary functions, such as control logic, event recording, fault location data, remote setting, self-monitoring and checking, etc.

In solid-state relays the analogue power system quantities from current and voltage transformers or devices are passed through transformers to provide electrical isolation and low-level secondary voltages.

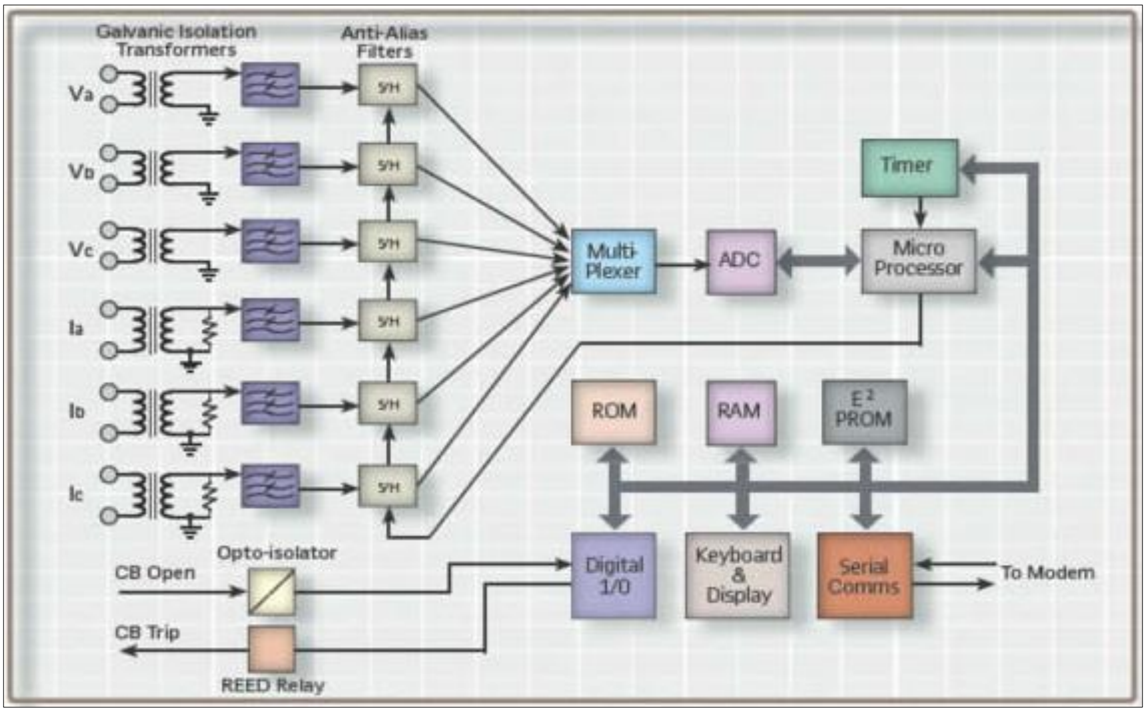


Figure 3-23. Schematic diagram of numerical relay

The protection functions outlined in the foregoing are available using microprocessor technology. Typical logic units that may be involved in a microprocessor relay are shown in Figure 3-23. In very general terms, these are

- Input transformers that reduce the power system current and voltage quantities to low voltages and provide first-level filtering;
- low-pass filter that removes high-frequency noise;
- sample-hold amplifier that samples and holds the analogue signals at time intervals determined by the sampling clock to preserve the phase information;
- multiplexer that selects one sample-hold signal at a time for subsequent scaling and conversion to digital;
- programmable gain amplifier for current signals that have a wide dynamic range (for voltage signals, the gain is 1);
- Analogue-to-digital converter that converts the analogue signals to digital;
- microprocessors with appropriate software, that provides the required protection characteristics that are amplified to operate auxiliary units for tripping, closing, alarms, and so on.

3.6 Substation Equipment Protection

At a substation we have essential and expensive equipment which require reliable protection. They include:

- Transformers
- Transmission lines
- Busbars
- Feeders

Protection of the various substation equipment are briefly discussed in the following sections.

3.6.1 Transformer Protection

The protection provided a power transformer depends upon its size and rating, and will comprise a number of systems each designed to provide the requisite degree of protection for different fault conditions. For large units high speed protection is essential.

3.6.1.1 Unbiased Differential Protection

The unbiased differential overall transformer protection system compares HV and LV currents, which are in a known relationship under healthy conditions. It is for this reason that the transformer differential protection system is capable of detecting inter-turn short circuits since these change the effective overall transformation ratio of the power transformers.

The CT connections must be arranged to give a through fault balance taking into account the transformer vector group reference with respect to windings, connections, and turns ratio. The guiding principles in establishing CT connections are that:

- zero-sequence currents should be eliminated from or correctly compensated in the relay circuits since, almost invariably, the transformer connections will not permit transformation of zero-sequence currents, and
- the phase shift due to the through transformation of positive and negative-sequence currents must be correctly compensated.

The elimination of zero-sequence currents from the relay circuits is usually achieved by associating a delta CT connection with a star connected transformer winding.

3.6.1.2 Biased Differential Protection

In protecting power transformers equipped with on load tap changing facilities the overall differential protection must incorporate a bias feature if a low fault setting and high operating speed are to be obtained.

With the larger and more important transformers, the relay current and time settings necessary to ensure stability on the magnetising inrush currents produced by switching in the transformer are inadequate to provide highs-peed protection. A high speed biased differential relay incorporating a harmonic restraint feature will prevent relay operation under magnetising inrush current conditions.

3.6.1.3 Restricted Earth-Fault Protection

The difficulties inherent in the provision of an adequate earth fault sensitivity in overall differential protection system often require that restricted earth fault protection should be added. Additional phase and neutral connected CTs may be used for this purpose, or the restricted earth-fault protection may be operated from the CTs associated with the overall differential protection.

3.6.1.4 Overcurrent Protection

The degree of protection afforded by an overcurrent relay of the IDMT type is somewhat limited when applied to a transformer. Since the relay must not operate under emergency loading conditions it requires a high current setting (often about 150% rating). Also, the time setting may have to be high in order to grade with other overcurrent relays downstream.

Clearly overcurrent relays provide negligible protection for faults inside the transformer tank, and may be very slow even for terminal faults where high fault currents are involved.

On large transformers, therefore, overcurrent relays are usually employed only as backup protection for terminal faults, or uncleared LV system faults. In such cases the overcurrent relays may be installed on one or both sides of the transformer, according to requirements.

Moreover the relays may trip only the side of the transformer with which they are associated, or they may trip both.

3.6.1.5 Winding Temperature Protection

Large transformers with forced cooling are usually fitted with winding temperature devices to detect overloading of the transformer or failure of the cooling equipment. The bulb is situated in a special pocket located in the flow of hot oil and is, in addition, heated by a small heater energised from a current transformer connected to measure the transformer winding current. The device thus indicates the top oil temperature of the transformer plus an increment proportional to the load on the transformer, this increment being arranged to match the difference between top oil and winding hot spot temperatures. Full use is made of the transformer overload capability by arranging the thermal time constant of the equipment to be similar to that of the transformer.

Two winding temperature instruments are generally fitted to each transformer; each instrument is fitted with two mercury switch contacts. Operation of one instrument is arranged to start cooling fans and pumps, and to give an alarm. The other instrument is arranged to give the same alarm and to trip the transformer.

3.6.1.6 Gas Generation and Oil Surge Protection

All faults within the transformer tank give rise to the generation of gas, which may be slow for minor or incipient faults or violent in the case of heavy faults. The generation of gas is used as a means of fault detection in the gas- and oil-operated relay which comprises one or two hinged floats, buckets, or similar buoyant masses which are inserted in the pipework between transformer tank and conservator and which are normally held in equilibrium by the oil.

The rising bubbles produced by the slow generation of gas, due to a minor fault, pass upwards towards the conservator but are trapped in the relay chamber causing a fall in oil level inside it. This disturbs the equilibrium of the gas float, thereby closing its contacts which would normally be connected to give an alarm. A heavy fault will produce a rapid generation of gas causing violent displacement of the oil which moves the surge float system of the relay in passing to the conservator. This will result in closure of the surge float contacts which are arranged to trip the transformer.

To relieve the violent surging of oil which may cause splitting of the transformer tank wall and the ejection of its bushings, transformers are fitted with a spring-loaded ***pressure relief diaphragm*** in the tank wall through which surging oil may escape into the bund surrounding the transformer. 'Qualitrol devices' as they are called are equipped with contacts which may be used for alarm or trip initiation.

The gas- and oil-operated relay gives the best possible protection against such conditions as defective coil bolt insulation and short-circuited laminations, and incipient failure of the main insulation. The alarm element will also operate for low oil conditions etc., as will the trip element if the condition deteriorates.

Analysis of the gas collected in the ***Buchholz relay*** chamber may frequently assist in the diagnosis of the type of fault, and the rate of gas generation gives an indication of the severity. Where the tap changer selector switches are in a separate oil compartment from the main transformer, protection can be provided by either a separate gas- and oil-operated relay, or by arranging the oil pipework so that the tap change compartment is connected to the transformer conservator via the main oil- and gas-operated relays.

In Figure 3-24 is a diagram showing typical power transformer protections

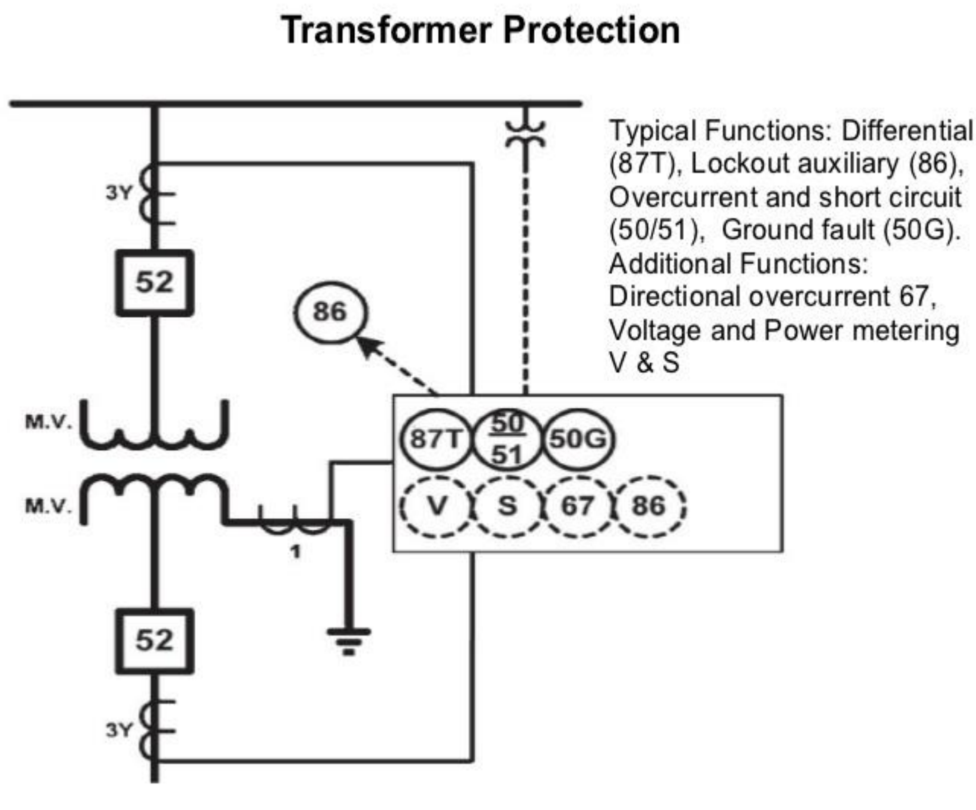


Figure 3-24. Diagram showing protections employed for a typical power transformer

3.6.2 Line Protection

The transmission line protection systems used for protection against different fault types are indicated below:

- Distance relays for phase fault protection
- Directional ground overcurrent relays for earth fault protection
- Current differential relays for phase and earth-fault protections
- Pilot wire relays for phase and earth-fault protection

3.6.2.1 Distance (Impedance) Relays

The operating principle of distance protection is based on the fact that, from, any measuring point in a power system the line impedance to a fault in that system can be determined by measuring the voltage and current at the measuring point.

In practice, the measuring relay is arranged to have a balance point such that, at a particular fault setting, a current proportional to the primary fault current is balanced against a voltage proportional to the primary voltage.

The balance point is defined by the relay impedance setting, Z_R. Thus, the relay either operates or restrains, depending on whether the fault impedance is less than, or greater than, the relay setting.

The setting of the relay must be matched to the primary system and because the latter comprises complex impedances it is necessary to take account of the phase angle of the protected line.

3.6.2.2 Tripping Schemes

There are three basic arrangements of protection based on a command 'to trip' and these are direct intertripping, permissive underreach and permissive overreach. Each of these is described in the following Sections.

3.6.2.2.1 Direct Intertrip

The principle of direct intertripping applied to distance protection is a scheme in which operation of the stage-1 relays at either end will initiate tripping at that end and also result in transmission of information to the remote end, the receipt of this information being sufficient to initiate tripping without any additional control by remote-end relays.

3.6.2.2.2 Permissive Intertrip Schemes

The basic principle is to convey zone-1 or zone-2 operation at one end of the protected circuit over an information link in order to accelerate an otherwise zone-2 tripping time towards zone-1 time.

In the case of permissive schemes, the tripping action of the received signal is made dependent on fault detecting relays, rather than allowing direct tripping, and such relays can be zone-2 or zone-3 distance relays.

3.6.2.2.3 Blocking Schemes

In contrast with the schemes described in section 3.6.2.2.2, which are based on a command 'to trip', an alternative class of protection is based on a command 'not to trip'. Such protections are commonly known as blocking schemes and the principle is one of detecting reverse faults at a relay location, i.e. faults external to the protected circuit, and using this to initiate a command via the information link which blocks tripping at the remote end.

The distance relays which initiate tripping at each end are set in an overreach mode. Thus any tendency to trip for a fault beyond the remote end will be blocked by receipt of a command from the remote end where the reverse fault has been detected.

It is essential that all external faults detected by the overreaching tripping relays at one end be detected by the block initiation relays at the other end.

3.6.2.3 Directional Overcurrent Relays

A directional inverse-time overcurrent relay comprises a directional element and an inverse-time overcurrent element, the two elements being mounted together in one case; the combination is single phase, so that three such combined relays are needed to form a protection system.

The operation of directional element is made as fast as possible, the relays having a nonadjustable travel which is as small as is practicable. They are usually arranged to control the inverse-time element by means of a contact inserted in a subsidiary circuit, which must be closed to permit operation (Figure 3-25). Directional ground overcurrent relays are usually employed in transmission lines for earth fault protection.

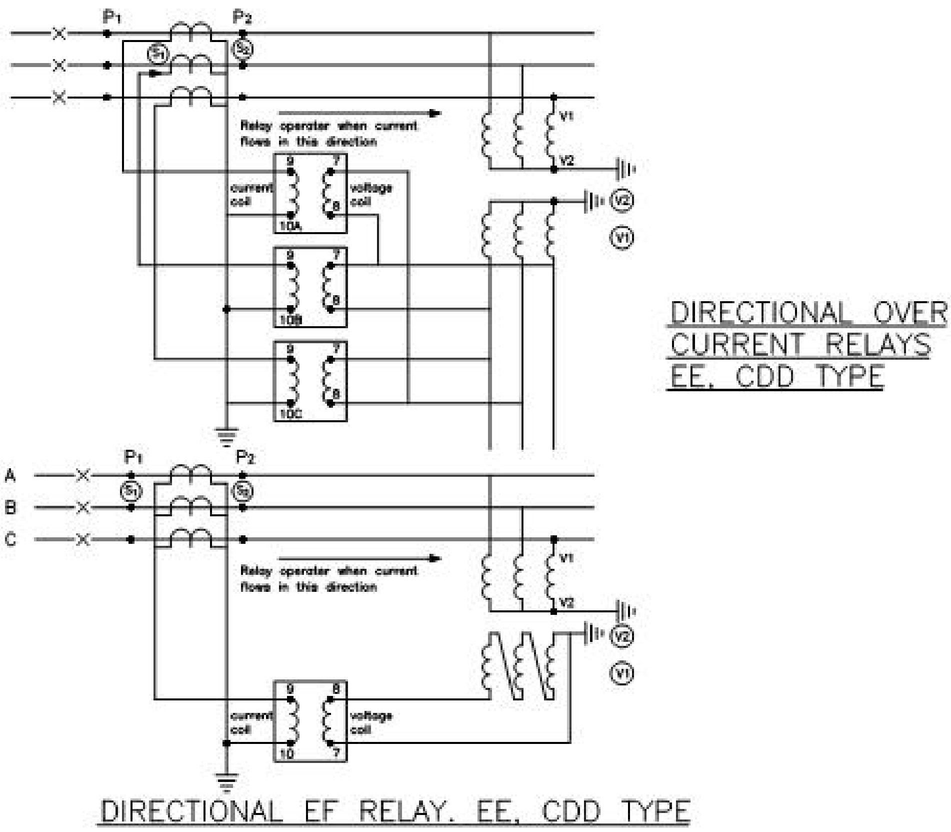


Figure 3-25. Schematic diagram of a directional overcurrent relay

3.6.2.4 Pilot Wire and Differential Current Systems

The problems of adequately protecting modern power systems, with their high degree of interconnection and with the need for fast clearance times have lately led to the adoption of unit protection.

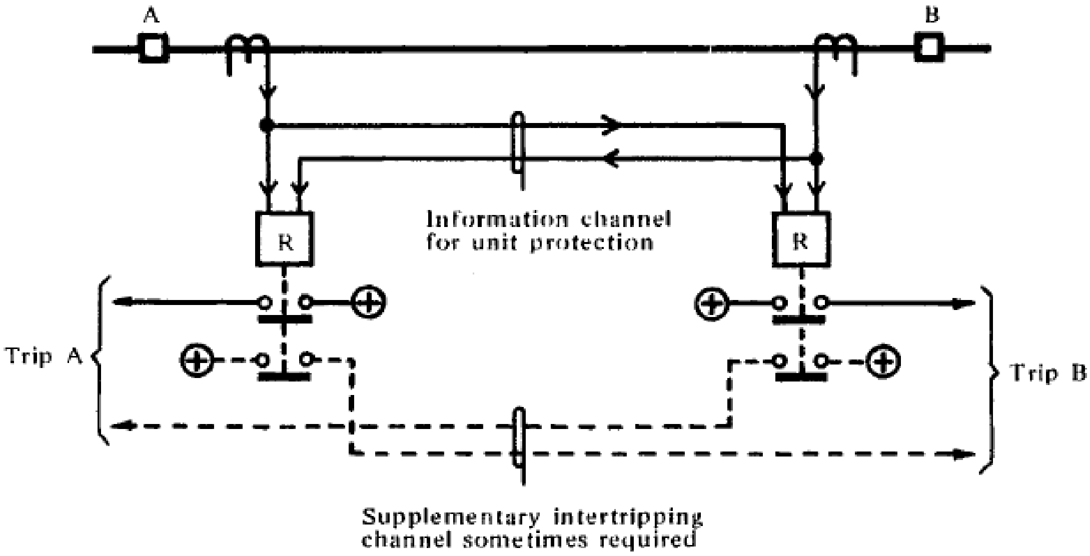


Figure 3-26. Unit protection with large distance between CTs

Since the terminations and their associated circuit breakers are separated by large distances, a relaying point is provided at each circuit breaker, with information about all the others in order to be able to assess this information together with its own and also to trip or stabilise as the case may be. Attenuation, distortion and delay in transmission are all important because significant distances are involved.

3.6.2.4.1 Basic Types of Protection Information Channels

There are three main types of information channel used for protection at the present:

- (a) auxiliary conductors, for example, pilot wires or fibre optic cables
- *(b)* the main conductors of the protected circuit
- *(c)* aerial transmission, for example, radio links.

There are different types of information which may be derived from the primary circuit and transmitted over the information channel. These range from complete information about both the phase and magnitude of the primary current to very simple information as, for example, when the action of some local relay is used to switch on or off a communication signal.

3.6.3 Busbar Protection

3.6.3.1 Introduction

Protections are employed for faults occurring within the busbar zone of a substation which initiates tripping of all those circuit breakers, the opening of which are necessary to isolate the faults. In Figure 3-27 which shows a double busbar substation with examples of typical circuits, the dotted line encloses the busbar zone but for simplicity CTs are not shown. Where unit protection is employed there may be one or more zones of busbar protection within the overall zone shown in Figure 3-27, the boundary of each being the circuit breakers (or the CTs thereof) connecting that zone to the transmission system, generators, transformers and to other zones of busbar protection.

The circuit breakers themselves are included in the respective zones so that a fault within a circuit breaker causes operation of the busbar protection. This ensures interruption of all infeeds of fault current in the same way as for faults occurring on the busbars themselves or on bus selector disconnectors, busbar section disconnectors and the connections between these items.

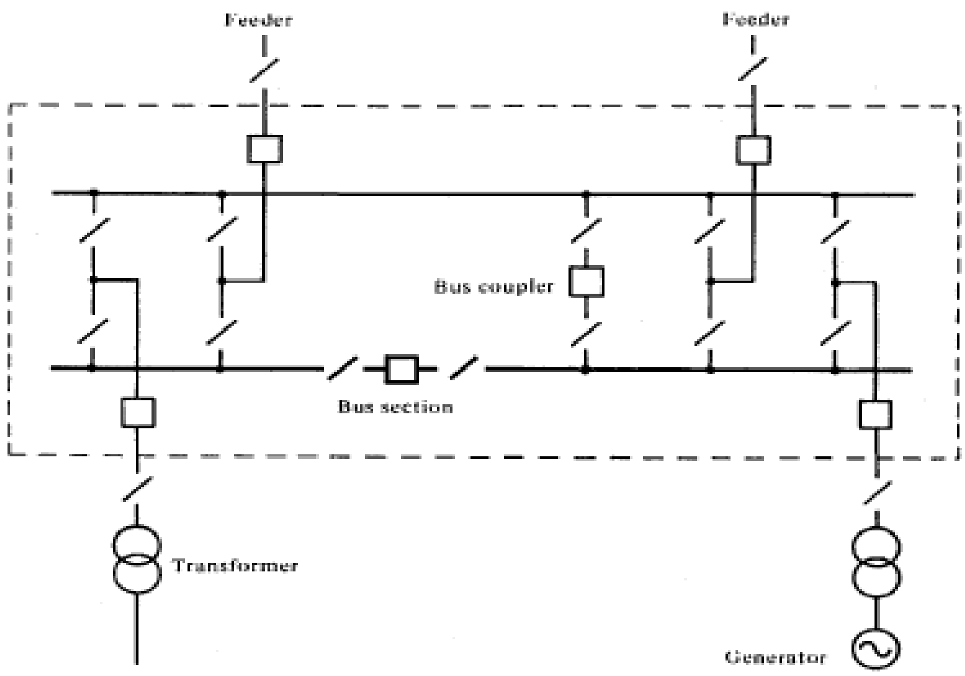


Figure 3-27. A double busbar substation showing (dotted) the zone covered by busbar protection

3.6.3.2 Back-Up Overcurrent and Earth-Fault Relays

Reliance on back-up protection to clear busbar faults is nowadays confined to Radial Systems at the lower distribution voltages where investment in unit busbar protections can be rarely be justified.

Where permitted by the substation configuration, some improvement in the security of supplies can be achieved by designing the protection so that, as a first step, relays operate to trip a limited number of circuit breakers so as to split the busbars into sections, each with its own infeed and as a second step to trip those infeeds still carrying fault current after a time-delay of, say, 0.4s.

3.6.3.3 Distance Protection

Where all feeders connected to a busbar station are protected by 3-zone distance protection, this can, in some circumstances, provide a limited degree of busbar protection. If, however, some of the circuits connected to the busbars concerned are generators, one must consider how these would be tripped for a busbar fault. Unit forms have been developed to ensure short clearance times and correct discrimination for such faults. The only present day application for distance protection as a limited form of busbar protection is as back-up protection.

3.6.3.4 Unit Protection

The main requirements of unit protection when fitted to protect busbars are that it must:

- Have a short operating time, especially where fault levels are high, in order to minimise damage to the switchgear and to assist system stability.
- Be certain to operate on internal faults. Busbar faults are rare, only by very careful design and regular comprehensive routine testing of the busbar protection can the desired reliability be achieved.
- Remain stable during all external faults. Since many more faults occur externally to busbars than internally, busbar protection is called upon to stabilize many more times than to operate.
- Discriminate correctly, that is decide on which section of the busbars the fault has occurred, and then trip rapidly only those circuit breakers connected to that section.
- Be immune from mal-operation. Since busbar protection has to trip a large number of circuits, it is most important that it does not do so when there is not an actual fault on the busbar. Thus, besides requiring a high stability factor, as discussed in item *(c)* the equipment and circuitry should be as far as possible immune to the effect of faults in wiring, auxiliary switches and human errors.

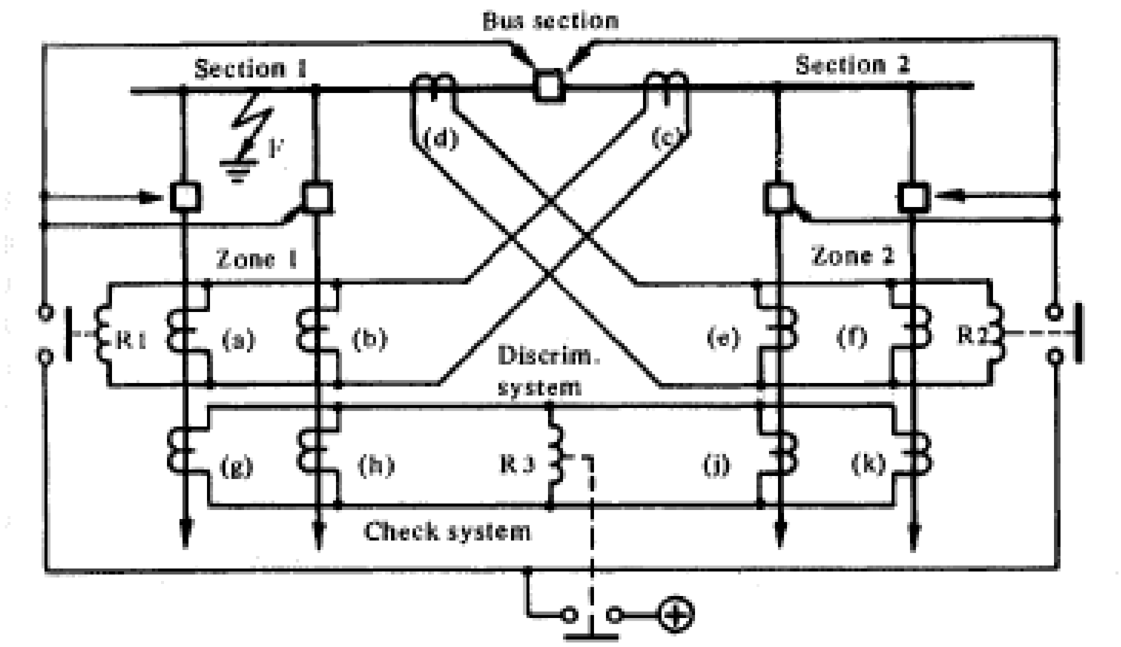


Figure 3-28. Circulating current duplicate line of defence busbar protection.

3.6.3.4.1 Current Balance Using Circulating Current Principle

A very simple form of unit protection of a circuit can be achieved by comparing the currents entering it with those leaving, the circuit being healthy if they are equal, and faulty if they differ by more than a certain amount. The single busbar arrangement below is used to explain the principle of check zone used to ensure stability circulating current protection

For simplicity, the application is first considered on a single-phase basis. In order to reduce the risk of wrong operation on external faults, the principle of having two independent lines of defence is used. These two separate forms of protection have both to operate before tripping can take place, and they are shown in Figure 3-28.

To appreciate the purpose of employing a check system consider now the condition of a healthy system carrying normal load currents.

If one of the leads say, CT (a) were to become open-circuited, then relay R1 would have a current flowing in it due to the lack of the CT current (a) balancing out those of CTs (b) and (c).

This current in R1 may not be large enough to operate it, but when an external fault occurs the current could well be large enough to cause R1 to pick. Tripping of zone 1 would, however, still be prevented by the fact that the check system relay R3 will not have operated.

The method of using separate check and discriminating systems also covers against the inadvertent operation of any one relay due, for example, to vibration, or operation by hand.

3.6.3.4.2 Basic Principles of High-Impedance Circulating Current Busbar Protection

The disadvantages of circulating current protection using low impedance relays is that relays could operate erroneously during through faults when CT saturate. Biased systems may be used to solve this problem.

It was found that this could also be overcome by the correct choice of CTs and relay circuit components, in what has become known as high-impedance circulating current protection.

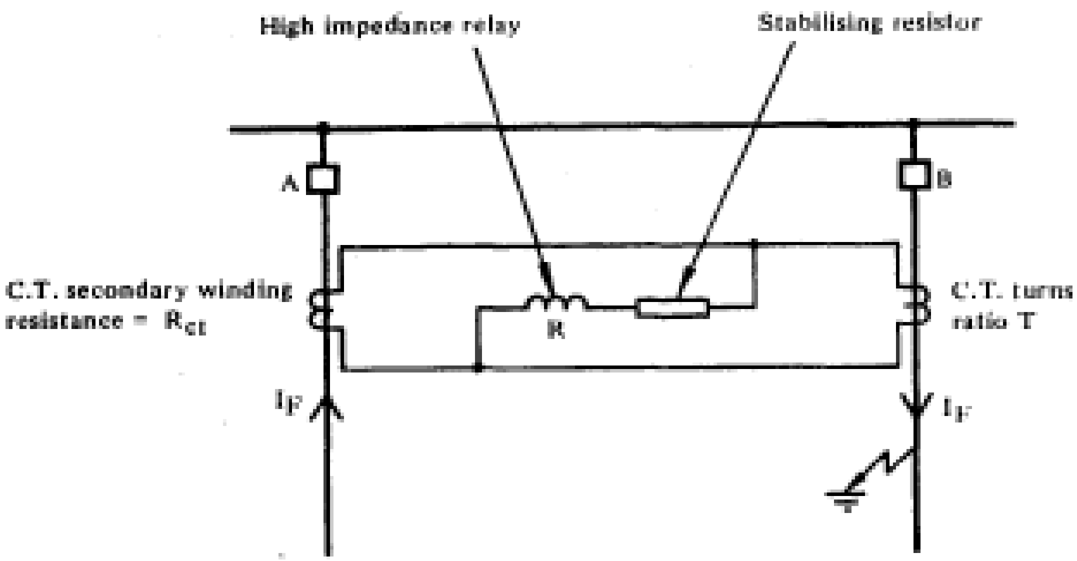


Figure 3-29. High impedance scheme

3.6.4 Feeder Protection

3.6.4.1 Overcurrent Protection

Overcurrent relays are mostly employed as primary protection for feeders. Overcurrent protection relays are usually energised via current transformers connected on each phase of the feeder being protected. The magnitude of an interphase fault current will normally be governed by the known impedances of the power plant and transmission lines, such currents are usually large. Phase-to-earth fault current may be limited by such features as

- (a) the method of earthing the system neutral
- (b) the characteristics of certain types of plant, e.g. faults on delta connected transformer windings
- (c) resistance in the earth path

In consequence, earth fault current may be of low or moderate value and also often rather uncertain in magnitude particularly on account of item *(c)* above. The protection is often required to have a high sensitivity to earth faults, i.e. earth-fault settings are often required to be lower than system rating. Response to an earth fault at a lower current value than system rating or loading is achieved by the residual connection shown in Figure 30. Three current transformers, one in each phase have their secondary windings connected in parallel and the group connected to a protective device, either circuit breaker tripping coil or a relay.

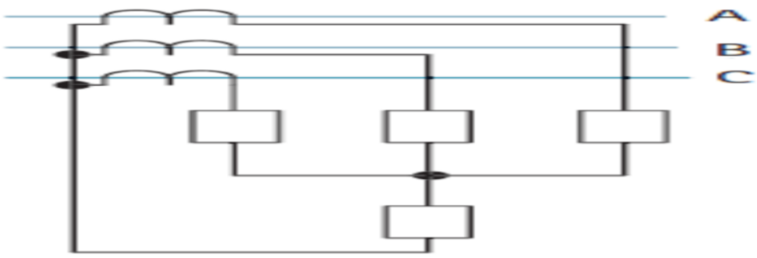


Figure 3-30. Combined phase and earth-fault protection

With a balanced load current, the output of such a group is zero, and this is also the case with a system phase to phase short circuit. Only when current flows to earth is there a residual component which will energise the protective device. Since the protection is not energized by the three-phase load current, the settings can be low, giving the desired sensitive response to earth fault current. Phase fault and earth fault protection can be combined as shown in Figure 3-30.

3.6.4.2 Feeder Overvoltage Protection

Feeders connected to an unearthed transformer winding have very low earth faults currents and so for such feeders overcurrent relays cannot be used for earth-fault protection. A voltage relay energized from the broken-delta connected secondary windings of voltage transformer with their primary windings connected to the feeder receives an input proportional to the zero sequence voltage of the feeder and can be used for earth fault protection. Earth fault elsewhere on the system may also result in displacement of the neutral and hence discrimination is achieved using definite or inverse time characteristics.

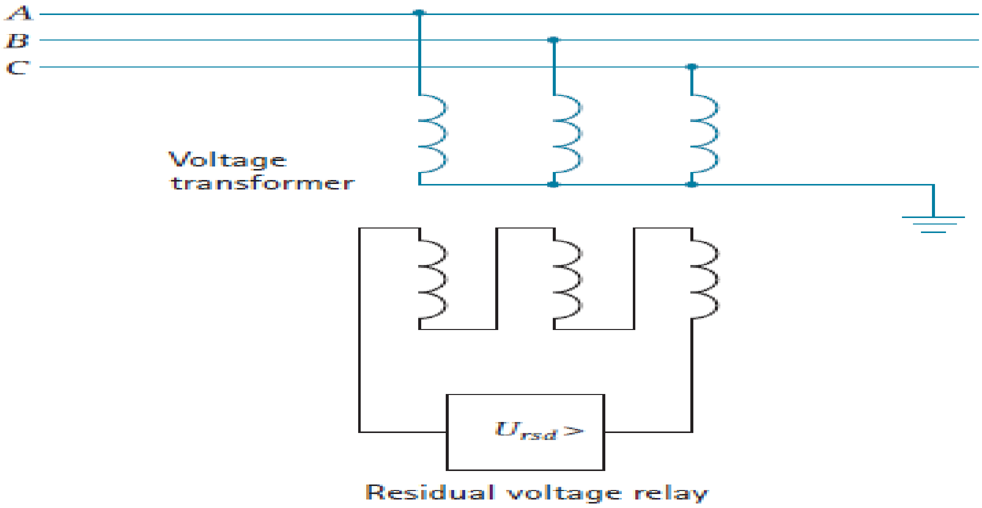


Figure 3-31. Neutral displacement detection using voltage transformers

M04 – BUS AND BREAKER FAIL PROTECTION

4.1 Objectives

This module seeks to help the participant to identify the following:

- The importance of bus protection in power system.
- Explain the various bus protection concepts
- Identify the various bus arrangements in the GRIDCo network
- Explain the following bus arrangement their applications:
  - Single bus single breaker arrangement.
  - Single breaker double bus with bus tie.
  - Double bus double breaker arrangement.
  - Ring bus arrangement.
  - One and a half circuit breaker arrangement.
- Explain high and low impedance bus protection scheme
- Define and explain breaker failure protection scheme.

4.2 Introduction

In the early days of the electricity supply industry, protective equipment for plants connected to a busbar installation was relied upon to clear busbar faults. This resulted in time delayed fault clearance by time graded protections such as distance relays or overcurrent time relays. With present day widely meshed power system networks with line sections varying in length and numerous intermediate infeeds, fault clearance by Zone 2 or Zone 3 of distance relay can be difficult plus the impossibility of selective tripping of different bus sections. In order to maintain system stability and minimise damage due to high fault levels time delayed tripping for busbar faults is no longer acceptable. It is therefore necessary to detect busbar faults selectively with a unit form of protection system.

Faults in a power system can be either apparatus faults or bus faults. Apparatus fault refer to faults in feeders, transformers, generators or motors.

A bus is an external interconnection point for terminals of different apparatus.

Bus faults is usually rare, but if and when they happen, the consequences can be quite severe. It can lead to loss of multiple feeders or transmission lines and hence has a potential to create a large enough disturbance to induce transient instability.

Even if it does not lead to transient instability, loss of load from an important substation can be quite high. Because of these reasons, bus rearrangement can have sufficient redundancy so that in case of a bus fault, an alternative bus automatically takes over the functions of the ‘main bus. Thus, the end user sees no disruption in service except during the fault interval.

This can however involve significant costs, viz the cost of new bus bar and additional circuit breakers to configure a parallel arrangement. Hence, different bus configurations are used in practice - each one representing a different tradeoff between cost, flexibility and redundancy.

4.3 Busbar Protection

4.3.1 Basic Requirement of a Busbar Protection Scheme

i) It must be completely reliable, since the protection may only be called to operate once or twice in the life of the switchgear installation and failure to operate under fault conditions would be unacceptable.

ii) It must be absolutely stable under all through fault conditions since failure to stabilise would cause unnecessary widespread interruption of supply.

iii) It must be capable of complete discrimination between sections of the busbars to ensure that the minimum number of circuit breakers are tripped to isolate the fault.

iv) It must possess high speed of operation to minimise damage and maintain system stability.

4.3.2 Differential Protection

Two forms of differential protection are adopted for busbar protection, namely, `High Impedance` and `Low Impedance`.

4.3.2.1 High Impedance Differential Protection

This is a unit type protective scheme in which currents entering and leaving the busbar installation are compared continuously.

The object is to provide fast operation at a low fault setting on internal faults and yet retain stability up to the highest possible value of short circuit current on through faults.

Current transformers on each of the busbar circuits are connected in parallel which will produce a resultant current to operate a relay for internal busbar faults only. Theoretically such a system is unaffected by through faults, but in practice the associated current transformer may not behave ideally when the current exceeds a certain value. Errors in transformation due to saturation of the current transformer cores may be sufficient to cause maloperation if special precautions are not taken. In order to ensure stability for external faults the current through the relay is limited by the insertion of an external resistor in series with the relay. This resistor is often referred to as a stabilising resistor.

The stability limit of a busbar protection scheme is based on the maximum through fault current. In general this takes the value of the associated switchgear rating irrespective of the existing or anticipated fault levels. Examples substations in the GRIDCo network that has high impedance bus protections are Mallam and Accra East substations

4.3.2.2 Low Impedance Protection Operating Principle

The basic operating principle of the differential protection is based on the application of Kirchhoff's law. This compares the amount of current entering and leaving the protected zone and the check zone. Under normal operation, the amount of current flowing into the area and the check zone concerned is equal in to the amount of the current flowing out of the area. Therefore, the currents cancel out. In contrast, when a fault occurs the differential current that arises is equal to the derived fault current.

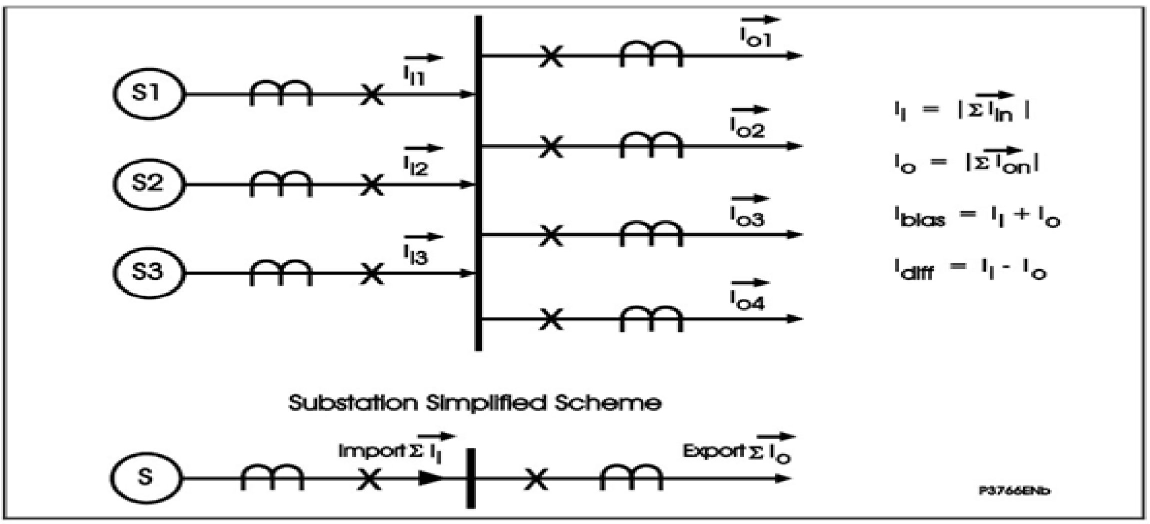


Figure 4-1. Differential Busbar protection Principle

Several methods of summation can be used for a differential protection scheme:

- Vector sum
- Instantaneous sum

The algorithms applied in relays for example MiCOM P746 use the vector sum method (on Fourier).

The instantaneous sum method has the advantage of cancelling the harmonic and DC components of external origin in the calculation and in particular under transformer inrush conditions.

The bias current is the scalar sum of the currents in the protected zone and for the check
zone. Each of these calculations is done on a per phase basis for each node and then summated.

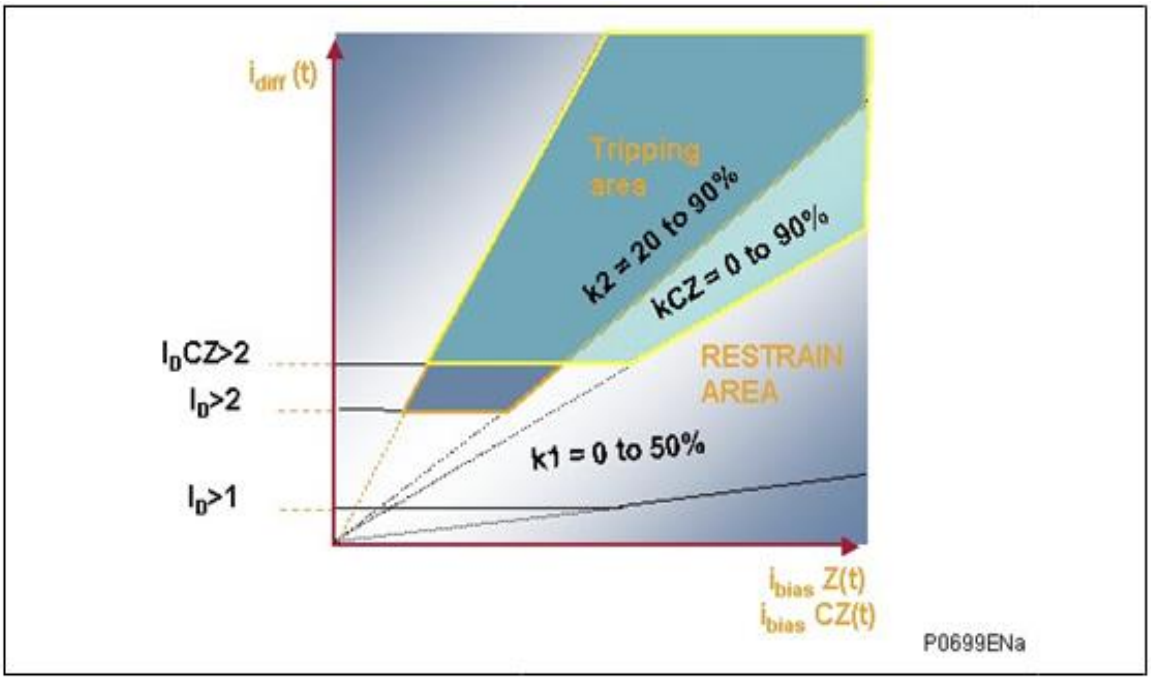


Figure 4-2. Differential relay scheme characteristics

The Phase characteristic is determined from the following protection settings:

Area above the ID>2 threshold zone differential current threshold setting and the set slope of the bias characteristic (k2 × Ibias) (k2 is the percentage bias setting ("slope") for the zone)

The origin of the bias characteristic slope is 0.

Advantages

Low impedance busbar protection has a number of advantages:

- Fast
- Modular scheme design allows relays to relate to each circuit and function of the protection
- High sensitivity for phase and earthfaults. Protection for each phase can be relatively independent
- Extremely stable for external faults. This is achieved by using saturation detectors
- Current transformers can be of different ratio, relatively smaller output and shared with other protective devices
- The current transformer secondary circuits are not switched
- Continuous supervision of CT circuits and constant monitoring of vital circuits can be included

Examples substations in the GRIDCO network that has low impedance bus protections include Smelter 2, Collector, Cape Coast, Takoradi substations

4.4 Busbar Configurations

In this lecture, we will discuss following bus arrangements:

- Single bus - single breaker
- Single breaker - double bus with bus-tie
- Double bus - double breaker
- Ring bus arrangement
- One - and - a - half circuit breaker arrangement

Several switching schemes are available and there are many variants of each scheme. When selecting a suitable scheme consideration should be given to the ability to take out any circuit breaker or other equipment for maintenance without removing the corresponding circuit from service, also the ability to isolate the busbar for maintenance, some schemes being more flexible than others in this respect.

4.4.1 Single Bus – Single Breaker Arrangement

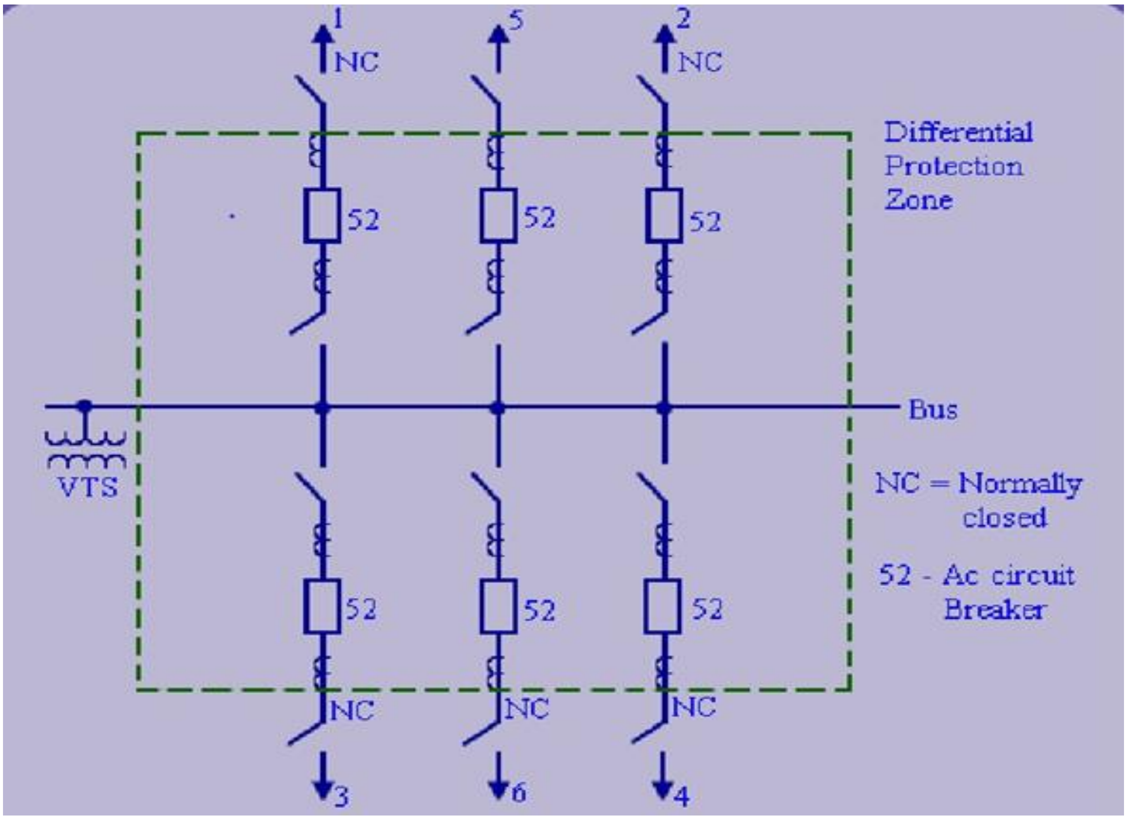


Figure 4-3. Single Bus Single Breaker Arrangement with 6-circuits

Figure 4-3 above shows the single bus-single breaker arrangement. In this particular example, there are six (6) feeders connected to a bus. Each feeder has a Current Transformer (CT) to monitor feeder current while a single Voltage Transformer (VT) is used to measure bus voltage.

The 'NC's are mechanical switches which are normally closed. During bus maintenance, these will have to be opened to guarantee safety to maintenance personnel.

In case of bus fault, all the breakers have to be opened to isolate the bus. In turn, it leads to severe disruption of service to loads. Hence, this scheme has minimum flexibility.

However, it uses minimum number of circuit breakers, (one per feeder) and it also requires only one VT.

Hence, it is cheap and is used for non-critical, low priority feeders where loss of service is not a prime consideration but low cost (investment) is.

4.4.2 Single Breaker – Double Bus With Bus Tie

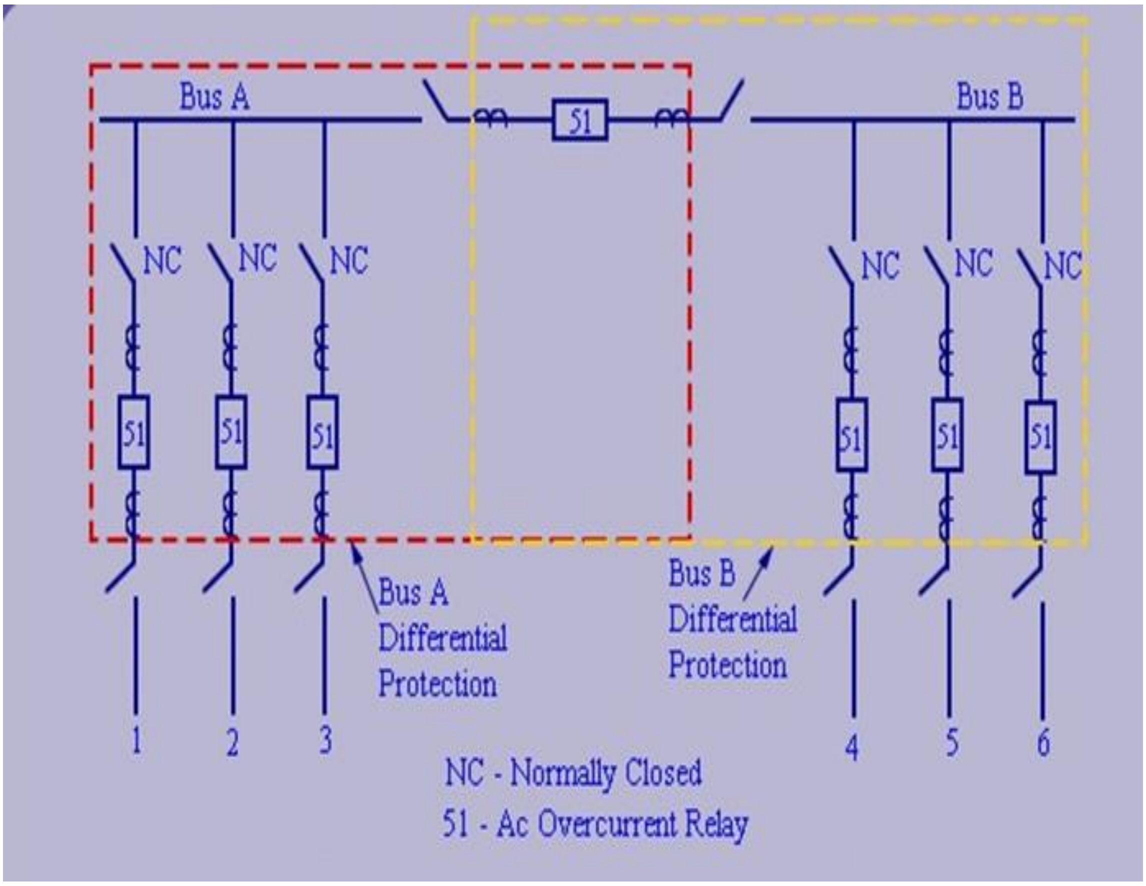


Figure 4-4: Single Breaker Double Bus with Bus Tie with 6 circuits

The Single Breaker-Double Bus with Bus Tie arrangement is used in conditions where:

- A large number of circuits exists especially at lower voltage and industrial substations.
- A substation is fed from two separate power supplies with one supply per bus:

If each bus has its own source, then bus coupler with overcurrent protection can be opened or closed. In case of loss of supply, 51 (AC time overcurrent relay) is closed.

For each bus, there is a differential protection is provided. For a bus fault, we have to open all circuit breakers on bus along with 51T (trip breaker).

Thus, bus fault leads to only partial loss of service. The arrangement requires two VTs. Hence, this scheme with addition of one bus bar and circuit breaker improves flexibility in comparison to the single bus single breaker scheme.

4.4.3 DOUBLE BUS DOUBLE BREAKER ARRANGEMENT

Figure 4-5 below shows a double bus, double breaker arrangement.

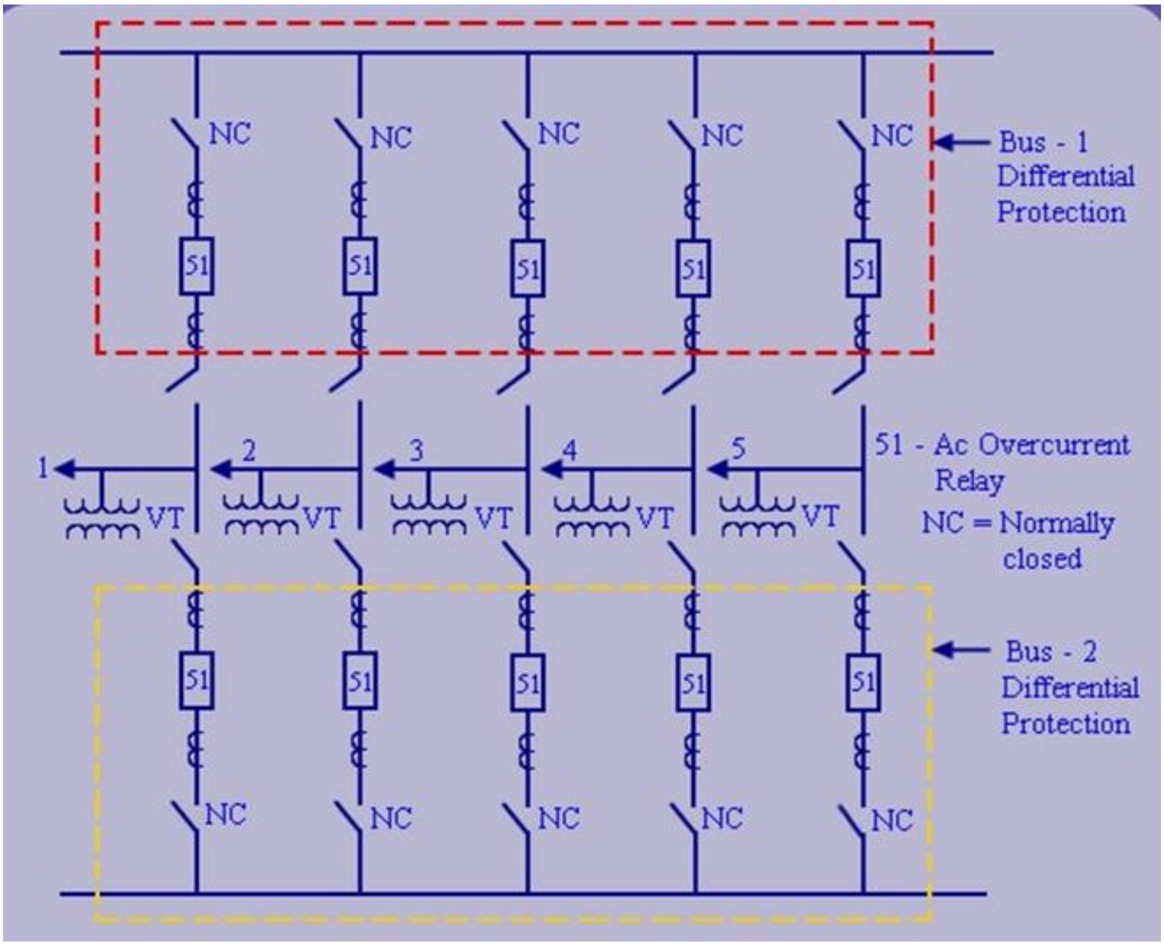


Figure 4-5. Double Bus Double Breaker Arrangement with 5 circuits

As shown in the figure, each feeder is connected to two buses, which in normal operation mode are paralleled. Bus differential protection is provided for each bus. This scheme would be used typically at high voltages like 400kV.

Distance protection of such voltage level has to be directional as fault in the primary line of Z2 of one of the relays cannot be left unattended for time required for Z2 operation. Hence, directional comparison scheme is required. In this scheme a Capacitor Voltage Transformer (CVT) is required for communication. Hence, one CVT per feeder would be used along with this scheme. In case of a bus fault (say on bus-1), the breakers connected to it will have to be opened. Subsequently, the system function then automatically switches to alternative bus (e.g. Bus 2) with no loss of service to load.

In case a feeder has to be isolated, both the breakers connected to it will have to be opened. For line (feeder) protection, to measure feeder current the CT contribution from both bus 1 and 2 have to be summed. i.e. corresponding CTs are paralleled. In case of a stuck breaker, local backup for breaker failure is to operate all the corresponding bus breakers. This bus arrangement provides maximum flexibility but it is also costly as two breakers per feeder are required.

4.4.4 Ring Bus Arrangement

Figure 4-6 below shows a typical ring bus arrangement with four feeders.

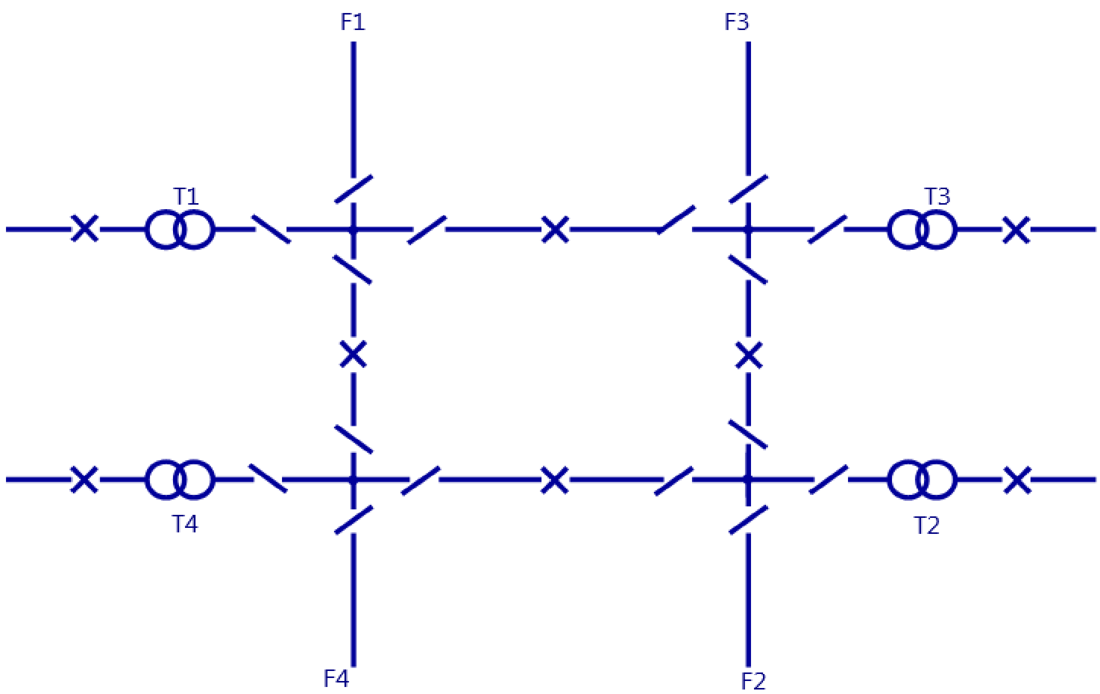


Figure 4-6. Ring Bus Arrangement with 4 circuits

The arrangement requires one circuit breaker per feeder and hence it is less costly. This arrangement is popular because of low cost and high flexibility. As the bus section between the two breakers becomes a part of the line, separate bus protection is not applicable or required. i.e, the feeder protection also provides the functionality of bus bar protection.

The ring busbar scheme is also frequently used in EHV busbar configuration. A transformer and a feeder are linked at each corner of the mesh and four circuit breakers used to complete the ring. This arrangement is justified on the grounds of economy.

Again to isolate a feeder, say on a feeder fault, two adjacent breakers have to be operated. Similarly, feeder current is calculated by summing or paralleling the appropriate CTs. Each feeder requires its own VT.

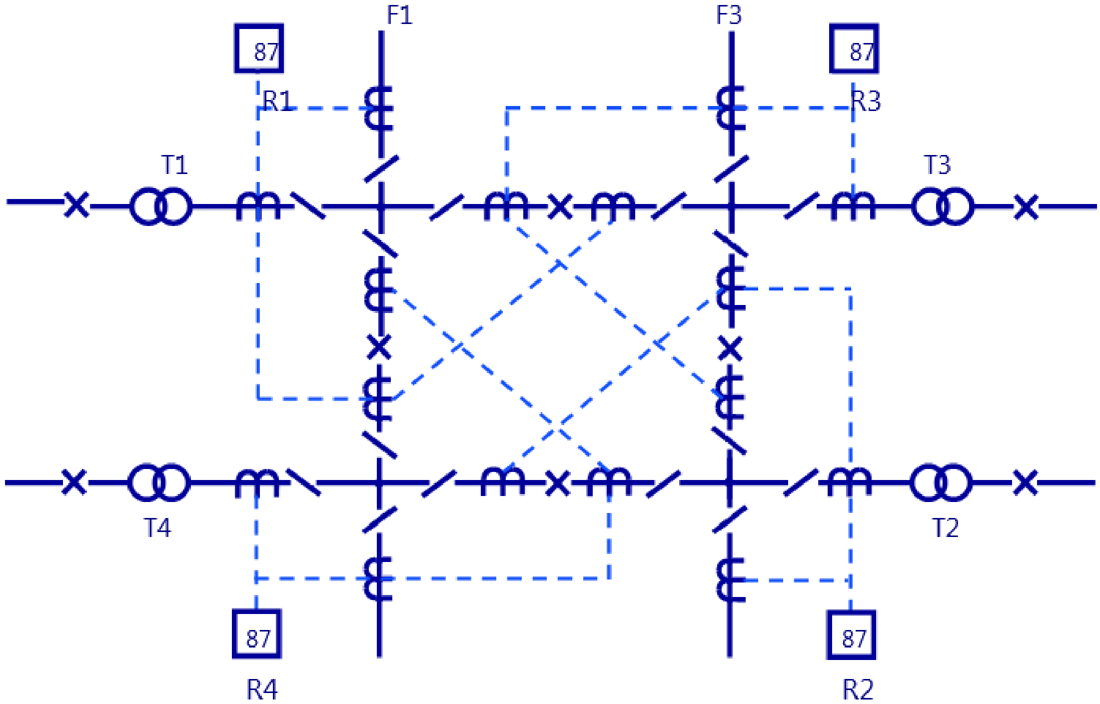


Figure 4-7. Ring Bus arrangement showing CT inputs for Differential Protection

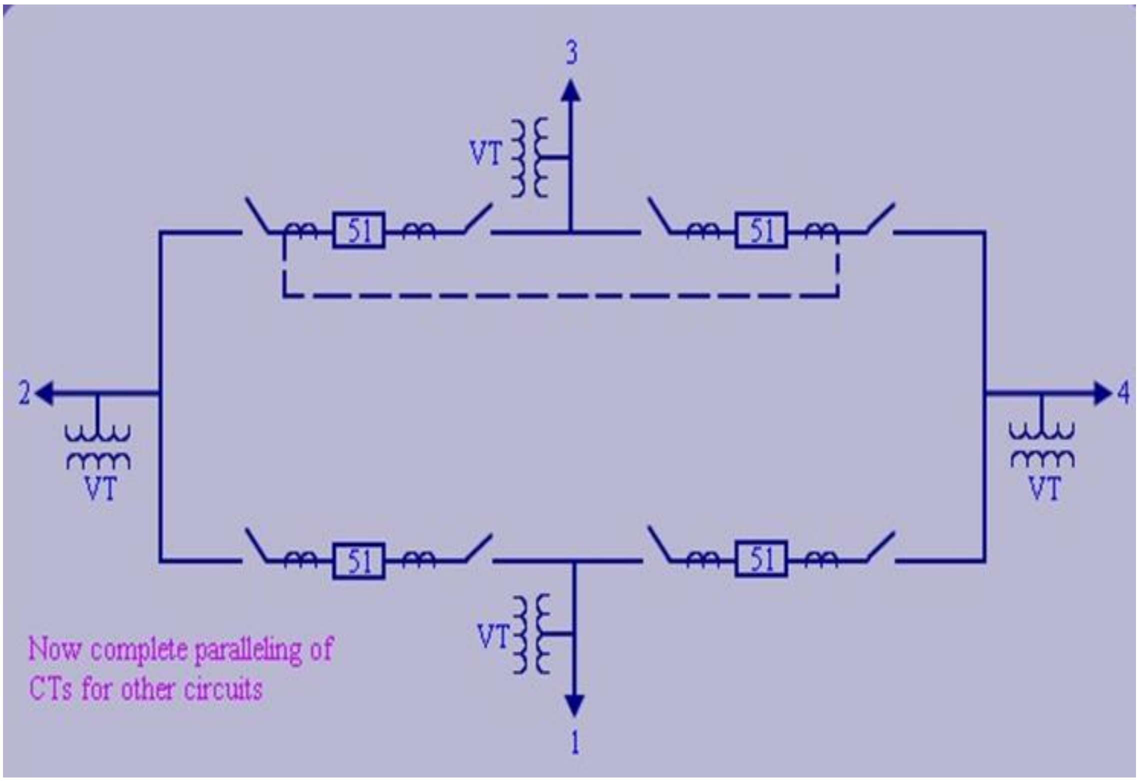


Figure 4-8. Ring Bus arrangement showing CT inputs for Overcurrent Protection

The protection shown consists of a fully discriminative scheme with a relay at each corner. A fault at any corner trips the two breakers associated with that corner and also initiates any intertripping necessary to open circuit breakers at remove ends.

4.4.5 One and a Half Breaker Scheme

This is a very popular and economical scheme, three breakers and two feeders being arranged between the two busbars, i.e the total number of breakers is 1.5 times the number of feeders. Under normal conditions all breakers are closed. During maintenance of a feeder breaker only that breaker would be kept open.

During maintenance of a busbar, all the breakers connected to that busbar would remain open to isolate that busbar.

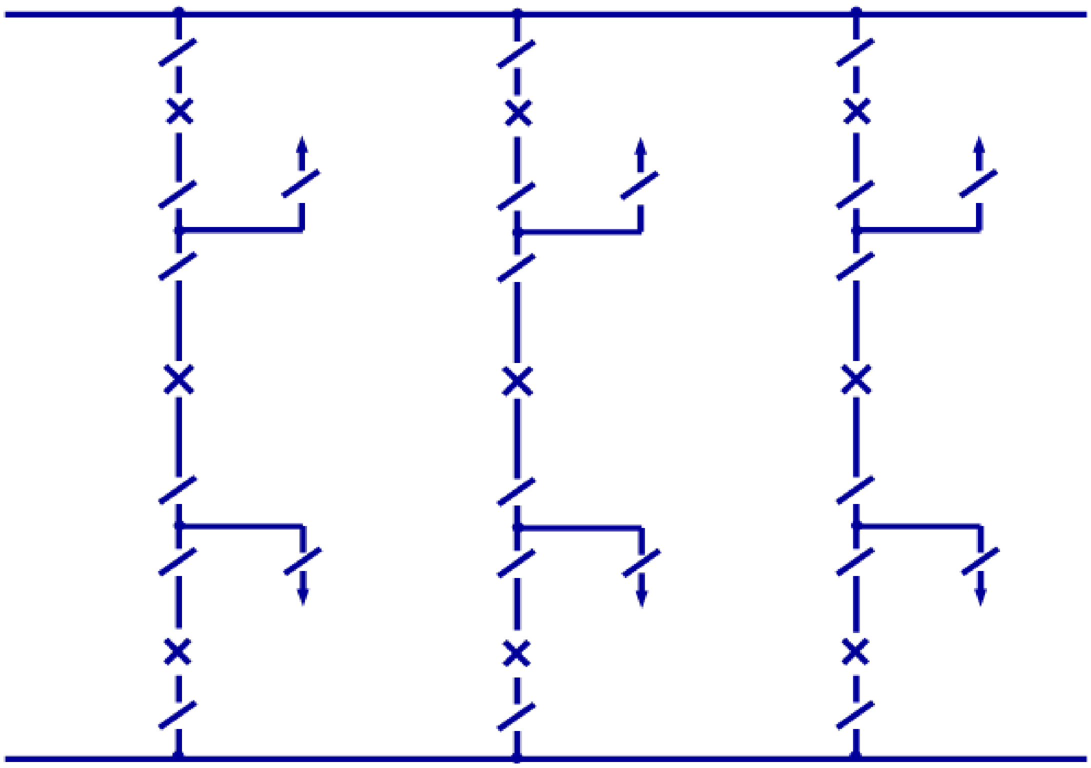


Figure 4-9. One and a Half Circuit Breaker Arrangement

When busbar protection is required, then each busbar is considered individually and a single busbar scheme applied to each as shown, as with the protection for the mesh busbar previously, the protection scheme does not require isolator auxiliaries for CT zone selection or in the tripping circuits, the scheme being very simple, and this together with the operational flexibility of this busbar configuration accounts for its popularity.

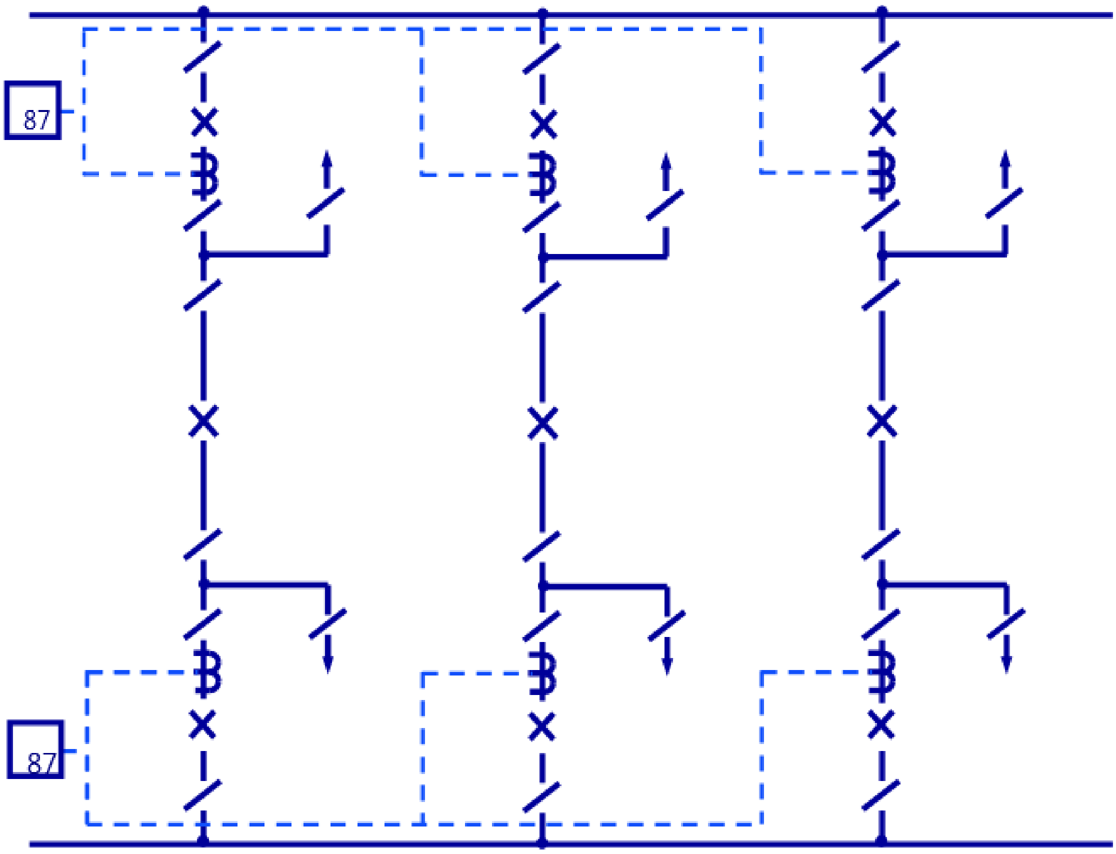


Figure 4-10. One and a Half Circuit Breaker Arrangement showing CT inputs for Differential Protection

Figure 4-11 below shows a one-and-a-half circuit breaker arrangement with 4 feeders and 6 breakers. There are two buses, each one having its own bus differential protection. In case of a bus fault, all breakers connected to the bus will have to be opened.

Automatically, the system operation moves to alternative bus without any further loss of service. Hence, this scheme also provides a high level of flexibility.

Now, consider the case of a stuck breaker say while clearing of feeder fault on L1. In case of a Stuck breaker which is connected to the bus (shown in red in figure 4-5), the local breaker backup (LBB) is to open all the breakers on the bus. In the case of stuck central breaker (see green breaker) i.e. when the shared breaker is stuck, LBB consists of opening the adjacent breaker. In addition, a transfer trip signal is required to the breaker at the remote end of the feeder (L2) connected to the stuck breaker.

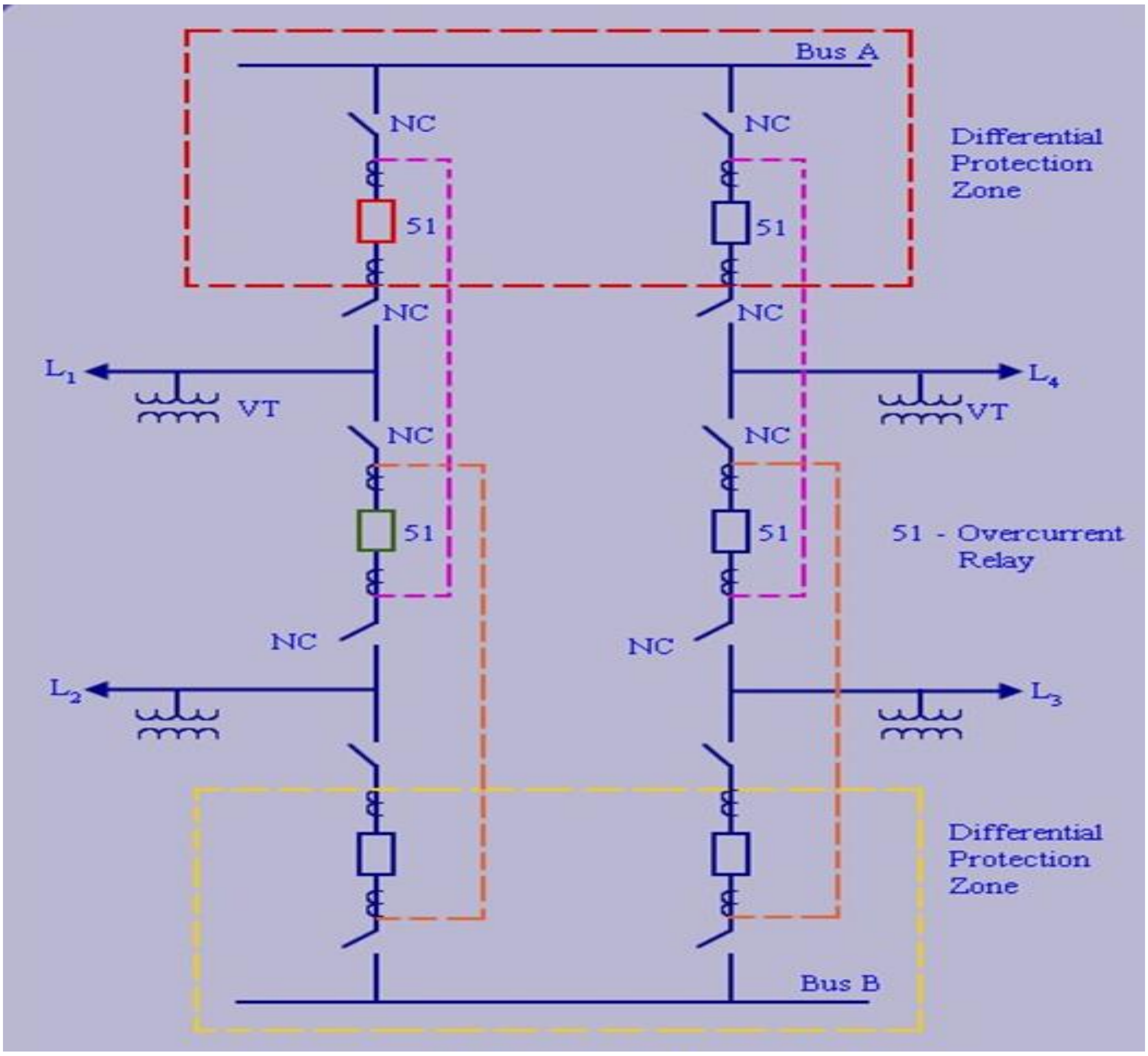


Figure 4-11. One and a Half Circuit Breaker Arrangement showing CT inputs for Overcurrent Protection and Busbar Differential zones

4.5 Breaker Fail Protection

4.5.1 Basic Description

The circuit breaker failure (CBF) function checks that the circuit breaker opens correctly when a tripping order is given.

For transmission or sub-transmission systems, slow fault clearance can also threaten system stability. It is therefore common practice to install circuit breaker failure protection, which monitors that the circuit breaker has opened within a reasonable time.

If the fault current has not been interrupted after a set time delay from the start of the circuit breaker trip, the circuit breaker failure protection operates.

Where breaker fail protection is applied to a system, back tripping of associated breakers is required in the event of breaker failure.

Often, breaker fail protection is arranged in conjunction with busbar protection tripping circuits to initiate tripping of breakers on a busbar zone associated with the failed breaker.

CBF operation can be used to backtrip upstream circuit breakers to ensure that the fault is isolated correctly.

In general, the tBF1 Output is connected to the emergency coils of the local circuit breaker "Retrip" and the tBF2 Output is connected to Busbar "Backtrip".

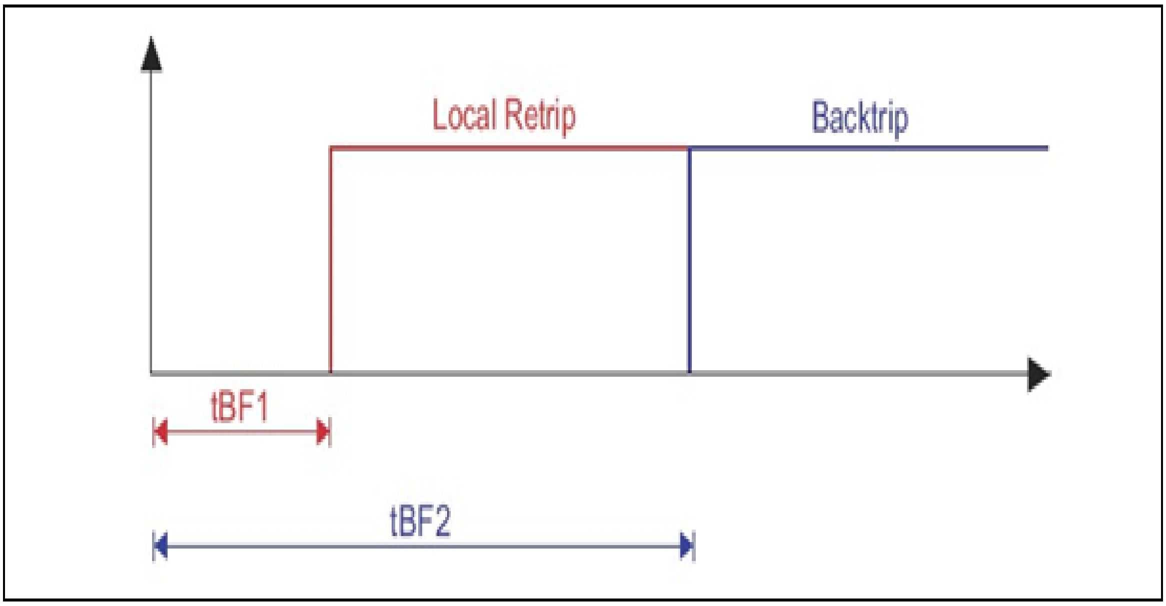


Figure 4-12. CB failure timer

In most applications in the Ghana network, a one stage breaker failure of tB1 of 250msec is adopted. In one or two isolated cases a two stage breaker failure scheme is used with tB1 and tB2 of 150msec and 250msec respectively

The circuit breaker failure function is initiated on the external tripping order. The circuit breaker failure is reset (stop the timers) when:

- Analogue current is lower than the detection threshold
- External tripping orders reset to 0 if RESET is set to “YES”.

Also the status of the CB can be a criterion for the CBF timer reset, when the CBF is initiated by a non-current protection trip.

4.6 Appendices

Figure 4-13. Volta Busbar Protection Panel

Figure 4-14. Achimota Busbar Protection Panel

Figure 4-15. Smelter 2 Busbar A protection Panel

Figure 4-16: Smelter 2 Busbar D protection Panel

M05 – TRANSFORMER AND REACTOR PROTECTION

5.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of transformer and reactor protection
- Explain types of transformer fault and transformer protection components

5.2 Introduction

Power transformer is one of the most important links in a power system. Its development stems from the early days of electromagnetic induction, when it was discovered that varying magnetic flux in an iron core linking two coils produces an induced voltage.

From the basic discovery has evolved the power transformer we know today using advanced insulation materials and having complex windings on a laminated core using special magnetic steels cold rolled to ensure grain orientation for low losses and high operating density.

With transformers of large capacity, a single transformer fault can cause large interruption to power supplies. If faulted transformer is not isolated quickly, this can cause serious damage and power system stability problems. Protective systems applied to transformers thus play a vital role in the economics and operation of a power system.

In common with other electrical plants, choice of suitable protection is governed by economic considerations brought more into prominence by the range of size of transformers which is wider than for most items of electrical plant. Transformers used in distribution and transmission networks range from a few KVA to several hundreds of MVA.

For transformers of lower ratings, only the simplest protection such as fuses can be justified and for large rating transformers; comprehensive protection scheme should be applied.

5.3 Transformer Fault Categories

Transformer faults are generally classified into four categories :

- i) Winding and terminal faults

- ii) Core faults
- iii) Abnormal operating conditions such as overvoltage, overfluxing and overload
- iv) Sustained or uncleared external faults.

5.4 Transformer Connections

With the development of polyphase systems with more complex transformer winding connections and also possible phase displacement between primary and secondary windings, standardisation was necessary to ensure universal compatibility.

There are a number of possible transformer connections but the more common connections are divided into four main groups :

Group 1	0°	Phase displacement	e.g.	Yyo Ddo Zdo
Group 2	180°	Phase displacement	e.g.	Yd6 Dd6 Dz6
Group 3	30°lag	Phase displacement	e.g.	Yd1 Dy1 Yz1
Group 4	30°lead	Phase displacement	e.g.	Yd11 Dy11 Yz11

High voltage windings are indicated by capital letters and low voltage windings by small letters (reference to high and low is relative).

The numbers refer to positions on a clock face and indicate the phase displacement of the low voltage phase to neutral vector with respect to the high voltage phase to neutral vector, eg Yd1 indicates that the low voltage phase vectors lag the high voltage phase vectors by 30° (-30° phase shift).

Individual phases are indicated by the letters A, B and C, again capital letters for the high voltage winding and small letters for the low voltage winding.

All windings on the same limb of a core are given the same letter. A further numerical subscript serves to differentiate between each end of the winding.

5.4.1 Determination of Transformer Connections

This is best illustrated by considering a particular example. The following points should be noted:

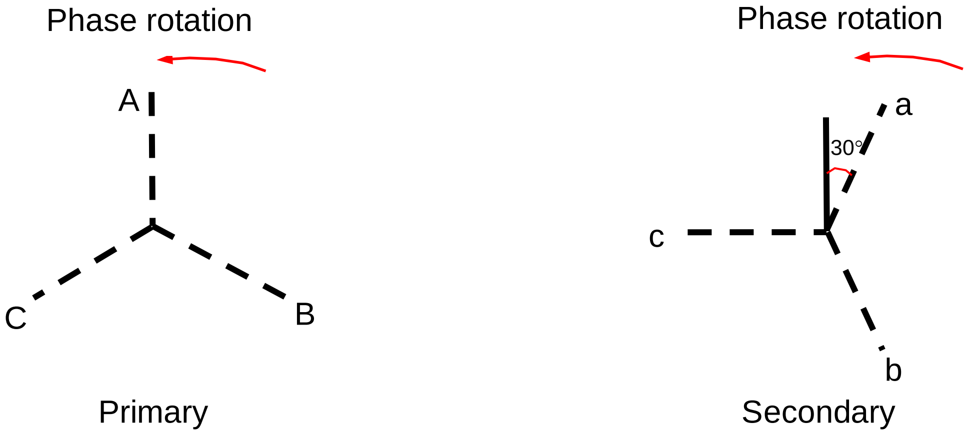
a) The line connections are normally made to the end of the winding which carries the subscript 2, ie : A_2, B_2, C_2 and a_2, b_2, c_2.

b) The line terminal designation (both letter and subscript) are the same as those of the phase winding to which the line terminal is connected.

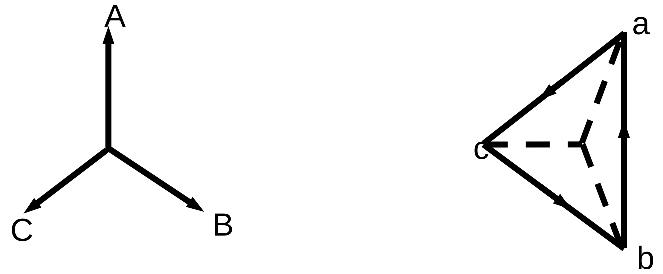
Consider the connection Yd1 :

Draw the primary and secondary phase to neutral vectors showing the required phase displacement :

i.e.

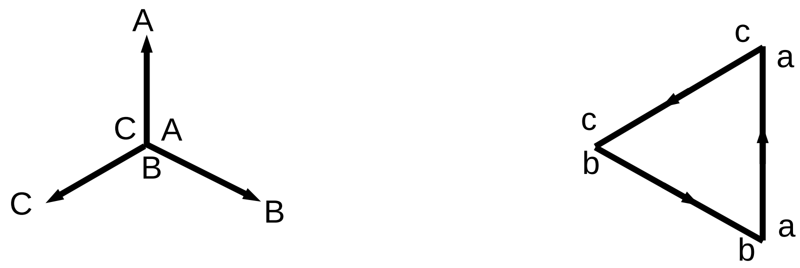


i) Complete the delta winding connection on the secondary side and indicate the respective vector directions :
i.e.



ii) It is now possible to indicate the winding subscript numbers bearing in mind that if the direction of induced voltage in the high voltage winding at a given instant is from A_1 to A_2 (or vice verse) then the direction of the induced voltage in the low voltage winding at the same instant will also be from a_1 to a_2.

i.e.



iii) It can now be seen that the delta connection should be made by connecting a_2 to c_1, b_2 to a_1 and c_2 to b_1 :

ie :

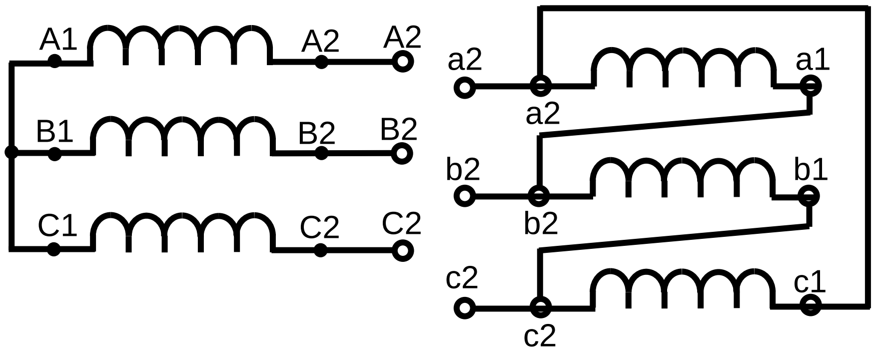


Figure 5-1. Transformer Connection

5.5 Fault Current Distribution in Transformer Windings

Under fault conditions, currents are distributed in different ways according to winding connections. Understanding of the various fault current distribution is essential for the design of differential protection, performance of directional relays and settings of overcurrent relays.

Fault current distribution on a delta-star transformer, star-star transformer with unloaded tertiary and star-delta transformer with earthing transformer for phase and earthfaults are shown in the diagrams below :

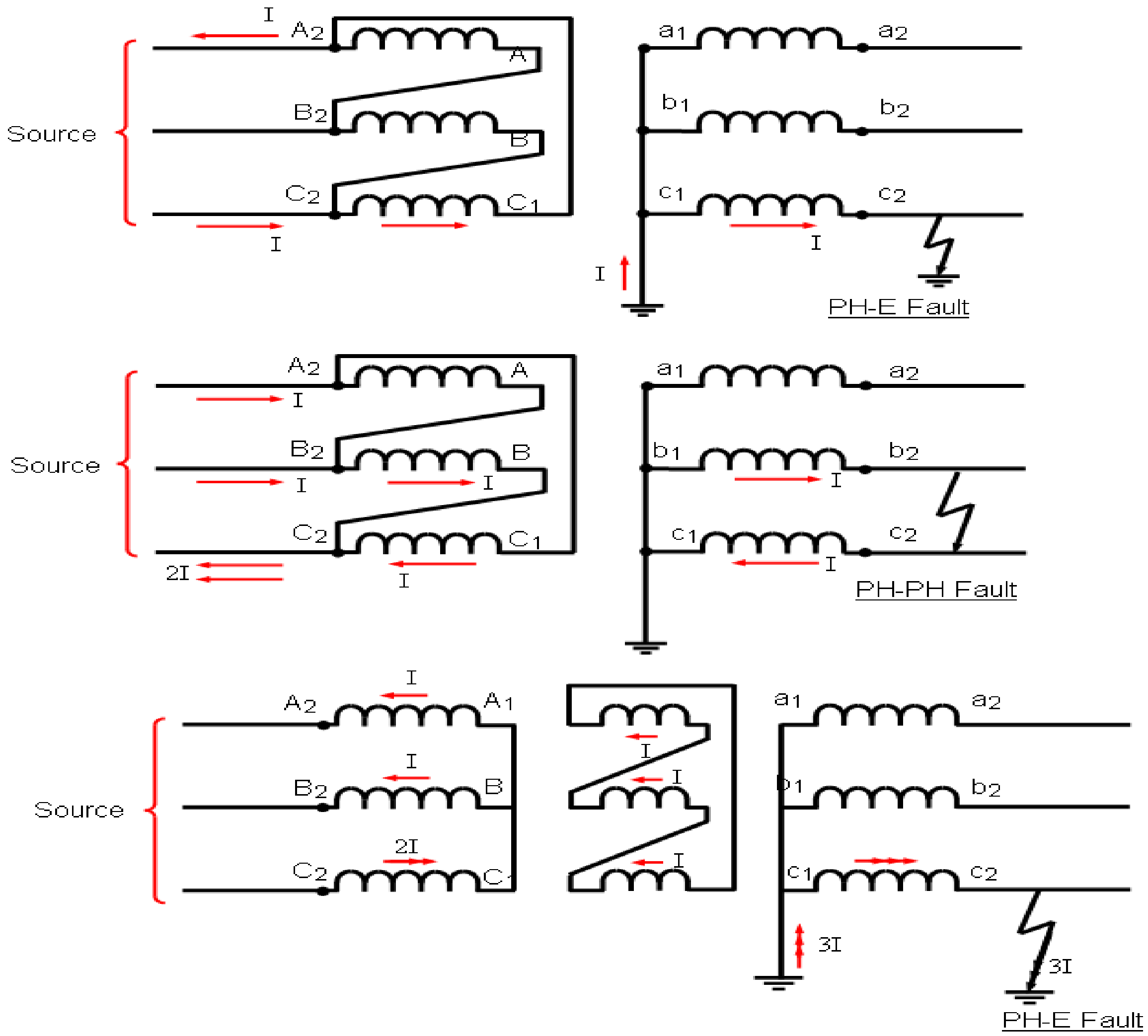


Figure 5-2: Fault Current Distribution in Transformer Winding

5.6 Current Transformer Connection

Consider a delta/star transformer. An external earth fault on the star side will result in zero sequence current flowing in the line but due to the effect of the delta winding there will be no zero sequence current in the line associated with the delta winding. In order to ensure stability of the protection this zero sequence current must be eliminated from the secondary connections on the star side of the transformer, ie the CTs on the star side of the transformer should be connected in delta. With the CTs on the delta side of the transformer connected in star, the 30° phase shift across the transformer is also catered for.

Since the majority of faults are caused by flashovers at the transformer bushings, it is advantageous to locate the CTs in the adjacent switchgear.

5.6.1 Interposing CT (ICT)

Where it is not possible to correct for zero sequence current and the phase shift across the transformer by using delta connected line CT`s on the star side of the transformer, or were CT ratio mismatch exists between primary and secondary CT`s, then interposing CT`s are used.

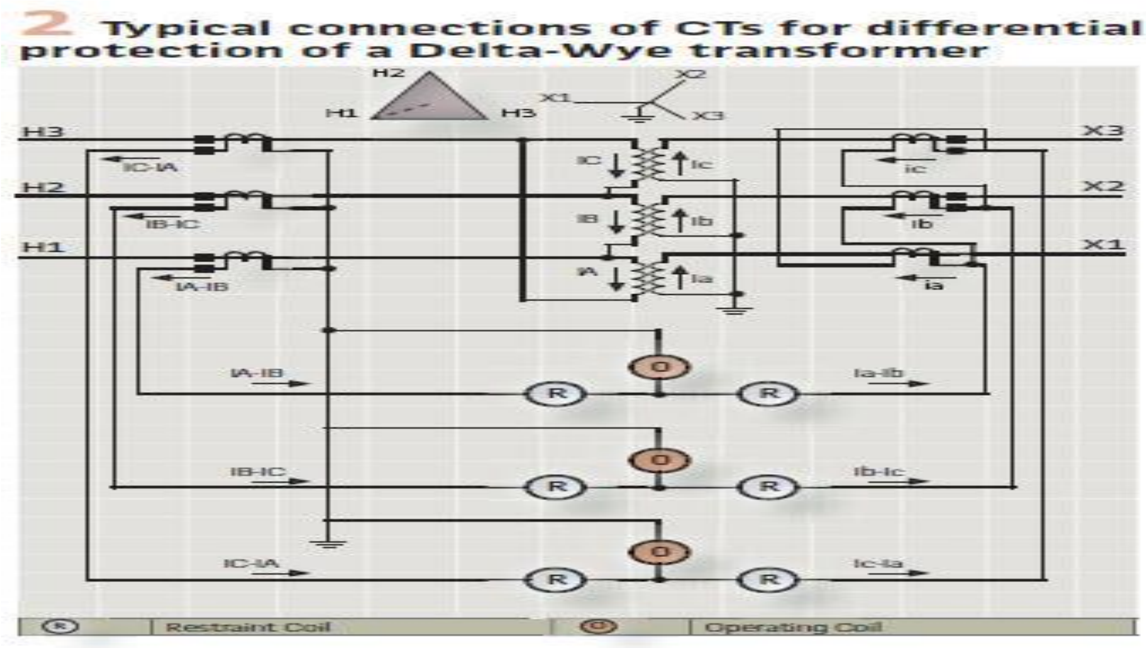
Traditional ICT`s were external devices, however **modern numerical relays are able to account for ratio error, phase shift and zero sequence current within the relay**. This eliminates the use of external ICT`s and allows the protection to be set up and installed more easily.

5.6.2 General Rules For Ct Connections

For electromechanical or static differential relays wiring schemes, CT connections types are opposite to main transformer connection types:

ie, star CTs on delta side and delta CTs on star side.

If similar primary terminals ie P1 or P2 are towards the transformer, then delta and star connection for the CTs should be the same as the transformer (or 180° opposite). It is usual to assume that if current flows from P1 $\rightarrow$ P2 then the secondary current will flow from S2 $\rightarrow$ S1. Note :If the transformer induced voltage is A1 $\rightarrow$ A2 then the secondary induced voltage will be a1 $\rightarrow$ a2. Therefore, current flow will be A1 $\rightarrow$ A2 and a2 $\rightarrow$ a1.



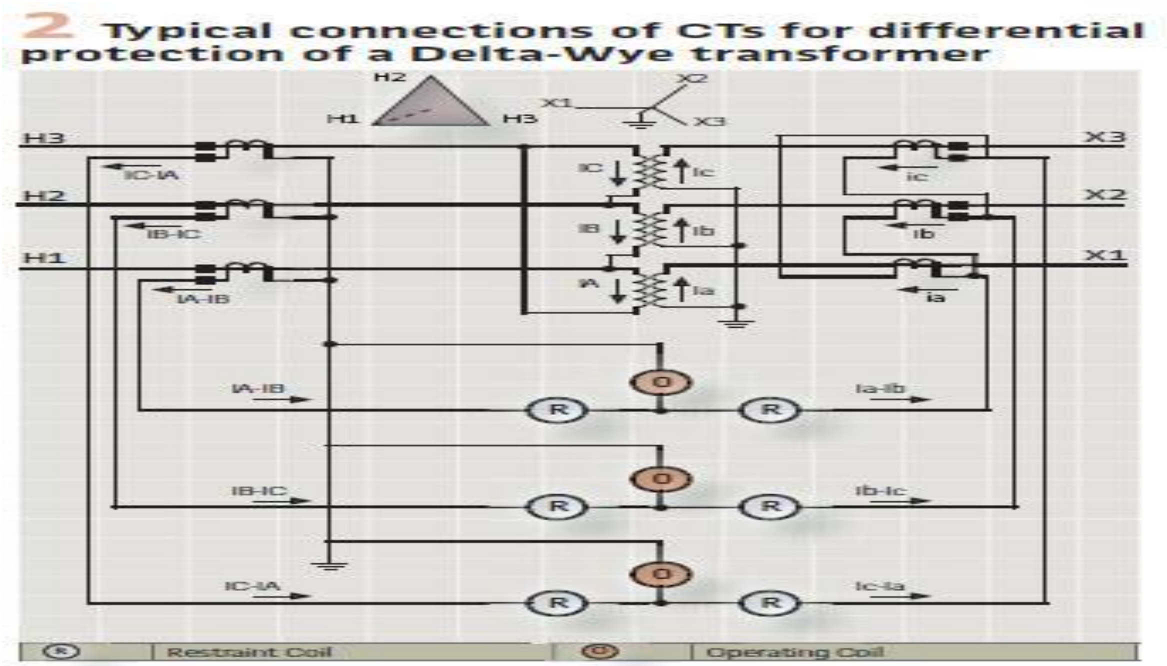
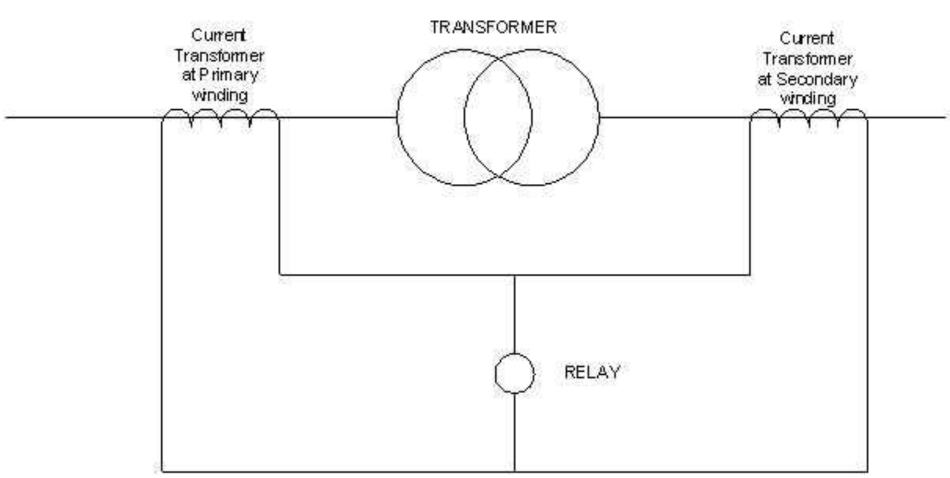


Figure 5-3. Typical Connections of CTs for differential protection(Delta-Wye)

5.7 Differential Protection

The differential protection scheme can be used to protect both the primary and secondary windings of a three-phase transformer against earth faults and phase-to-phase faults. This is possible because the efficiency of the power transformers is high and the magnetizing current is negligibly small. In a differential protection scheme a circuit compare the current entering the protective equipment to the current leaving the equipment, in each phase. Any difference of current of sufficient magnitude operates a relay, which in turn indicates fault clearance. Figure 5-4 shows a simplified diagram of a single-phase differential protection scheme.



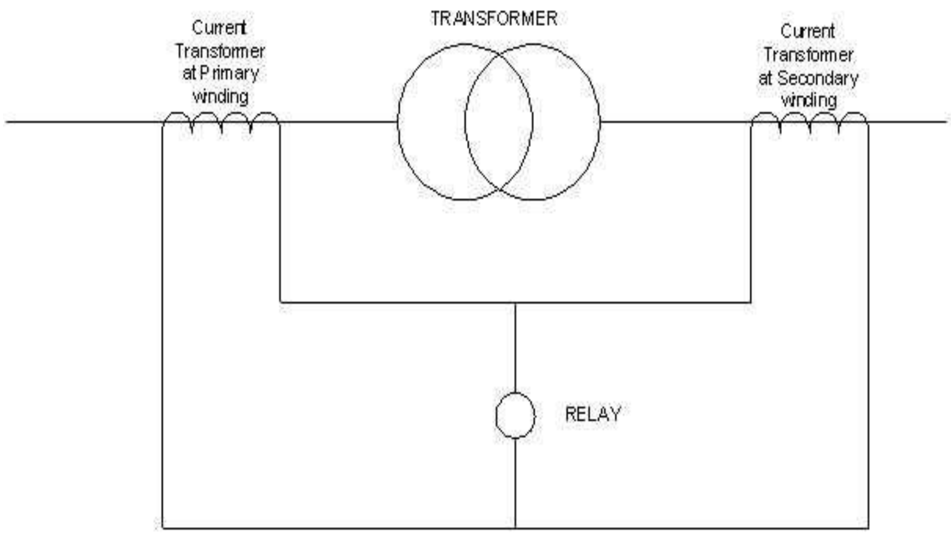


Figure 5-4. Diagram of a single-phase differential protection scheme

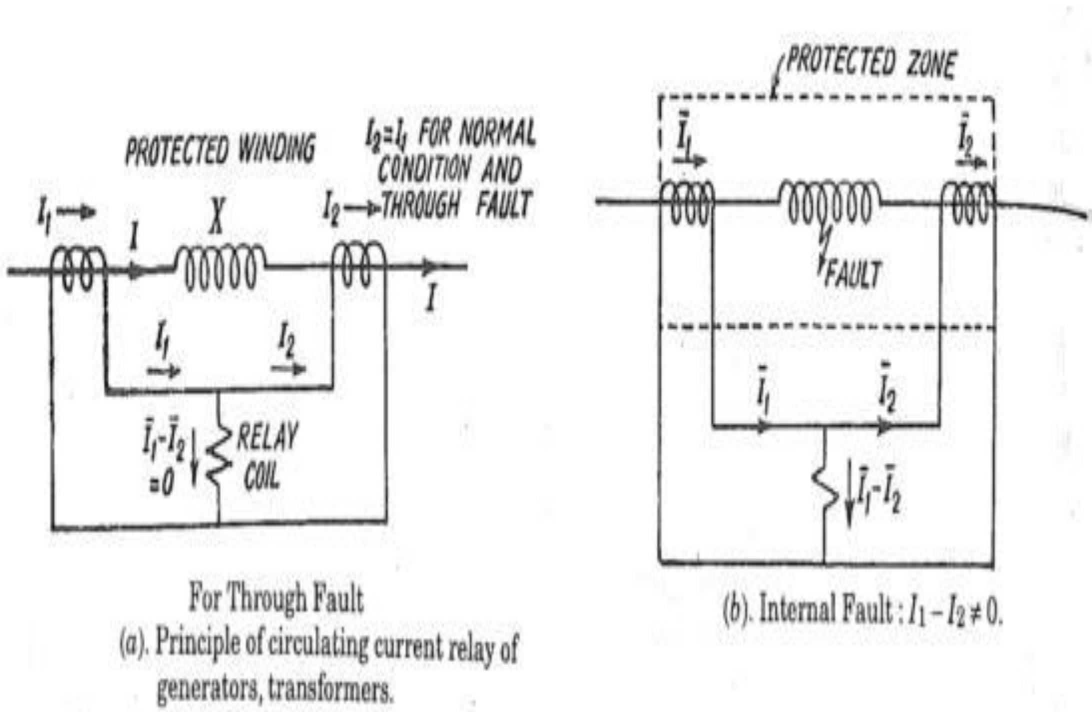


Figure 5-5. For Through (External) Fault and Internal Fault

The currents entering and leaving the protected equipment (for example, I1 and l2) are sensed through two identical current transformers. When there is no fault in the protected equipment, currents I1 and I2 are equal and the currents at the transformer secondaries are also equal (i1 = i2) because the current transformers are identical.

When the current transformers are connected with the polarities indicated in Figure 5-5(a), the secondary currents flow round the circuit and no current flows in the coil of the protective relay ($i1-i2 = IR = 0$), which can be an overcurrent relay.

However, when a fault occurs in the protected equipment, currents l1 and l2 are no longer equal. Consequently, currents i1 and i2 are also no longer equal ($i1-i2 = IR \neq 0$) as indicated in figure 5-5(b).

The current resulting from the difference between these two currents (i1-i2) flows in the protective relay coil. This trips the protective relay, there by, initiating fault clearance.

Similar differential protection scheme can be employed for the protection of transformers.

In this case, when the turns ratio of the protected transformer is not unity, the primary and secondary currents are different, and thereby, current transformers with different turns ratio are required for the CT secondary currents to be equal and the residual current IR to be zero under no fault condition.

When protecting three-phase power transformers, some additional considerations must be taken into account:

There is a 30° phase shift between the primary and secondary currents of a three-phase power transformer that is connected delta-wye or wye-delta and supplies a balanced load.

When a three-phase power transformer is connected delta-wye or wye-delta, the zero sequence current on the wye side of the power transformer has no replica on the delta side.

The 30° phase shift must be compensated and the zero sequence current on the wye side of the power transformer must be eliminated, for the CT secondary currents to be equal under no fault condition. This is achieved by proper connections of the current transformer secondary windings as stated above.

For modern numerical protection relays, current transformers are connected in star connection irrespective of the transformer configuration

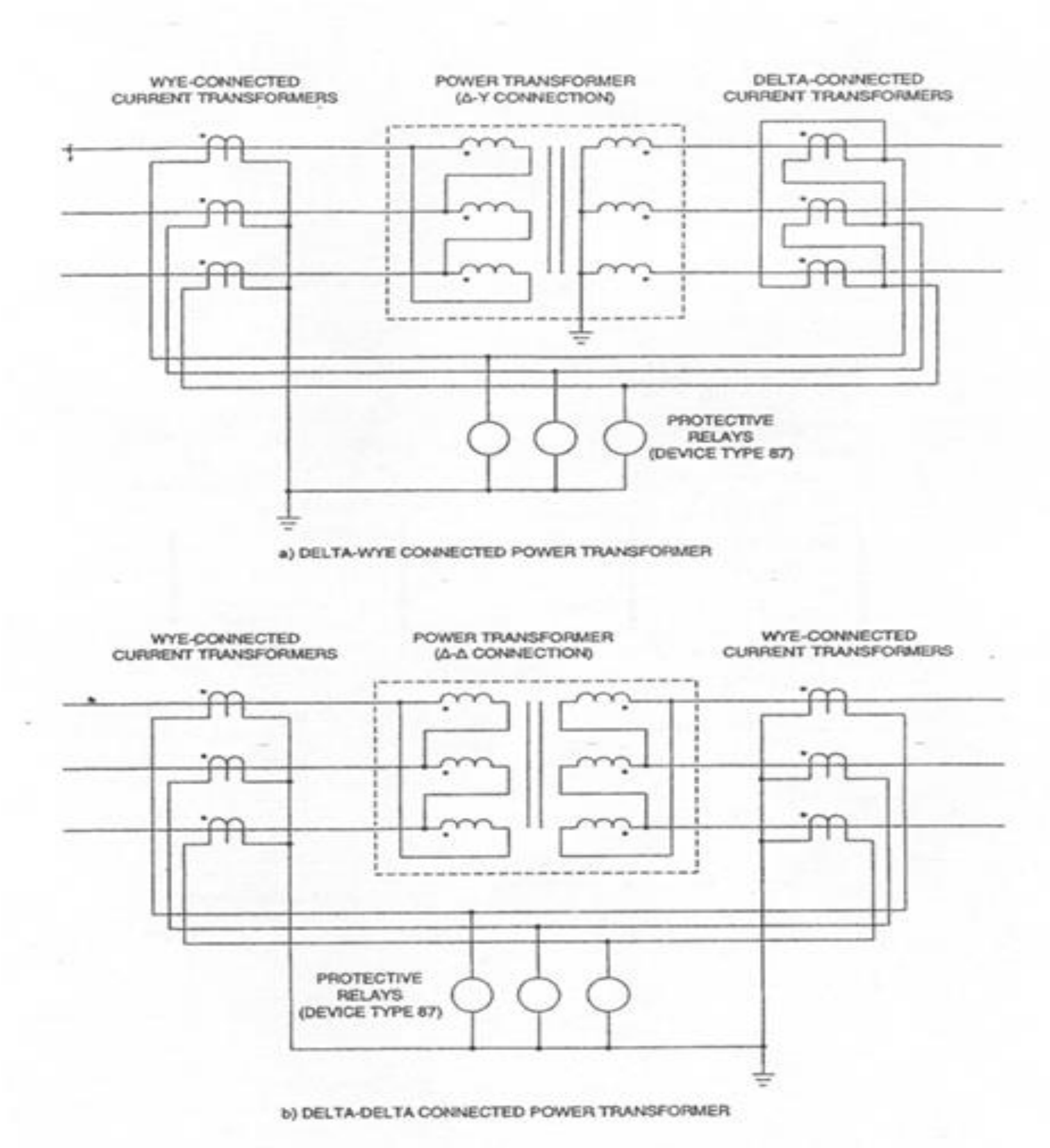


Figure 5-6. Current transformer connections for differential protection (a) Delta-Wye, (b) Delta-Delta

5.7.1 Characteristic Curve

In practice, it is very difficult to maintain perfect balance of the currents in a differential protection system protecting a three-phase power transformer. This is mainly due to the following factors:

- Change in the power transformer turns ratio (on transformers with a tap-changing facility).

- Current transformer mismatch (difficulty in having current transformers with ratios that perfectly balances the differential protection system).
- Transformer magnetizing current.

All these factors cause unbalance in the differential protection system and produce a residual current IR in the differential relay coil. This residual current increases as the line currents flowing through the three-phase power transformer increase. Therefore, the current setting of the differential relay must be increased to prevent undesired relay tripping, thereby reducing the system sensitivity.

Differential relays with bias coils are often used in transformer differential protection systems to reduce the negative effect of current unbalance on the system sensitivity. Figure 5-7 shows the bias characteristic of a differential relay. This characteristic shows that the current required to trip the differential relay (differential operating current) increases as the current flowing through the transformer increases.

Note that, in general, the sensitivity of transformer differential protection systems is less than that achieved in differential protection systems protecting the stator windings of a synchronous generator.

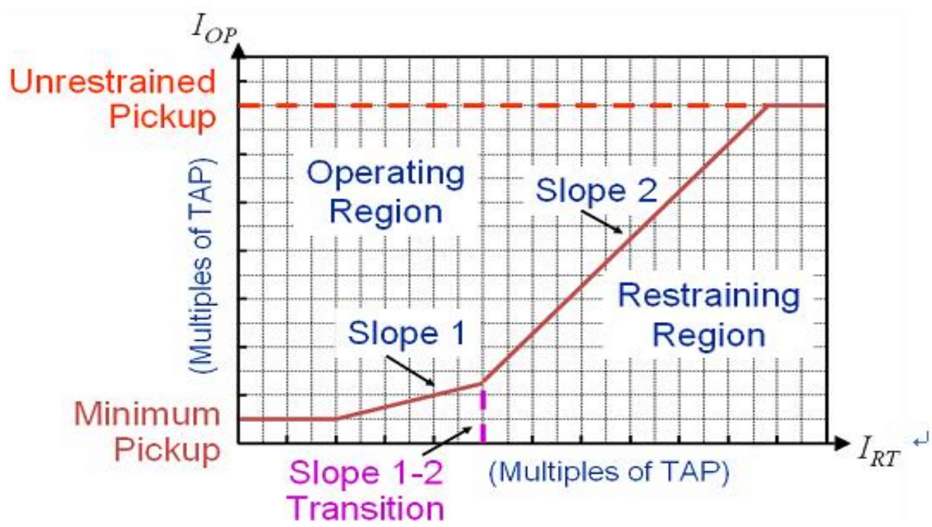


Figure 5-7. Typical bias characteristics of a differential relay.

5.7.2 Tap Changers

Any differential scheme can only be balanced at one point and it is usual to choose CT ratios that match at the mid point of the tap range. Note that this might not necessarily be the normal rated voltage. For example, if the tapping range is +10%, -20% then the CT ratio should be based on a current corresponding to the -5% tap.

The theoretical maximum out of balance in the differential circuit is then $\pm 15\%$. In setting the threshold for the relay, this maximum unbalance must be taking into account.

5.7.3 Three Winding Transformers

Differential protection of three winding transformers is essentially similar to that of two winding transformers. The same rules regarding CT connections still apply but the CT ratios used should be based on the MVA rating of one of the windings (usually the highest rated winding) and not on the ratings of each individual winding.

For example, consider a 132/33/11 kV transformer with windings rated for 100/60/40 MVA respectively, then the current transformer ratios at all voltage levels should be based on 100 MVA, ie 440/1, 1760/1 and 5280/1 respectively (these effective ratios are normally obtained by the use of interposing CTs which means that, for example, all the main CTs associated with the 11 kV system can be made equal to 2000/1 - rated current).

If there is a source associated with only one of the transformer windings, then a relay with only two bias coils can be used - the CTs associated with the other two windings being connected in parallel.

If there is more than one source of supply then it is necessary to use a relay with three bias windings in order to ensure that bias is available under all external fault conditions.

5.8 Variation of Earthfault Currents on Transformer Windings

An earthfault is the most common type of fault that occurs in a transformer.

For an earthfault current to flow, the following conditions must be satisfied :

- A path exists for the current to flow into and out of the windings, ie a zero sequence path
- The ampere turns balance is maintained between the windings.

The magnitude of earthfault current is dependent on the method of earthing solid or resistance and the transformer connection.

5.8.1 Star Winding - Resistance Earthed

An earthfault on such a winding will give rise to a current which is dependent on the value of earthing impedance and is also proportional to the distance of the fault from the neutral point, since the fault voltage will be directly proportional to this distance.

The ratio of transformation between the primary winding and the short circuited turns also varies with the position of the fault, so that the current which flows through the transformer terminals will be proportional to square of the fraction of the winding which is short circuited.

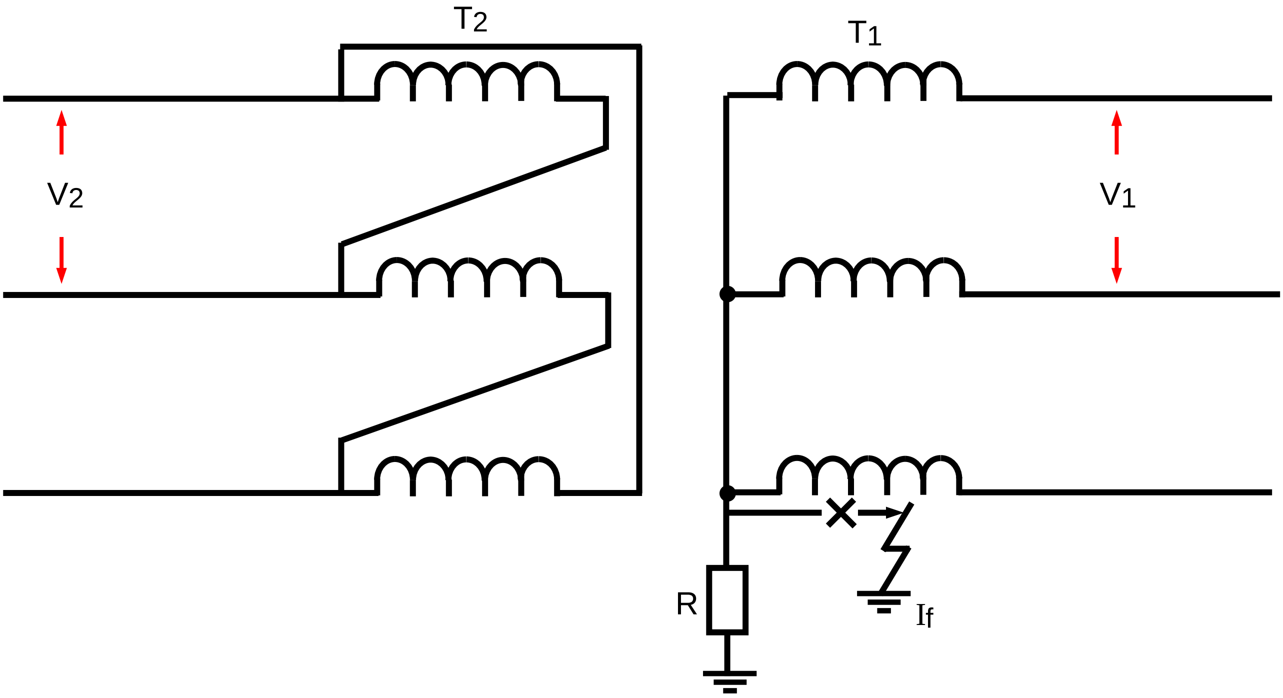


Figure 5-8. Star Winding – Resistance Earthed

If the earthing resistor is rated to pass full load current, then

$$\frac{V_1}{\sqrt{3}R} = I_{F.L.}$$

Assuming $V_1 = V_2$, then $T_2 = \sqrt{3}\, T_1$

For a fault at x p.u. distance from the neutral,

$$I_f = \frac{x.V_1}{\sqrt{3}R}$$

Effective turns ratio = T_2 / x T_1

$$\therefore \quad I\,\text{primary} = \frac{x.V_1}{\sqrt{3}R} \; \frac{XT_1}{T_2}$$

$$= x^2 . I_{F.L.} \frac{1}{\sqrt{3}}$$

Primary C.T. ratio is based on $I_{F.L.}$ for differential protection.

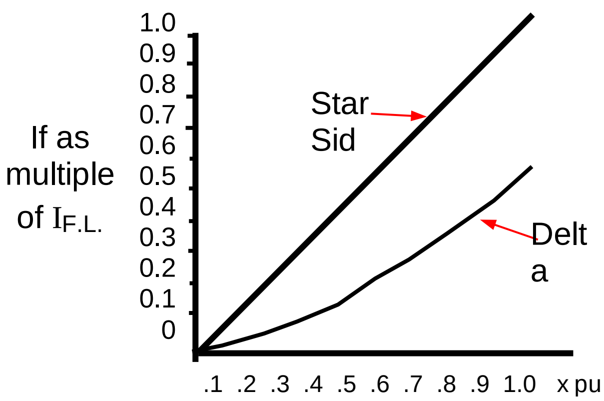
$$\therefore \quad \text{C.T. secondary current (on primary side of transformer)} = \frac{x^2}{\sqrt{3}}$$

If differential setting = 20%

$$\text{For relay operation} \; \frac{x^2}{\sqrt{3}} > 20\%$$

thus x > 59% i.e. 59% of winding is unprotected.

Differential relay setting	% of winding protected
10%	58%
20%	41%
30%	28%
40%	17%
50%	7%



5.8.2 Star Winding - Solidly Earthed

In this case, the fault current is limited only by the leakage reactance of the winding, which varies in a complex manner with the position of the fault. For the majority of the winding the fault current is approximately 3 x Iflc, reaching a maximum of 5 x Iflc.

From a study of the various current distributions shown for earth faults, it is evident that overcurrent relays do not provide adequate earth fault protection. If the system is solidly earthed, some differential relays adequately cover the majority of faults, but in general separate earth fault protection is necessary.

5.9 Earth Fault Protection

It is usual to provide instantaneous earth fault protection to transformers since it is relatively easy to restrict the operation of the protection to transformer faults only, ie the protection remains stable for external faults. This protection is called balanced or restricted earth fault as shown in figure 5-9(a) below and the high impedance principle is utilised. However, modern numerical relays do provide both high and low impedance restricted earth fault protection. Balanced earth fault for a delta (or unearthed star) winding can be provided by connecting three line CTs in parallel (residual connection). The relay will only operate for internal earth faults since the transformer itself cannot supply zero sequence current to the system. The transformer must obviously be connected to an earth source.

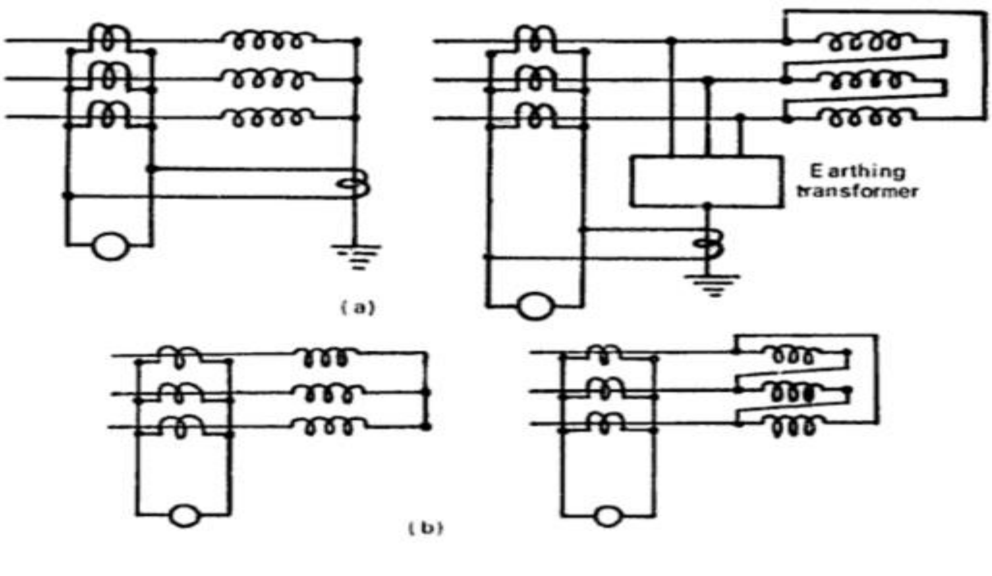


Figure 5-9. Earth Fault Protection

For an earthed star winding, the residual connection of line CTs are further connected in parallel with a CT located in the transformer neutral. Under external earth fault conditions the current in the line CTs is balanced by the current in the neutral CT. Under internal fault conditions, current only flows in the neutral CT and since there is no balancing current from the line CTs, the relay will operate.

On four wire systems in order to negate the effect of the neutral return current a further CT placed in the neutral and wired in parallel with the existing CT`s. On a four wire system with the transformer earthed at the neutral point 5 CT`s are required. However, if the transformer is earthed at the LV switch board only 4 CT`s are required. If no neutral CT is used then the relay will have to be set above the maximum expected unbalance current in the neutral return.

5.9.1 High Impedance Scheme

A relay, insensitive to the dc component of fault current is normally used for this type of protection. If a "current operated" relay is used, an external stabilising resistor is placed in series with the relay to ensure protection stability under through fault conditions. The protection setting voltage is calculated by conventional methods. To reduce the setting voltage it is often useful to run three cores from the neutral CT in order that the relay is connected across equipotential points.

5.9.2 Typical Settings for Ref Protection (FROM ESI 48-3 1977)

Solidly earthed	-	10-60% of winding rated current
Resistance earthed	-	10-25% minimum earth fault current for fault at transformer terminals

5.9.3 Unrestricted Earth fault Protection

Unrestricted earth fault or backup earth fault protection can be provided by utilising a single CT mounted on an available earth connection eg transformer neutral, or (on an earthed system) by using a residual connection of three line CTs. In this case, the relay should be of the inverse or definite time type in order to ensure correct discrimination.

On resistance earthed system, unrestricted earth fault protection is referred to as standby earth fault protection. An inverse time relay is used which matches the thermal characteristic of the earthing resistor. Earthing resistors normally have a 30 second rating and are designed to limit the earth fault current to transformer full load current.

5.10 Protection Of Parallel Transformers

Parallel transformers are typically protected by directional overcurrent and earth fault protection on the LV side set to look back into the transformers. Where an LV bus section exists the directional relays can be replaced by non-directional relays, with the addition of a non-directional overcurrent and earth fault relay at the bus-section.

If a transformer is connected in parallel with another transformer which is already energised, magnetising inrush will occur in both transformers. The dc component of the inrush associated with the switched transformer creates a voltage drop across the line resistance between the source and the transformer. This voltage causes an inrush in the opposite direction in the transformer that was already connected. After some time the two currents become substantially equal and since they flow in opposite directions in the transmission line they cancel and produce no more voltage drop in the line resistance. The two currents then become a single circulating current flowing around the loop circuit made up of the two transformers in series - the rate of decay being determined by the R/L ratio of the transformer. As far as protection is concerned, non-harmonic restraint should not be used due to the long time delay required for the decay of the DC current. A harmonic restrained relay should be used for each transformer since if a common relay were used the 2nd harmonic restraint could be lost due to cancellation as described above.

5.10.1 Magnetising Inrush

When a transformer is first energised, a transient magnetising current flows, which may reach instantaneous peaks of 8 to 30 times those of full load. The factors controlling the duration and magnitude of the magnetising inrush are :

- i) Size of the transformer bank
- ii) Size of the power system
- iii) Resistance in the power system from the source to the transformer bank
- iv) Residual flux level
- v) Type of iron used for the core and its saturation level.

There are three conditions which can produce a magnetising inrush effect :

- i) First energisation
- ii) Voltage recovery following external fault clearance
- iii) Sympathetic inrush due to a parallel transformer being energised.

Under normal steady state conditions the flux in the core changes from maximum negative value to maximum positive value during one half of the voltage cycle, ie a change of 2 0 maximum. Since flux cannot instantly be created or destroyed this transformers are normally designed and run at values of flux approaching the saturation value, an increase of flux to double this value corresponds to relationship must always be true. Thus, if the transformer is energised at a voltage zero when the flux would normally be at its maximum negative value, the flux would rise to twice its normal value over the first half cycle of voltage. This initial rise could be further increased if there was any residual flux in the core at the moment the transformer was energised.

As the flux enters the highly saturated portion of the magnetising characteristic, the inductance falls and the current rises rapidly. Magnetising impedance is of the order of 2000% but under heavily saturated conditions this can reduce to around 40% ie an increase in magnetising current of 50 times normal. This figure can represent 5 or 6 times normal full load current.

Analysis of a typical magnitude inrush current wave shows (fundamental = 100%) :

Component	-DC	2nd H	3rd H	4th H	5th H	6th H	7th H
	55%	63%	26.8%	5.1%	4.1%	3.7%	2.4%

The offset in the wave is only restored to normal by the circuit losses. The time constant of the transient can be quite long, typically 0.1 second for a 100 KVA transformer and up to 1 second for larger units. Initial rate of decay is high due to the low value of air core reactance. When below saturation level rate of decay is much slower.

The magnitude of the inrush current is limited by the air core inductance of the windings under extreme saturation conditions. A transformer with concentric windings will draw a higher magnetising current when energised from the LV side, since this winding is usually on the inside and has a lower air core inductance. Sandwich windings have approximately equal magnitude currents for both LV and HV.

Resistance in the source will reduce the magnitude current and increase the rate of decay.

5.10.2 Effect on Differential Relays

Since magnetising inrush occurs on only one side of the transformer, the effect is similar to a fault condition as far as differential protection is concerned. The following methods are used to stabilise the relay during magnetising inrush period.

Time delayed - acceptable for small transformers or where high speed operation is not so important. (Note : necessary time delay when associated with parallel transformers could be excessive).

Harmonic restraint - usual to use 2^{nd} H restraint since magnitude inrush current contains pronounced 2nd harmonics.

Note : 3rd H restraint should not be used for two reasons :

- a) Due to delta connections in the main transformer and in the CT circuits (which provide a closed path for third harmonic currents), no third harmonic current would reach the relay.
- b) CT saturation under internal fault conditions also produces harmonics of which the 3rd is the most predominant. Second harmonics are also produced under these conditions (combination of dc offset and fundamental) so excessive saturation of CTs should be avoided.

The problem of any restraining tendency due to 2nd H currents produced by CTs saturating under heavy internal fault conditions is usually overcome by using high set instantaneous units set at 8-10 x rated current.

While the second harmonic produces a useful restraint during external faults, it can produce unwanted restraint for internal faults, due to dc saturation of CTs. Extremely large CTs are required such that they do not saturate and affect the operating times of the differential relay.

Gap Detection - If the various current waveforms that occur during magnetising inrush are analysed, it can be found that the magnetising currents have a significant period in each cycle where the current is substantially zero. Fault current, on the other hand, passes through zero very quickly. Detection of this zero is considered a suitable criteria for restraining the relay during inrush conditions.

Thus, a transformer differential relay can be made to restrain if zero is detected in a cycle for more than a certain period (typically 1/4f seconds). With the above principle of detection of magnetising inrush, fast operation of the relay can be achieved for internal faults and economically designed CTs can be used, without affecting the speed of operation.

M06 – MECHANICAL PROTECTIONS ON TRANSFORMERS

6.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of mechanical protections on transformer
- Explain characteristics of mechanical protective relays on transformer

6.2 Introduction

Overloads can be sustained for long periods with the limiting factor being the allowable temperature rise in the windings and the cooling medium. Excessive overloading will result in deterioration of insulation and subsequent failure. Overloads can be split into two categories :

Overloads which do not reduce the normal expectation of life of the transformers. Overloads in this category are possible because the thermal time constant of the transformer means that there is a considerable time lag before the maximum temperature correspond to a particular load is reached. Quite high overloads can therefore be carried for short period. Overloads in which an allowance is made for a rapid use of life than normal.

The length of life of insulation is not easily determined but it is generally agreed that the rate of using life is doubled for every 6°C temperature increase over the range 80-140°C (below 80°C the use of life can be considered negligible).

A hot spot temperature of 98°C gives what may be considered the normal rate of using life, ie a normal life of some tens of years. This temperature corresponds to a hot spot temperature rise of 78°C above an ambient temperature of 20°C. The graph below indicates the relative rate of using life against hot spot temperature.

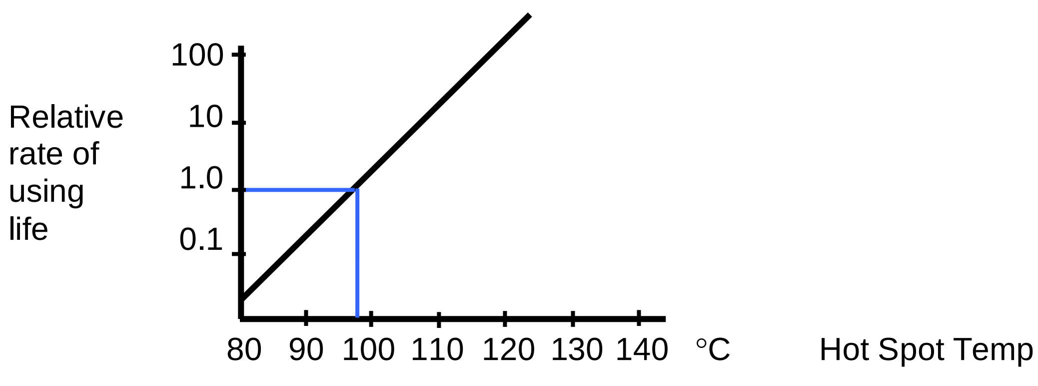


Figure 6-1. Relative rate of using life against hot spot temperature

6.2.1 Protection for Overloads

Since overloads cause heating of the transformer above the normal recommended temperatures, protection against overloads is normally based on winding temperature.

6.2.2 Oil Transformer Protection

The power transformer protection is realized with two different kinds of devices, namely the devices that are measuring the electrical quantities affecting the transformer through instrument transformers and the devices that are indicating the status of the physical quantities at the transformer itself.

An example of the former could be current-based differential protection and of the latter oil temperature monitoring. The collective term for the latter is mechanical protective devices.

6.2.3 Mechanical Protection Devices

The following discusses protection devices typically delivered as a part of the power transformer delivery.

- Buchholz (Gas) Relay (63)
- Pressure Relay (63)
- Oil Level Monitor Device (71)
- Top-oil Thermometer (26)
- Winding Thermometer (49)

6.3 Buchholz Relay

All types of fault within a transformer will produce heat which will cause decomposition of the transformer oil. The resulting gases that are formed rise to the top of the tank and then to the conservator.

A buchholz relay connected between the tank and conservator collects the gas and gives an alarm when a certain volume of gas has been collected. A severe fault causes so much gas to be produced that pressure is built up in the tank and causes a surge of oil.

The Buchholz relay will also detect these oil surges and under these conditions is arranged to trip the transformer circuit breakers.

The main advantage of the Buchholz relay is that it will detect incipient faults which would not otherwise be detected by conventional protection arrangements. The relay is often the only way of detecting interturn faults which cause a large current to flow in the shorted turns but due to the large ratio between the shorted turns and the rest of the winding, the change in terminal currents is very small.

The transformer gas relay is a protective device installed on the top of oil-filled transformers. It performs two functions. It detects the slow accumulation of gases, providing an alarm after a given amount of gas has been collected. Also, it responds to a sudden pressure change that accompanies a high rate of gas production (from a major internal fault), promptly initiating disconnection of the transformer.

The Buchholz protection is a mechanical fault detector for electrical faults in oil-immersed transformers. The Buchholz (gas) relay is placed in the piping between the transformer main tank and the oil conservator. The conservator pipe must be inclined slightly for reliable operation.

Often there is a bypass pipe that makes it possible to take the Buchholz relay out of service.

Figure 6-2. Installed Buchholz gas relay

The Buchholz protection is a fast and sensitive fault detector. It works independent of the number of transformer windings, tap changer position and instrument transformers. If the tap changer is of the on-tank (container) type, having its own oil enclosure with oil conservator, there is a dedicated Buchholz relay for the tap changer.

A typical Buchholz protection comprises a pivoted float (F) and a pivoted vane (V) as shown in Figure 6-3. The float carries one mercury switch and the vane also carries another mercury switch. Normally, the casing is filled with oil and the mercury switches are open.

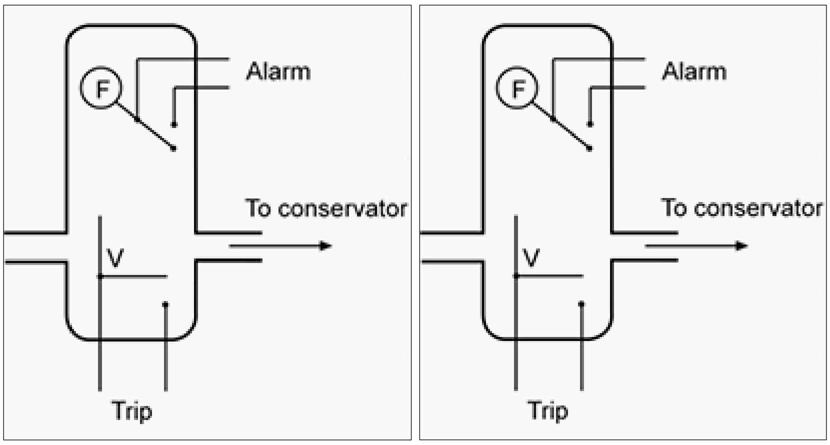


Figure 6-3. Buchholz relay principal construction

When minor fault occurs, gases produced by minor faults rise from the fault location to the top of the transformer. Then the gas bubbles pass up the piping to the conservator. The gas bubbles will be tapped in the casing of the Buchholz protection.

This means that the gas replaces the oil in the casing. As the oil level falls, the float (F) will follow and the mercury switch tilts and closes an alarm circuit.

When major fault occurs, either to earth of between phases or windings, occurs within the transformer. Such faults rapidly produce large volumes of gas (more than 50 cm3/(kWs) and oil vapor which cannot escape.

They therefore produce a steep buildup of pressure and displace oil. This sets up a rapid flow from the transformer towards the conservator. The vane (V) responds to high oil and gas flow in the pipe to the conservator. In this case, the mercury switch closes a trip circuit.

The operating time of the trip contact depends on the location of the fault and the magnitude of the fault current.

Tests carried out with simulated operating conditions have shown that operation in the time range 0.050-0.10 seconds is possible. The operating time should not exceed 0.3 seconds.

The gas accumulator relay also provides a long-term accumulation of gasses associated with overheating of various parts of the transformer conductor and insulation systems. This will detect fault sources in their early stages and prevent significant damage.

Figure 6-4. A typical outlook of a Buchholz relay with flanges on both sides for pipe connections

When the transformer is first put into service, the air trapped in the windings may give unnecessary alarm signals. It is customary to remove the air in the power transformers by vacuum treatment during the filling of the transformer tank with oil.

In addition, the Buchholz relay can detect if the oil level falls below that of the relay as a result of a leakage from the transformer tank.

6.3.1 Generation of Gas Due to Faults

Internal transformer electrical faults result in the production of ionized gases. A significant volume of gas is frequently generated in the early stages of a fault by rapid oil breakdown. The generated gases rise through the oil to the top of the equipment and collect in the gas relay.

Once a sufficient volume of gas has accumulated, an alarm is generated by contacts within the gas relay.

In the event of a gas alarm, it is necessary to sample and analyze the gas being generated. This analysis, together with knowledge of the rate at which gas is accumulating, will determine the proper course of action.

If a fault is thought to be developing, the device must be removed from service. Ignoring this early warning sign can lead to severe equipment damage as the fault progresses.

6.4 Pressure Relay

Many power transformers with an on-tank-type tap changer have a pressure protection for the separate tap changer oil compartment. This protection detects a sudden rate-of-increase of pressure inside the tap changer oil enclosure.
Figure 6-5 shows the principle of a pressure relay.

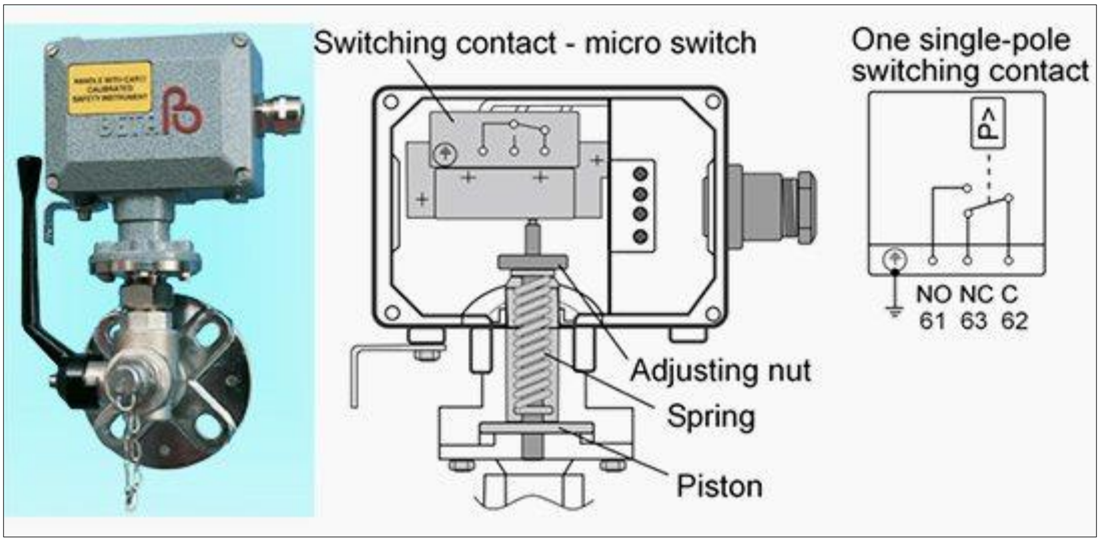


Figure 6-5. Pressure relay

When the pressure in front of the piston exceeds the counter force of the spring, the piston will move operating the switching contacts. The micro switch inside the switching unit is hermetically sealed and pressurized with nitrogen gas.

6.5 Pressure Relief Relay

An internal fault in an oil-filled transformer is usually accompanied by overpressure in the transformer tank.

The simplest form of pressure relief device is the widely used frangible disk. The surge of oil caused by a heavy internal fault bursts the disk and allows the oil to discharge rapidly.

Relieving and limiting the pressure rise prevent explosive rupture of the tank and consequent fire.

Also, if used, the separate tap changer oil enclosure can be fitted with a pressure relief device.

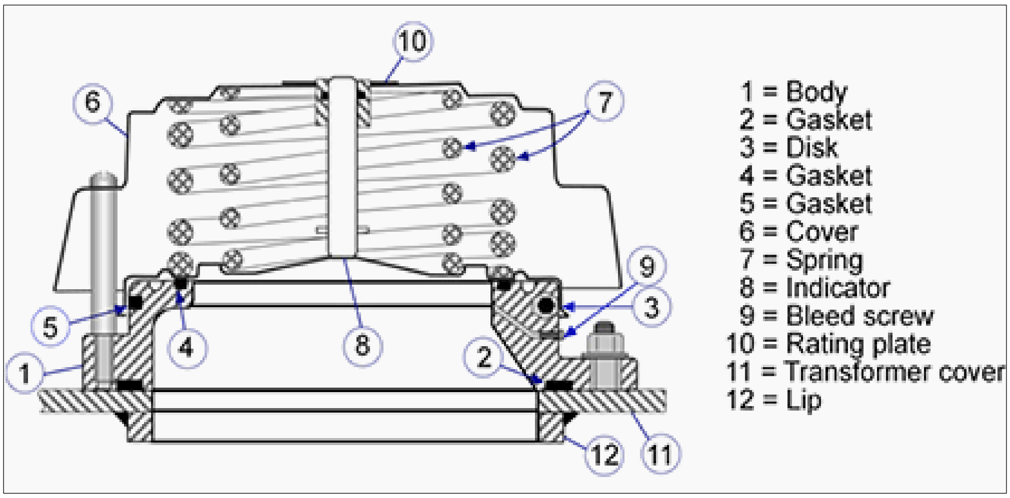


Figure 6-6. Principle construction of a pressure relief device

The pressure relief device can be fitted with contact unit(s) to provide a signal for circuit breaker(s) tripping circuits.

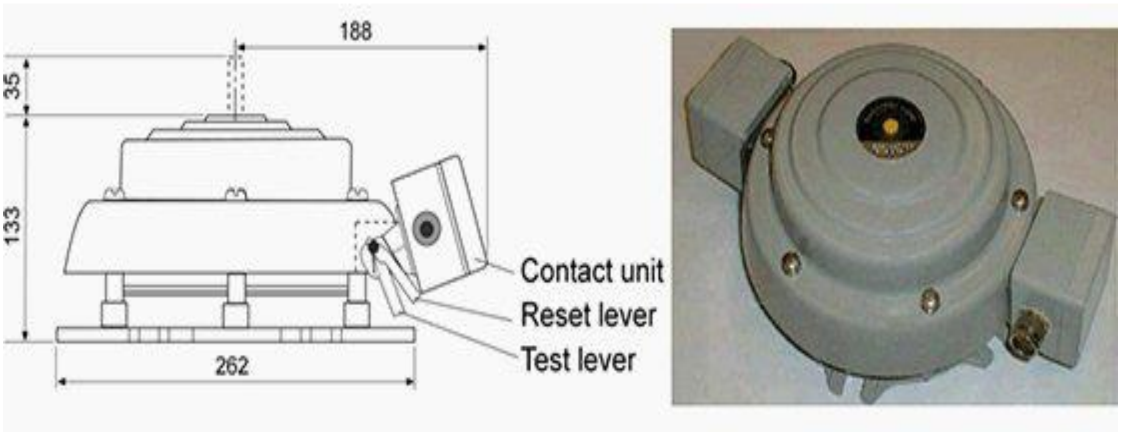


Figure 6-7. A pressure relief device with contact units

A drawback of the frangible disk is that the oil remaining in the tank is left exposed to the atmosphere after a rupture. This is avoided in a more effective device, the pressure relief valve, which opens to allow the discharge of oil if the pressure exceeds the pre-adjusted limit.

By providing the transformer with a pressure relief valve, the overpressure can be limited to a magnitude harmless to the transformer.

If the abnormal pressure is relatively high, this spring-controlled valve can operate within a few milliseconds and provide fast tripping when suitable contacts are fitted. The valve closes automatically as the internal pressure falls below a critical level.

6.6 Oil Level Monitor Device

Transformers with oil conservator(s) (expansion tank) often have an oil level monitor. Usually, the monitor has two contacts for alarm. One contact is for maximum oil level alarm and the other contact is for minimum oil level alarm.

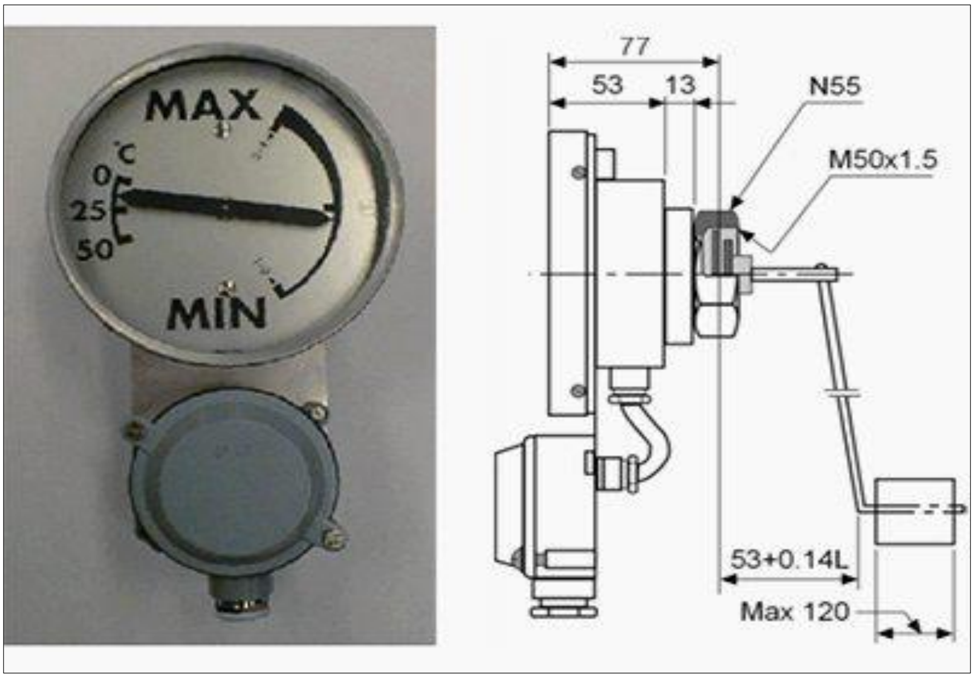


Figure 6-8. A typical outlook of an oil level monitor device

6.7 Winding/Oil Thermometer

Transformer Thermal Overload

Heat is generated in a power transformer by current flow in the primary and the secondary windings as well as internal connections due to I^2R losses. At low loads, the quantity of heat produced will be small.

But, as the load increases, the amount of heat becomes significant. At full load, the windings will be operating at or near their design temperature. The nameplate on a transformer will provide information on the maximum allowable in-service temperature rise for its windings and connections and will indicate what method of cooling is employed to remove the heat generated under load.

A temperature of about 105°C is considered to be the normal maximum working value for large power transformers, based on an assumed maximum ambient temperature of 40°C.

6.7.1 Top-Oil Thermometer (26Q)

The top-oil thermometer has a liquid thermometer bulb in a pocket at the top of the transformer. The thermometer measures the top-oil temperature of the transformer. The top-oil thermometer can have one to four contacts, which sequentially close at successively higher temperature.

With four contacts fitted, the two lowest levels are commonly used to start fans or pumps for forced cooling, the third level to initiate an alarm and the fourth step to trip load breakers or de-energize the transformer or both.

The figure below shows the construction of a capillary-type top-oil thermometer, where the bulb is situated in a “pocket” surrounded by oil on top of the transformer. The bulb is connected to the measuring bellow inside the main unit via a capillary tube. The bellow moves the indicator through mechanical linkages, resulting in the operation of the contacts at set temperatures.

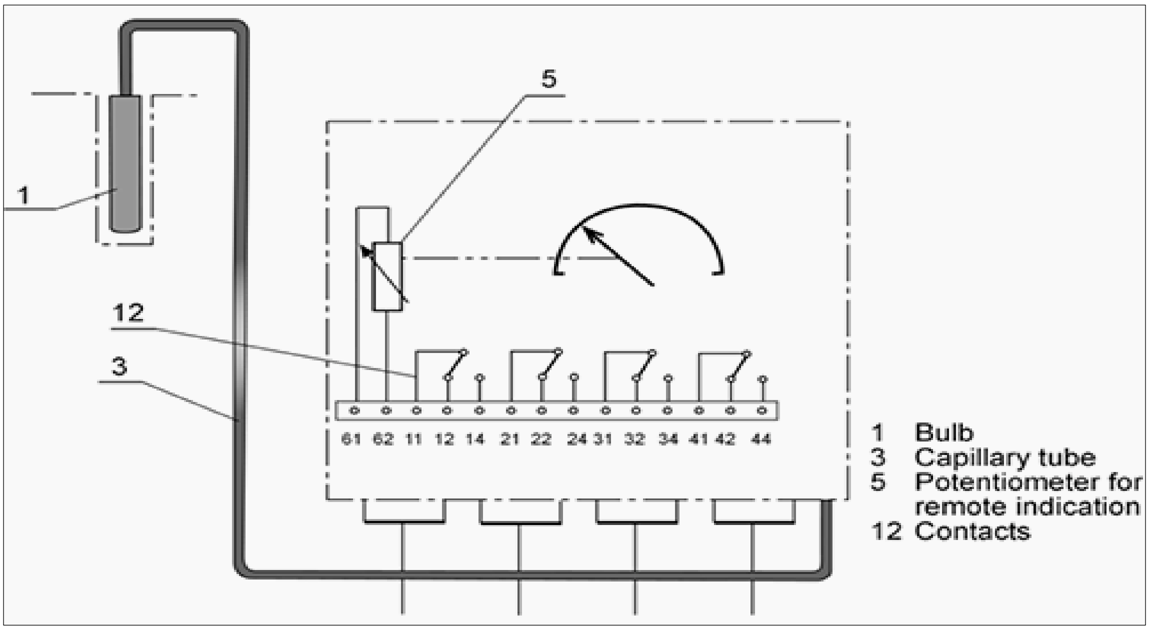


Figure 6-9. Capillary type of top-oil temperature measurement device

The top-oil temperature may be considerably lower than the winding temperature, especially shortly after a sudden load increase. This means that the top-oil thermometer is not an effective overheating protection. However, where the policy towards transformers’ loss of life permits, tripping on top-oil temperature may be satisfactory. This has the added advantage of directly monitoring the oil temperature to ensure that it does not reach the flash temperature.

6.7.2 Winding Thermometer (49W)

The winding temperature is sensed and indicated by a winding temperature gauge/alarm assembly. The purpose of this gauge is to provide a thermal image of the hottest point within the transformer. The sensing bulb of the assembly is placed in a well located near the top of the transformer tank. The well is immersed in the hot transformer oil. A heating coil, supplied from a load sensing current transformer, is installed around the sensing bulb to provide a local temperature rise above the general oil temperature. The affect of the heating coil, coupled with the heat of the oil on the bulb, allows the gauge to simulate the winding temperature hot spots.

Operation of the transformer above its rated voltage by even 10% can cause a significant temperature rise, initiating an over-temperature alarm. Over voltage operation may be a result of tap changer or voltage regulation problems. Such over-temperature operation can lead to physical insulation damage reducing the useful life of the insulation and thus the life of the unit. A temperature rise of 8 -- 10°C beyond the normal maximum working value, if sustained, will halve the life of the unit.

The winding thermometer, shown in the figure below, responds to both the top-oil temperature and the heating effect of the load current.

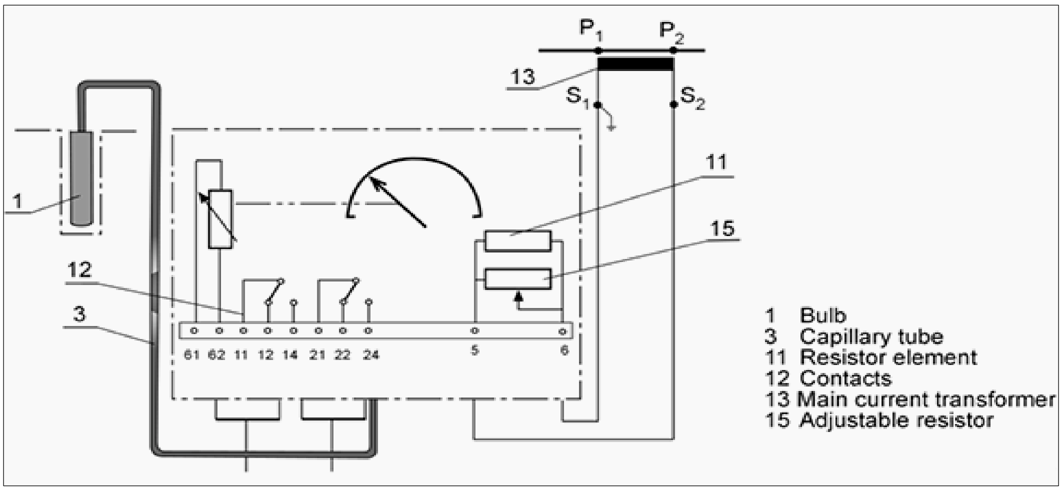


Figure 6-10. Capillary type of winding thermometer

The winding thermometer creates an image of the hottest part of the winding. The top-oil temperature is measured with a similar method as introduced earlier.

The measurement is further expanded with a current signal proportional to the loading current in the winding.

This current signal is taken from a current transformer located inside the bushing of that particular winding. This current is lead to a resistor element in the main unit. This resistor heats up, and as a result of the current flowing through it, it will in its turn heat up the measurement bellow, resulting in an increased indicator movement.

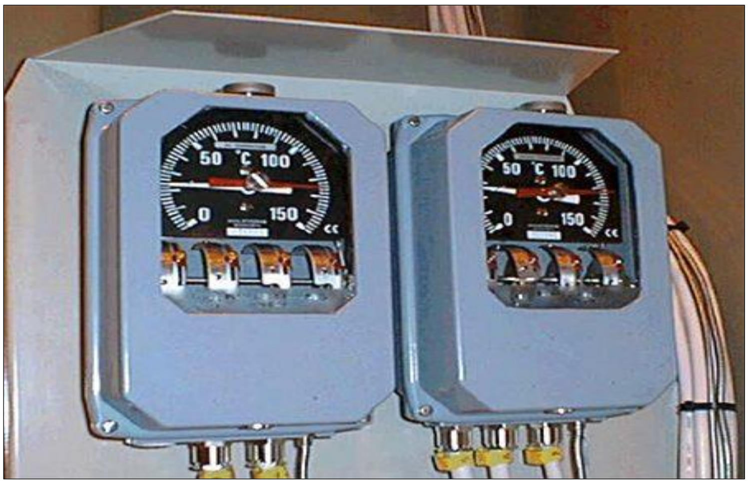


Figure 6-11. Top-oil thermometer and winding thermometer main units fitted on the side of a power transformer

The temperature bias is proportional to the resistance of the electric heating (resistor) element.

The result of the heat run provides data to adjust the resistance and thereby the temperature bias. The bias should correspond to the difference between the hot-spot temperature and the top-oil temperature. The time constant of the heating of the pocket should match the time constant of the heating of the winding.

The temperature sensor then measures a temperature that is equal to the winding temperature if the bias is equal to the temperature difference and the time constants are equal.

The winding thermometer can have one to four contacts, which sequentially close at successively higher temperature.

With four contacts fitted, the two lowest levels are commonly used to start fans or pumps for forced cooling, the third level to initiate an alarm and the fourth step to trip load breakers or de-energize the transformer or both.

In case a power transformer is fitted with top-oil thermometer (26Q) and winding thermometer (49W), the latter one normally takes care of the forced cooling control.

M07 – TRANSMISSION LINE PROTECTION

7.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of transmission line protection
- Explain types of transmission line fault
- Explain components of transmission line protection

7.2 Introduction

7.2.1 The Structure of the Power System

Power is generated by generating plants (Akosombo GS, Aboadze, and Bui) most of the time at places far from the load centers (Achimota, Tarkwa, Kumasi and Tamale BSPs) . The power is then transmitted by transmission lines (H3M, TT4T, and W2M) mostly overhead or underground to the load centers where the generated power is utilized by industrial (VALCo, Aluworks, Diamond Cement) or the residential consumers.

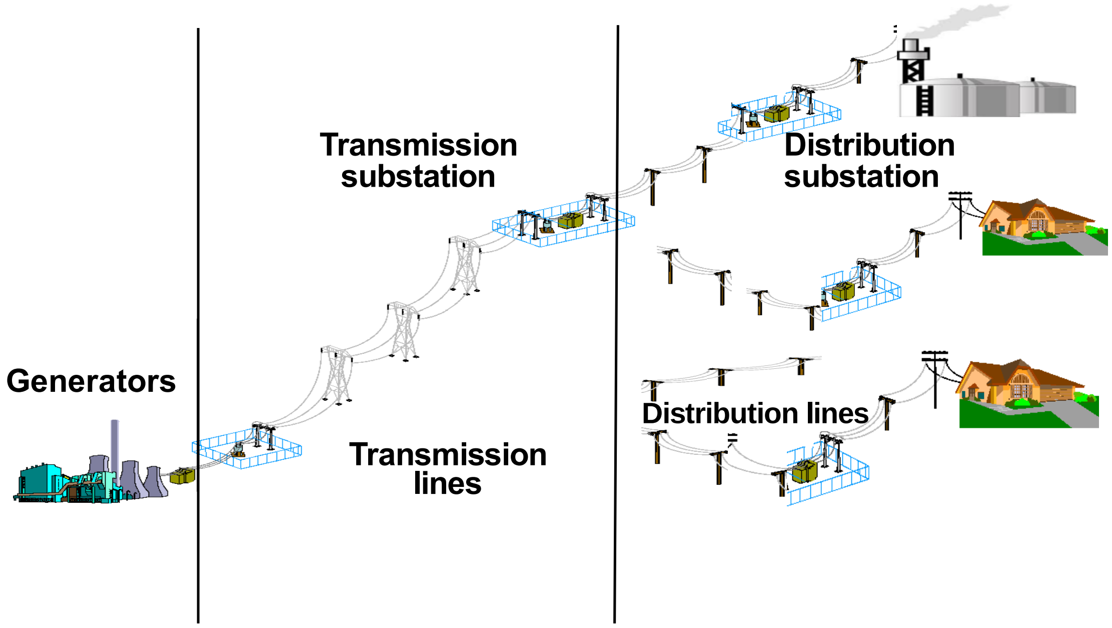


Figure 7-1. Power structure

7.2.2 Transmission Lines

Transmission lines constitute the major part of power system. Transmission lines are vital links between the generating stations and load centres to achieve the continuity of electric supply. To economically transfer large blocks of power between systems and from remote generating sites, High voltage (HV) and Extra high voltage (EHV) overhead transmission systems are being used. Transmission lines also form a link in interconnected system operation for bi-directional flow of power. Transmission lines run over hundreds of kilometres to supply electrical power to the consumers. They are exposed to atmosphere, hence chances of occurrence of fault in transmission line is very high which has to be immediately taken care of in order to minimize damage caused by it.

It will also facilitate quicker repair, improve system availability and performance, reduce operating cost and save time and effort of maintenance crew searching in, sometimes in harsh environmental conditions. It has always been an interest for engineers to detect and locate the faults in the power system as early as possible. Fast clearing and restoration is very essential as it not only provides reliability but sometimes also stops propagation of disturbances which may lead to blackouts

7.2.3 Transmission Line Faults

Under normal conditions, a power system operates under balanced conditions with all equipment carrying normal load currents and the bus voltages within the prescribed limits. This condition can be disrupted due to a fault in the system. A fault in a circuit is a failure that interferes with the normal flow of current. A short circuit fault occurs when the insulation of the system fails resulting in low impedance path either between phases or phase(s) to ground. This causes excessively high currents to flow in the circuit.

Transmission line faults can be phase to ground, phase to phase, phase to phase to ground, three phase or three phase to ground fault, as illustrated below Figure 7-2 below. Transmission line faults are mostly caused by falling conductors or other hardware, tree brushing, lighting strikes, flash over insulators and many more.

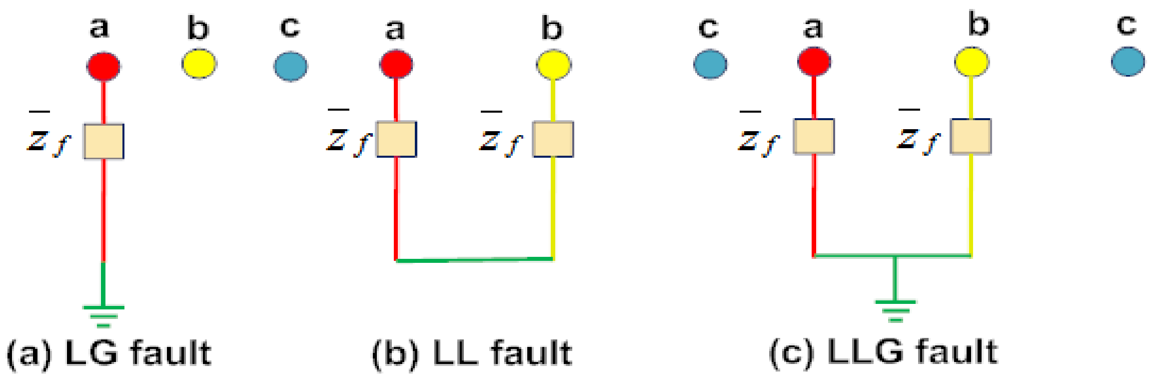


Figure 7-2. Transmission Line Faults

7.2.4 Types of Transmission Line Protection

Various types of protection used on transmission lines include;

i. Overcurrent Protection
ii. Impedance Protection
iii. Current differential Protection.

7.3 Overcurrent Protection

The overcurrent relay can be used to detect the increase in current due to fault on the transmission line. Overcurrent relaying is the cheapest for of protection for the transmission line, but the most difficult to apply, and the quickest to need re-adjustment or even replacement as a system changes.

It is generally used for phase- and ground-fault protection on some transmission lines where the cost of distance relaying cannot be justified.

7.3.1 Directional Overcurrent Protection

Because of the nature of the interconnected transmission network fault current can flow from both ends of the protected line, therefore the overcurrent relays mostly used on the transmission lines are directional overcurrent relays to allow for easier time co-ordination.

The details of the overcurrent and directional overcurrent protection is treated in another module The directional overcurrent relay 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.

7.3.2 Drawback of the Overcurrent Protection

The drawback of the use of overcurrent relay for transmission line protection is the fact that, the fault current based on which the relay is set, depends on the source impedance of the protected line. This is illustrated below.

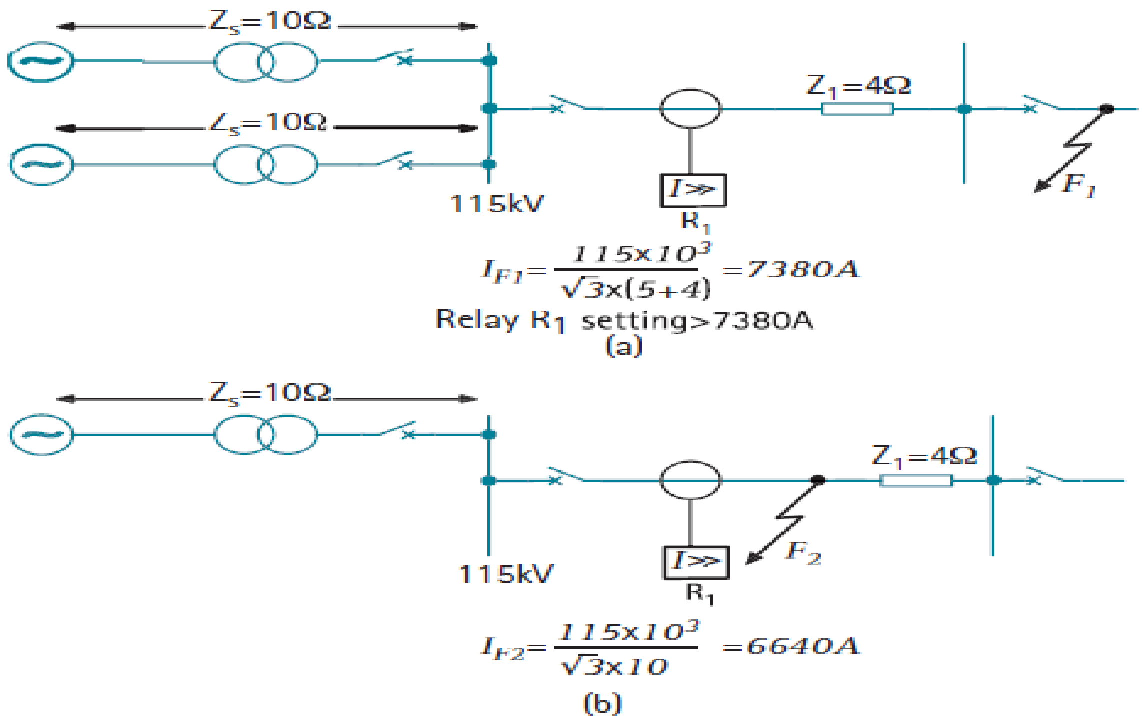


Figure 7-3. Overcurrent Relay Setting difficulties

From the above illustrations, for relay operation for line faults, relay current setting <6640A and >7380A. This is impractical; overcurrent relay not suitable must use Distance or Unit Protection.

7.4 Distance or Under Impedance Protection

Since the impedance of a transmission line is proportional to its length, for distance measurement it is appropriate to use a relay capable of measuring the impedance of a line up to a predetermined point (the reach point). Such a relay is described as a **Distance Relay** or **Impedance Relay** and is designed to operate only for faults occurring between the relay location and the selected reach point, thus giving discrimination for faults that may occur in different line sections. This protection is not affected by the source impedance of the protected line.

7.4.1 Principles of Distance Protection

The basic principle of distance protection involves the division of the voltage at the relaying point by the measured current. The apparent impedance so calculated is compared with the reach point impedance. If the measured impedance is less than the reach point impedance, it is assumed that a fault exists on the line between the relay and the reach point. The reach point of a relay is the point along the line impedance locus that is intersected by the boundary Characteristic of the relay. Since this is dependent on the ratio of voltage and current and the phase angle between them, it may be plotted on an R/X diagram. The loci of power system impedances as seen by the relay during faults, power swings and load variations may be plotted on the same diagram and in this manner the performance of the relay in the presence of system faults and disturbances may be studied.

7.4.2 Impedance Measurement

Distance relays use both power system voltage and current measurements derived from primary transducers (CT and PT) to decide whether or not the protected plant is faulted. The relaying point is defined by the position of the Voltage Transformer or PT. A simplified representation of a distance relay is shown in the figure below. The relay's inputs are the PT's secondary voltage measured at the relaying point and the line CT's secondary current. In this simplified case, the relay will trip when the ratio of the measured voltage and current is less than the known impedance of the protected transmission line. This decision-making process can be reduced to a comparison technique by comparing the amplitude of the measured voltage with that of the voltage generated by the *replica impedance* through which the measured current passes, rather than actually measuring the impedance of the circuit.

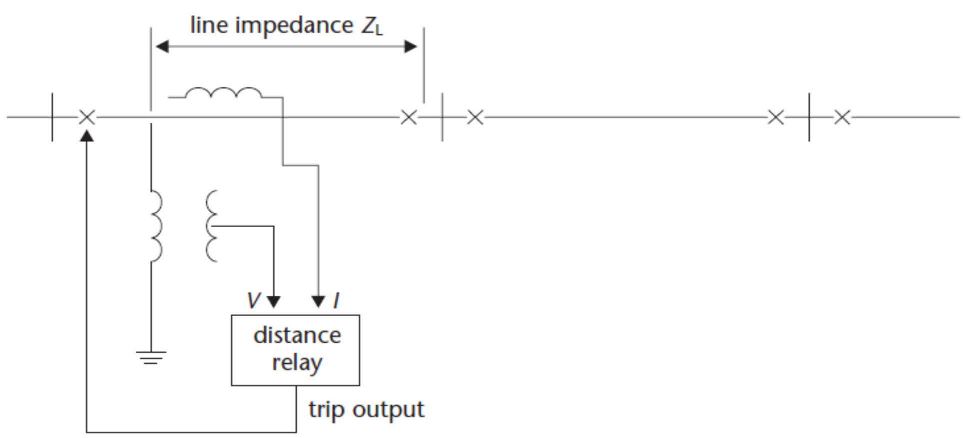


Figure 7-4. Simplified Distance Relay

From figure 4 above, the trip criterion is given by;

$$|V/ZL| \leq |ZL|$$

7.4.3 The Amplitude Comparator

The above technique formed the basis for the first time independent distance relays using the electromechanical balanced beam amplitude comparator, as illustrated in Figure 7-5 below, under normal (unfaulted) conditions, the voltage across the restraint coil exceeds that across the operate coil and the beam is attracted to the restraint arm holding the relay trip contact open. When however, the voltage across the operate coil exceeds that across the restraint coil, the beam is attracted to the operate arm and causes a trip when |SO|>|SR| as shown below.

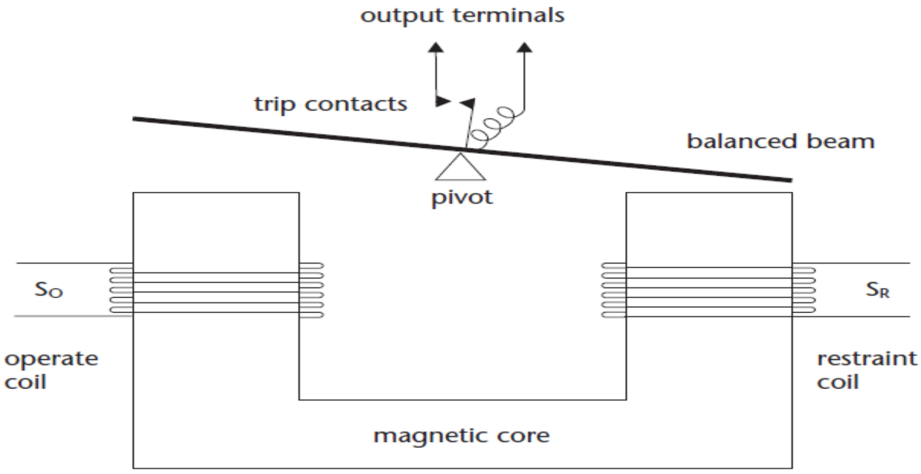


Figure 7-5. The Balance beam Amplitude Comparator

The measurement of impedance by the above method is called Amplitude Comparison. This is illustrated by the impedance circle below.

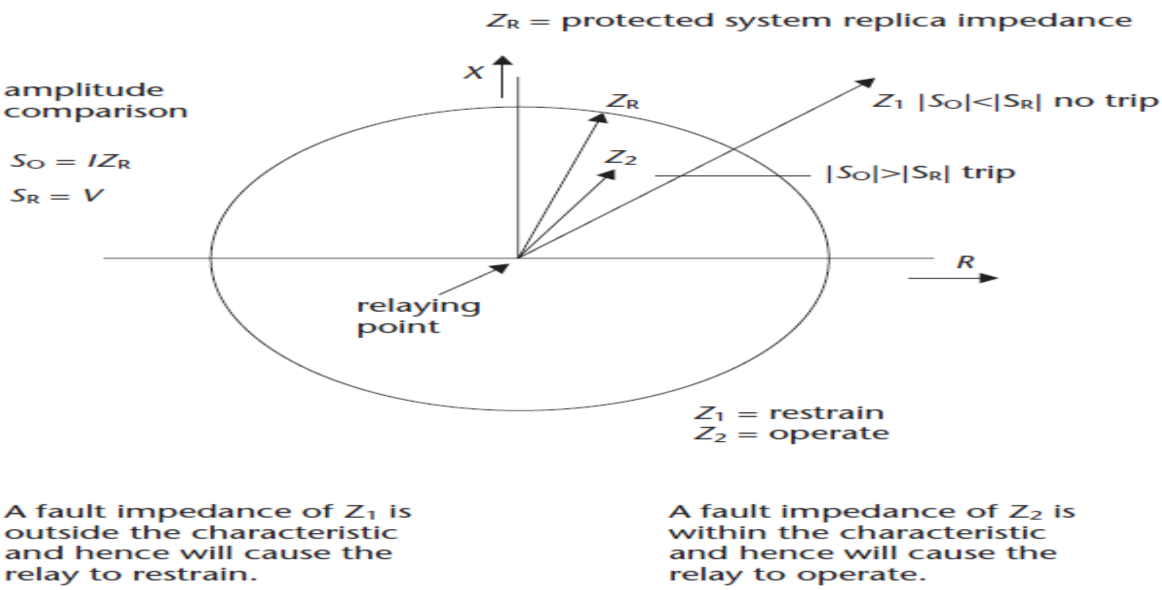


Figure 7-6. The Amplitude Comparator Impedance Characteristics

7.4.4 The Phase Comparator

Phase angle comparison techniques, where the operation of the relay depends upon the phase angle between the relaying measurands and not the comparison of the signal amplitudes, provides an improved sensitivity and hence were found to be easier to apply. The most successful electromechanical phase angle comparator was the induction-cup relay, illustrated in the Figure 7-7 below. This design provided a long-lasting principle for a generation of distance relays which was manufactured by most of the leading suppliers from the 1940s. For this type of relay, the decision to trip is performed by a light metal cup suspended in the field generated by the operate and restrain coils. When restrained, the cup is held against an end-stop. When the phase angle between the two input phasors is between the trip limits, the cup rotates away from the end-stop. Eventually, the cup rotates sufficiently for a contact attached to the cup to meet a fixed contact mounted on the relay assembly and complete the electrical trip circuit.

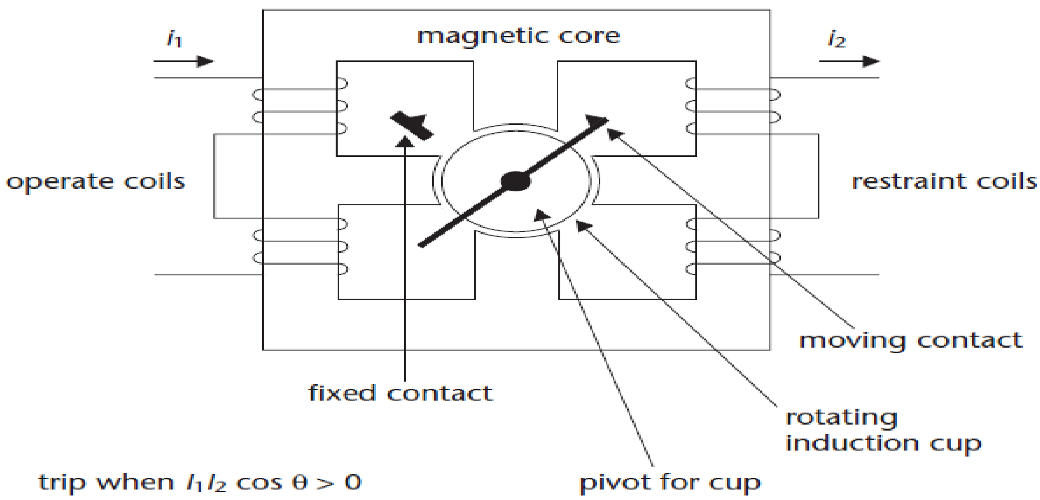


Figure 7-7. The Induction Disc Comparator

By convention, the induction disc’s rotation results in tripping when:

$$I_1 \, I_2 \cos\theta > 0$$

where I_1 and I_2 are the r.m.s. values of i_1 and i_2 respectively and θ is the phase angle between these inputs. The induction cup relay is commonly referred to as a *cosine comparator* because the tripping is controlled by the cosine of the angle between the two relay input signals, θ; the relay trips when cosine θ is positive i.e. when the angle between its inputs θ is between the values –90° and +90°.

Cosine comparator techniques have become the standard for most designs of phase angle comparators and are used in designs based on electromechanical, static and microcomputer technologies. The use of a phase angle comparator to generate an MHO circle is illustrated in the Figure below. The boundary restrain and operate conditions are shown. The relay measurands for the MHO circle are: $S_1 = IZ_R - V$ and $S_2 = V$

Where Z_R is the relay's setting impedance, often referred to as the *replica impedance* because it represents the impedance of the protected system.

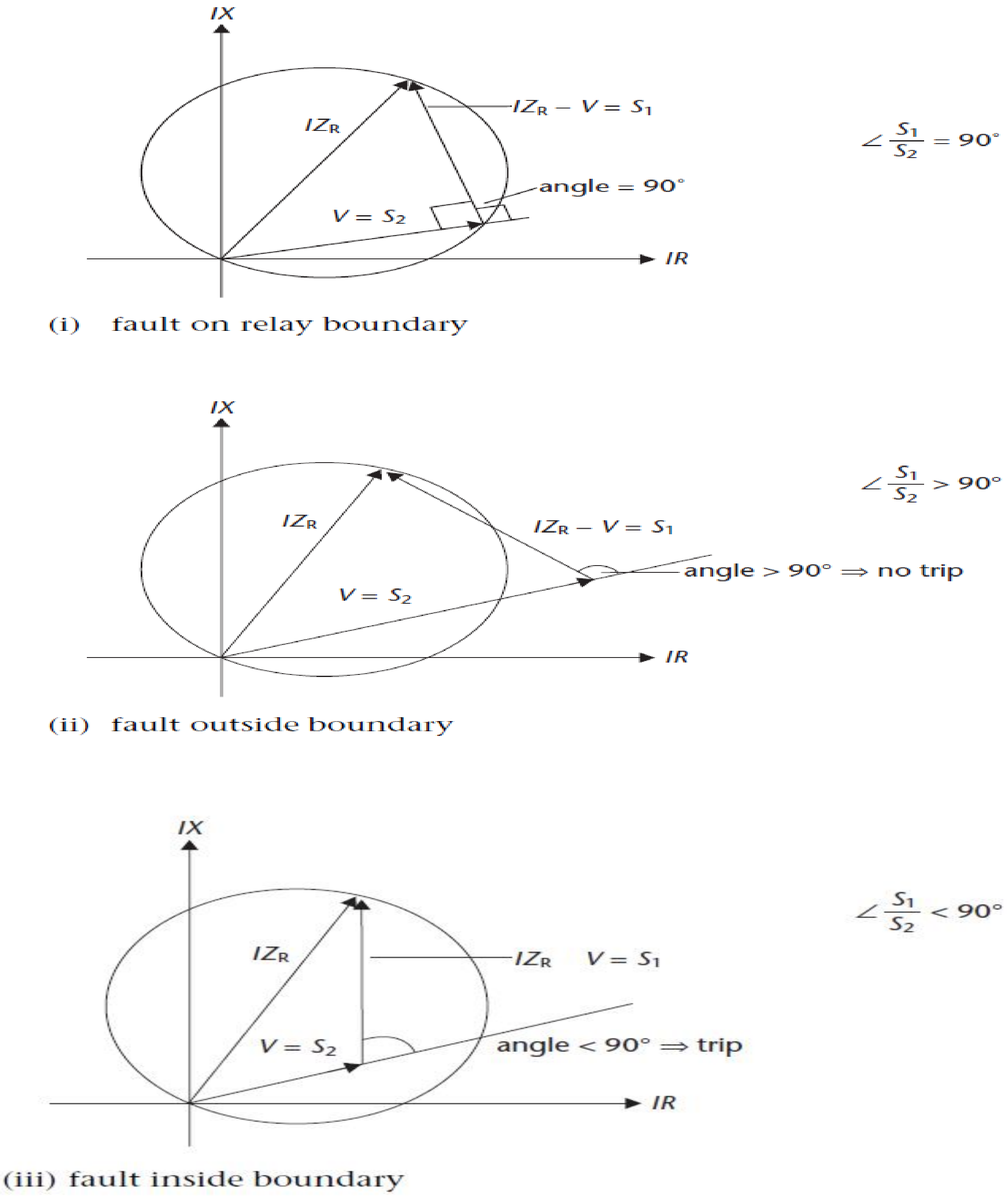


Figure 7-8. Phase Comparator for Mho Characteristics

7.4.5 Distance Relay Characteristics

The impedance seen by the relay when there is a fault on a transmission circuit consists of the impedance of the line and return path from the relaying point to the fault point plus the impedance of the fault arc. The combination for all likely values of fault impedance lies within the speckled area of Figure 7-9 below, which is the locus of probable fault impedance values.

In the figure below, the impedance of the protected line is shown as Z_L and hence, for a fault at x along that line, the fault impedance includes xZ_L. The fault impedance Z_f, comprises xZ_L and the fault's arc resistance Rf. The probable fault impedance area includes all possible values of Z_f and is a quadrilateral defined by all values along Z_L and all values of R_f from zero to R_f(max).

The distance relay's operating characteristic is required to cover protected line and must avoid the probable fault impedance areas for faults outside the protected zone.

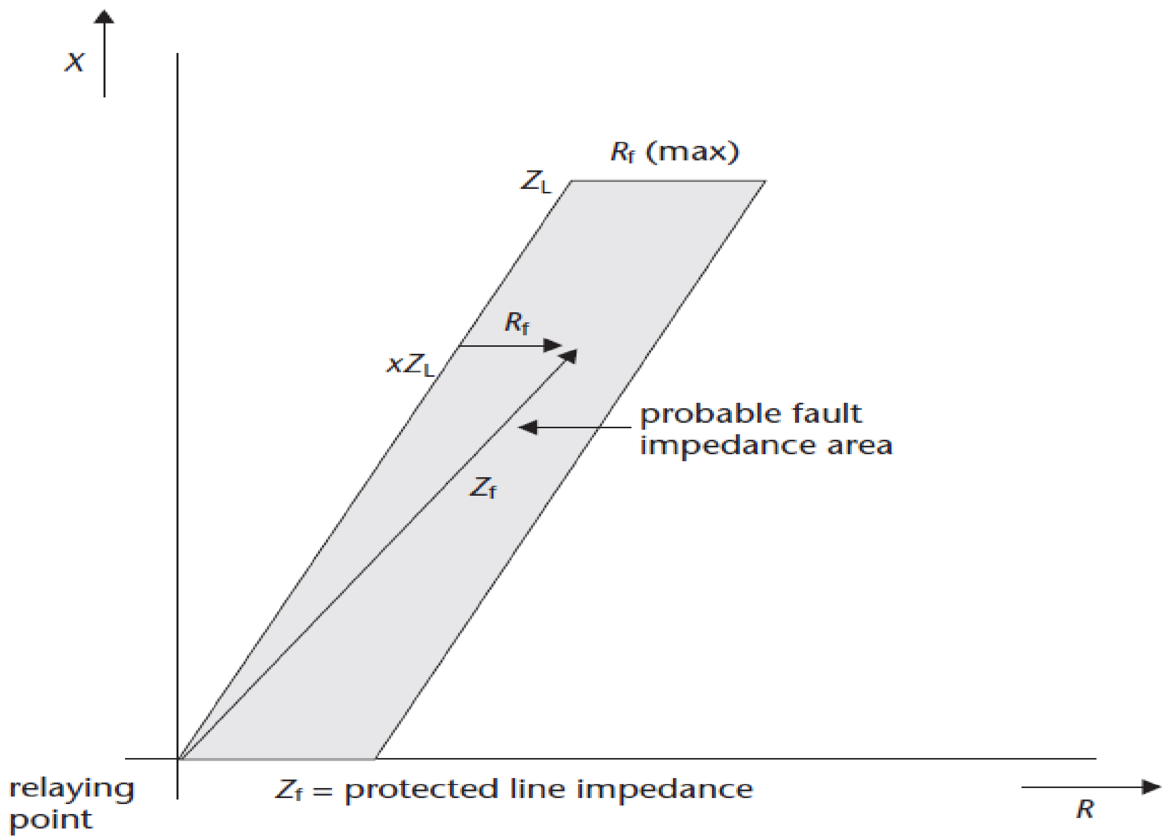


Figure 7-9. The Probable Fault Impedance Characteristics

However for an ordinary impedance relay, the characteristics is a circle with the centre at the origin as shown in Figure 7-10 below.

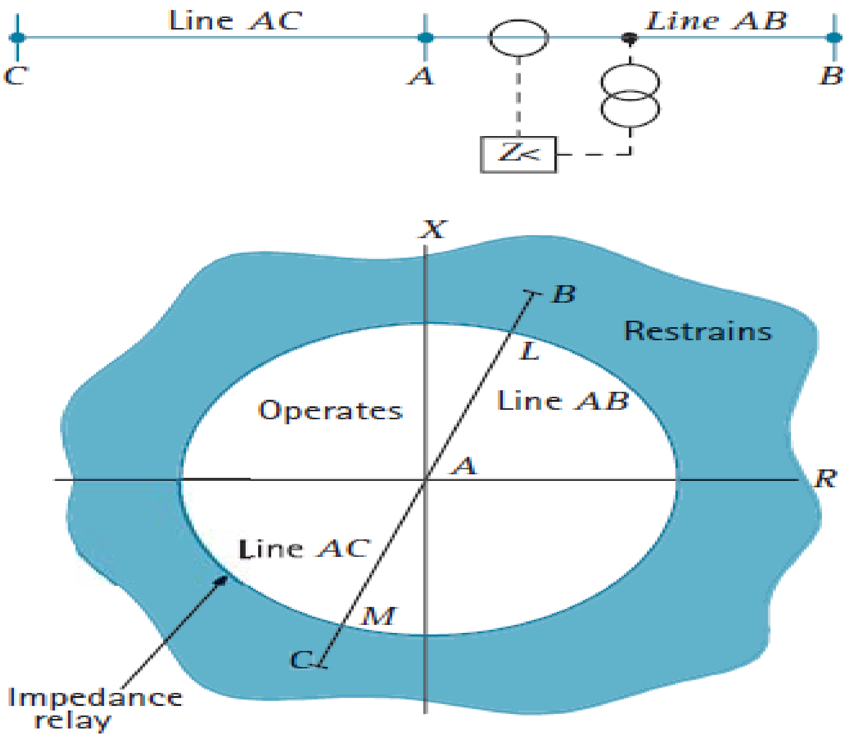


Figure 7-10. The Impedance Circle

For the impedance characteristic, its principal limitation is that it is a non-directional and will trip equally for faults in front of and behind the relaying point on a system fed from both ends which is the case in almost all transmission networks.

Offsetting the circle such that the relaying point is moved to the circumference of the circle produces the directional characteristic shown in the Figure below.

This offsetting of the circle is achieved by moving its centre away from the origin to the point corresponding to $\frac{1}{2}Z_R$ and reducing its diameter to Z_R. Both the operate and restrain phasors are modified by

subtracting $\frac{1}{2}IZ_R$, thus producing:

$$S_O = \tfrac{1}{2}IZ_R$$

$$S_R = V - \tfrac{1}{2}IZ_R$$

The characteristic produced is the MHO circle which has become the industry standard for distance protection. It provides both a well-defined and limited forward reach, together with an inherent directional capability.

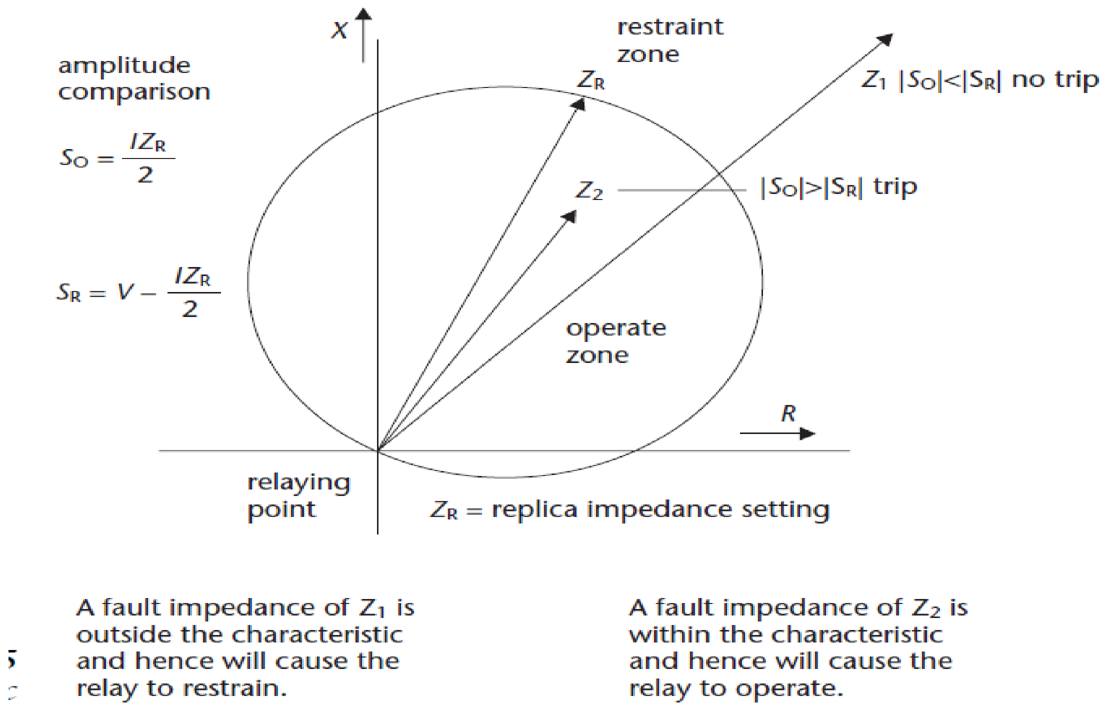


Figure 7-11. The Mho Circle

The mho characteristics above is based on the amplitude comparison, however any type of impedance characteristic obtainable with one comparator is also obtainable with the other.

The addition and subtraction of the signals for one type of comparator produces the required signals to obtain a similar characteristic using the other type. For example, comparing V and I in an amplitude comparator results in a circular impedance characteristic centred at the origin

of the R/X diagram. If the sum and difference of V and I are applied to the phase comparator the result is a similar characteristic.

7.4.6 The Offset Mho

The offset Mho characteristic includes a deliberate reverse reach with the result that the relay will trip if a fault occurs which the relay sees in that area.

This is attractive for several applications because the relay will trip for faults just behind the relaying point, i.e. in the feeder's substation. The reverse reach is defined by the reverse replica impedance Z_{R2} and faults further behind that will not result in tripping.

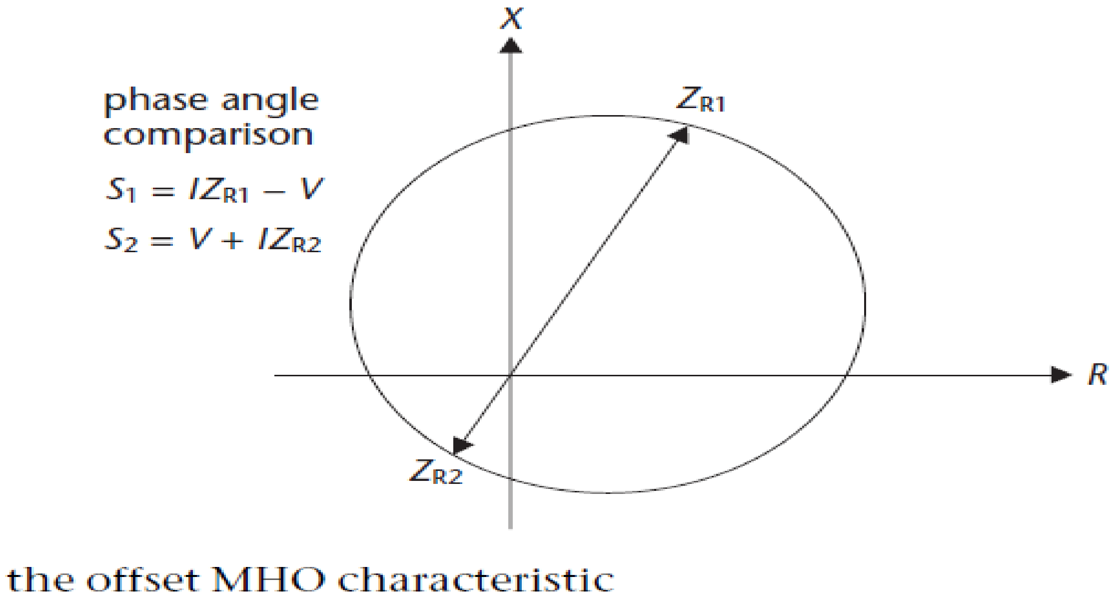


Figure 7-12. The Offset Mho Characteristic

7.4.7 The Quadrilateral Characteristics

The introduction of digital techniques and the desire for shorter trip times has led to the development of several other comparators. Also the desire to produce a closer match between the relay's trip characteristic and the probable fault impedance area has led to the introduction of quadrilateral characteristics.

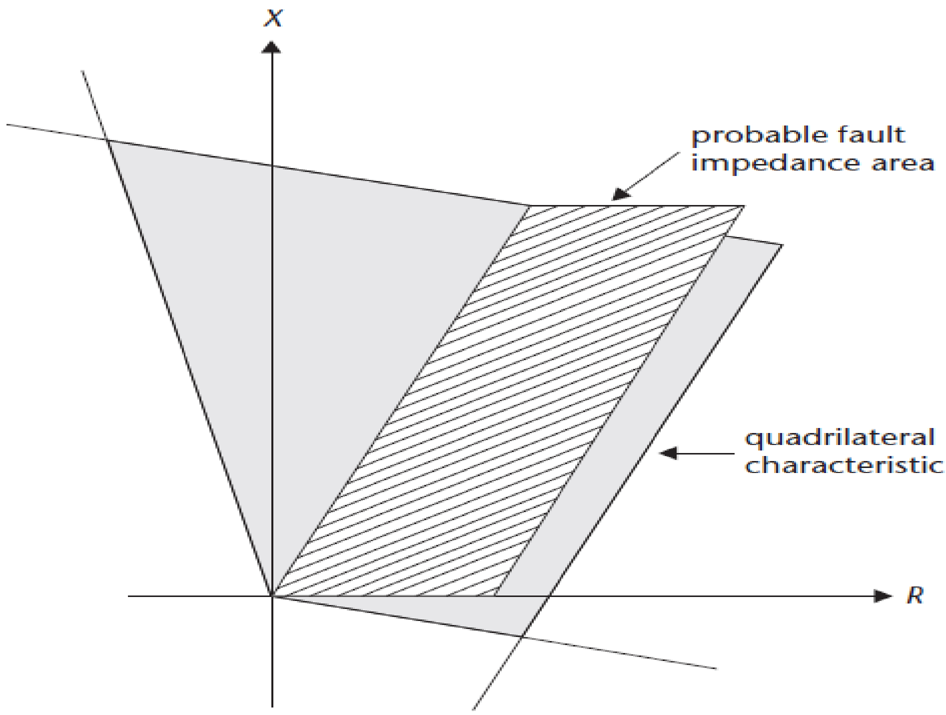


Figure 7-13. The Quadrilateral Characteristics with Probable Fault Impedance

7.4.8 The Lenticular Characteristics

There is a danger that the offset Mho characteristics relay may operate under maximum load transfer conditions if the Mho Circle of the relay has a large reach setting. A large reach setting may be required to provide remote back-up protection for faults on the adjacent feeder. This may trip during large system loadings. The lenticular characteristic was developed to carter for such situations.

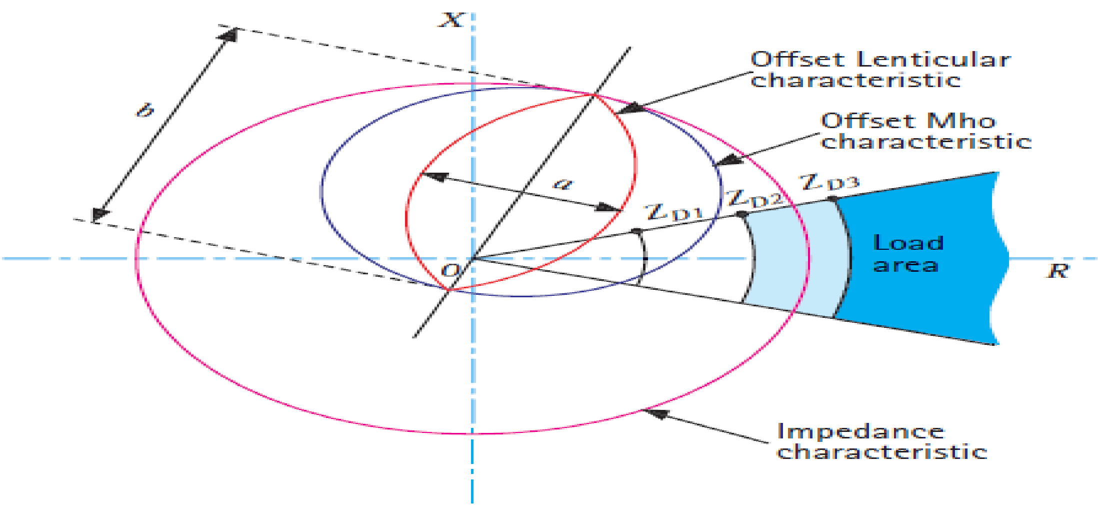


Figure 7-14. The Lenticular Characteristics

7.4.9 ZonesoOf Protection

Careful selection of the reach settings and tripping times for the various zones of measurement enables correct coordination between distance relays on a power system. Basic distance protection will comprise instantaneous directional Zone 1 protection and one or more time delayed zones. Typical reach settings for a 3- zone distance protection is shown in the Figure 7-15 below.

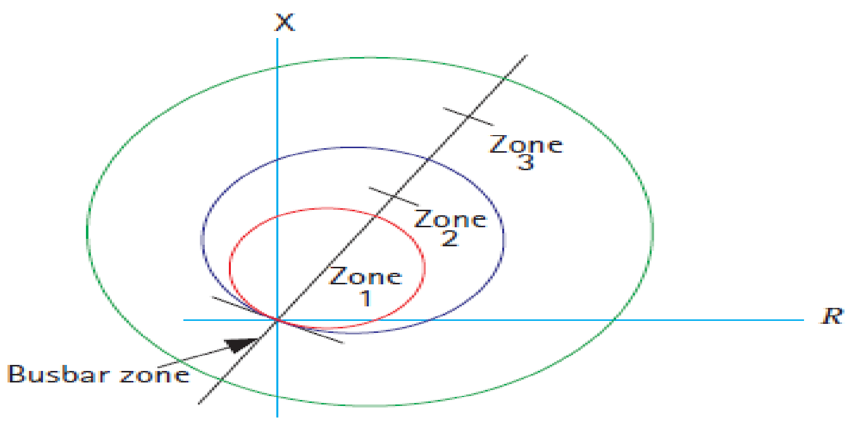


Figure 7-15. Three Zones Of Reaches

Digital and numerical distance relays may have up to five zones, some set to measure in the reverse direction. Typical settings for three forward-looking zones of basic distance protection are given in the following sub-sections.

7.4.10 Zone 1

Electromechanical/static relays usually have a reach setting of up to 80% of the protected line impedance for instantaneous Zone 1 protection. For digital/numerical distance relays, settings of up to 85% may be safe. The resulting 15-20% safety margin ensures that there is no risk of the Zone 1 protection over-reaching the protected line due to errors in the current and voltage transformers, inaccuracies in line impedance data provided for setting purposes and errors of relay setting and measurement. Otherwise, there would be a loss of discrimination with fast operating protection on the following line section.

7.4.11 Zone 2

To ensure full coverage of the line with allowance for the sources of error already listed in the previous section, the reach setting of the Zone 2 protection should be at least 120% of the protected line impedance thus covering the remaining 15-20% of the line left out by the zone1 reach. In many applications it is common practice to set the Zone 2 reach to be equal to the protected line section +50% of the shortest adjacent line. This ensures that the resulting maximum effective Zone 2 reach does not extend beyond the minimum effective Zone 1 reach of the adjacent line protection. This avoids the need to grade the Zone 2 time settings between upstream and downstream relays. Zone 2 tripping must be time-delayed to ensure grading with the primary relaying applied to adjacent circuits that fall within the Zone 2 reach. Thus complete coverage of a line section is obtained, with fast clearance of faults in the first 80-85% of the line and somewhat slower clearance of faults in the remaining section of the line.

7.4.12 Zone 3

Remote back-up protection for all faults on adjacent lines can be provided by a third zone of protection that is time delayed to discriminate with Zone 2 protection plus circuit breaker trip time for the adjacent line. Zone 3 reach should be set to at least 1.2 times the impedance presented to the relay for a fault on the remote end of the second line section.

7.4.13 Other Zones

Modern digital or numerical relays may have additional impedance zones that can be utilised to provide additional protection functions. For example, where the first three zones are set as above, Zone 4 might be used to provide back-up protection for the local Busbar, by applying a reverse reach setting of the order of 25% of the Zone 1 reach.

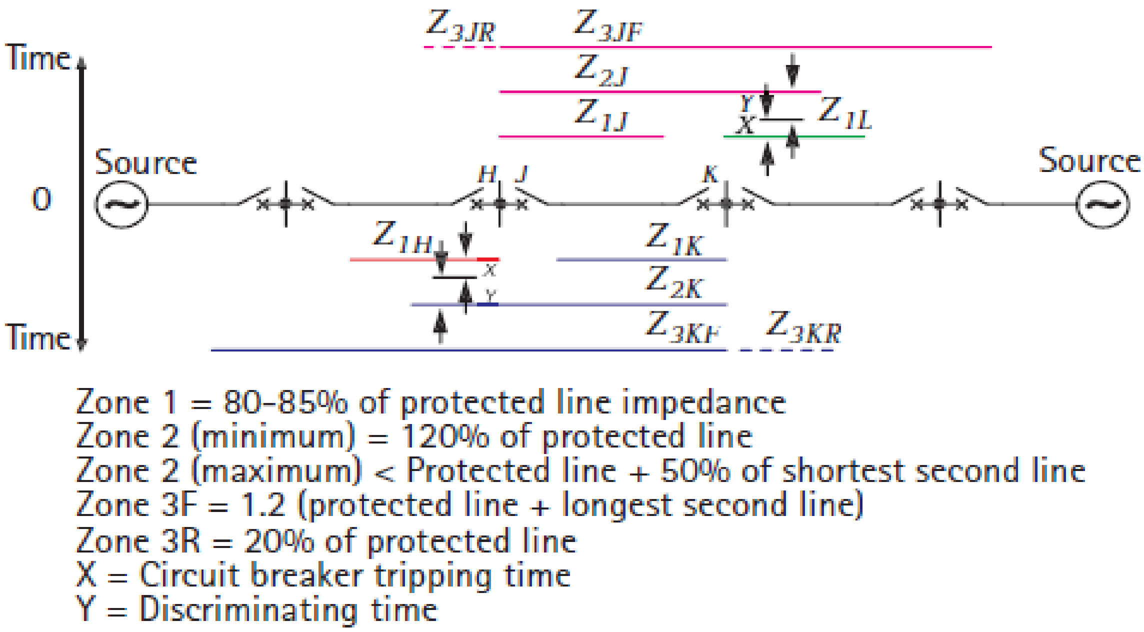


Figure 7-16. Zones of Protection

7.4.14 Polarisation

This refers to the use of a reference quantity, voltage or current to determine the position of fault (in front of or behind relay point). The MHO circle, correctly referred to as the *self-polarised MHO circle characteristic*, relies on the voltage signal to provide a reference to determine whether or not the fault is inside the trip characteristic.

For faults close to the relaying point, difficulties may arise with the MHO circle characteristic when the relay's input voltage falls to zero or nearly to zero. Similar difficulties also exist for the directional and idealised quadrilateral characteristics, where the characteristic passes through the origin of the impedance diagram.

For those characteristics which suffer from this problem, the difficulties can be overcome using several methods, either alone or in combination. These techniques include:

- The stability notch
- Healthy phase cross-polarisation
- Memory polarisation.

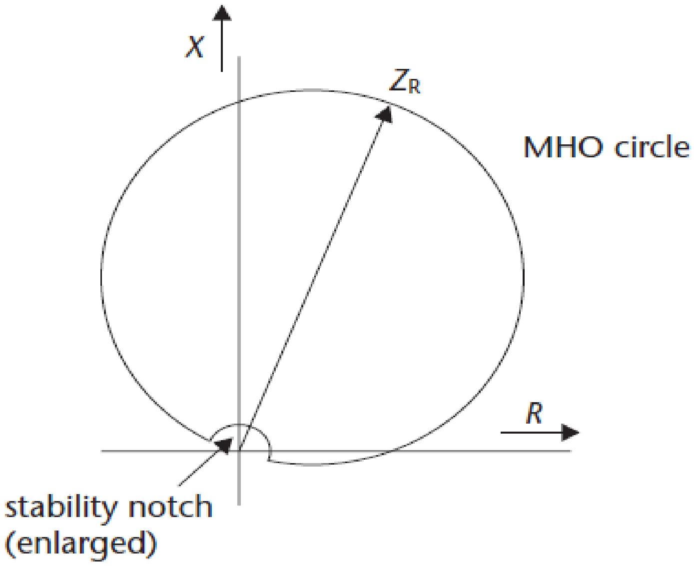


Figure 7-17. Stability Notch

7.5 Residual Compensation Factor

For fault involving phase to phase the impedance measured by the comparator is the Positive impedance up to the point of fault, however with ground fault, the story is different because of the return path for the fault current.

The three combinations of input measurands used to monitor for phase to earth faults are:

phase a to earth faults	$V_{aN} = V_a$	$I_{aN} = I_N + K_N I_N$
phase b to earth faults	$V_{bN} = V_b$	$I_{bN} = I_N + K_N I_N$
phase c to earth faults	$V_{cN} = V_c$	$I_{cN} = I_N + K_N I_N$

The current I_N (the residual current), is the effective earth current derived from the summation of the three phase currents:

$$I_N = I_a + I_b + I_c$$

The value of K_N (the residual compensation factor), is chosen so that the impedance derived from the phase-to-earth measurands is also the positive phase sequence impedance of the system between the relaying point and the fault derived from the summation of the three phase currents:

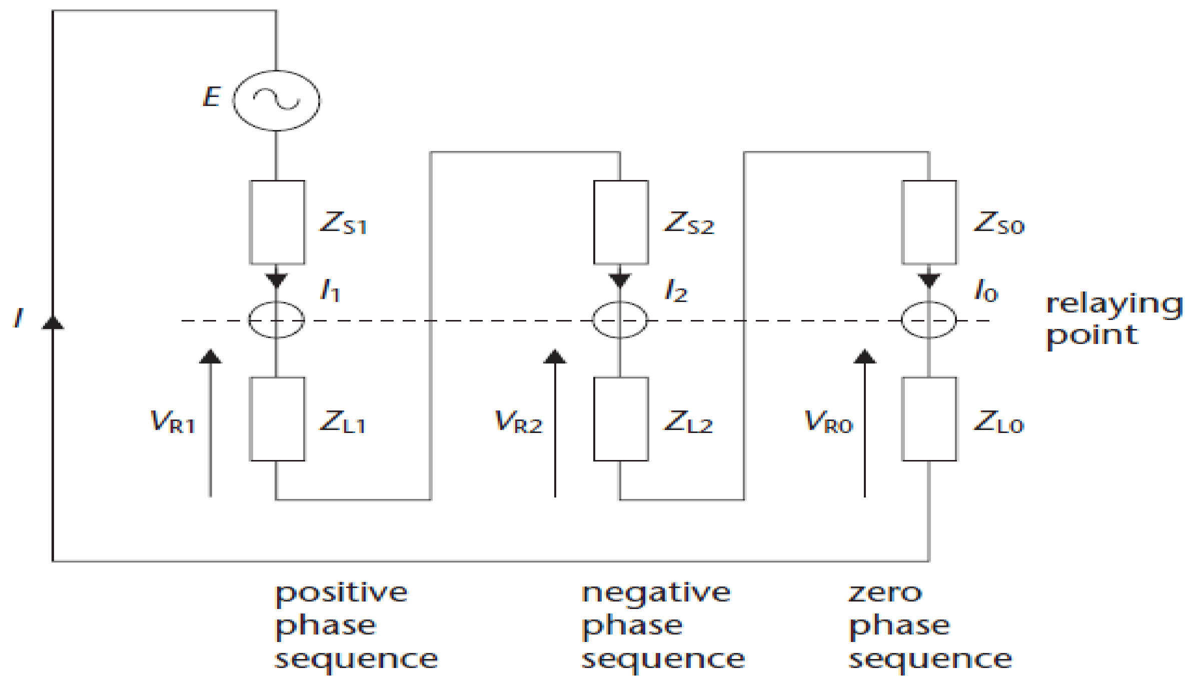


Figure 7-18. Symmetrical components for Single Phase to Ground Fault

The current at the relay will be:

$$I_r = I_{r1} + I_{r2} + I_{r0}$$

We are looking at a phase to ground fault, therefore:

$$I_{r1} = I_{r2} = I_{r0}$$

$$\text{i.e. } I_r = 3I_{r1}$$

The voltage at the relay will be:

$$V_r = V_{r1} + V_{r2} + + V_{r0}$$

$$= I_{r1}(Z_{r1} + Z_{r2} + Z_{r0})$$

$$= I_{r1}(2Z_{r1} + Z_{r0}) \text{ (because } Z_{r1} = Z_{r2})$$

To obtain the correct voltage using the relay setting of Z_{r1} and the modified value of relay current, the following equation must hold:

$$(V_r =)\ I_{r1}(2Z_{r1} + Z_{r0}) = I_r\ (1 + K)\ (Z_{r1})$$

$$\therefore \frac{2Z_{r1} + Z_{r0}}{3Z_{r1}} = 1 + K$$

$$\therefore \frac{Z_{r0} - Z_{r1}}{3Z_{r1}} = K$$

The residual compensation Factor (K) setting is derived from the positive sequence impedance Z_1 and the zero sequence impedance Z_0 using the equation:

$$K = \frac{(Z_0 - Z_1)}{3Z_1}$$

7.6 Distance Protection Schemes

There are two main schemes used in the implementation of distance protection for protection transmission lines. They are

- Non Carrier Assisted Schemes
- Carrier Assisted Schemes

7.6.1 Non Carrier Assisted Schemes

These are the Basic schemes employing the three stepped distance protection with the Z_1, Z_2 and the Z_3 elements.

It is a kind of non-unit protection with the Z_2 and Z_3 providing back up for the adjacent lines.

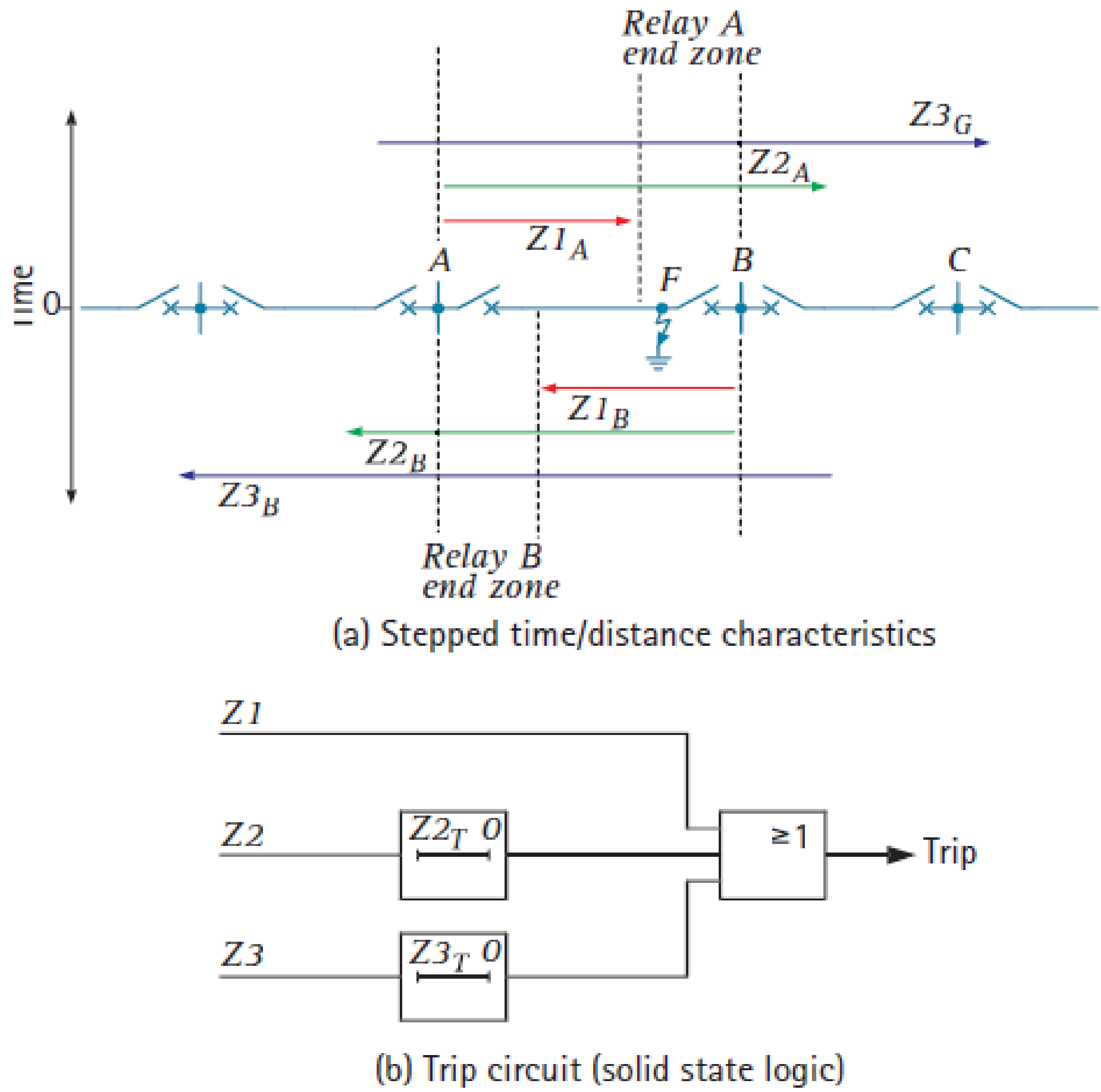
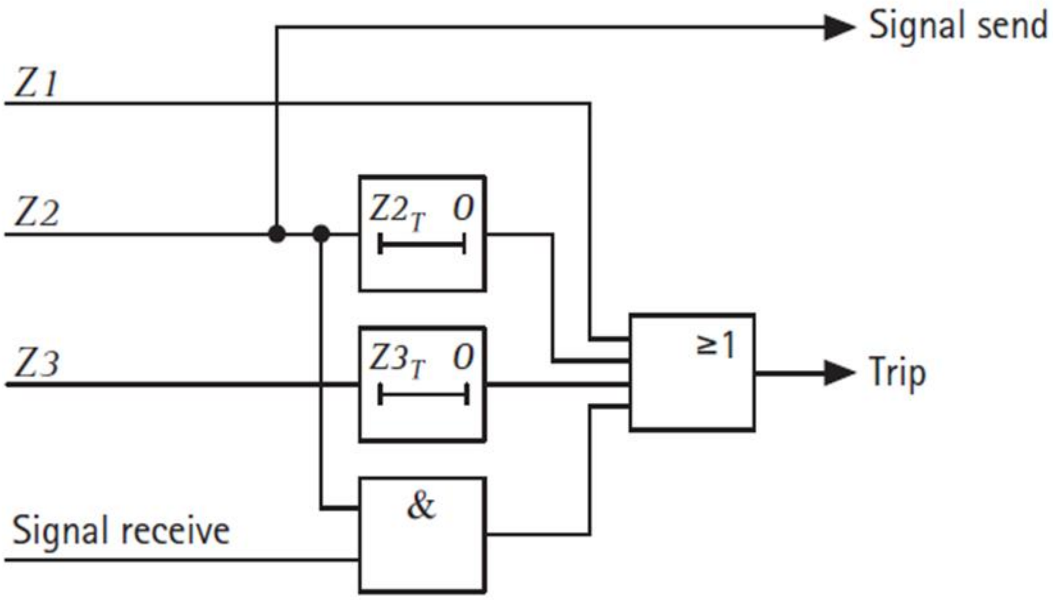


Figure 7-19. Three Stepped Distance Protection Scheme

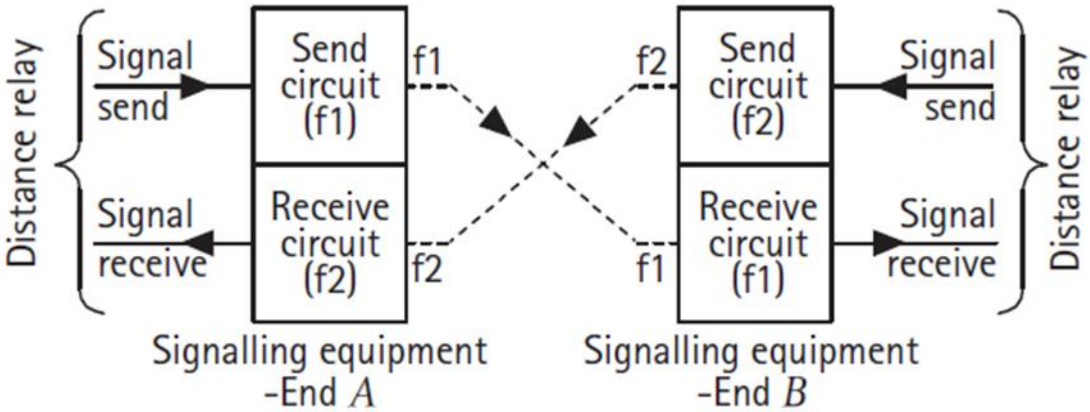
7.6.2 Carrier Assisted Schemes

One of the main disadvantages of basic scheme or the stepped distance scheme is that the instantaneous Zone 1 protection at each end of the protected line cannot be set to cover the whole of the feeder length and is usually set to about 80%.

This leaves two 'end zones', each being about 20% of the protected feeder length. Faults in these zones are cleared in Zone 1 time (instantaneously) by the protection at one end of the feeder and in Zone 2 time (typically between 0.25 to 0.4 seconds, In GRIDCo it is 0.3sec) by the protection at the other end of the feeder. This is shown below:



(a) Signal logic



This situation cannot be tolerated in some applications, for two main reasons:

- Faults remaining on the feeder for Zone 2 time may cause the system to become unstable
- Where high-speed auto-reclosing is used, the non-simultaneous opening of the circuit breakers at both ends of the faulted section results in no 'dead time' during the auto-reclose cycle for the fault to be extinguished and for ionised gases to clear. This results in the possibility that a transient fault will cause permanent lockout of the circuit breakers at each end of the line section

Even where instability does not occur, the increased duration of the disturbance may give rise to power quality problems, and may result in increased plant damage.

The response of the remote relays together with the response of the local relays at both ends of the line provides the basis for the unit protection scheme. A communications system is required to transfer the status of selected relaying elements between the relays at each end of the line.

Carrier Assisted schemes includes;

- Direct Transfer Trip (DTT)
- Permissive Under-Reach Transfer Trip (PUTT)
- Permissive Over-Rich Transfer Trip (POTT)
- Blocking Scheme

7.6.3 Direct Transfer Trip (DTT)

The simplest type of carrier-assisted scheme uses a direct transfer tripping scheme in which whenever a relay trips in zone one, the trip signal is also used to trip the breaker at the opposite end of the feeder.

This ensures that faults in the end zone are tripped in no more than the zone tripping time plus the time delays incurred in the communications channel.

The disadvantage of this system is that, the interference on the communications channel could cause malfunctioning of the scheme and incorrect tripping of the circuit breakers. The diagram below explains this scheme.

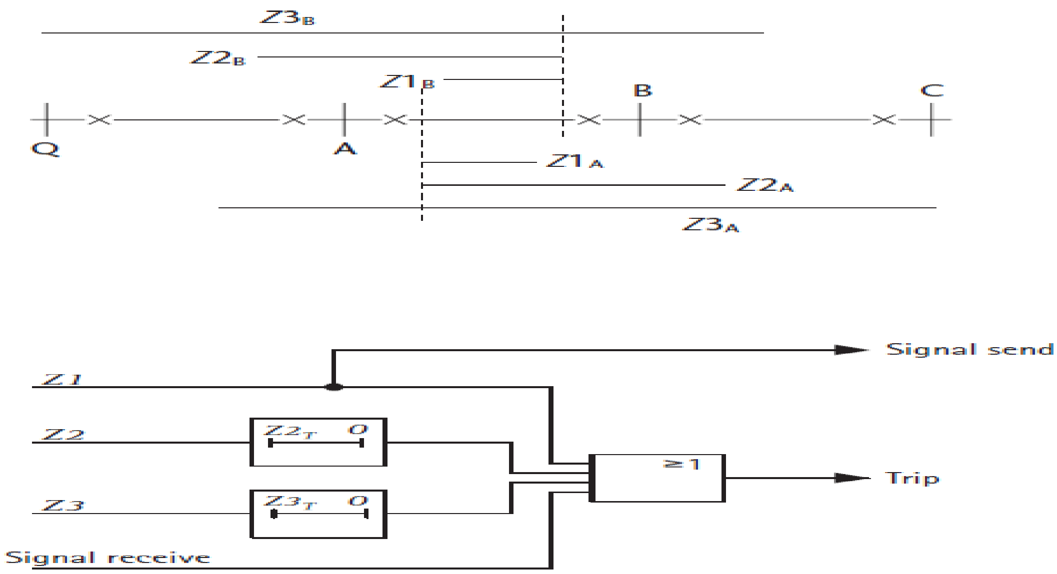


Figure 7-20. The Logic For DTT

7.6.4 Permissive Under-Reaching Transfer Trip (PUTT)

The possibility of malfunctioning of the scheme can be dramatically reduced by checking the validity of the inter-tripping signal with the operation of comparators in the receiving scheme's relays. This produces the *permissive under-reaching transfer trip scheme* by which the transfer trip is permitted only when the fault is also seen by the receiving relay's zone two or zone three comparators. The operation Permissive Under-Reaching Transfer Tripping scheme is shown in the figure below.

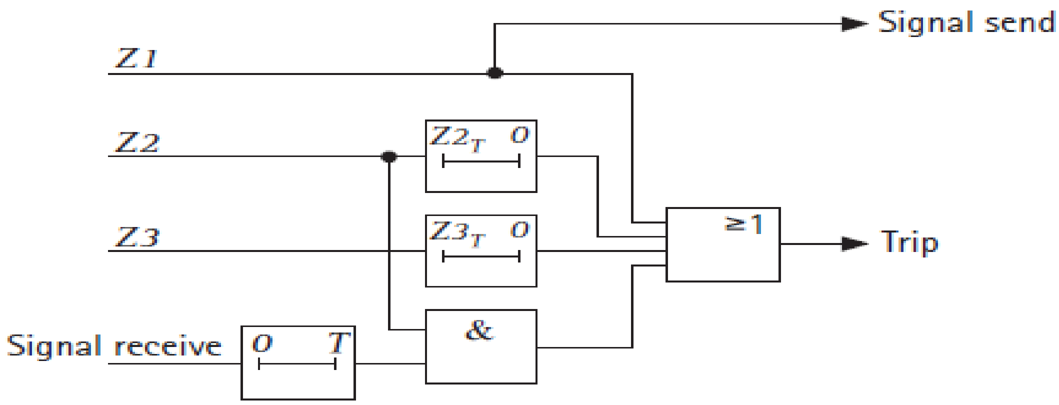


Figure 7-21. Permissive Under Reaching Transfer Tripping Logic

7.6.5 Permissive Over-Reaching Transfer Tripping (POTT)

An alternative to the use of the zone one comparator to send the permissive signal to the remote zone two relay in the case of the PUTT is to use the zone two comparators to send the permissive signal to the remote zone two relay.

This result in the Permissive Over-Reaching Transfer Tripping Scheme (POTT). The Logic for the Tripping is as shown below.

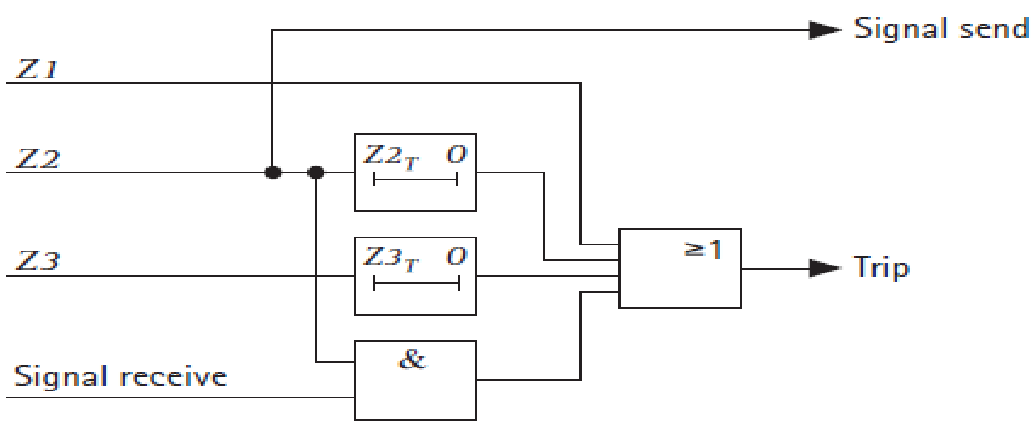


Figure 7-22. Permissive Over-reaching Transfer Trip

7.6.6 Blocking Scheme

The arrangements described so far have used the signalling channel(s) to transmit a tripping instruction. If the signalling channel fails or there is no Weak Infeed feature provided, end-zone faults may take longer to be cleared.

Blocking over-reaching schemes use an over-reaching distance scheme and inverse logic. Signalling is initiated only for external faults and signalling transmission takes place over healthy line sections.

Fast fault clearance occurs when no signal is received and the over-reaching one zone 2 distance measuring elements looking into the line operate. The signalling channel is keyed by reverse looking distance elements Z4 or Z3 (*Z3* in the diagram)

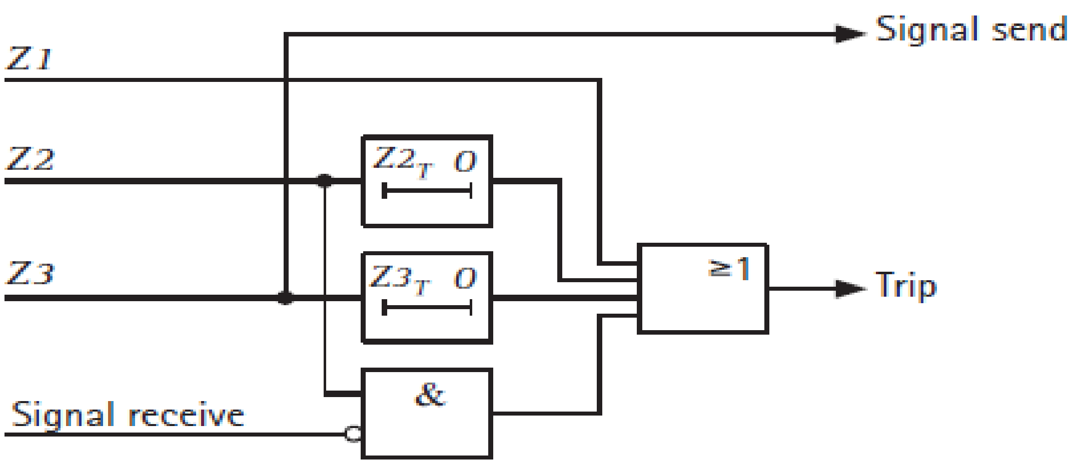


Figure 7-23. The Blocking scheme Logic

7.6.7 Power Swing Detection and Blocking

Power swings are caused by system disturbances where the generators swing with respect to each other to achieve a new equilibrium point. They produce abnormal phase shifts between the voltages connected to the transmission system and impedance trajectories seen by the distance relays which can cut across the trip characteristics. Power swing detection and blocking is frequently an optional feature of a distance protection scheme. The key difference between a fault condition and a power swing is that, whereas during a fault the post-disturbance impedance is relatively fixed, during a power swing the impedance seen by the relay follows that swing, which is a relatively slow phenomenon. The impedance trajectory of the impedance seen by a distance relay is shown in the figure below.

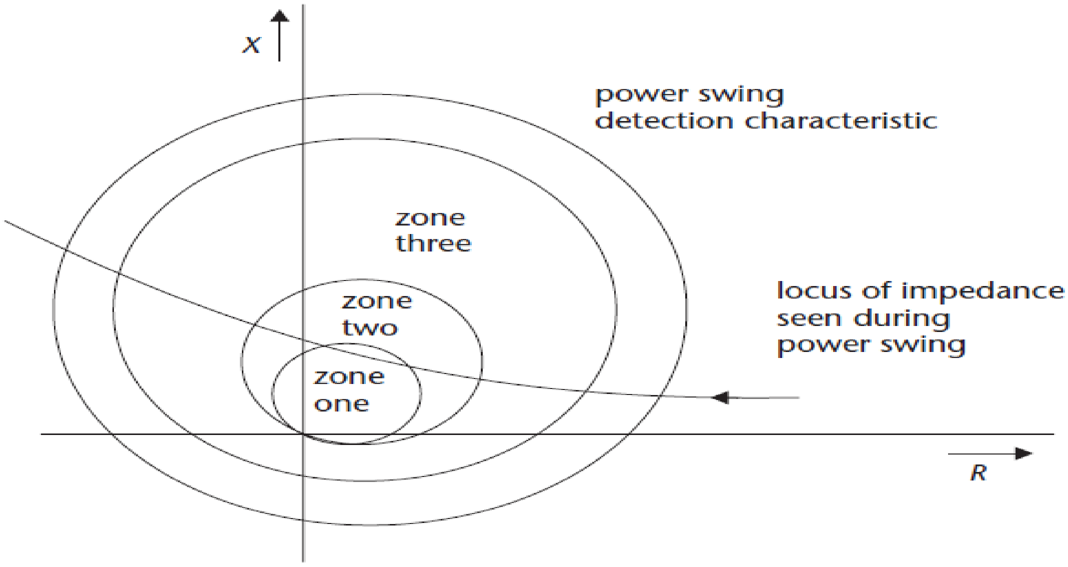


Figure 7-24. Power Swing Blocking

The method used to differentiate a power swing from a fault condition is to use two similar characteristics, where one is larger than and includes the other, and measure the difference between the times when they trip. This time is then compared with a pre-set timer. For a fault condition they should trip almost together, however for a power swing there will be a time delay between the tripping of the outer and inner characteristic. Apart from this Optional Features of Distance Protection, there are others depending on the Relay manufacturer. Examples include switch on to fault, CT supervision, synchronizing check, Auto Reclosing, Broken Conductor Detection, Open PT fuse or Lost of PT voltage Detection.

7.7 Line Differential Protection

7.7.1 Introduction

As a unit protection having its zone delimited by location of current transformers (CTs), the differential protection principle is considered superior with respect to selectivity, sensitivity, and speed of operation as compared with directional comparison, phase comparison, or stepped distance schemes.

7.7.2 The Basic Principles of Differential Protection

Current differential relaying is applied to protect many elements of a power system. The simplest example of a current differential relaying scheme is shown in Figure 7-25. The protected element might be a length of circuit conductor, a generator winding, a bus section, etc. From Figure 25 it can be seen that current differential relaying is a basic application of Kirchhoff's Current Law. The relay operates on the sum of the currents flowing in the CT secondaries, I1 + I2.

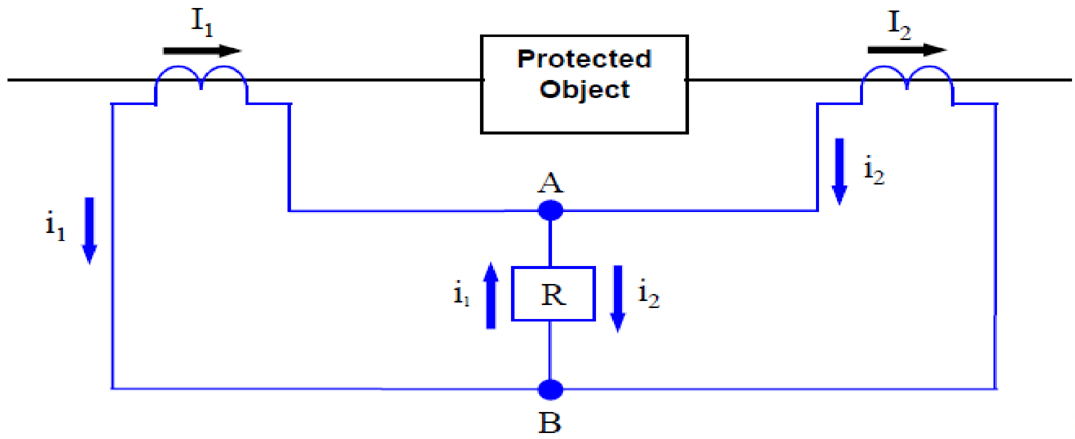


Figure 7-25. Basics of differential protection

For through current conditions, such as load or an external fault, the currents in the two CT's will be equal in magnitude and opposite in phase (assuming the CT's have the same ratio and are properly connected), and there will be no current flow in the relay operate coil However for an internal fault the fault currents will add up in the operating coil thereby obtaining sufficient operating torque to operate the contact to isolate the protected equipment.

Line current differential (87L) protection is applied on long and short lines and on various voltage levels. Because the relays are located independently at each terminal of a line, 87L schemes depend on reliable communications to exchange and align the currents. This is shown in Figure 7-26 below.

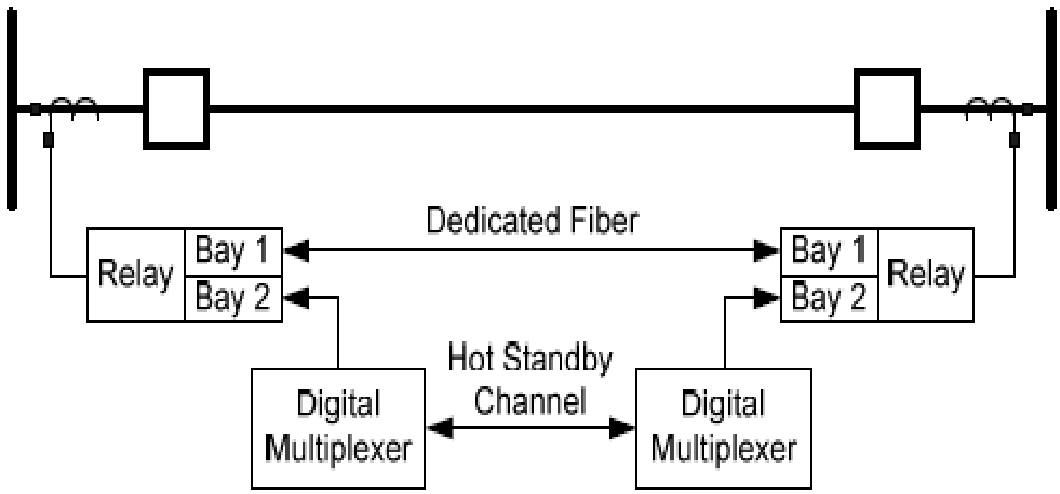


Figure 7-26. Line differential Relaying

To improve the selectivity and security of the current differential scheme, it is often designed as a percentage restraint differential relay. In a percentage restraint current differential relay, the operating current is the vector sum of the CT currents.

$$I_{operate} = | I_1 + I_2 |$$

This operating current must be greater than some percentage (K1) of the restraint quantity which is derived from the sum of the magnitude of the individual CT currents. A typical restraint current could be:

$$I_{restraint} = k*[| I_1 | + | I_2 |]$$

The operating characteristic of the percentage restraint current differential relay with a slope of K1 is shown in Figure 7-27.

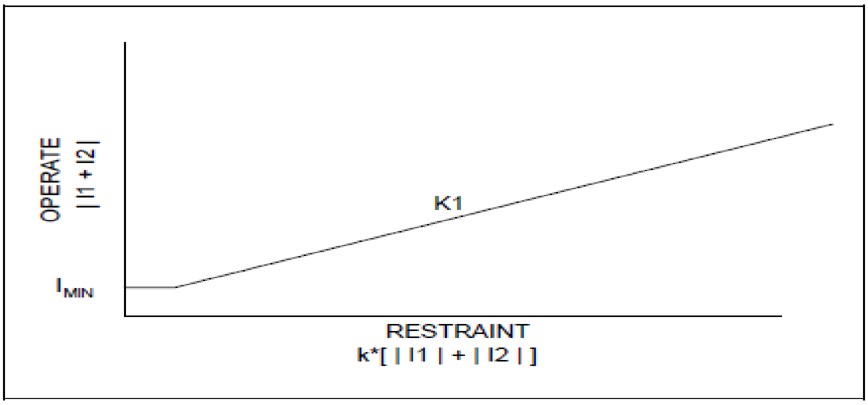


Figure 7-27. Differential Relay Characteristic

Modern line differential relays have other back up schemes like the impedance protection that are used in case of the communication channel failure. They also have optional features like Auto Reclose Event recorder, Fault Locater etc.

7.8 GRIDCo Line Protection Schemes

GRIDCo's transmission network is made up mostly of 161kV and a few 330kV transmission lines. However, GRIDCo is interconnected to the CIE network with a single 225kV transmission line. The 225kV as well as 161kV lines use primary and back-up protection philosophy whilst the 330kV uses the Main one and Main two protection philosophy.

On the 161 and the 225kV lines the primary protection are mostly distance with relays ranging from digital to numerical from a number of manufacturers including ABB, Alstom, Schneider and others.

Figure 7-28. Numerical Line Relay

The distance protection uses three forward zones; Z1, Z2 and Z3 and one reverse zone Z4, which is set to provide back-up for the busbar. The Z1 is often set with no time delay and the Z2 Z3 and the Z4 with time delays of 300mS, 600mS and 800mS respectively. The distance protection uses carrier assisted schemes; the most widely used is the Permissive Over-Reach Transfer Tripping (POTT). Some of the 161kV lines especially the shorter lines and some average length lines uses Line differential relays with dark or multiplexed fibre communication. These differential relays are configured such that in the event of a communication failure the protection will switch to stepped distance scheme. The Back-up protection on the 225kV and the 161kV are implemented with directional ground overcurrent relays having time delays of about 600mS. A typical tree line diagram of distance protection in GRIDCo is shown in Figure 29 below.

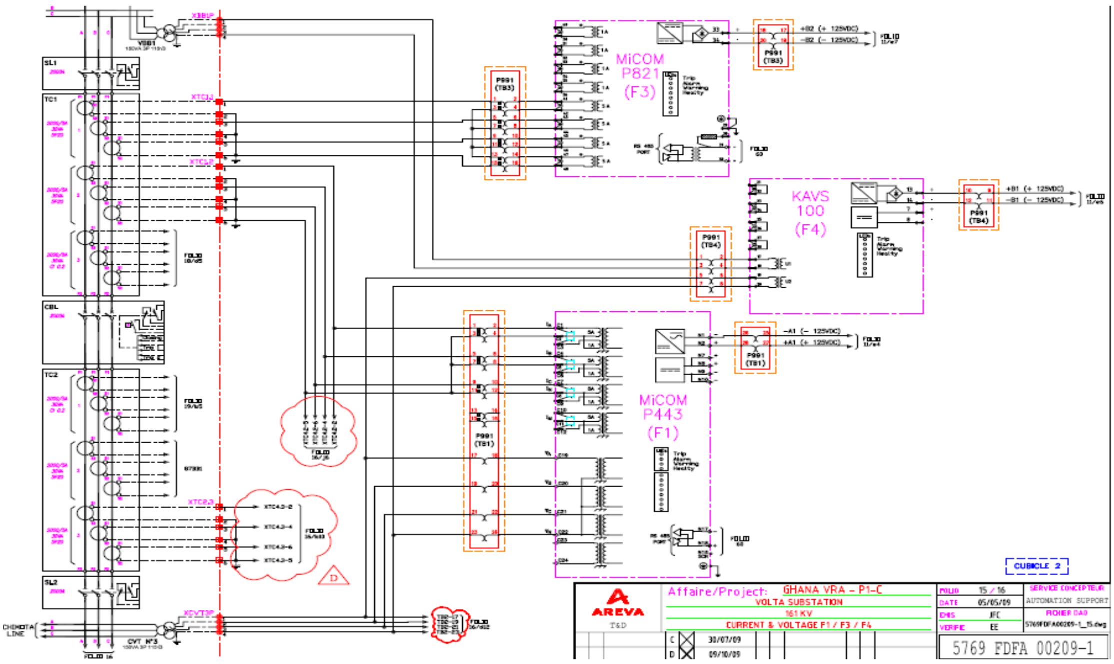


Figure 7-29. Typical 3 line diagram of distance protection in GRIDCo

On the 330kV network, the main one has distance as the as the primary and directional ground overcurrent. The main two is also distance protection but the only difference is that it is from a different manufacturer. For instance if the main one is from Siemens, the main two is from ABB. They both implement carrier assisted and the same scheme as the 161kV network. The main one and the main two uses different communication channels.

M08 – RETRIEVAL AND ANALYSIS OF FAULT AND EVENT RECORDS

8.1 Objectives

Upon completion of this module the participant will be able to:

- Understand the basic concepts of fault analysis and event records
- Explain principles of fault recording and system monitoring

8.2 Introduction

Proper interpretation of fault and disturbance data is critical for the reliability and continuous operation of the power system. A correct interpretation gives you valuable insight into the conditions and performance of various power system protective equipment.

Analyzing records is not an intuitive process and requires system protection knowledge and experience. Having an understanding of the fundamental guidelines for the event analysis process is imperative for new power engineers to properly evaluate faults.

The power system, a matrix composed of hundreds and thousands of electrical elements, is so massive that it can cover inter-continental territories and sometimes different countries. This colossal living matrix has to be properly synchronized, operated, and coordinated where power generation must equal power consumption. If sporadic interruptions are experienced inside of it, they must be isolated, investigated, and repaired until the cause of interruption has been resolved. Its advantage in size has it downsides since a failure in a small part of its structure can crumple the whole system.

It is important to understand the meaning of fault analysis and recording, and this notes offers the new engineers in GRIDCo some practical explanations and applications. Digital fault recorders (DFRs) and microprocessor-based relays offer recording capabilities in the form of waveforms and sequences of events. However, these two differ in the sampling rate processing power, type of record they can capture, lengths of records, and the ability to record wide system response. Depending on the utility philosophy, one type of equipment might be preferred to the other. The important factor is to know the characteristics that both pieces of equipment offer and determine which one offers the best information for event analysis.

The basic concepts of symmetrical components and their respective sequences can be applied to decipher types of faults. In addition, phasor diagrams for current and voltages can greatly aid in the visualization of distinguishing fault behavior. This guide exhibits real time fault events where the concepts of phasor diagrams and symmetrical components are applied to decipher faults.

The analysis of power system events can be as exciting as it can be laborious. It can also be time-consuming since faults might happen in different parts of the system and may involve different utilities.

8.3 Purpose of Fault Recording

Fault records are one of the most important pieces of evidence that event analysts can have during system event investigations. They can provide the reasons for premature equipment failure, supply waveforms and status of equipment behavior during an event, and give necessary information to perform post-fault event analysis.

Proper use and interpretation of event records can lead to corrective action for a given system problem resulting in improved performance and reliability of any generation, transmission, and distribution system.

Fault records are now captured by microprocessor relays but records are limited to sampling rate and record length. Digital fault recorders offer specialized, specific, and dedicated microprocessor equipment with far superior sampling rates, record lengths, and unfiltered recording abilities.

Utility engineers have to make balanced decisions as to what equipment is better to use for pre- and post-event analysis. Regardless of the equipment employed, both come at some economic cost. Nevertheless, as expected maximum use of their recording capabilities assures maximum return in their investment.

Fault recording has been used for decades now, and it is generally used for two main purposes:

- Recording of system events
- Monitoring of system protection performance

8.3.1 Recording of System Events

Recording of system events can be classified as fast transient recordings and slow swing recordings.

- Relays and recorders are capable of recording fast system events such as power system faults, lighting strikes, switching events, insulator flashing, etc. These types of transient events are usually short-lived and fast; therefore, they do not require long record lengths unless faults have cascaded into multiple system elements or a fault has remained in the system longer than normal. In these cases longer transient records are needed to capture the entire event. These types of records let the analyst know the current and voltage magnitudes, time, and duration that were observed during the course of the event. This information can then be analyzed and dissected to look for potential problems in the timing, current and voltage magnitudes. Analysts can detect abnormalities such as current transformer saturation, breaker restrikes, ferroresonance, CCVT transients, etc. Investigation of current magnitudes can also be used to determine the deviation of actual fault values vs. calculated values from software. Short circuit databases, due to their large composition, can contain errors that yield misleading fault values. Comparing actual and calculated values is a good practice to check for possible inconsistencies. Transient records can further improve the analysis of such events mentioned above by providing the symmetrical component quantities of the current and voltage during steady state and fault conditions. The positive, negative, and zero sequence components can be used to determine their individual magnitudes during the transient event. They can also be used to verify the type of fault. This process is further expanded in the section below about deciphering power system faults. Another type of system event is incipient faults such as early signs of insulator failure. Such conditions require longer record lengths to capture the early development of the event and are better handled by DFRs because of their record length capabilities.
- Slow swing recordings are designed to capture the power system's response in RMS values following a power swing or disturbance. These records can usually help to determine how well the system is designed. These types of records can

capture the response of generators, power swings on transmission lines, load variations caused by voltage and frequency fluctuations, and transient phase angle changes (7). Since these records measure system response, swing recorders are required in specific spots and under different owners of an interconnected system. Swing records do not have the fast rise or sharp current changes that transient records have since they are sampled at very slow rates.

Therefore, accurate time stamps are needed to analyze system event records from many pieces of recording equipment. The records themselves need to cover a much longer period than transient records. There are some microprocessor relays capable of swing recording data, but they are limited by record length. DFRs have swing recording as part of their design and can capture incredibly long records. It is recommended to use maximum record length.

8.3.2 Monitoring Power System Performance

Fault recording devices have proven to be invaluable assets in in identifying proper as well as improper behavior of system protection schemes and associated equipment. The ability to record protection system performance such as relays, circuit breakers, and control systems has resulted in design improvements and corrections of the power system. Consequently, companies have prevented future equipment damage and failure, generating economic savings and improving the overall performance of the power system.

Some practical applications of the fault recording devices include monitoring the "failure of a relay system to operate as intended, incorrect tripping of terminals for external fault zones, determination of the optimum line reclose delay, impending failure of fault interrupting devices and insulation systems. Another application is to monitor trip coil energization. Monitoring of trip surges is far superior to monitoring breaker auxiliary contacts. Monitoring the coil energization tells precisely when the breaker command was received. The coil is de-energized by a 52a contact indicating the precise time when the contact motion began, which can sometimes be quite long. This can be combined with the line current information revealing when the last breaker interrupted the current, though not the first. Other record events that help to monitor the credibility of a protection system include: lockout relays, transfer trip keys, and receipts. The advantages of trip coil and transfer trip monitoring are expanded in the sequence of events section.

Triggering of records should be sensitive enough to capture all local faults independent of relay response. Most importantly, the goal is to trigger for many events without resulting in local tripping so power system response can be reviewed. Secondly, it is important to capture a record of a local fault accompanied by a relay failure. Fault recorders have an advantage over recording relays in this regard.

Monitoring circulating zero sequence currents (Io) in autotransformers is very useful since they capture all local and most remote ground faults. Triggering for under-voltage conditions during voltage depressions is also advantageous. A wide variety of local and remote faults can be captured since faults will tend to depress or collapse the voltage. Also, complex line relaying schemes with weak feed provisions can mis-operate on these voltage depressions, so it is good to capture them. A combination of under-voltage and zero sequence current triggers will capture almost all faults near the recording equipment.

Many people have questioned the value of digital fault recorders in an era of digital relays with recording capabilities. Nevertheless, digital fault recorders offer far advanced recording capabilities which results in better analysis of system problems and economic savings.

Advantages of fault recorders include:

- They are independent of a failed or partially failed relay that a DFR maybe monitoring.
- They do not filter analog signals as many digital relays do.
- They offer more memory capacity, enabling longer records.
- They have faster sampling rates.
- They have broader frequency response.
- They are designed with more triggering options.
- They can monitor many power system components simultaneously.

- They can be used to monitor power quality issues, especially with connections with windfarms, FACTS, static VAR generators, arc furnaces, and variable frequency drives.
- They are useful in studying problems associated with current inrush where large autotransformers are applied in parallel combinations.
- They offer a wide spectrum of system responses during faults.

8.4 Oscillography Data

The analysis of oscillography data requires an excellent understanding of the recording equipment, protection system schemes, and behavior of power system elements. It is necessary for the event analyst to comprehend the characteristics and tools provided with recording equipment in order to maximize the equipment's use and to properly interpret the data. An understanding of the design, concepts, philosophies, and application of system protection is vital to decipher system events. Knowledge of the behavior and characteristics of power system elements, such as transformers, reactors, breakers, and capacitors, can aid the explanation and reasoning behind certain system events. Without a doubt, becoming proficient with system protection and power system element knowledge comes with years of experience and practice. For this reason, these two broad subjects cannot be covered fully in this paper. Nevertheless, understanding some of the recording equipment's oscillography characteristics can prove to be helpful when interpreting fault records. Concepts such pre-post triggering characteristics, time frames, fundamental RMS versus true RMS, sampling rates, and time synchronization are given below.

8.4.1 Pre-Post Initiation Of Fault Data

The power system operates under steady state conditions when equal amounts of power are generated and consumed. This assumes that the system is working under its voltage, current, and element limits. We can also deduce that due to vast geographical exposure of the power system, this normal or steady state operation can be interrupted in certain parts of the system. No matter how well the system is designed, faults are going to occur for many reasons such as equipment failure, acts of nature, operator or technician errors, etc. The vital evidence that tells what happens during the fault is found in the pre- trigger, event duration, and post fault information of the captured record. Figure 8-1 exhibits these characteristics. There are other pieces of information such as SCADA logs that can also aid in the analysis of an event.

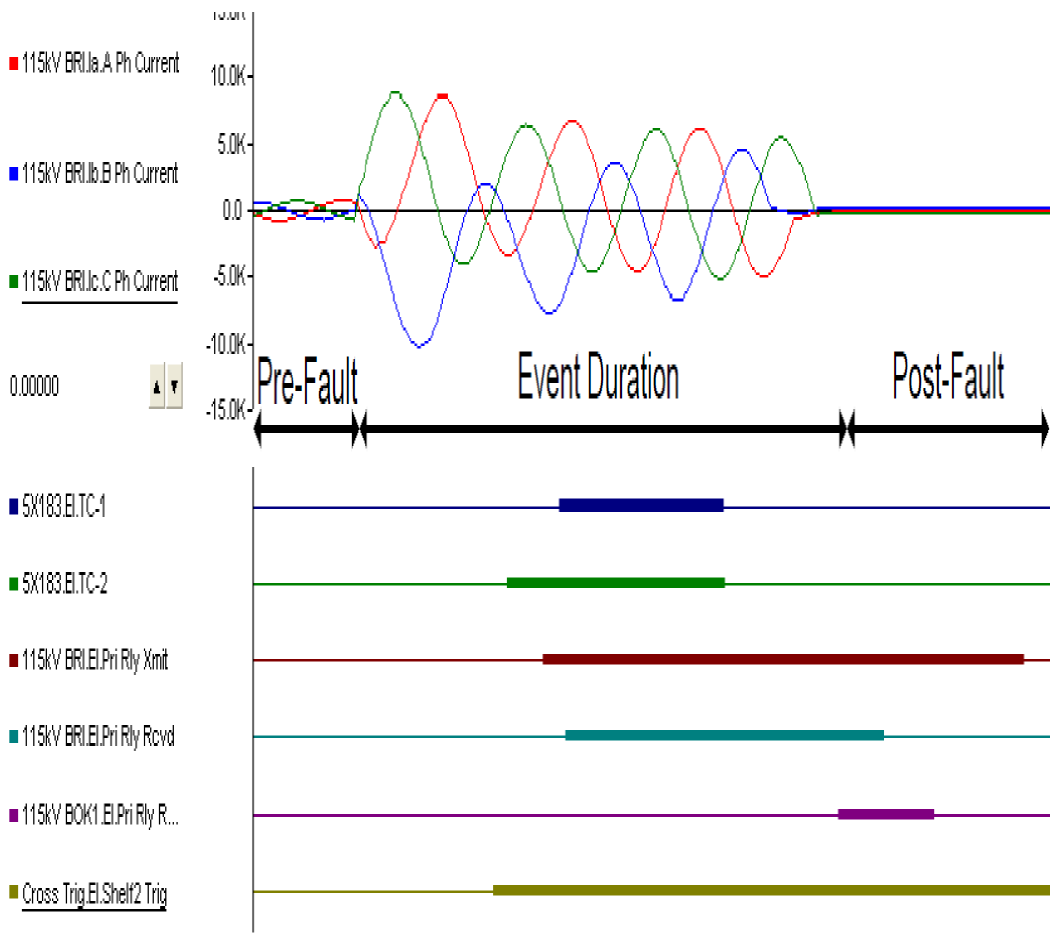


Figure 8-1. Fault Oscillography Data

Pre-triggering of the record's fault section is identified by all the voltages, currents, and sequence of events that existed during the steady state conditions before the inception of the fault. The system voltages and currents should reflect a balanced system except for normal unbalances caused by changes in load demand.

The pre-trigger information is critical during analysis of an event since any loss of waveform data can delay event investigations. Therefore, it is recommended to use the recording equipment's maximum available pre-trigger settings.

Post-triggering indicates the beginning of the event duration. It is triggered immediately after an event detector such as over-current, under-voltage, or impedance, has indicated a fault inception. For proper fault analysis, the record should capture plenty of pre-fault data, total fault duration, clearing time of the fault, the magnitude of the fault voltages and currents, type of fault, and digital signals. For transmission line faults it is desired to capture the fault from its inception through its clearing time and reclosing for about 50 cycles. The duration characteristics of the pre-trigger, duration, and post-trigger of an event record depend on the type of record and application for the analysis. This could be classified into two different classes:

- Transient record lengths.
- swing record lengths

Transient records are designed to capture very fast events such as faults, lighting strikes, switching events, etc. Depending on the recording equipment, transient fault records can include several cycles of pre-trigger data to seconds of post-trigger data.

Some micro-processor relays allow 10 cycles of pre-trigger data to 120 cycles of post-trigger data, sampled at 96 samples per cycle. As shown in Figure 8-2, long records in DFRs and microprocessor relays are advantageous to capture and check reclosing events.

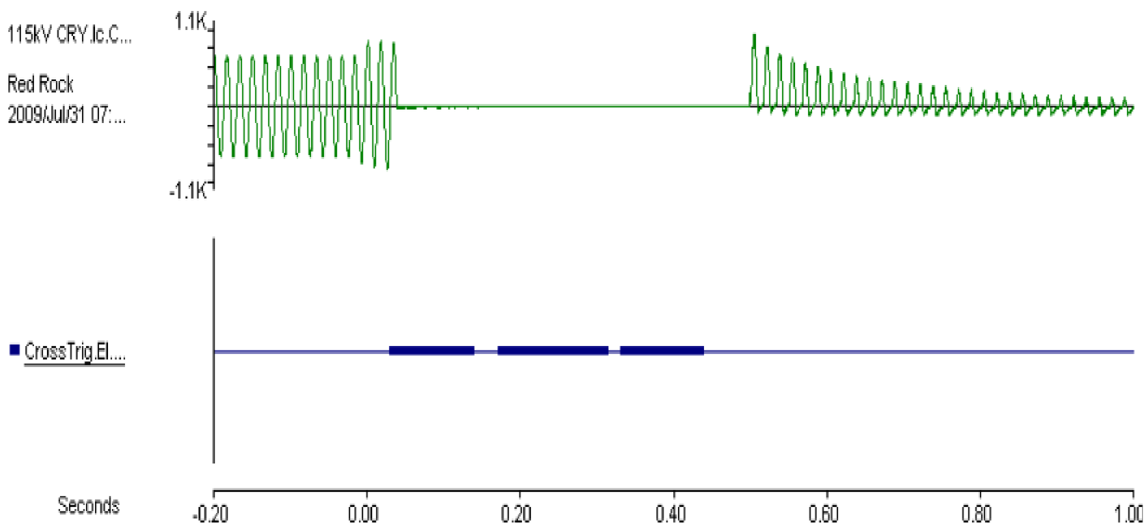


Figure 8-2. CrossTrig. Element

For digital fault recorders, the pre-trigger data length for a transient record can last as long as 60 cycles (or 1 second) and post-trigger data can last as long as 30 seconds sampled at very fast rates of 384 samples per cycle. Long records become especially beneficial during multiple faults or triggering events, showing the event analyst the entire spectrum of the incidents during the fault. Sufficient data enables faster and better quality event investigations.

8.4.2 Time Frames

Working with oscillographic information usually requires analyzing time frames that could be in the form of cycles, microseconds, milliseconds, seconds, minutes, or sometimes hours and days. Each time frame is used differently during an analysis and is usually a function of the application or purpose. **Table 8-1** gives the different time periods where a time unit is associated with a particular application.

Time Period	Event	Application
Microseconds	Switching Surges	Breaker Restrikes
Milliseconds	Harmonics	Variable Frequency Drives
Cycles	Faults	Relays
Seconds	Load Flow Changes	Governor, Exciter Response
Minutes	System Stability	Power Swings
Hours	Load Variations	Generation Schedules
Days	Continuous Data Recording CDR	NERC Requirements

Table 8-1. Time Poriod

During fault analysis, electrical cycles are the most common time frame used. They are very easy to distinguish, and most engineers and techs are already familiar with their concept.

8.4.3 Fundamental RMS VS True RMS

The analysis of waveforms sometimes involves analyzing currents and voltages based on the true or fundamental RMS values. Understanding the concepts, differences, and applications of these two RMS quantities can help explain the behavior of protective relays.

True RMS.

True RMS can be simply defined as the RMS measurement values of waveforms that contain all the harmonic components summed in the waveform (4). The number of harmonics available depends on the sampling rate of the relay or DFR.

The true RMS values become important when analyzing mis-operation from electromechanical relays since these relays are said to be true RMS responsive. It has been shown that true RMS responsive relays can mis-operate due to excessive harmonic content. The true RMS values are very useful when analyzing harmonic content created by power electronic equipment such as variable frequency drives, soft starters, rectifiers, etc.

Fundamental RMS.

Power system frequency is mostly composed of 50Hz or 60Hz since this is the frequency at which voltage and current are generated. However, due to the existence of non-linear loads, harmonics are injected into the power system. As a result, the voltage and current signals measured by protective and recording equipment include this harmonic content.

With new microprocessor technology, it is possible to extract the fundamental frequency waveform by employing different filtering techniques such as the Discrete Fourier Transformer and attenuate all other harmonic signals. Consequently, the fundamental RMS waveform is based only on the fundamental frequency of 60 Hz or 50Hz. In contrast to electromechanical relays or solid state relays, which respond based on the true RMS or peak signal, microprocessor relays operate on the fundamental RMS waveform.

The benefit of using the fundamental frequency of a fault voltage or current waveform is that the relay can be designed to only operate on the fundamental waveform and extract all other harmonic components. In consequence, microprocessor design enables avoidance of mis-operations seen in classical relays due to harmonics.

Transformer differential relays experience the benefit of working on the fundamental quantities during in-rush conditions. During energization, with the secondary side open, the in-rush current of the transformer will cause only the primary current transformers to provide current to the relay, resulting in a differential trip.

Past experience and research have shown that the in-rush current contains significant amounts of the 2nd harmonic. Using the filtering techniques mentioned earlier, differential relays can be set to recognize the 2nd harmonic quantity and block the relay from operating. Figure 3 shows the in-rush currents during energization and their respective harmonic content as a percentage of the fundamental. The circulating current in the tertiary winding of the transformer is shown in the graph below the in-rush currents.

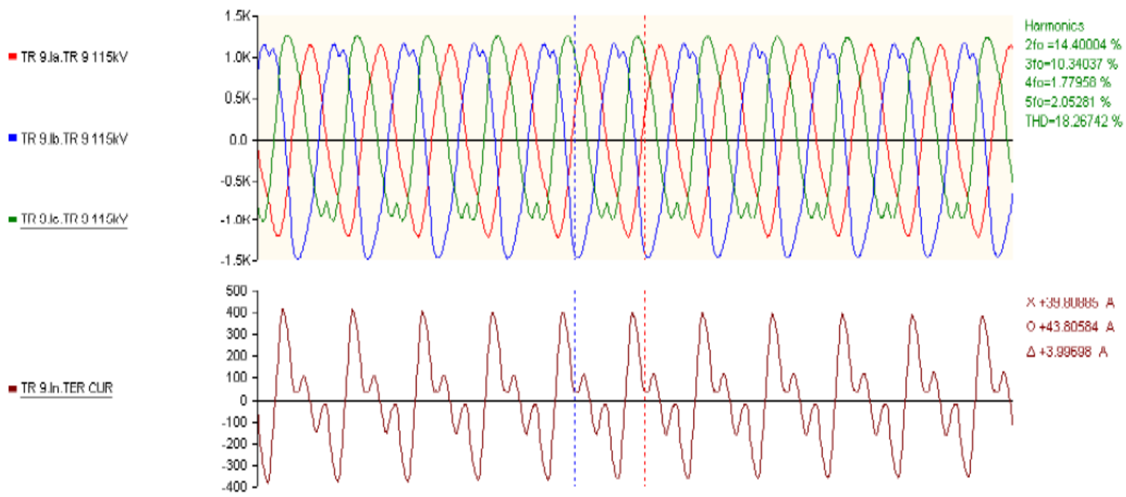


Figure 8-3. In-rush currents during energization

8.4.4 Time Synchronization

A power system disturbance can happen at any time in various sections of an interconnected system, and it can involve multiple elements. Investigations of wide area disturbances can be time-consuming, laborious, and difficult to analyze.

Investigations can be rationalized and simplified when records used to analyze events have been synchronized to the same time frame reference. The investigations and analysis of the August 2003 blackout was very difficult and time-consuming since disturbance recording equipment was not properly synchronized. Therefore, time synchronization of data becomes a critical factor in the analysis of power system events.

The North American Electric Reliability Corporation (NERC) requires that internal clocks in disturbance monitoring equipment be synchronized to within 2 milliseconds or less of Universal Coordinated Time (UTC) Scale. Digital relays and records are equipped with IRIG-B communication ports that allow the records to be accurately time-stamped with the GPS system.

A network synchronization method called precision time protocol (PTP) is being proposed that allows 1 μs timing accuracy for devices that are connected to a network such as Ethernet. This protocol is discussed in the IEEE 1588 standard.

8.4.5 Sequence of Event Recording

The most straightforward method of monitoring changes in breaker status is to monitor a breaker auxiliary contact. Since the change of state of typical concern is from closed to open, a 52a contact that opens early in the breaker stroke is preferable to a 52b contact. Using a 52a contact is a low-cost, unobtrusive method of monitoring breaker status.

When more than one breaker is tripped to clear a line fault, comparing the times of 52a contact opening can often identify marginally slow breakers before they result in breaker failure operation.

Using high speed current operated relays to sense the current surge in trip coils provides much more information than monitoring breaker auxiliary contacts. These devices typically operate in one millisecond. When placed in both trip coils, they provide very precise measurements of primary and secondary relay operating times.

The two trip coils in any breaker are usually operated by different schemes, for example primary and secondary line relays. The onset of the coil energization can be used to determine the different operating speeds of the two schemes for a given fault.

The interruption will typically happen at the same time, since that is a function of breaker auxiliary contacts. If a trip coil is energized for as long as 50ms, it probably indicates a breaker problem. It is valuable to catch and attend to these before they result in breaker failure operation or worse. **Figure 8-4** shows how the trip surge detector relay is used in series with the trip coil.

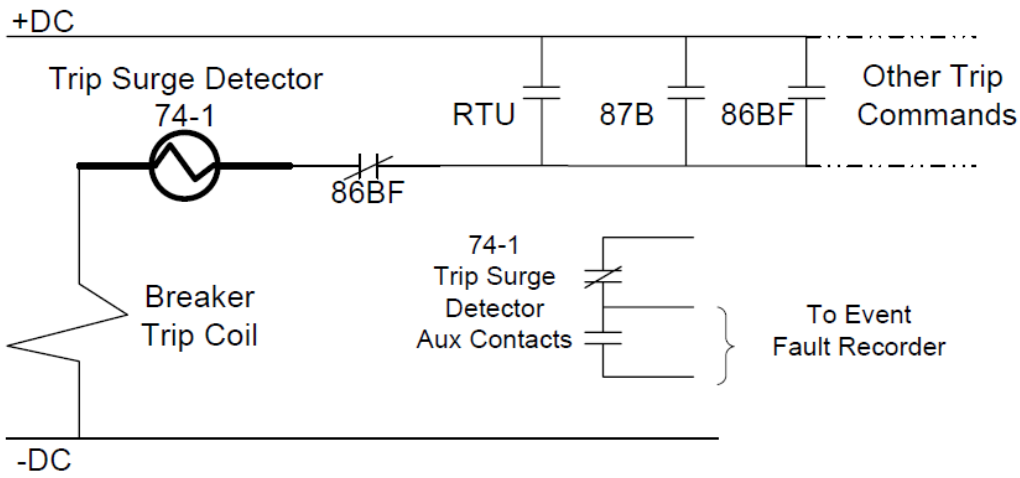


Figure 8-4. Trip Surge Detector

Early acting 52a contacts are used to interrupt trip coil currents, and the fast drop out time of the current operated relay will give a very precise measurement of the time from trip command to the beginning of the breaker motion.

In independent pole breakers, this will be the speed of the slowest pole, but that pole is usually the one of most interest. The current operated relay does add a series element to the trip path, but the relay is very robust. It is far more likely to identify a developing breaker failure than it is to cause one.

Figure 8-5 shows a three phase fault being cleared 2.5 cycles after trip coil energization. It can be observed that the trip surge detector TC2 is faster than TC1 in energization.

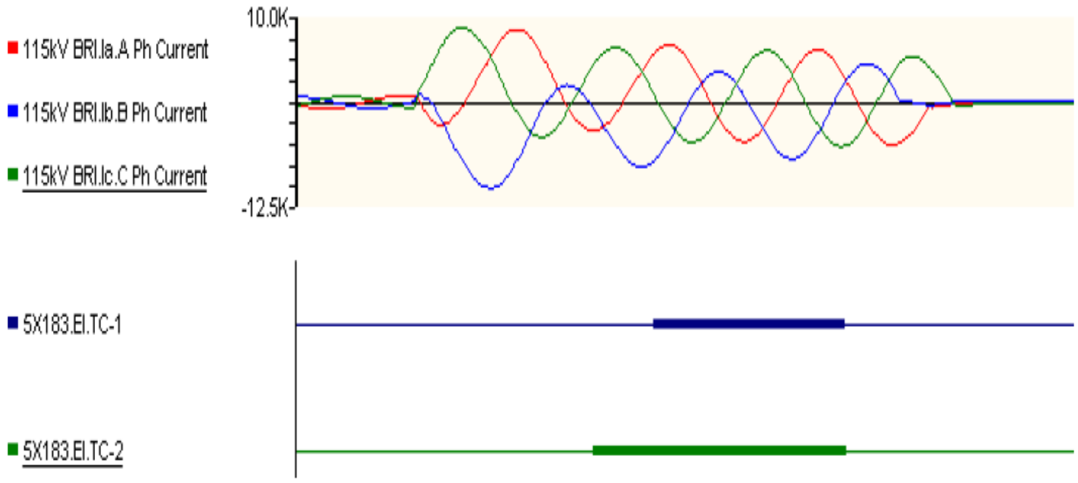


Figure 8-5. Clearing of a three phase fault

8.4.6 Analyzing Power System Faults

There are many different reasons for the existence of faults or short circuits in power systems. Some of these reasons could be equipment failure, design fallacies, forces of nature, operator errors, vandalism, etc. Each incident causes a different type of fault, and its type will depend on the phases involved. For example, a lighting strike produces excessive high voltage that can exceed the rating of the line, causing a flash over between the conductor and the tower.

The current will then flow to ground resulting in a phase to ground fault. Power system faults can also be classified as symmetrical and unsymmetrical faults. During symmetrical or balance faults the current magnitudes in each phase are maintained during the fault and are seen only in three phase disturbances. On the other hand, during unsymmetrical faults the current magnitudes experience an unbalance.

Type of Fault	Symbol	Type
Single Line-to-Ground	SLG	Unsymmetrical
Line-to-Line	LL	Unsymmetrical
Double Line-to-ground	LLG	Unsymmetrical
Three Phase	3P	Symmetrical

Table 8-2. summarizes faults according to the type and symmetry

The quality of the analysis of unsymmetrical and symmetrical faults relies on how well the analyst understands the concepts of symmetrical components. Digital fault recorders and microprocessor relays are based on the symmetrical components method, which provides the foundation to understanding faults.

The intention of this section of the paper is to outline what symmetrical components sequences to expect with different types of faults rather than to describe the theory behind them. However, this section does allow the future analyst to appreciate the practical use of such techniques. Figure 8-6 shows the open and close system of phasors during balance conditions. The figure also shows the current and voltage vector behavior for different types of faults during unbalance conditions, which aids the visualization of faults.

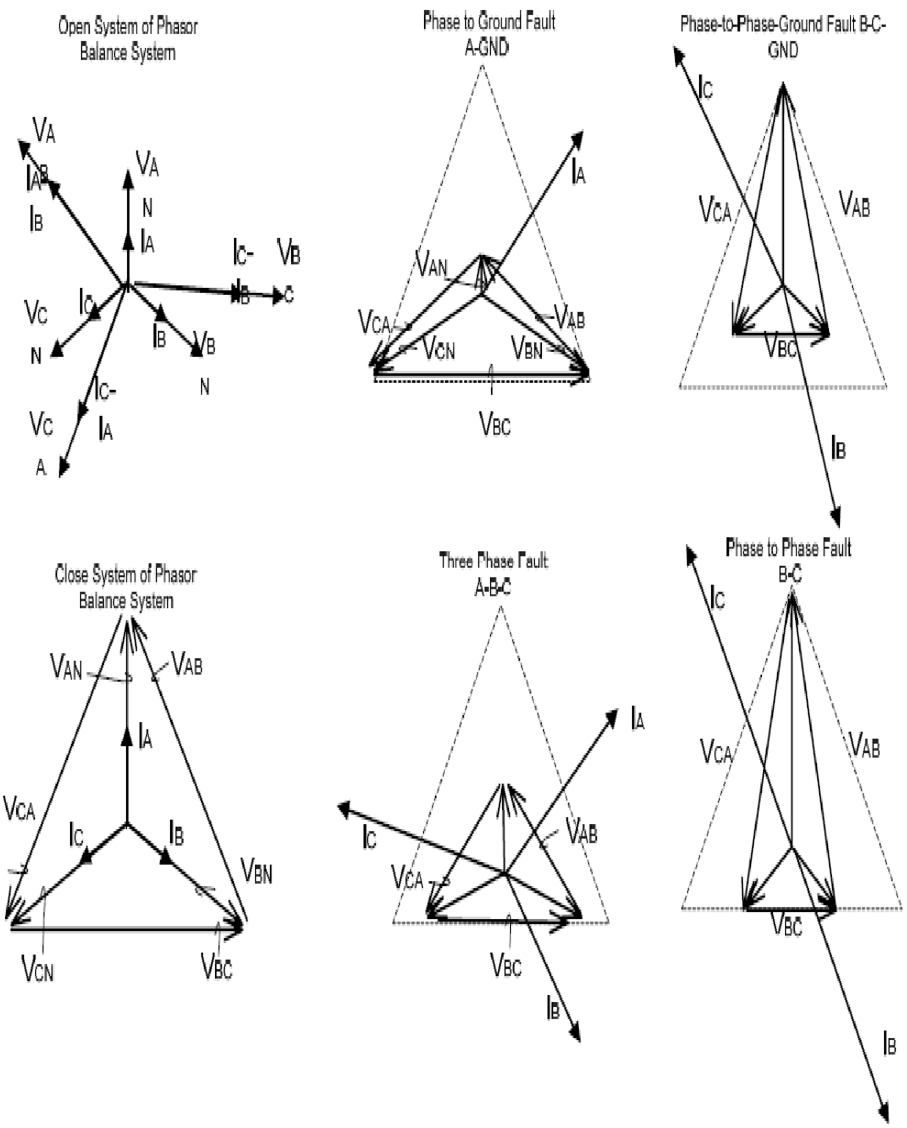


Figure 8-6. Phasor representation

8.4.7 Line to Ground Fault

From symmetrical components, we know that for a line to ground fault we expect to see the positive, negative, and zero voltage and current components. We also expect to see a depression on the faulted phase voltage and a sharp increase in phase and residual current.

These concepts are visualized in Figure 8-7 for an A phase to ground fault. Notice the sharp increase in A phase current in the first phasor diagram taken from the second trace. The presence of all three sequence components for the three currents, are also shown in the other phasor diagrams as expected.

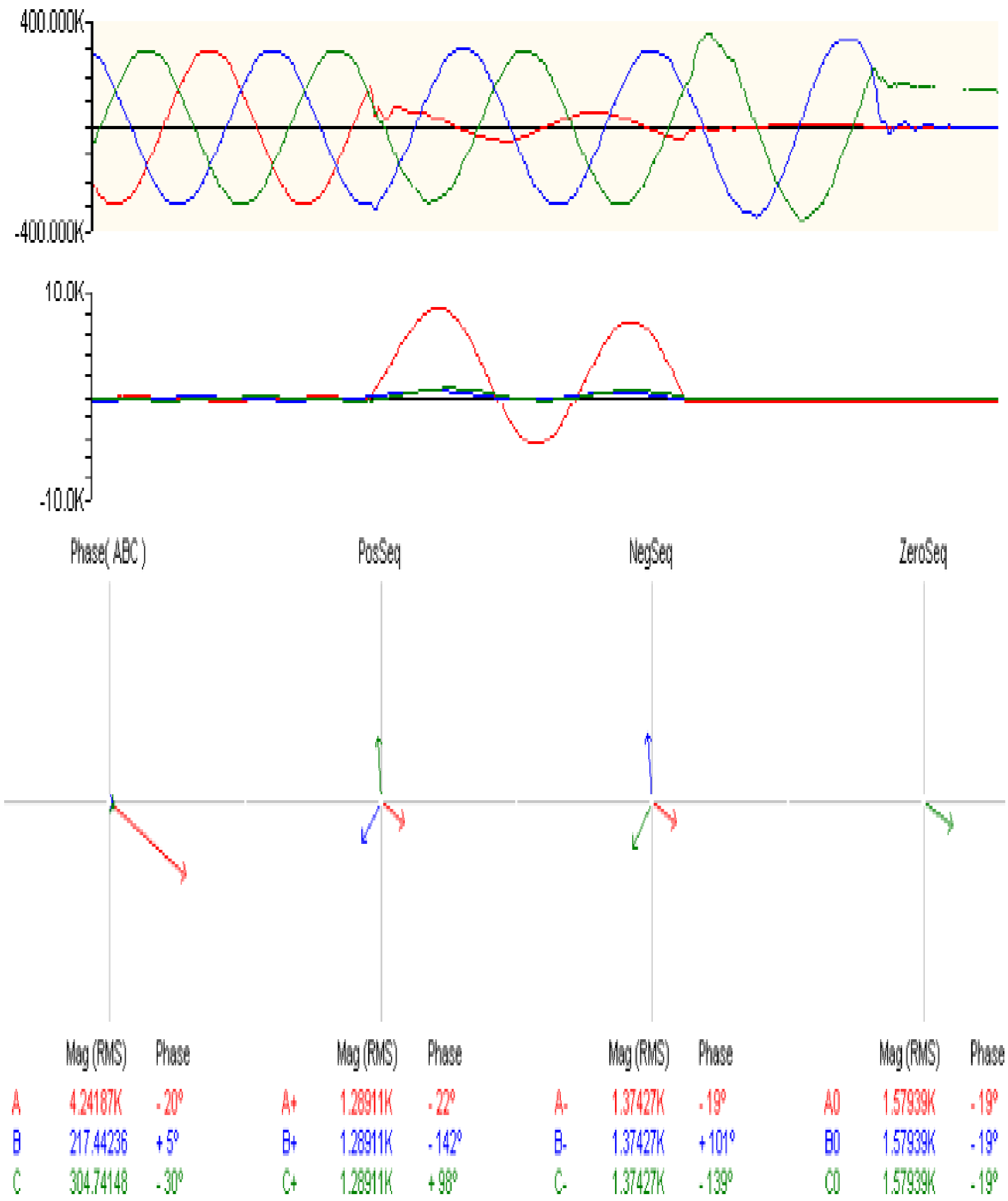


Figure 8-7. Phase A to Ground Fault

Figure 8-8 and 8-9 show oscillography of line differential relays installed at two ends of a line for example Kumasi – Anwomaso line (AW1K). Figure 8-8 represent the relay at the sending end, Anwomaso (AW58) and Figure 8-9 representing the receiving end, Kumasi (K13).

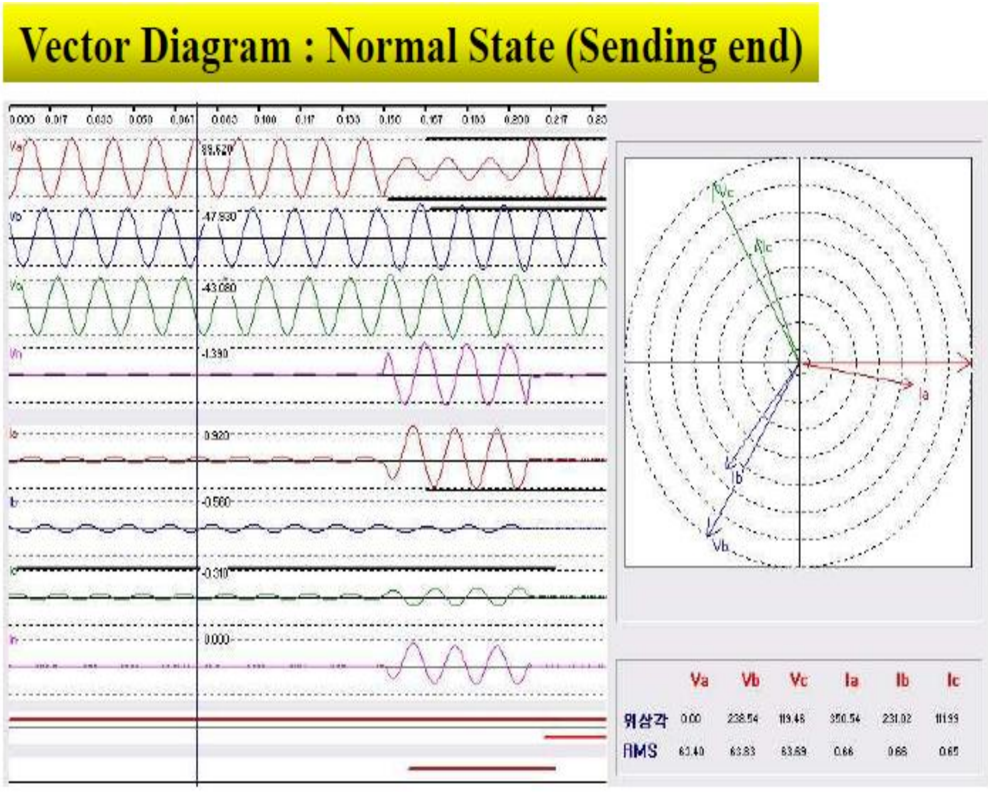


Figure 8-8. Line differential relay sending end oscillography

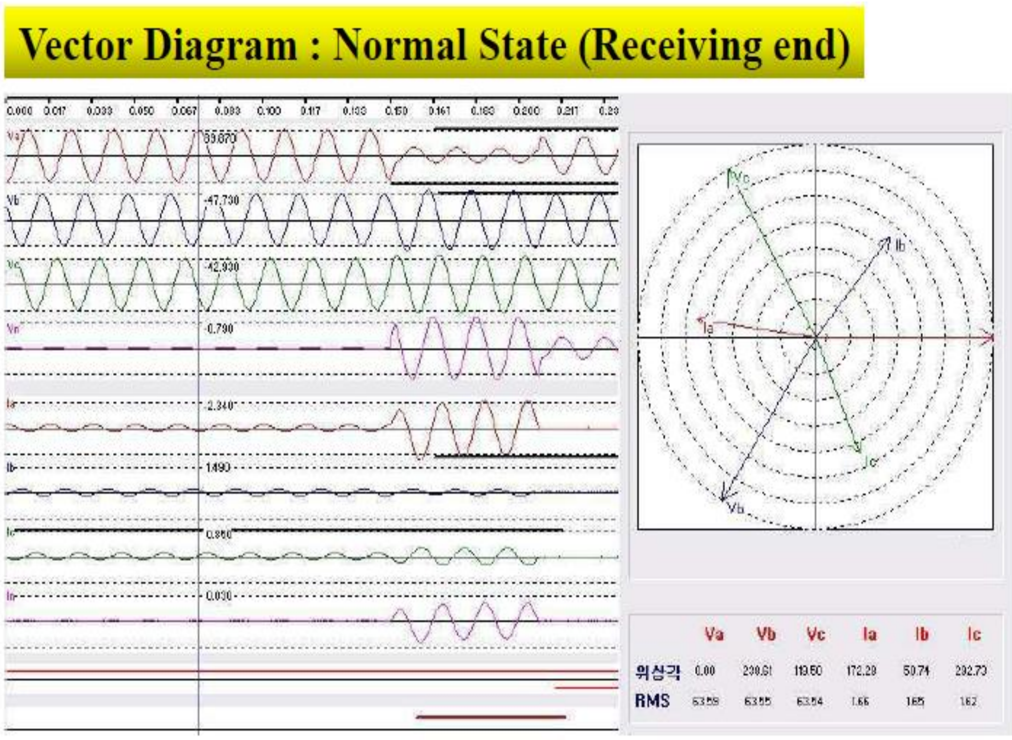


Figure 8-9. Line differential relay receiving end oscillography

A close look at the two oscillography shows a 180° out of phase in the pre-fault state. For a single line to ground fault, it also shows a reduction in "A" phase voltage and a rise in 'A" phase current at both ends of the line. A similar oscillography is similar for a phase to ground fault for a distance relay.

Example is the figure mmm shown below for a single phase to ground fault on Z10A line at Kpong GS.

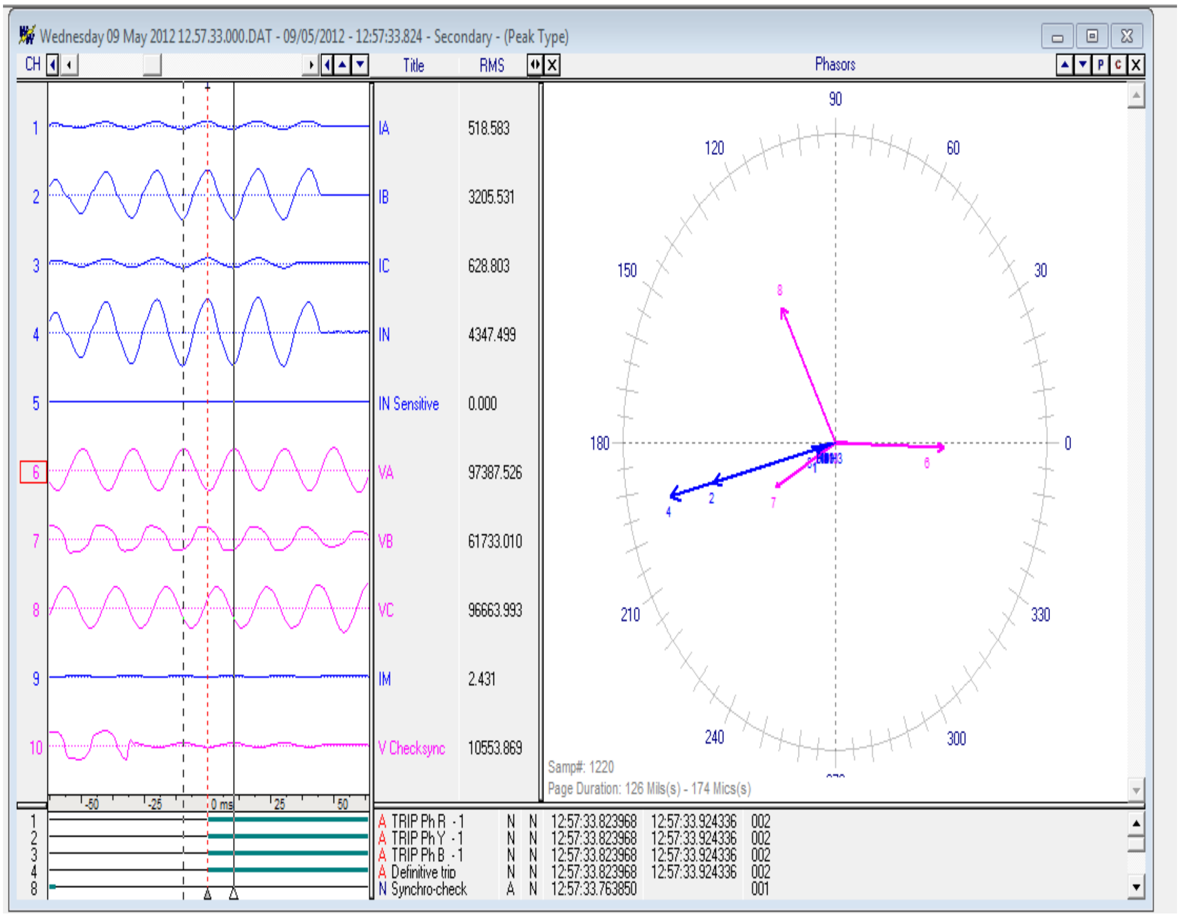


Figure 8-10. Fault oscillography of a phase to ground(B-N) fault

8.4.8 Line-to-Line Fault

A line-to-line fault is another type of unsymmetrical fault in which only positive and negative sequence components should be anticipated. For the phases involved in a phase-to-phase fault, a rapid increase in current and a voltage depression on each phase should be observed. In addition, both currents should be 180 degrees apart. This principle is illustrated in **Figure 8-11** for an A-C fault.

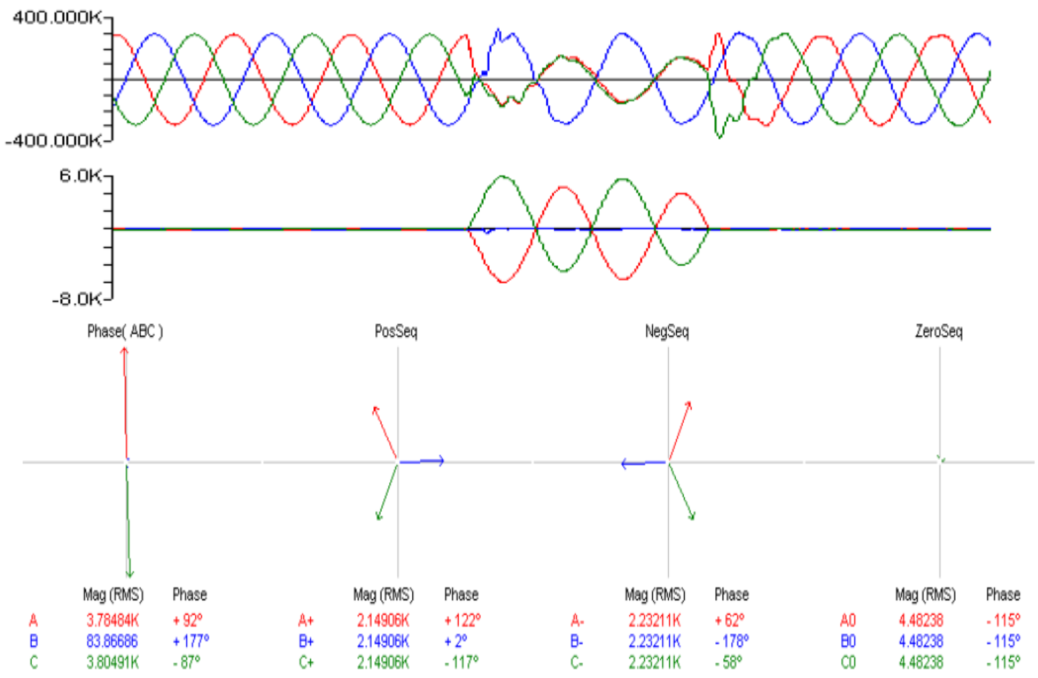


Figure 8-11. Phase to phase (A –C) fault

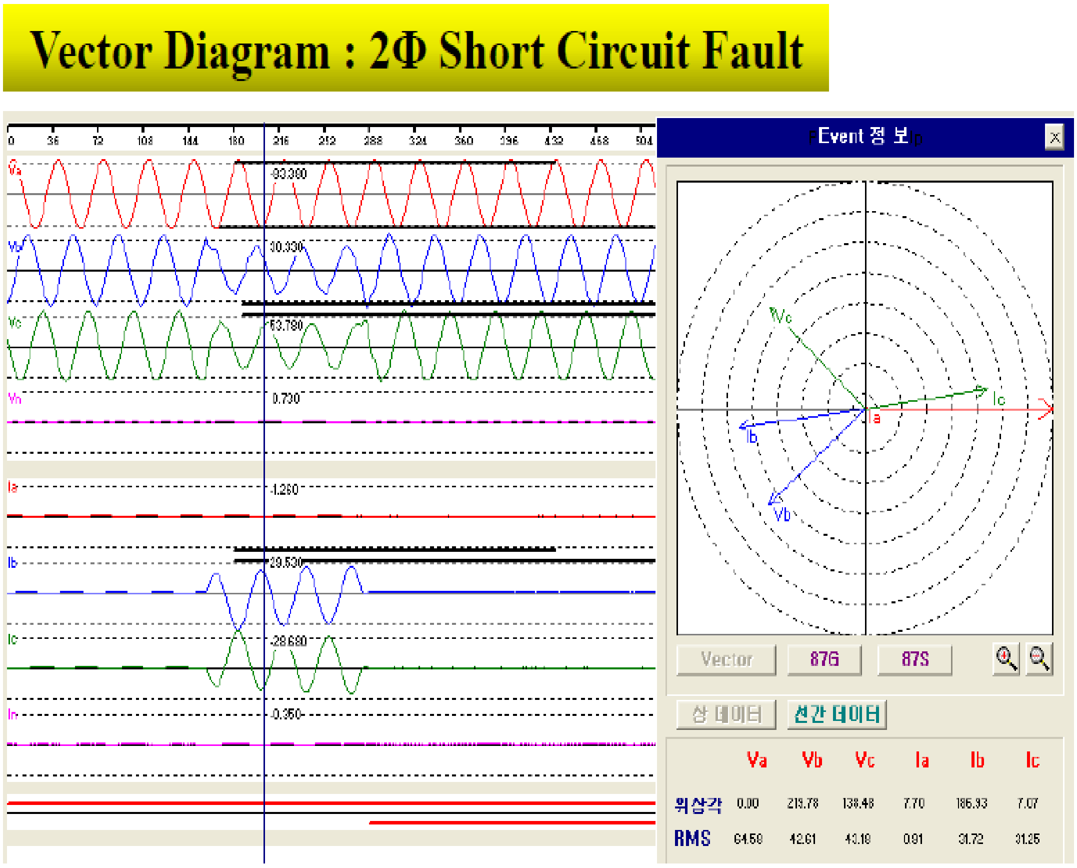


Figure 8-12. Phase to phase (B –C) fault

8.4.9 Double-Line to Ground

A similar scenario occurs during a line-to-line-to-ground (or double-line) fault where the two involved phases will see an increase in current and a decrease in voltages. The difference is that a zero sequence component will be present. This can be appreciated in the phasor diagram in **Figure 8-13**.

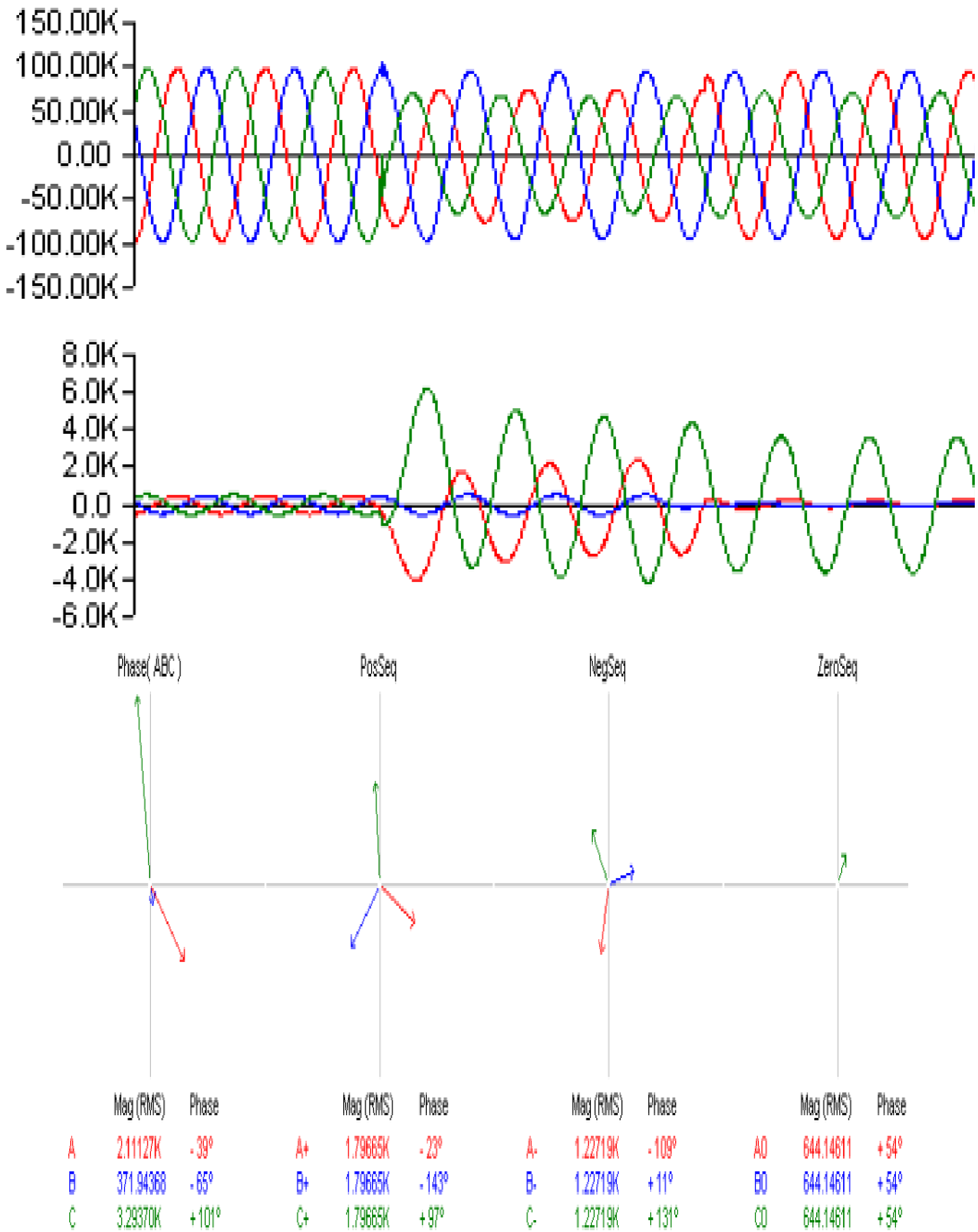


Figure 8-13. Phase to Phase to Ground (A- C – G) fault

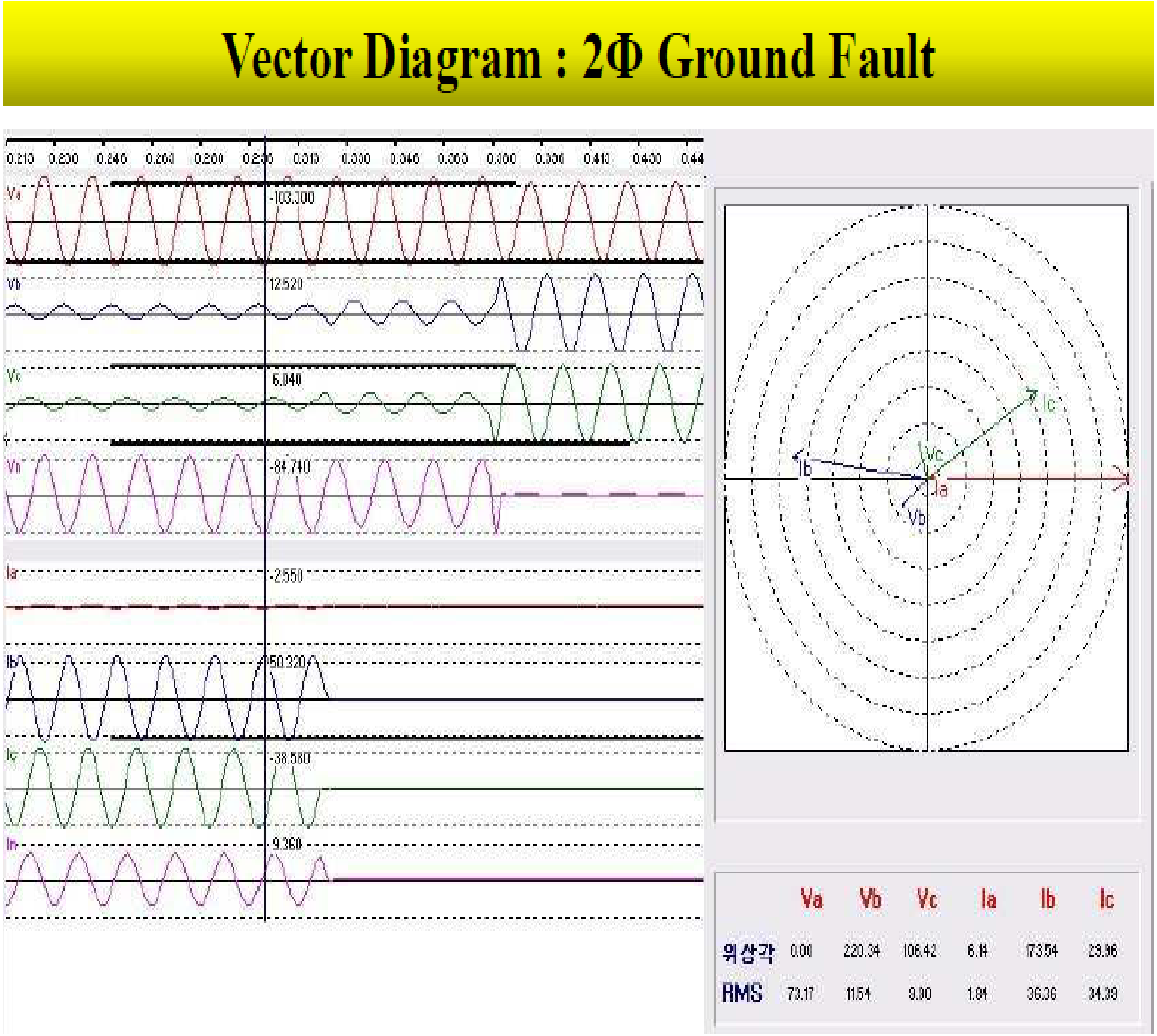


Figure 8-14. Phase to Phase to Ground (B- C – G) fault

8.4.10 Three Phase Fault

A three phase fault will be reflected by a high, sharp increase in all three phase currents, and all three voltages should collapse. A three phase fault can be seen in **Figure 8-15**. Upon inspection, we notice the rapid increase in all three phase currents and a depression in all three voltages.

Since three phase faults are considered symmetrical, there should be no presence, or very small values, of negative and zero sequence components as seen below in the phasor diagrams. In theory, the negative and zero sequence components should be zero; however, it could take some time for all three phases to become involved, and some zero and negative sequence quantities might be seen.

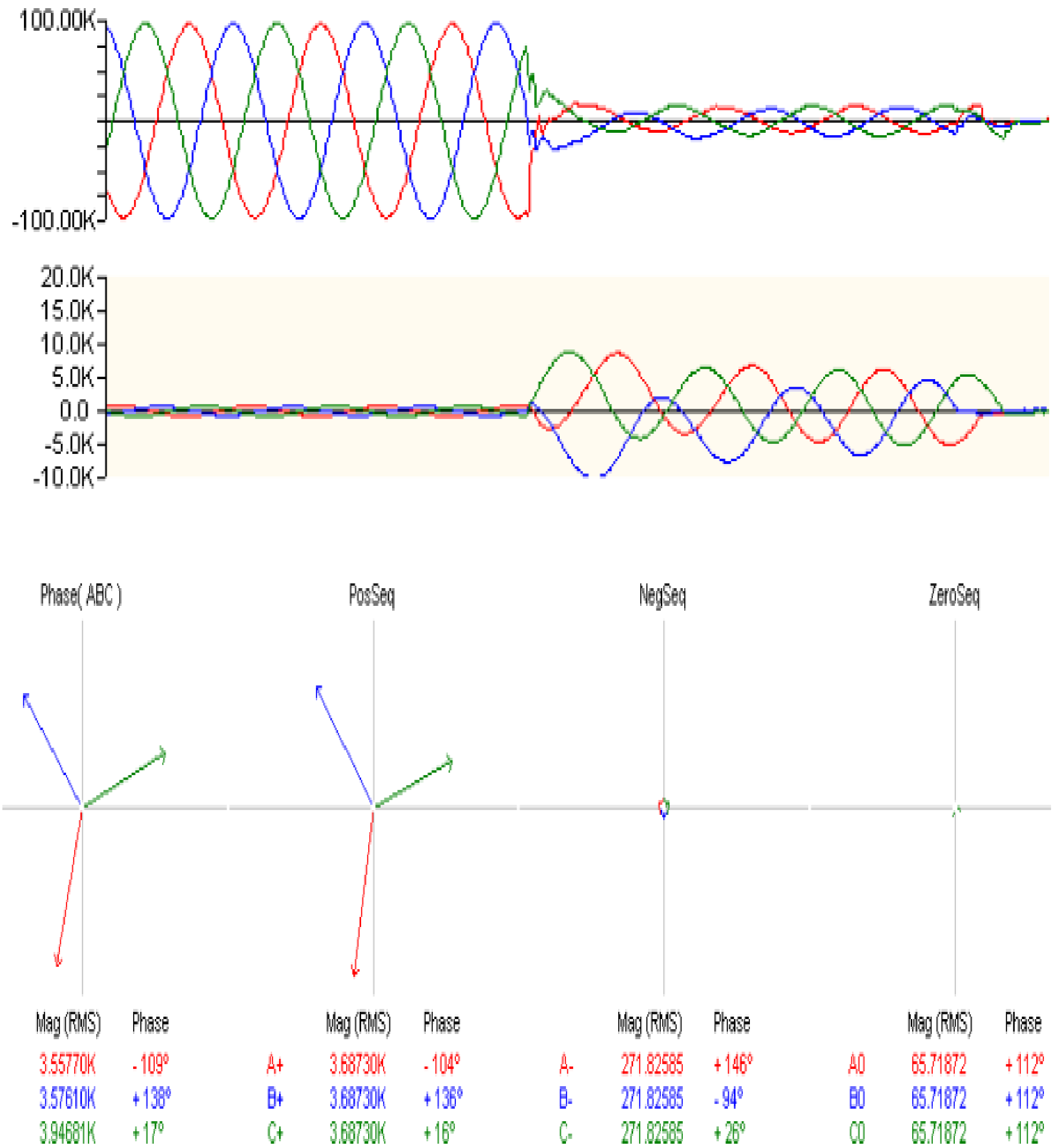


Figure 8-15. Oscillography of a three phase fault