KWAME NKRUMAH UNIVERSITY OF SCIENCE AND TECHNOLOGY, KUMASI

INSTITUTE OF DISTANCE LEARNING

(*BSc. ELECTRICAL AND ELECTRONIC ENGINEERING, 3*)

EE 362: SUBSTATION AND TRANSMISSION LINE DESIGN

[Credit: 3.]

E. K. ANTO

Publisher Information

For any information contact:

Dean
Institute of Distance Learning
New Library Building
Kwame Nkrumah University of Science and Technology
Kumasi, Ghana

Phone: +233-03220-60013
+233-03220-61287
+233-03220-60023

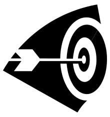
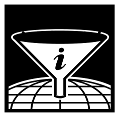
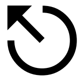
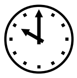
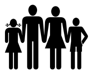
Fax: +233-03220-60014

E-mail: idldean@kvcit.org
idloffice@kvcit.org
kvcit@idl-knust.edu.gh
kvcitavu@yahoo.ca

Web: www.idl-knust.edu.gh
www.kvcit.org

Publisher's notes to the Learners:

1. Icons: - the following icons have been used to give readers a quick access to where similar information may be found in the text of this course material. Writer may use them as and when necessary in their writing. Facilitator and learners should take note of them.

Icon #1	Icon #2	Icon #3	Icon #4	Icon #5
				
Learning Objective	Activity	Assignments	Information	Summary
Icon #6	Icon #7	Icon #8	Icon #9	Icon #10
				
Time For Activity	Self Assessment	Group Discussion	Read	New Terms
Icon #11	Icon #12	Icon #13	Icon #14	Icon #15
				
Well Done	Note/Learning Tip	Pause	Question	Online

2. Guidelines for making use of learning support (virtual classroom, etc.)

This course material is also available online at the virtual classroom (v-classroom) Learning Management System. You may access it at www.kvcit.org

Course Writer

Mr. E. K. Anto completed his Bsc (Hons) Degree at the Department of Electrical & Electronics Engineering at the then University of Science and Technology (UST), Kumasi, Ghana in June 1985, and was selected as a Teaching Assistant to do his mandatory National Service at the same Department. He later pursued his postgraduate studies at the Technical University of Berlin, Germany, where he obtained the Dipl.-Ing. Degree, (the equivalent of MSc Degree) in 1997.

He returned to Ghana as the Reintegration Counsellor in charge of the German Office for Germany-trained Returning Experts (Rueckkehrerbuero), an office dedicated to ensuring the smooth and comfortable reintegration back into Ghana of Germany-trained Ghanaian experts.

He later joined the Ghana Standards Board (GSB) as Senior Scientific Officer attached to the Metrology Division and worked on the Electricity Meter Testing, Calibration and Verification Project. He has finally settled as Lecturer at the Kwame Nkrumah University of Science and Technology (KNUST), Kumasi, Ghana, since October 2001.

He has been an External Moderator for the National Board for Board for Professional And Technician Examinations (NABPTEX) since 2005, and was a Visiting Lecturer for the National University of Rwanda during the period of 2004 to 2006. He was a member of the team of consultants that conducted survey for the Private Enterprise Foundation (PEF) on the Impact of Power Outages on Some Selected Manufacturing Industries in Ghana.

His research interests are on electrical energy management systems, prepayment metering system, rural electrification, power system quality and application of local material as backfills for improving earthing. He has been the University Electrical Services Consultant since 2004. He has also served as Faculty Exams Officer and is currently the Head of the Electrical Engineering Department.

Course Introduction

Introduction

This course introduces the student to basic principles and considerations made in substation and transmission line design. Power generated at the generating stations (be they hydro, thermal, nuclear, etc.) are transmitted at higher voltages to reduce losses and voltage drops. The transmission medium may either be an overhead line or underground cable, the choice of the particular medium depending upon a number of factors such as cost, terrain suitability, right-of-way issues, aesthetic considerations, etc.

Before it can become useful to the ultimate consumer, a number of transformations and switching stations have to be created. Usually, the voltage is stepped down to a lower value through the use of a step-down transformer located at a substation. A substation is an assembly of switchgear components used to control the flow of electrical energy in a power system. For purposes of safety to equipment and personnel, the switching and transformation equipment must be properly earthed, and so system earthing would also treated in this course.

The course will generally address, amongst others, the general principles considered for substation and transmission lines design, and delve into the various system earthing schemes.

Learning objectives

After going through this course, you should:

- understand the technical and other considerations that influence substation design and busbar arrangements
- be familiar with various system earthing schemes, and their peculiar merits and demerits
- have understanding of the technical and other considerations that inform the design of transmission lines, be they overhead lines or underground cables
- undertake exercises in overhead line and underground cables.

Course Outline

For the achievement of these objectives, the course is divided into four units. Each unit is broken down into sessions, each of which will address one or more of the course objectives.

Unit 1: Substations Design

Unit 2: System and Equipment Earthing

Unit 3: Overhead Transmission Line Design

Unit 4: Underground Cable Design

Table of Content

UNIT 1

SUBSTATIONS DESIGN

Introduction

This unit introduces you to substations, which are switching stations composed of an assembly of switchgear components used to direct the flow of electrical energy in a power system.

Learning objectives

On completion of this unit, you would be able to:

- State the types and elements of a substation
- Describe substation layout and operation
- Explain busbar systems and switching arrangements
- Identify voltage regulation equipment

SESSION 1-1 TYPES AND ELEMENTS OF A SUBSTATION

The economics of generation of electrical energy and the huge demand for power in modern times necessitates the creation of bigger and bigger generating stations. Long and high voltage transmission lines are necessary to transmit the huge blocks of power from the sources of generation to the load centers, to interconnect powerhouses for increased reliability of supply, greater system stability and lesser standby (reserve) power plants and hence cheaper electric energy.

In between the powerhouses and the ultimate consumers, a number of transformation and switching stations have to be created. These stations are generally referred to as *substations*.

An electrical substation is an assembly of switchgear components used to direct the flow of electrical energy in a power system. Switchgear is the general term used to define switching (and/or interrupting), protective, regulating and metering devices, including all associated controls and interconnections, as well as accessories used for generation, transmission and distribution of electrical energy.

1-1.1 Types of Substations

Depending on the purpose, substations may be classified as follows:

1. Step-up substation
2. Primary Grid Substation
3. Secondary Substation
4. Distribution Substation
5. Bulk Supply and Industrial Substation
6. Mining Substation
7. Rural Substation

The *step-up substations* are normally associated with generating stations. The generated voltage is limited due to the limitation of the rotating machinery (13.8 kV at VRA), and needs to be stepped up to the primary transmission voltage (161 kV in VRA) so that huge blocks of power can be carried over long distances to the load centers.

The *primary grid substations* are created at suitable load centers along the primary transmission lines. The primary transmission voltage is stepped down to a number of suitable secondary voltages (say 33 or 11 kV for ECG and the mines). From here, secondary lines are carried over to the load centers.

Along these secondary transmission lines at actual load points, *secondary substations* are created where the voltage is further stepped down to sub-transmission and primary distribution voltage.

Distribution substations are created where the sub-transmission and primary distribution voltages are stepped down to supply voltage to feed actual consumers through a network of distribution and service lines. Metering, relaying and automatic controlling are some of the functions included in most distribution substations. Metering is required for statistical purposes or for billing of customers.

The *bulk supply and industrial substations* are generally distribution substations, with the difference that these substations are created each for one consumer and the subsequent distribution of electric power is left to the particular consumer who may be a bulk supply consumer or an industrial consumer of large or medium supply group.

The *mining substations*, as their name indicates, are substations required for very special purposes and need special design considerations, because of the extra precautions for safety needed in the operation of the electric supply.

The *rural substation* is very simple and designed with the lowest possible cost in mind. The sub-transmission line connects through the disconnecting switch and through high-rupturing capacity (HRC) fuses to the substation transformer. No circuit breaker is used. The low voltage from the transformer is supplied to the distribution bus and from there to several feeders.

In rural areas where, where the load density is low and overhead lines are used, pole-mounted transformers with ratings from 5 to 315 kVA form the *rural substatio*n. For MV/LV transformers below 315 kVA, it is possible to bolt the transformer onto a single pole or place it on a metal frame to the pole. Low voltage distribution in rural areas is by means of overhead lines with bare or insulated conductors. The use of aerial bunched conductors is increasing, particularly in villages, towns and forested areas.

1-1.2 Components of a Substation

Basically, a substation consists of a number of incoming and outgoing circuits, the main components of each circuit being:

- Section of busbar or busbars
- Switching devices (Circuit breakers, Fuses, Disconnecting Switches or Isolators)
- Instrument transformers (Current and Voltage Transformers)
- Power Transformers (for voltage transformation)
- Protective devices (Lightning arresters, earthing grids, surge diverters, etc.)
- Voltage regulating devices (Shunt and series capacitors, voltage regulators)
- Telecontrol systems
- Auxilliaries (DC supply backups, fire fighting equipment, overhead cranes, etc)

The power transformers have been adequately covered in previous lectures. The switching devices, instrument transformers and protective devices will be given a more extensive coverage in protection lectures.

1-1.3 Voltage Regulating Devices

The quality of supply is considerably influenced by the quality of the voltage provided to customers, which can be affected in various ways. There may be long periods of variation from the normal voltage, sudden changes in voltage, rapid fluctuations or imbalance of 3-phase voltages.

In addition to variations in the actual value of the voltage being supplied, other irregularities such as harmonics, variations in frequency and the presence of non-linear system or load impedances will distort the voltage waveform, and transient spikes and surges may be propagated along circuits in the supply system and cause improper operation of utility equipment or customers' appliances.

There are a number of factors that cause such irregularities and fluctuations in the voltage supplied to the customers' installations. Some of these problems are caused by equipment within a customer's own installation, e.g., the opening of switches or contactors, and appliances using thyristors or triacs, as well as starting currents of motors. The actual value of supply voltage needs to be kept within a given range for the correct operation of customers' appliances. With extreme excursions outside the accepted voltage range, it is possible that some appliances could be badly damaged. Excessively high voltage is usually due to failures in the voltage control equipment or the result of system faults producing overvoltages. Too low voltage generally results from excessive voltage drops on the distribution network.

To avoid harmful effects to equipment belonging to the supply authority or the customer, various forms of legislation and recommendations exist in different countries to ensure that the level of voltage supplied does not go outside prescribed tolerances. In Europe, a common voltage tolerance for LV customers is around ±5%, with –10% being permitted for some rural areas. Under abnormal conditions, relaxation of the lower limit by a further 5% tolerance is allowed in some countries. ±10% tolerances have been quoted for Austrian and Italian utilities. The US standard for service voltage tolerance is ±5%.

Through the International Electrotechnical Commission (IEC), the standardization of most items of distribution equipment on an international basis is now taking place. In 1983, the IEC recommended that the standard voltage should ultimately be 230/400 V ± 6%. The international standardization of voltages will be a difficult process from technical, economic and political viewpoints. In view of the considerable burden voltage standardization would place on the resources and investment programs of supply authorities, transitional arrangements have been suggested.

The problem of voltage fluctuations is largely due to huge voltage drops in conductors, which are occasioned by continually changing loads and alterations in network configurations. Larger conductors may be used to reduce the voltage drop under load, but it is costly.

Voltage regulation is affected, among others, by the following:

- Type and size of wires or cables
- Reactances of transformers and cables
- Means of motor starting
- Circuit design
- Power factor correction
- Type and degree of loading

A large number of ***voltage-control facilities*** are available. These include:

- Automatic on-load tap-changers on transformers
- Voltage regulators
- Line-drop compensation (also known as voltage compounding)
- Power factor correction equipment such as synchronous motors, shunt and series capacitors, phase advancers

Although a large variety of compensation methods for voltage drops are available, it must be noted that such equipment increases the complexity of network operation and maintenance.

Where it is not economical to control voltage drop through conductor sizing, circuit design or other means, voltage regulators are employed. Voltage regulators are frequently used by electric utility companies in their distribution system feeders and are seldom needed within commercial buildings.

1-1.4 Telecontrol Systems

Telecontrol systems enable real-time information to be obtained from the supply system and permit remote-control operation of various switching equipment. Such systems thus actively assist in improving fault-clearance times and the overall security of the supply. Microprocessor-based modular telecontrol systems make it possible to monitor and control individual remote items of equipment to achieve a better operational standard.

The information collected via the telecontrol system can easily be processed and stored in data banks and then later used as the basis for network design studies. The telecommunication network is an essential part of any telecontrol system. Public and utility-owned telephone networks, radio links, power line carrier (PLC) systems as well as optical fibre arrays now offer alternative data transmission paths.

SESSION 2-1 SUBSTATION LAYOUT AND OPERATION

Substation layout consists essentially in arranging a number of switchgear components in an ordered pattern governed by their function and by rules of spatial relationship, and connecting them together electrically in accordance with a pre-determined diagram: *the busbar system.*

The *principles of layout are* ***not much*** *affected by variations in voltage or current*, which merely affect the size of the components and the scale of the distance separating them. The principles of substation layout are influenced by specific considerations resulting from its situation. These include:

- Spatial relationships of equipment
- Maintenance zoning
- Electrical separations
- Limits imposed by the nature of the site
- Type of substation - whether indoor or outdoor type
- Aesthetic considerations
- Planning authority requirements

2-1.1 Spatial Relationships of Equipment

Four clearance distances govern the spacing of components and conductors:

1. *Earth clearance*: between live parts and earthed structures, walls, screens and ground
2. *Phase clearance*: between live parts of different phases
3. *Isolating distance*: between terminals of an isolator or connections thereto; also applies between connections to the terminals of a CB.
4. *Section clearance*: between live parts and the limits of a maintenance zone (work section). The limits of the maintenance zone may be the ground or a platform from which a man works. If men are allowed to walk about freely under live equipment, then it is also necessary to provide enough clearance between the lowest point on each insulator (where it meets earthed metal) and the ground, to ensure that a man cannot encroach into the region of voltage stress. This clearance, called *ground clearance*, is based on the reach of a man with outstretched arms, and is given a value of *2.44 m* in the British Standard BS 162.

With the exception of ground clearance, the values to be assigned to clearances are determined by the maximum overvoltages to which the system can be subjected, and by the contours of the parts.

The insulation of a system, which includes air gaps in which atmospheric air is the dielectric, is subject to *voltage stress due to the continuous power-frequency voltage and the transient impulse voltages caused by lightning and switching surges*.

The value at which insulation breaks down depends on the shape and polarity of the impulse wave. Overvoltages caused by lightning are usually the determining factor for outdoor substations associated with overhead lines up to about 300 kV. Above the 300 kV, the determining factor becomes the overvoltage caused by switching surges, the waveshape and magnitude, which vary considerably. Insulation co-ordination is usually attained by the use of shielding, surge diverters or arc gaps to limit the overvoltages imposed on equipment to about 80% of the basic insulation level.

It is accepted practice to prove the basic insulation level (BIL) of main components by full-scale laboratory tests, so that the influence of their contours is taken into account and the needed clearances can be established.

2-1.2 Maintenance Zoning

One of the most important aspects of substation layout is the *zoning of equipment for maintenance*. It is necessary at the outset to have a clear idea of how the various items of equipment are to be grouped, how they are to be isolated and physically separated from neighbouring live equipment and how safe access to them is to be achieved. Some of the principles described involved in obtaining physical separation of isolated units, and safe access to them, are described with illustrated examples in the Appendixes of B, C and K of the British Standard BS 162.

2-1.3 Electrical Separations

Together with maintenance zoning, the electrical separation (by isolating distances and phase clearances) of the substation components and of the conductors interconnecting them, constitute the main basis of substation layout.

Fundamentally, at least three such electrical separations per phase are needed in a circuit.

(a) between the terminals of the busbar isolator(s) or their connections

(b) between the terminals of the CB or their connections

(c) between the terminals of the feeder isolator or their connections

Additional separations may be needed to obtain phase clearances at points where conductors of different phase cross.

2-1.4 Site Limitations

These include such obvious factors as

- Limited ground area or a peculiarly shaped site, often imposed by built-up areas
- Restrictions on the position and direction of line entries, and
- The need to integrate the substation with other projects such as power stations, or buildings housing low-voltage switchgear or other equipment.

Occasionally, it may be necessary to construct a substation underground, or on a series of terraces at different levels. *While, in extreme cases, unusual site conditions may require special substation layouts, every attempt should be made, in the interests of economy of development and uniformity of operation, to evolve standard layouts that will meet the majority of site conditions*. Compactness and flexibility are obvious aims.

2-1.5 Indoor or Outdoor Substation

The design to put EHV open-type switchgear indoors or outdoors is usually influenced by one or more of the following factors:

- Atmospheric pollution
- Ease, safety and comfort in operation and maintenance
- Small site area
- Aesthetic considerations

The cost of putting a substation indoors is a widely variable factor, as it depends on the busbar system adopted, the local cost of materials and land, the layout (particularly whether it is of cellular or open-hall type), and other conditions. It is estimated that the extra cost involved in indoor substations is 10-25% of the cost of an equivalent outdoor substation. Even at the lower estimate, the additional cost requires justification, and it is therefore worthwhile to look closely at the various factors outlined above. *Wherever possible, at the HV level, it is common practice to install equipment outdoors, provided there are no major environmental or weather constraints.*

2-1.5.1 Atmospheric Pollution

Atmospheric pollution affects switchgear in several ways; the most important is the lowering of the insulation security. Others include the corrosion and deterioration of materials and equipment, leading to the need for frequent maintenance and an increase in the difficulty and discomfort of performing maintenance and switching operations.

Various means are available in combating atmospheric pollution in an outdoor substation.

- The overall creepage length or the protected creepage length of the insulators may be increased
- Live washing may be carried out or
- Insulators may be protected by coatings of grease.

Good design of substation and components can reduce the quantity of insulation used and the susceptibility of equipment to corrosion. *Evaluation of the inconvenience and the cost of these methods against that of putting the switchgear indoors may be undertaken to decide whether the latter course is justified*.

2-1.5.2 Safety and Comfort of Operation and Maintenance

How much importance is attached to this, when deciding between indoor and outdoor substations, is largely a matter of individual opinion. It is unlikely to be a sole deciding factor, except in climatic conditions of extreme severity.

2-1.5.3 Small Site Area

Although sometimes true, it is not axiomatic that an indoor substation is smaller than an outdoor substation, and wrong impressions have sometimes been created by comparisons between poor, wasteful outdoor layouts and good, compact indoor layouts.

In that context, the following idea deserves consideration. In spite of smoke-abatement measures, the subsequent growth of pollution in the vicinity of a substation must sometimes be taken into account. Where such growth is accurately predictable, an indoor substation may be justified. In less certain cases, it may be worthwhile to design an outdoor substation so that the addition of simple cladding can convert it to an indoor substation.

In considering the area to be occupied by a substation, due regard must be paid to the space required for line-terminal towers, power transformers and auxiliary-plant buildings.

2-1.5.4 Aesthetic Considerations

This is a controversial issue, in which personal preferences inevitably play a large part. There is little doubt that a well-designed building is considered by the majority of people to be less objectionable than an outdoor substation. *In urban areas, particularly in the heart of cities, aesthetic considerations sometimes combine with the need for a small ground area and protection from pollution to justify the choice of an indoor arrangement.* Modern techniques have made the transplanting of mature trees a possibility, and although this is expensive, it may be justified in areas of natural beauty.

2-1.5.5 Planning Authority Requirements

Planning authority requirements affect substation design mainly with respect to site limitations and aesthetic considerations.

SESSION 3-1 BUSBAR SYSTEMS AND SWITCHING ARRANGEMENTS

The simplest way to join a number of circuits together is to attach them (like branch) to a single conductor called *busbar*. To improve security, reliability, facilitate maintenance and increase flexibility of power system operation, various elaborations or busbar system arrangements have been evolved over the years. This has resulted in some complex modern systems. Before considering the principal busbar system arrangements, it is expedient to describe some features common to a number of busbar systems.

3-1.1 Bypassing Facilities

An important contribution to continuity of supply is provided by facilities for bypassing components so as to allow them to be maintained. Because of the duty on them, their relative complexity, and the fact that they contain moving parts and elements subject to deterioration, circuit breakers usually need more frequent prolonged maintenance than any other components. And so it is for CB maintenance that bypassing facilities (use of isolators) are generally provided.

3-1.2 Current-Limiting Reactors

Reactors are sometimes incorporated in a busbar system to reduce the fault level so *that circuit breakers and other equipment of lower apparent-power (kVA) rating can be used*. Usually they are connected between busbar sections, and to avoid unnecessary energy consumption due to their losses, provision is made for short-circuiting the reactors through a CB, when the amount of plant connected does not have a fault value beyond the capabilities of the switchgear. It is also desirable to include additional CBs to protect the busbars from the effects of a fault on the reactor.

When a short circuit occurs in a feeder connected to an alternator without reactors, a high current flows, which is limited only by the impedance of the alternator and the section of the line extending to the short circuit. For a moment, the current is given as $I = V/Z$, where

V = terminal voltage,
Z = impedance of line to the short circuit.

This high current demagnetizes the alternator field and reduces the alternator's terminal voltage, thus reducing the current supplied. This shows that when an alternator is short-circuited, it supplies, for a moment, a current that is much greater than will flow after the current becomes steady. *The momentary current is about three times as great as the steady current. The steady current is from four to nine times as great as the full-load current*.

The magnetic field established by the high momentary current will set up forces that may destroy circuit breakers. To eliminate this high momentary current, to reduce the steady current during a short circuit, and to permit the use of lower capacity circuit breakers, it is customary to insert *current-limiting reactors* in alternator leads, between bus sections and in outgoing feeders. With this arrangement, the alternators can maintain a voltage to the system while a short-circuited section is being removed.

To justify the inclusion of reactors, the capital, running and depreciation costs of the reactors themselves and the additional CBs, isolators, protective equipment, etc, must be balanced against the savings in switchgear cost due to the reduced kVA rating. The number of circuits in a substation usually has to be large to justify the use of reactors, and it is in LV distribution substations that they mostly find application. Sometimes when fault levels are increased by system expansion, reactors are added to existing substations to keep fault level within the capacity of the existing switchgear.

Since the incorporation of reactors does not materially affect the consideration of busbar systems or basic layout, they will be omitted in the diagrammatic representation of busbar systems.

3-1.3 Busbar Systems

In designing networks, supplies can be provided to different areas of the system in a variety of ways, depending on the load density and system voltage level. Furthermore, depending on the level of security of power supplies to be provided, the future growth and development of the supply system, the reliability of supply during maintenance or faults, etc., various arrangements of busbar and the associated networks are possible. Whatever system arrangement is used, the designer must ensure that he has achieved a practical arrangement at the lowest cost, with some flexibility to cater for as yet unknown future expansions.

The following busbar arrangements may be considered.

1. Radial or single busbar system
2. Ring system
3. Mesh system
4. Interconnected system
5. Transfer busbar system
6. Duplicate busbar system

3-1.3.1 Radial or Single busbar System

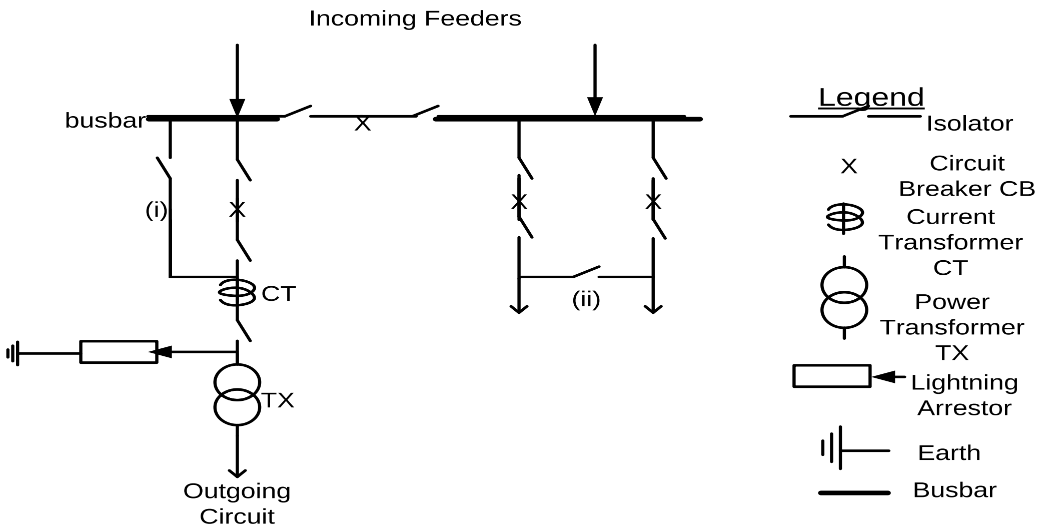


Fig 1.1: Single Busbar System

The single busbar arrangement is the simplest configuration of busbar system to provide a convenient method of operation. Here a number of incoming feeders are bussed together with local transformers. The single busbar system has a low level of security as far as power supply is concerned.

The **single busbar or radial system** has a number of ***disadvantages***. These include:

- With single busbar arrangement, a circuit or transformer has to be taken out of service to enable maintenance of the associated CB to be carried out.
- Maintenance or extension of the busbar, or of any busbar isolator in a single-busbar substation, would require a complete shutdown of the substation and loss of all circuits connected to the busbar.
- Furthermore, it has no security against a fault on the busbar, and so a *busbar fault* would cause *all CBs* connected to the faulty busbar to trip, thus isolating the switchboard and disconnecting all the circuits connected.

The number of circuits lost during maintenance or extension work or fault on the single busbar can be reduced by *sectionalizing*, i.e., by adding a busbar-section circuit breaker as shown. *The ultimate reduction in lost circuits is achieved when there are as many busbar sections as circuits*. Further security improvements can be obtained by connecting the ends of the single busbar to obtain the ring busbar.

If maintenance is the only consideration, isolators can be used instead of circuit breakers for sectionalizing. It was probably considerations such as these that led to the evolution of the ring busbar and mesh systems.

Circuit breaker bypassing facilities can be added to a circuit in a single busbar system by providing an extra isolator as shown at point (i) in the figure above. This permits the servicing of the circuit breaker without disconnecting the transformer. This puts the circuit protection out of service during the course of CB maintenance, and a circuit fault would cause a busbar shutdown. *Therefore when bypassing the circuit breaker, a fault-making switch is used for back-up protection, in case a fault occurs whilst the CB is being serviced*.

Another form of bypassing can be achieved by installing an extra isolator between two adjacent circuits as at point (ii) in the above figure, so that the circuit can be paralleled onto one CB during maintenance of the other. In this arrangement, protection is retained on the circuits, but there is no discrimination; a fault on one circuit involves the temporary loss of the other.

3-1.3.2 Ring System

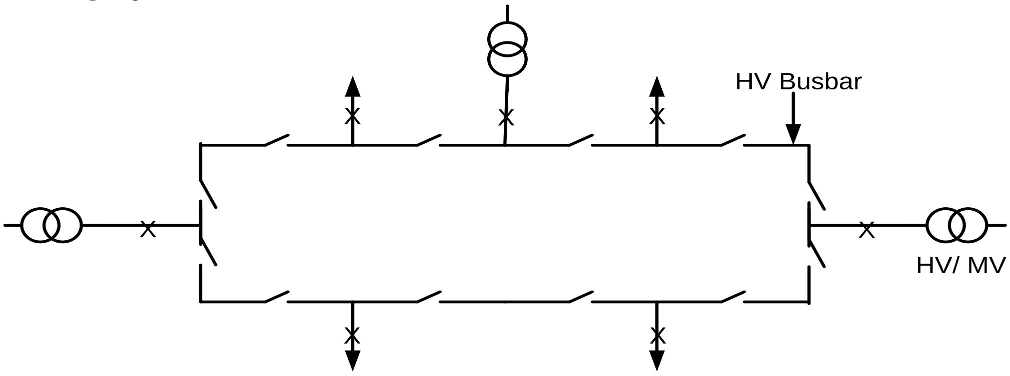


Fig 1.2: Ring System

The **ring busbar system** gives rather better security than the single busbar system because alternative routes round the busbar are available to outgoing circuits. It should be emphasized, however, that the immediate result of a busbar fault is the same as that with a single busbar system, namely, the loss of all circuits connected to the busbar. The difference lies in the fact that the fault can be isolated by opening busbar-section isolators, allowing reinstatement of most of the circuits.

The busbar-section isolators decrease the security of the busbar zone by adding more insulated paths to earth, and increase the number of units to be maintained. Furthermore, unless each busbar-section isolator is duplicated, its maintenance involves the loss of two adjacent circuits. Whether this can be tolerated depends on the importance of the circuits and on the degree of duplication of supply routes in the power system.

The ring busbar system requires more space than an equivalent single busbar system, particularly if the busbar-section isolators are duplicated. The ring system is used in distribution substations, but not for main transmission substations.

3-1.3.3 Mesh System

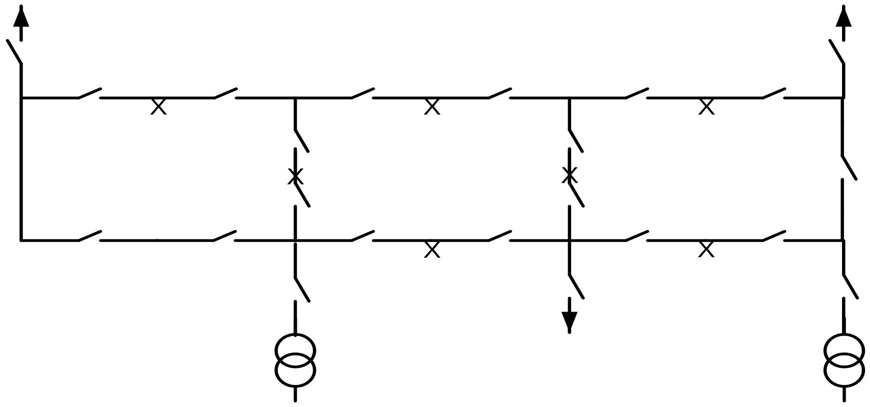


Fig 1.3: Mesh System

In the mesh arrangement, the CBs, instead of being in the circuit tee offs, are in the busbar, which is of the ring type. The operation of two circuit breakers is therefore required to connect or disconnect a circuit, and at disconnection, the ring is broken.

The **mesh system** has three **advantages** over single or ring busbar systems.

a) It allows maintenance of any circuit without loss of supply or protection, and without added bypassing facilities
b) A fault at any point on the busbar causes loss of only one circuit
c) A fault on a circuit breaker causes the loss of only two circuits, regardless of the total number of circuits.

To cover all contingencies of switching, all the CBs and CTs in a mesh must be able to pass maximum current that may flow around the mesh, which is the equivalent of the busbar current rating in other types of busbar systems. This may increase cost.

3-1.3.4 Interconnected System

Increased security can be provided by the addition of further interconnecting circuits to obtain the *interconnected system* as shown in Fig. 1.4. Subject to satisfactory network circuit loadings, such an arrangement can accept the loss of one infeed (feeder) without interruption of supplies within the network.

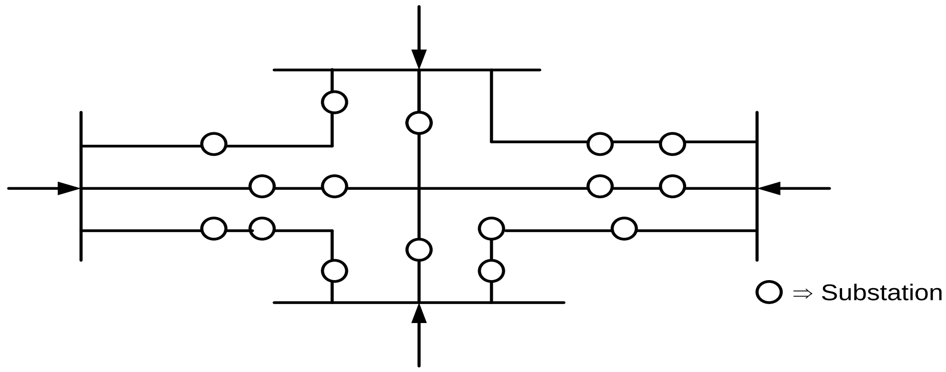


Fig 1.4: Interconnected System

Care must, however, be taken that the fault levels within the network are acceptable. Voltage levels and reactive power flows throughout the network may be a problem on extended interconnected systems, and parallel operation of the infed points can result in reverse power flows through the infed transformers under outage conditions on the higher-voltage system.

Due to the increased security of supply, the mesh and interconnected arrangements are frequently used in HV systems. Whilst this arrangement requires more substation equipment overall (e.g. switchgear and electrical connections), it is usually more efficient in terms of total circuit costs. The mesh and interconnected arrangements are easier to extend, and has a higher utilization of circuits when fully developed, although this can result in higher network losses.

3-1.3.5 Transfer Busbar System

The transfer busbar system is a single busbar system to which has been added facilities for *bypassing any one circuit breaker on load*, with retention of protection on the circuit concerned.

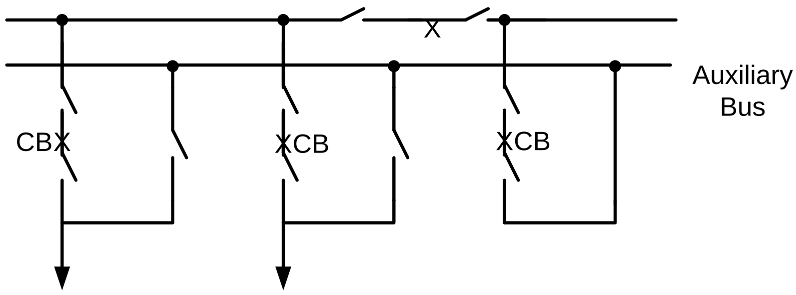


Fig 1.5: Transfer Busbar System

By connecting an auxiliary transfer busbar and a *busbar-coupler circuit breaker* BC to the original single busbar layout, a circuit can be selected to the auxiliary busbar by suitable use of busbar-selector disconnectors.

The protection is arranged to trip the bus-coupler circuit breaker, so that it takes the place of the normal circuit breaker. *Circuit breaker CB can then be isolated for routine maintenance or repair, or examination after fault clearance, with the circuit still in operation.*

The **transfer busbar system** has the following ***advantages***:

1. It is possible to arrange the various circuits into different configurations on the two busbars, as required for operational reasons.
2. It is also possible to select all circuits to one busbar, releasing the other busbar for maintenance such as insulator cleaning.
3. The bus-coupler circuit breaker enables *on-load transfer* of a circuit to be carried out from one busbar to the other.
4. The installation of a busbar-section circuit breaker in one of the busbars provides improved circuit marshalling facilities, and permits segregation of circuits to minimize the effect of busbar faults.

For reasons of space, ‘wrap round’ arrangements are often adopted with the reserve busbar encircling a central main busbar.

3-1.3.6 Duplicate/Double Busbar System

The duplicate busbar system is one of the commonest systems in use, and makes it possible to cater for a wide variety of system operational requirements.

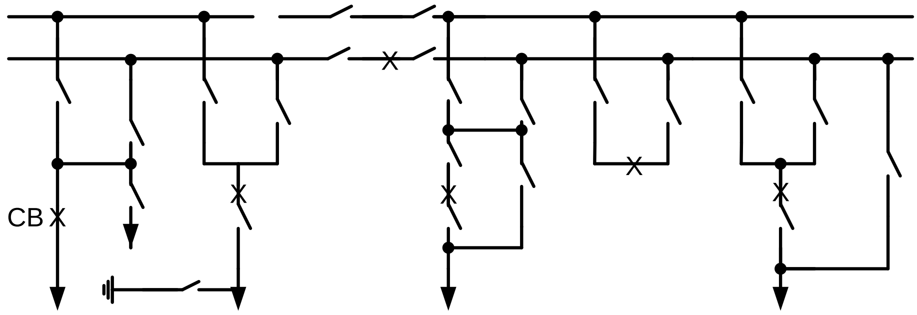


Fig 1.6: Duplicate Busbar System

The duplicate or double busbar system is most suitable for highly interconnected power supply system in which the facility to group circuits together, in a variety of combinations changeable at will, is of paramount importance. This is made possible by the fact that each circuit has the capability of being connected to either busbar by means of its two busbar-selector isolators. It is often usual to connect two circuits from one area to different sections of busbars, in order to avoid huge loss of supply on busbar faults. The number of incoming lines, generators, and transformers connected to a particular section of busbar or group of busbars, can be restricted to avoid excessive phase-earth or 3-phase fault currents.

If a busbar-coupler circuit breaker is provided, the selection can be carried out *on-load* by first paralleling the busbars by closing the busbar-coupler circuit breaker and its isolators. Whether a duplicate busbar substation is operated with circuits shared between its two busbars or all connected to one busbar, the effect of a busbar fault is the same as in the case of a single busbar substation, namely, the loss of all circuits connected to the faulty section.

The **advantages** of the **duplicate busbar system** are:

1. In the event of a fault on a busbar, it enables all the circuits on the faulty busbar to be transferred to the unfaulted busbar and reinstated immediately. *This takes away the loss time needed to operate the busbar-selector isolators of all the involved circuits, plus any time required for investigation and decision-making*. Particularly, if the busbar-selector isolators are hand operated, it is unlikely that the total time will be any less than that required to discover the fault and reinstate the circuits on the original busbar.
2. Maintenance of the busbars or busbar-isolators and extensions to the busbars can be performed without the loss of more than one circuit.
3. The second busbar reduces the extent of outage required and busbar-isolator maintenance.

On-load circuit breaker bypassing facilities, similar to those of a transfer busbar system, can be provided in a duplicate busbar substation by adding an isolator as shown at point (iii) to each circuit, and a busbar-coupler circuit breaker and its isolators. *If the substation is operated with both busbars in service, it is necessary to clear one busbar by transferring its circuits on-load to the other busbar before a circuit is bypassed*.

Since there is little advantage in being able to bypass to either busbar, and it also results in complications in interlocking and operational procedures, it is preferable in practice to pre-select one busbar as the reserve busbar to which all circuits will be bypassed.

3-1.4 Selecting a Busbar System

The selection of a busbar system must be considered in relation to the needs of the power system as a whole.

The *disconnection of a large portion* of the generating capacity of a power system can *result from a fault on the busbars of the associated substation*. *It is therefore not advisable to have too many generators on one section of busbar, and if the generators are of very large output, it is wise to limit the number to one*.

The large number of busbar-section circuit breakers required to achieve this in a duplicate busbar system, however, makes it expensive.

The vulnerability of a substation to the various hazards must be taken into account. The effect of atmospheric pollution on the frequency of maintenance may justify expenditure on circuit-breaker bypassing or sectionalizing. Lightning and the possibility of sabotage – all have their influence. In extreme form, these hazards may necessitate putting a substation indoors and this may affect the choice of busbar system.

The future growth and development of the supply system must be catered for. The need for economy in the early stages, coupled with the desire for the later introduction of more elaborate features, such as switching flexibility, may justify the conversion of a substation from one busbar system to another during its lifetime. Ease of extension is influenced by physical layout as well as by the busbar system. Generally, extension of single busbar and transfer busbar substations involves shutting down all the circuits on a busbar section; whereas extensions to ring busbar, mesh and duplicate busbar substations can usually be done without losing more than one circuit. However, it must be noted that the reliability of supply during maintenance or faults is often the most important factor.

3-1.5 Busbar Protection

Fault levels at substation busbars are usually higher than elsewhere on the system. Consequently, *faults at substations can often cause serious damage to equipment, and be a source of potential danger to staff and buildings, and seriously affect the reliability of supply*. To protect against busbar faults, a form of ***differential protection*** is used where incoming and outgoing feeder flows are summated. A busbar fault would result in an imbalance in the summated CT currents, causing the protection to operate to ensure that all circuit breakers connected to the faulty busbar are opened to clear the fault.

Because of the importance of not isolating busbars unnecessarily, it is usual to provide two sets of busbar protection. Tripping of CBs is then only initiated when both sets of protection operate. In addition, mechanical, electrical and electromechanical *interlocking systems* are in use to prevent incorrect interconnection of equipment; e.g. to ensure that disconnectors cannot be opened on load or energized circuits connected to earth.

\

SESSION 4-1 EXERCISES ON SUBSTATION DESIGN

Exercise 1.1

(a) Give a sketch of the radial and transfer bus system configurations, and discuss the merits and demerits of each.
(b) What is voltage regulation? State THREE means of achieving voltage regulation at a substation?
(c) Discuss the *sequence of operation* of circuit breakers and isolators in a switching operation.
(d) Mention any FIVE elements of a power substation, and explain their main functions in the substation.

Exercise 1.2

(a) Using a single line diagram illustration, discuss THREE disadvantages of the single busbar system. How can these demerits be minimized?
(b) Mention any FIVE considerations that influence a substation design.
(c) Using a single line diagram illustration, discuss THREE advantages of the transfer bus system.
(d) Briefly comment on any THREE considerations made when selecting a particular busbar system

Exercise 1.3

(a) Give a sketch each of the radial and transfer bus system configurations, and discuss TWO advantages and disadvantages of each.
(b) Explain what voltage regulation is, and state THREE means of achieving voltage regulation at a substation?
(c) State ONE main difference between circuit breakers and disconnecting switches as far as their switching operation is concerned? Why the need for two switching devices, in stead of one?
(d) If a transformer is to be switched out of a power system for maintenance purposes, what must be the correct *sequence of operation* of the circuit breaker and the disconnecting switch, and why?

UNIT 2

SYSTEM AND EQUIPMENT EARTHING

Introduction

This unit is on earthing. The subject earthing may be divided into:

- Equipment or general earthing and
- System or neutral earthing.

Learning objectives

On completion of this unit, you would be able to:

- Understand the various system earthing schemes, and their peculiar merits and demerits
- Explain the factors that are considered in the selection of an earthing scheme
- Understand ground or earthing resistance, and the factors that affect ground electrode resistance
- State typical grounding resistance values for different installations

SESSION 1-2 EQUIPMENT EARTHING

The main purpose of the *equipment earthing system*, that is, earthing the non-current carrying metallic frames of electrical equipment, is to improve safety to the general public, operational staff, property in general and to system electrical equipment. In a substation or other installations, the main earthing conductor in the form of a ring main around the site, is usually either accommodated in as series of trenches that may also contain multicore cables, or buried in the ground. Spurs join the various components to the main earthing conductor, and this is connected at a number of points to buried electrodes.

In outdoor substations, the muiticore cables and main earthing conductors only affect the substation layout in that their routes have to be planned to avoid structure foundations. All aspects of earthing, including methods of calculating the resistance of electrodes, recommended types of and sizes of electrodes and conductors, and also special arrangements for the earthing of structures, fences, lightning-protection devices and carrier-current equipment, are covered in the code of practice.

SESSION 2-2 SYSTEM EARTHING

The objects of *system or neutral earthing* are to:

I. Reduce the voltage stresses due to switching and lightning surges and
II. Control fault currents to satisfactory values

The method of earthing/grounding employed for earthing the star-point or neutral of a system affects the system behaviour, e.g., the maximum levels of earth-fault currents and permanent overvoltages. In general, a low earthing impedance means high earth-fault currents but low overvoltages during fault conditions.

The discussion will focus on neutral-point earthing practices for both HV/MV systems and LV systems. The neutral earthing practices of systems differ from utility to utility. Let us first consider the effects of various neutral earthing practices on HV/MV system operations, before dealing later with earthing of LV systems. In modern EHV systems, it is usual practice to earth the neutral either solidly or through resistors or reactors of low impedance. Occasionally, arc-suppression coils, the so-called Peterson coils, are used.

Resistors or arc-suppression coils are usually connected to the neutral of generators or power transformers through isolators, and current transformers associated with earth-fault protection are generally included in the neutral-earthing connection. (These would be dealt with in detail later).

2-2.1 Hazard Voltage or Transfer Potential

On the occurrence of a fault to earth, the *value of the resultant earth fault current will depend on* the following three factors:

- phase voltage
- neutral earthing arrangement of the system and
- local earthing resistance R_e between the metallic frames and earth.

The flow of ground fault current results in voltage gradients on the surface of the earth in the vicinity of the grounding system as shown in the figure below.

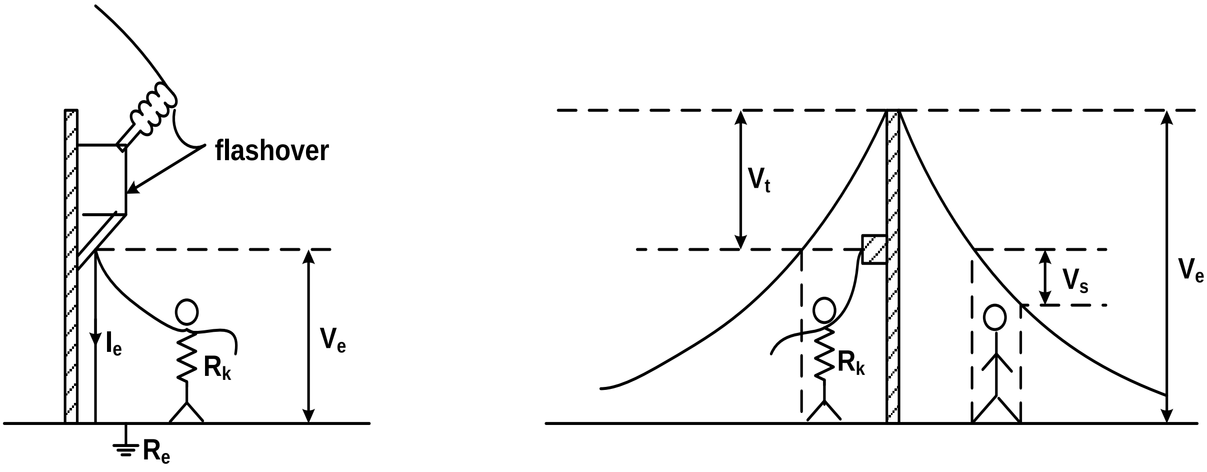


Fig 2.1: Voltage Gradient of Hazard Voltages

Where V_e = *maximum earth-fault voltage*

V_t = *touch voltage*

V_s = *step voltage*

R_e = *resistance to earth*

The figure shows the variation in hazard voltage (voltage gradient) around a steel pole or tower when touched by a live phase conductor, and illustrates how a person can be subjected to *touch and step voltages* with earth fault current flowing through the pole.

The earth-fault current I_e causes a so-called *transfer potential or hazard voltage* $V_e = I_e R_e$ between the frames of the faulted equipment and earth. *In practice, the full hazard voltage V_e seldom completely affects the person, as shown in the figure above, since the earth potential near the earth point is not zero, and there is a further earthing resistance between the feet of the person and 'solid earth' where there is zero potential.*

The ***step voltage*** is the voltage that exists between the two feet of a person standing on the grounding system, whereas the ***touch voltage*** is the voltage that exists between the hand and both feet of the person upon touching a faulted part. In order to limit the hazard voltages, either the fault current I_e must be reduced or the resistance R_e between the metallic frames and earth lowered.

2-2.2 Neutral Earthing Arrangements

In general, four earthing or grounding arrangements for the neutral points of HV/MV electrical systems can be envisaged. These are:

1. Isolating the neutral entirely
2. Solidly or direct earthing
3. Impedance earthing
4. Arc suppression or Peterson-coil earthing

The selection of a method for power system grounding is very difficult because a large number of factors must be considered before a power system earthing method can be chosen. On HV/MV transformers, the appropriate earthing arrangements can be applied to both the primary and secondary windings. On distribution systems, it is only necessary to earth at the source supply point. Thus MV system earthing, if any, is normally carried out on the secondary neutral of the infed HV/MV transformers. *In addition, the metal frames of all transformers and other equipment are solidly earthed in HV/MV systems*, whichever neutral earthing practice is adopted.

When applying methods (1), (2) and (3), the appropriate earth connection is made on to the neutral point of the transformer winding, i.e., at the neutral point of the star windings of a transformer, where the neutral of the network is directly available.

2-2.2.1 Isolated or Ungrounded Neutral Systems

In an isolated network, there are no direct or low-resistance connections between the system neutrals and earth. This results in the zero-sequence impedances of the generators and transformers having infinite value, and the network zero-sequence impedance being determined by the earth capacitances of the lines. *Ungrounded neutral systems are thus in effect capacitive grounded neutral systems, the capacitance being the conductor capacitance to earth.*

The figure below shows an isolated neutral system and the phasor representations of the phase voltages and *capacitive* currents.

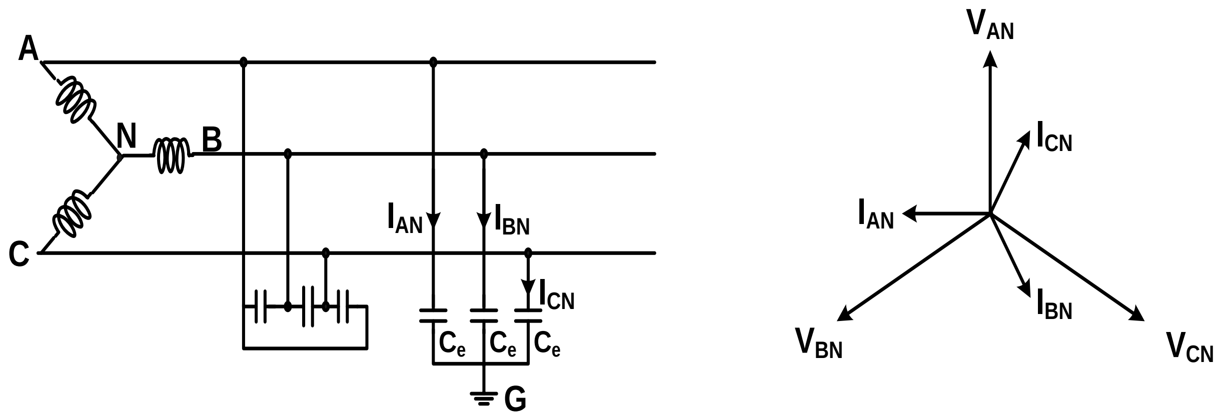


Fig 2.2: Isolated Neutral System and Phasor Representations of Voltages and Currents

The line conductors have capacitances between one another and to ground. The former as represented by the delta set of capacitances have little influence on the grounding characteristics of the system, and will be discarded from the considerations.

In normal balanced operation, the capacitive currents in each of the earth capacitances will be equal and displaced 120° from each other. The voltages across each branch are therefore equal and also displaced by 120° to each other. The capacitive currents of all three-phase lines are leading the respective line to neutral voltages by 90°, and the vector sum of all three currents is zero.

But during a phase-earth fault on say phase B, the charging/capacitive current of the faulted phase goes to zero because its voltage to earth is zero. The phasor relationships after the line-ground fault on the isolated system are shown in the figure below:

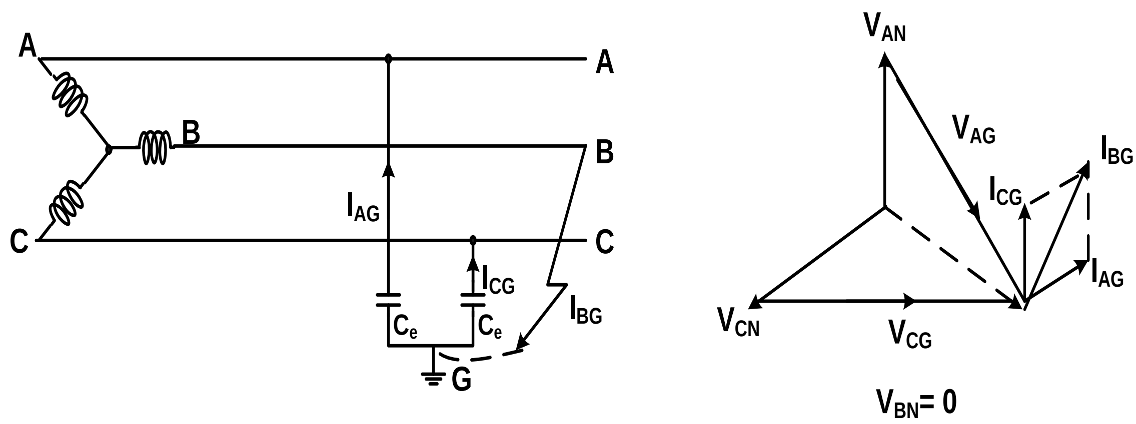


Fig 2.3: Isolated System with Ground Fault on Phase B

As shown in Fig 4.3 (b), when phase B is grounded, the voltages of the unfaulted phases V_{AN} and V_{CN} across the other two earth capacitance branches will *increase* to line-to-line values V_{AG} and V_{CG} respectively with respect to ground. As can be seen, these voltages V_{AG} and V_{CG} are no longer 120° out of phase, but 60°.

Hence the sum of currents I_{AG} and I_{CG} is ***three times*** the original capacitive current to neutral. That is, $I_{BG} = 3I_{AG} = 3I_{CG}$. The faulty phase B supplies current, which is equal and opposite to I_{BG}. This fault current being capacitive, leads the original phase to neutral voltage by *90^0*, and appears in the neutral, returning to the system through the fault.

If the fault can be interrupted, it is most likely to be done at current zero. However, since the current leads by *90^0* in the capacitive circuit, current zero occurs at the instant of a voltage maximum. Thus, if the fault momentarily clears, a high voltage immediately appears across the fault and restrike of the fault will probably occur. This is the so-called phenomenon of *arcing grounds*.

In the momentary interval of time that the fault has been cleared, the excessive voltage charge of the capacitors on the unfaulted lines has been trapped as a DC charge. When the arc restrikes again, the capacitors are again recharged by a line-to-ground voltage added to the trapped charge.

Thus a restrike after current zero clearing is more inevitable, adding another charge. The phenomenon thus probably becomes an oscillating and self-perpetuating buildup in voltage, which eventually will lead to an insulation failure on another phase and a major two-phase fault.

While the first failure may have been a tree branch in the line, the second failure (as a result of arc restrike and buildup of overvoltages) may occur at some other location entirely, perhaps involving expensive equipment insulation, such as a transformer. *Thus the principal advantage claimed for the ungrounded system actually caused troubles that resulted in its abandonment.*

The maximum value of the earth-fault current in the isolated system being considered is virtually only dependent on the total capacitance to earth of the lines. The earth-fault current I_f in a phase-earth fault is:

$$I_f = \frac{V_{ph}}{R_f + (1/j3\omega C_0)} \tag{2.1}$$

where R_f = fault resistance

C_0 = earth capacitance of one phase

V_{ph} = phase-earth voltage before the fault

Isolated or ungrounded neutral systems offer the following ***advantages***:

- ❖ Operating a system with the neutral isolated results in low values of earth-fault current equal to the system capacitance current.
- ❖ The voltage between faulted equipment and earth is consequently small, which improves safety. Thus for the same hazard voltage, *relatively higher* protective earthing resistances are acceptable, compared with most other neutral earthing systems.
- ❖ The voltages of the healthy phases are unaffected by a ground fault, thus avoiding outages of healthy phases.

However, the ungrounded system also suffers the following main ***disadvantage***:

- There exists the high probability of *arc restrike* when interrupting the fault current, and this can lead to the phenomenon of *unsafe buildup of transient overvoltages in the system*, dangerous to both personnel and equipment.

***NB**: This trouble, coupled with other factors, led to the adoption of grounded neutral systems in some form.*

Some of the other factors that led to the adoption of grounded systems were as follows:

- Because of the greater danger to personnel, code authorities frowned on ungrounded systems.
- Equipment costs were generally lower for equipment rated for grounded neutral systems because of the reduction in insulation permissible.
- At high voltages being used today (69 kV and above), material savings in transformer costs can be realized by employing reduced basic insulation levels (BIL). The requirement for safely reducing insulation level demands that system neutral be earthed.

2-2.2.2 Solid or Direct Earthing

The simplest method of earthing is to solidly connect the neutrals of any wye-connected transformers or generators to earth. HV systems are usually solidly earthed. Let us consider a ground fault on a simple neutral earthed system where a direct metallic connection is made between the system neutral and earth, as shown in the figure below:

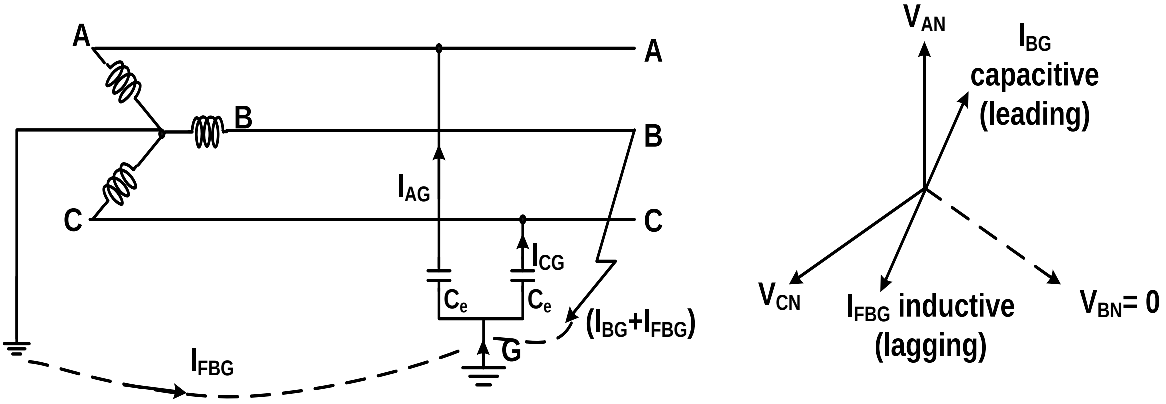


Fig 2.4: Ground Fault on Phase B of Solidly Grounded System

Due to the solid grounding of the system, the neutral point of the transformer is at ground potential. Therefore the healthy phases, in general, remain at their normal phase value, almost unaffected by the ground fault.

When a ground fault occurs on phase B, the voltage to earth of phase B becomes zero, and capacity current I_{GB} flows from faulty phase B to earth, and is then divided into two components I_{AG} and I_{CG} . In addition, the power source provides a faulty current I_{FBG} which flows through the faulty phase conductor to the fault location and returns to the power source by way of the earth path and the neutral connection.

The magnitude of this fault current I_{FBG} is determined by symmetrical components from the relation:

$$I_{FBG} = \frac{3V_{ph}}{Z_1 + Z_2 + Z_0} \qquad (2.2)$$

The resistance component of the zero sequence impedance of the power source winding is usually very small, so that the value $(Z_1 + Z_2 + Z_0)$ is predominantly inductive and the fault current I_{FBG} lags behind the original voltage of the faulty phase, by approximately *90⁰*. The resultant flow of the current, by superimposition of the leading capacity current I_{GB} and the lagging predominantly inductive current I_{FBG} , is shown in Fig (b) above.

The flow of the heavy lagging current through the fault will completely nullify the effect of the capacity current. No arcing ground phenomenon or its resultant overvoltage conditions can therefore occur.

The ***advantages*** of the system operation with the neutral **solidly earthed** include:

- It is simple and inexpensive in that it requires no extra equipment. The expense of the earth-current limiting device such as resistors, reactors, etc, is eliminated. This is an important consideration on HV systems when multiple earthing is used.
- The neutral point is held at earth potential under all operating conditions. Consequently, the voltage of any conductor to earth under earth-fault conditions will not exceed the normal phase voltage of the system.
- Hazard voltages are reduced to acceptable levels. Power frequency *phase-earth overvoltages* are lowest, typically below 1.4 p.u., and this explains why HV systems are solidly earthed.
- On HV systems 132 kV and above, additional savings are available because transformer windings with graded insulation can be used.
- The protection of the system is simplified by virtue of the fact that the ground fault current compares in magnitude with inter-phase fault currents. Near *generating stations*, the earth-fault current *may exceed* the corresponding 3-phase current. There is consequently no need to apply special sensitive earth fault relays. This tends towards simplification and in some cases, results in reduced earth fault clearing times.

In spite of the advantages of the solidly earthed systems, there are associated disadvantages such that other grounding methods are used. The ***disadvantages of solidly earthed systems*** are:

- A solidly grounded system produces the greatest magnitude of fault current when a ground fault occurs
- The *increased* ground fault current results in greater influence (interference) on neighbouring communication circuits.
- The *increased* ground fault current produces more conductor burning.
- Any third harmonic currents that may circulate between neutrals tend to be excessive. This applies when earthed neutrals are those of star-connected generators or transformers without a delta winding.

It must be mentioned that most of the adverse effects due to heavy ground fault currents have been overcome nowadays with high rupturing capacity (HRC) and high-speed circuit breakers and fast protective relays.

2-2.2.3 Impedance Earthing

MV systems often use different types of impedance earthing. When it becomes necessary to limit the earth fault current, a current-limiting device is introduced in the neutral and earth. Impedance earthing involves connecting a resistor or reactor between the system neutral point and earth. (See the figure below).

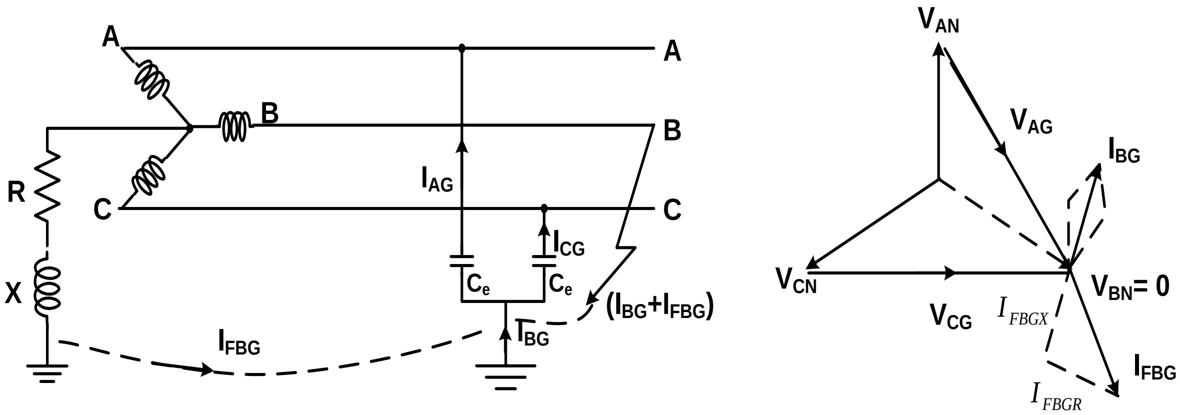


Fig 2.5: Impedance Earthing System – Phase B Faulted to Ground

The principle of current flows in the impedance earthing system is similar to that of solid grounding system, except that in the event of a ground fault, the phase-earth voltages of the healthy phases will increase to line values. Furthermore, the magnitude and phase relationship of the inductive fault current I_{FBG} depends on the relative values of the zero sequence reactance of the power source circuit and the ohmic value of the impedance.

The fault current I_{FBG} can be resolved into two components, one I_{FBGR} being in phase with the voltage to neutral of the faulty phase and the other I_{FBGX} lagging it by 90°. The lagging component of the fault current I_{FBG} will be in direct phase opposition to the resultant capacity current I_{GB} at the fault location.

By suitable choice of the ohmic value of the impedance, the lagging component I_{FBGX} of the fault current can be made equal to or more than the capacity current, so that no transient oscillation due to arcing grounds can occur.

However, if the ohmic value of the impedance is sufficiently high so that the lagging current I_{FBGX} is less than the capacity current I_{GB}, then the system condition approaches that of the ungrounded neutral system with the risk of transient overvoltages occurring. Another important but conflicting consideration in the choice of the ohmic value is the power loss during line to ground faults.

Therefore when using a resistor as grounding material, the value of its resistance must be fixed such that the earth-fault current passing through the transformer or generator windings is limited to the full rating of the largest transformer or generator.

Based on this practice, the value of the resistance R to be inserted in the neutral connections of earth is

$$R = \frac{V_{ph}}{I} \tag{2.3}$$

Where V_{ph} is phase to neutral voltage and

I the full-load current of the largest generator or transformer.

The ***advantages*** of **impedance grounding** are:

- It permits the use of discriminative protective gear
- It minimizes the hazard of arcing grounds (only in case of low resistance value)
- The ground fault currents are reduced, thus obviating the harmful effects of the heavy currents associated with solid earthing such as interference with communication circuits and burning of conductors, switchgear, motors, cables,
- It improves system stability under ground fault conditions.
- It reduces momentary line-voltage dip by clearing of ground fault
- It minimizes stray ground fault currents for personnel safety

The ***disadvantages*** of impedance earthing are:

- With an impedance-earthed system, the phase-earth voltage of a healthy phase can reach $\sqrt{3}$ *times the normal value under earth-fault conditions*, and occasionally some 5% higher, depending on the system R/X ratios. This should, however, not pose problems with system equipment, since the insulation level in MV systems is based on much higher lightning overvoltages.
- The *system neutral* will almost invariably be displaced during ground fault, thereby necessitating the use of lightning arrestors at an increase in cost and sacrifice in protective performance.
- The provision of the earth-current limiting device (resistor or reactor) means extra investment cost in the system.
- The inductive nature of the impedance earthing is of particular disadvantage with overhead lines exposed to lightning, since traveling waves or impulses are subject to positive *wave reflection*. This higher reflected wave voltage may unduly stress the insulation of the equipment and cause breakdown.

2-2.2.4 Arc-Suppression-Coil Earthing/Resonant Grounding

One of the earliest methods of attempting to eliminate the faults of the isolated system and still retain the claimed advantages for it was by means of *resonant grounding* using the arc-suppression-coil, also called Peterson coil after the inventor. The method attempted to eliminate the fault current that could cause the *arcing ground* condition.

Arc suppression coil earthing is the logical development of reactance earthing, whose inductance can be adjusted to closely match the network phase-earth capacitances, depending on the system configurations.

The inductance of the arc-suppression-coil is adjusted such that the inductive current due to the coil approximately neutralizes capacitive current through the total network capacitance 3C, at the fault. The resultant earth-fault current is theoretically nil and in any case inadequate to maintain the arc. *Hence the name "**arc suppression coil**".*

Because the resultant earth fault current is very small, the associated touch or step voltage is also small, so that most systems could be operated for long periods with a sustained fault until the fault can be cleared. Since the fault current in an arc-suppression-coil earthed system is small of the order of some tens of amperes, it is unlikely to cause damage to lines, cables or other equipment.

The figure below shows a ground fault on phase B of a system with the neutral earthed through an arc-suppression-coil. The corresponding phasor diagram for the voltages and currents is shown in the figure (b).

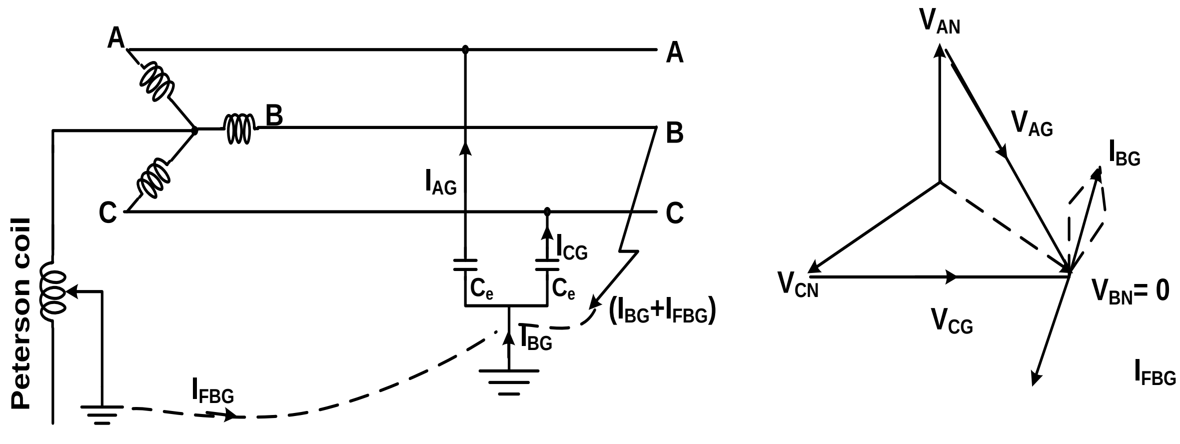


Fig 2.6: Resonant/Arc-Suppression-Earthing System – Phase B Faulted to Ground

It would be seen that under a single line to ground fault conditions, the following hold:

1. Voltage to earth of the faulty phase at the point of fault becomes zero
2. Voltage on the healthy phases is increased to √3 times the normal value
3. A resultant capacity current I_{GB} equal to ***three times*** the normal line to neutral charging current flows through the fault. This leads the voltage of the faulty phase by 90^o.
4. Voltage of the faulty phase, i.e., phase voltage, is impressed across the arc suppression coil, and a fault current I_{FBG} restricted in magnitude by the impedance of the coil, flows through the faulted conductor, lagging the voltage of the faulty phase by 90^o.
5. The capacity current I_{GB} and the fault current I_{FBG} are in direct phase opposition.

By suitably adjusting the value of reactance on the coil, the inductive fault current I_{FBG} can be made exactly equal to the capacity current I_{GB} , so that the resultant current is limited practically to zero.

In actual practice, however, there will always be a small residual current present in the fault due to the effect of resistance in the arc suppression coil itself and corona losses. This residual current is usually too small to maintain an arc and will not affect the arc extinction properties of the Peterson coil.

Moreover, very close tuning between the inductance of the Peterson coil and the capacitance of the system may not be obtained for all operating conditions in which small section of the system may sometimes be switched in or out of circuit without retuning the arc suppression coil.

Experience with MV systems has shown that it is possible to depart from the ideal tuning value of the Peterson coil by about 25% before operational problems with protection and high fault currents appear. It is therefore possible to place inexpensive small compensating equipment, each comprising a star-point transformer and arc-suppression coil with no automatic control, around the system. By properly locating these equipment on individual feeders around the distribution network, no additional automatically operating arc-suppression-coil compensation is required.

Determination of Inductance of Arc-Suppression-Coil

The inductance of the arc suppression coil may be determined as follows:

The capacitive current is *three times* the normal phase to neutral current. Thus

$$I_{GB} = \frac{3V_{ph}}{X_C} \tag{2.4}$$

Also, the fault current is given as

$$I_{FBG} = \frac{V_{ph}}{X_L} \tag{2.5}$$

And so for resonant grounding, $I_{FBG} = I_{GB}$ or $X_L = X_C / 3 \Rightarrow \omega L = \dfrac{1}{3\omega C}$

Thus

$$L = \frac{1}{3\omega^2 C} \tag{2.6}$$

where C is the capacitance of each sound conductor to earth.

2-2.3 Selection of Earthing System

The selection of a grounding system should be based on the following system factors:

- Magnitude of the fault current
- Transient overvoltage
- Lightning protection
- Application of protective devices for selective earth fault protection
- Types of load served, such as motors, generators, etc.

In the selection of earthing equipment and methods, many factors must be considered. It is desirable from the point of view of reduction of fault damage, repair costs, and switching equipment maintenance to limit the earth fault current as much as possible.

However, the greater the limitation of current, the higher the possible transient overvoltages that will be encountered. This will determine the equipment insulation levels required and the rating of lightning arresters required to protect the equipment, and will consequently affect costs. Therefore these factors are in conflict with the desire for maximum fault limitation.

Whether resistors or reactors are used will determine the degree of overvoltage expected on a given system for a given degree of current limitation and thus affect the selection of the use of resistors or reactors.

Since the degree of current limitation employed may well have a serious effect upon the ability of protective devices (relays, fuses, etc) to operate as desired, it follows that the degree of current limitation that can be employed may well be determined by the sensitivity of protective devices used, or conversely, the type and sensitivity of the protective devices required may be determined by the degree of current limitation.

However, since a multiplicity of feeders at generator voltage depends upon earth overcurrent relays for their earth fault protection, earth fault current must be kept up to a value that will give adequate relay operating torque for any and all earth faults on them, with reasonable current transformer ratios and relay current ranges.

The selection of the value to which the earth fault is to be limited becomes the problem of making a selection between the minimum ground fault current to limit damage, the minimum ground fault that will give adequate protective device operation and the maximum earth fault current that the generator and transformer windings can tolerate before there is the danger of magnetic forces forcing windings out of the generator armature slots.

2-2.4 Ground or Earth Resistance

*The term "**earth or ground**" is defined as a conducting connection by which a circuit or equipment is connected to earth*. The connection is used for establishing and maintaining as closely as possible the potential of the earth on the circuit or equipment connected to it. A "ground" consists of a grounding conductor, a bonding connector, its grounding electrode(s) and the soil in contact with the electrode.

Grounds have several fundamental protection applications. For natural phenomena, such as lightning, grounds are used to provide a discharge path for the current to reduce shock hazard to personnel and to prevent damage to equipment and property.

For induced potential due to faults in electric power systems with ground returns, grounds help in ensuring rapid operation of the protection relays by providing low resistance fault current paths. This provides for the removal the included potential as quickly as possible. The ground should drain the induced potential before personnel are injured and the power or communications system is damaged.

Ideally, to maintain a reference potential for instrument safety, to protect against static electricity and limit the equipment ground voltage for operator safety, an earth resistance should be zero. In reality, this value cannot be achieved. However, low earth resistance is required by electrical safety codes and standards.

2-2.4.1 Ground Electrode Resistance

The figure below illustrates a grounding rod-(electrode). The resistance of the earthing is made up of the following components:

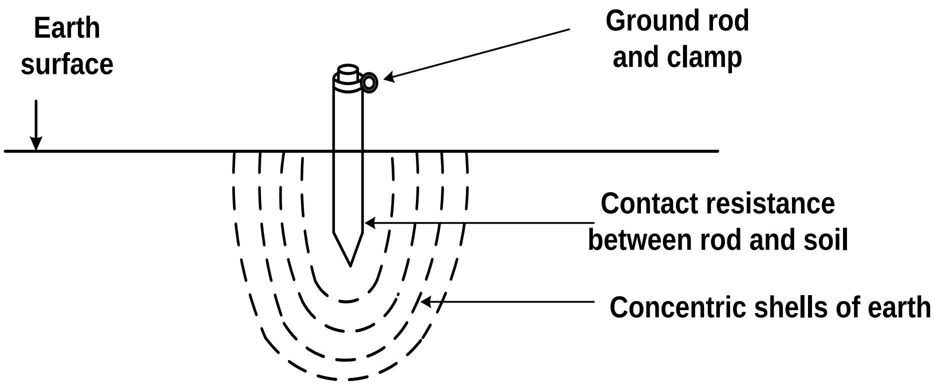


Fig 2.7: Grounding Electrode

1. Resistance of the electrode itself and that of the connection to it
2. Contact resistance of the surrounding earth to the electrode
3. Resistance of the earth immediately surrounding the grounding electrode or resistivity of earth, which is often the most significant factor.

The grounding electrodes are usually made of a very conductive metal (copper or copper clad) with adequate cross-sections, so that the overall resistance is negligible. The resistance between the electrode and the surrounding earth is negligible, if the electrode is free of paint, grease or other coating, and if the earth is firmly packed. The only component remaining is the resistance of the surrounding earth.

The electrode can be thought of as being surrounded by concentric shells of earth or soil, all of the same thickness. The closer the shell to the electrode, the smaller its surface; hence the greater its resistance. The farther away the shells are from the electrode, the greater the surface of the shell; hence the lower the resistance.

In theory, the grounding resistance may be derived from the general formula:

$$R = \frac{\rho l}{A} \quad \Rightarrow \quad \textit{resistance = resistivity x length/area} \tag{2.7}$$

This formula illustrates why the shells of concentric earth resistance decrease in resistance the farther away they are from the ground rod.

$$\textit{resistance = resistivity of soil x thickness of shell/area} \tag{2.8}$$

In the case of ground resistance, uniform earth (or soil) resistivity throughout the volume is assumed, although this is seldom the case in nature. The equations for system electrodes are very complex and often expressed only as approximations. The most commonly used formula for single ground electrode systems, developed by Prof. H. R. Dwight, is the following:

$$R = \frac{\rho}{2\pi L}\left\{\frac{(\ln 4L) - 1}{r}\right\} \qquad (2.9)$$

where:

R = resistance (ohms) of the ground rod to the earth soil
L = grounding electrode length
r = grounding electrode radius
ρ = average resistivity (ohms-cm)

2-2.4.2 Effect of Ground Rod Size and Depth on Resistance

Depth:

As a ground rod is driven deeper into the earth, its resistance is substantially reduced. In general, doubling the rod length reduces the resistance by an additional 40%. *The NEC code requires a minimum of 8 ft (2.4 m) to be in contact with the soil. The most common is a 10 ft (3 m) cylindrical rod that meets the requirements of the code*.

Size:

Increasing the diameter of the rod, however, does not materially reduce its resistance. Doubling the diameter of the ground rod reduces resistance by less than 10%. A minimum diameter of 5/8 in (1.59 cm) is required for steel rods, and 1/2 in (1.27 cm) for copper or copper clad steel rods. Minimum practical diameter for driving limitations for 10 ft (3 m) rods are:

- 1/2 in (1.27 cm) - in average soil
- 5/8 in (1.59 cm) - in moist soil
- 3/4 in (1.91 cm) - in hard soil or more than 10 ft driving depths.

2-2.4.3 Effect of Soil Resistivity on Ground Electrode Resistance

Dwight's formula shows that the resistance to earth of grounding electrodes depends not only on the depth and surface area of grounding electrodes, but also on soil resistivity. *Soil resistivity is the key factor that determines what the resistance of a grounding electrode will be, and to what depth it must be driven to obtain low ground resistance*.

Soil resistivity is determined largely by its content of electrolytes, consisting of moisture, minerals and dissolved salts. A dry soil has high resistivity if it contains no soluble salts. Soil resistivity is also influenced by temperature.

Because soil resistivity directly relates to moisture content and temperature, it is reasonable to assume that the resistance of any grounding system will vary throughout the different seasons of the year.

*Since both **temperature** and **moisture content become more stable at greater distances below the surface of the earth**, it follows that a grounding system to be most effective at all times should be constructed with the ground rod driven down a considerable distance below the surface of the earth. Best results are obtained if the ground rod reaches the water table.*

2-2.4.4 Ground Resistance Values

The NEC code states that the resistance to ground shall not exceed 25 Ω. This is the maximum value of ground resistance, and in most applications, a much lower ground resistance is required. The question that lends itself to be asked is *"how low should a ground resistance be?"* An arbitrary answer to this question is difficult.

The lower the ground resistance, the safer; and for positive protection of personnel and equipment, it is worth the effort to aim at less than 1 Ω. It is generally impractical to reach such a low resistance along a distribution system or a transmission line or in small substations.

In some instances, resistances of 5 Ω or less may be obtained without much trouble. In others, it may be difficult to bring resistance of driven grounds below 100 Ω.

Accepted industry standards stipulate that transmission substations should be designed not to exceed 1 Ω resistance. In distribution substations, the maximum recommended is for 5 Ω or even 1 Ω. In most cases, the buried grid system of any substation will provide the desired resistance.

In light industrial or in telecommunication central offices, 5 Ω is often the accepted value. For lighting protection, the arresters should be coupled with a maximum ground resistance of 1 Ω. The table below shows typical values of ground resistance for various types of installations.

Table 2.1: Typical Grounding Resistance Values of Substations for Various Installations.

Installation	**Type**	**Maximum Substation Grounding Resistance Values***
Commercial	1. Metallic buildings 2. Wet wells, etc 3. Homes	≤ 25 Ω
Industrial	1. General facilities 2. Chemical 3. Computer 4. High speed loading facilities for chemical	5 Ω 3 Ω less than 1 Ω to 3 Ω less than 1 Ω
Utilities	1. Generating stations 2. Large substations 3. Distribution substations 4. Small substations	1 Ω* 1 Ω 1.5 – 5 Ω 5 Ω

***** For solidly grounded systems.

SESSION 3-2 EXERCISES ON SYSTEMS EARTHING

Exercise 2.1

(a) With the aid of diagrams, explain the following:
  (i) step voltage
  (ii) touch voltage

(b) With the aid of diagrams, explain the term *"resonant grounding"* as applied in systems grounding.
(c) Give TWO advantages and disadvantages EACH of ungrounded system earthing.
(d) With the aid of diagrams, show and explain the current distribution when a single phase-earth fault occurs in an *"impedance grounded"* power system.

Exercise 2.2

(a) What is earthing? Give any TWO reasons why earthing is employed.
(b) With the aid of diagrams, show and explain the current distribution when a single phase-earth fault occurs in a *"solidly grounded"* power system.
(c) Give 2 advantages and disadvantages each of an *impedance grounding* in a power system.

UNIT 3

OVERHEAD TRANSMISSION LINE DESIGN

Introduction

This unit is on overhead transmission line systems and their design. Here we shall look at the mechanical and electrical designs of the overhead transmission lines as well as insulators.

Learning objectives

On completion of this unit, you would be able to:

- Understand the components of an overhead transmission line
- Explain the mechanical and electrical considerations for the design of an overhead transmission line
- Know insulator types, and the measures adopted to obtain uniform voltage distribution along suspended insulators
- Understand sagging and factors that affect it
- Explain corona and corona loss
- Undertake exercises on sagging and corona.

SESSION 1-3 OVERHEAD TRANSMISSION LINE SYSTEMS

Electrical power can be transmitted or distributed either by overhead lines or underground cables. The transmission voltage is to a large extent determined by economic considerations. Given a particular power to be transmitted at a particular power factor, high voltage transmission results in low currents along the transmission line. Thus high voltage transmission requires conductors of smaller cross-section, which results in economy in conductor material, i.e., copper or aluminium. But at the same time, cost of insulating the line and other expenses are increased. Hence the economical transmission voltage is that for which the saving in copper or aluminium is not offset by;

(i) increased cost of insulating the line
(ii) increased size of transmission line structures and
(iii) the increased size of generating stations and substations.

Overhead lines mar the beauty of the surroundings, besides being susceptible to uncertain weather conditions and other external interferences such as lightning strikes, interruption due to trees falling on them to cause faults, etc. The underground system of transmission is therefore preferred to the overhead system in densely populated and lightning-prone areas where safety and beauty play greater roles in power distribution considerations.

However, underground systems are much more expensive. The heavy cost of underground cable systems, coupled with the fact that it is difficult to provide proper insulation to cables to withstand higher voltages, make power transmission over long distances a restricted area for overhead lines.

1-3.1 Mechanical Design of Overhead Transmission Line Systems

As mentioned earlier, overhead lines are deployed in the transmission and distribution of electrical power. Due to the unfavourable weather conditions and external interferences to which overhead lines are subjected, (such as temperature, humidity, pollution, wind, rain, lightning and solar effect, etc), there is the need to have proper mechanical factors of safety in order to ensure regular uninterrupted supply of power using overhead lines.

1-3.2 Components of Overhead Lines

The main components of an overhead line system are:

- *Conductors* – they carry power from the sending-end to the receiving-end.
- *Supports* – they may be wooden poles, steel poles, reinforced concrete poles or towers. The supports keep the conductors at a suitable level above the ground
- *Insulators* – they are attached to the supports and insulate the conductors from the ground
- *Cross-arms* – they provide support for the insulators
- *Miscellaneous items* – such as cross plates, danger plates, lightning arresters, anti-climbing wires, etc.

The correct choice of the above components can influence the continuity of operation of the overhead line systems.

1-3.2.1 Conductor Material

The conductor is one of the important items of overhead transmission line system, since most of the capital outlay is invested in it. Therefore the proper design and choice of conductor material and size is of considerable importance. An over-dimensioning of the overhead line system can have serious financial implications for the investment, whilst under-dimensioning might not serve operational (with respect to voltage drop) or future expansion requirements as the load on the system increases.

The selection of the type of conductor material is influenced by the:

- forces that act on it
- distance to be spanned
- cost of conductor
- required electrical and mechanical properties
- local prevailing conditions

Atmospheric forces vary with climate and situation, and short-circuit forces and those due to the weight of the conductor are also variable factors. A conductor for universal application therefore has to cater for horizontal and vertical forces of varying magnitudes acting simultaneously, which means that the line of action of the resultant force may occur in any plane. The optimum section to meet this condition is circular. *Therefore round or tubular conductors are favoured most.*

For short spans of a few metres, the effect of the forces is not significant, and other sections can be used, whilst for very long spans, transmission line practice using tensioned stranded conductors, can be adopted.

1-3.2.2 Properties of Conductor Material

An ideal conductor system should possess some ***properties***. These include:

1. Capability of carrying the specified load current and short-circuit current
2. High electrical conductivity (low impedance) – to reduce drops and losses, and hence improve voltage regulation
3. High tensile strength – to withstand mechanical stresses or forces on it due to its situation; these forces comprise:
    - forces due to its own weight and weight of any other conductors or equipment that depend on it for their support
    - short-circuit forces
    - atmospheric forces, i.e., wind and ice load
4. Corona-free at the rated voltage
5. Minimum number of joints
6. Minimum number of supporting insulators
7. Economical or low cost – so that it can be used for long distance operations.

All the above requirements are not found in a single material. Therefore while selecting a conductor material for a particular case, a compromise must be made between the desire for low cost and the required electrical and mechanical properties.

The two most suitable and common materials for overhead conductor systems are *copper* and *aluminium. Steel has been used, but it has the obvious limitations of poor conductivity and high susceptibility to corrosion.*

Copper:

- It is an ideal material for overhead lines owing to its high electrical conductivity and greater tensile strength
- It is always used in the hand-drawn form as stranded conductors
- It has high current density, i.e., the current-carrying capacity of copper per unit cross-sectional area is quite large. This leads to two ***advantages***:
    - Smaller cross-sectional area of conductor required and hence lower cost
    - Smaller cross-sectional area offered for wind loading
- The copper metal is quite homogeneous, durable and has a high scrap value
- However, copper is very expensive and not readily available.

NOTE: *There can be no doubt that copper is most ideal for transmission and distribution of electric power. However, due to its higher cost and non-availability, it is rarely used for these purposes. As such, the trend these days is to use aluminium in place of copper.*

Aluminium:

- It is cheap and light as compared to copper.
- Being light, aluminium conductors are subject to greater swings and hence larger cross-arms are required.
- It has much smaller conductivity and tensile strength.
- The lower conductivity necessitates increased cross-sectional area.
- Due to lower tensile strength and higher coefficient of linear expansion of, the sag in aluminium is greater than in copper.

NOTE: *Considering the combined properties of cost, conductivity, tensile strength, weight, etc., aluminium is gaining more edge over copper. It is particularly economical to use aluminium for heavy-current transmission, where the conductor size is large and its cost forms a major portion of the total cost of complete installation.*

1-3.3 Types of Line Conductors

Although aluminium-alloy conductors are used, generally at the smaller conductor sizes for LV and MV distribution, the more common type of overhead-line conductor in service is made from aluminium wires, which conduct the current, wound around a core of steel strands, which provide the mechanical strength for the whole conductor. This is designated as *aluminium-conductor steel-reinforced* ***(ASCR)*** *conductor*.

Conductors may be of the solid/flat-surfaced, stranded or tubular type.

1-3.3.1 Solid or Flat-surfaced Conductors

It is common for terminals of components to consist of flat palms, and a conductor having a flat surface that can be drilled at the ends so as to bolt directly to the terminal palm, gives the minimum number of joints, and eliminates the need for clamps and adaptors. *Lack of mechanical strength and rigidity limits the use of such solid conductors to short spans*, and corona susceptibility limits the maximum voltage at which they can be used.

Solid wires are only used when the cross-sectional area is small. If solid wires are used for larger cross-sectional area and longer spans, continuous vibrations and swinging would produce mechanical fatigue and they would fracture at the points of support.

1-3.3.2 Stranded Conductors

Where exceptionally long spans are required, *stranded* conductors are used. The use of tensioned stranded conductors leads to the system with fewest joints and the minimum of supporting insulation, but structure costs are high.

In stranded conductors, there is generally one central wire and around this are successive layers of wires containing 6, 12, 18, 24, ……. wires. Thus if there are *n*-layers, the total number of individual wires is given by the relation $3n(n+1)+1$. The standard sizes of stranded conductors that are available necessitate *bundling*, i.e., using two or more conductors in parallel, held apart by spacers. The bundling is to prevent corona at high voltages.

Stranded conductors offer the following ***advantages*** over tubular conductors:

i. The number of joints can be reduced, because spans can be longer and no special provision for expansion is required.
ii. Erection is simpler, and discrepancies in the civil works are easily accommodated.
iii. For large installations, and where overseas transport is involved, a drum of stranded conductor is easier and cheaper to handle, and is less liable to loss or damage, than are multiple tubular conductors.

1-3.3.3 Tubular Conductors

These are suitable for spans which are too long to be dealt with by stranded conductors. If tubes can be made to span greater distances, fewer joints and supporting insulators will be needed.

1-3.4 Overhead Line Supports

The required properties of overhead line supports are:

- High mechanical strength to withstand the weight of conductors and loading due to wind and/or (ice)
- Light weight without loss in mechanical strength
- Cheap in cost and economical to maintain
- Easy accessibility of conductors for maintenance
- Longer lifespan

The line supports used for transmission and distribution are of various types. These include wooden poles, steel poles, reinforced concrete poles and lattice steel towers. The choice of supporting structure for a particular case depends on the life span, cross-sectional area of conductors, line voltage, cost and local conditions.

1-3.4.1 Wooden Poles

- ❖ Are made of *seasoned wood* (e.g. teak) and are suitable for lines of *moderate cross-sectional area* and of relatively shorter spans, say up to *50 metres*.
- ❖ Are cheap, easily available, provide insulating properties and are therefore widely used for distribution in rural areas as an economic proposition.
- ❖ Have tendency to rot below the ground level, causing foundation failure. To prevent this, the portion of the pole below ground level is impregnated with preservative compound like creosote oil
- ❖ Comparatively smaller lifespan (20-25 years)
- ❖ Not recommended for voltages above 20 kV
- ❖ Less mechanical strength
- ❖ Requires periodic inspection

NOTE: *Double pole structures of H-type or A-type are often used to obtain a higher transverse length than could be provided economically by single poles.*

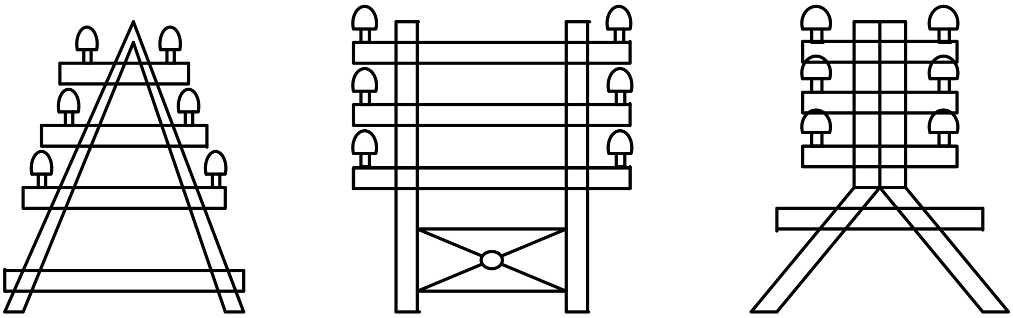


Fig 3.1: Wooden Pole Configurations

1-3.4.2 Steel Poles

- Normally employed for distribution in cities
- Possess greater mechanical strength
- Longer lifespan. They can be galvanized or painted in order to prolong their life
- Support longer spans
- Are of 3 types, namely, rail poles, tubular poles and rolled steel joints

1-3.4.3 Reinforced Concrete Poles

- Have greater mechanical strength
- Longer lifespan
- Permit longer spans than steel and wooden poles
- Give good outlook
- Require little maintenance
- ❖ Heavy weight

1-3.4.4 Steel Towers

- Normally employed for long distance transmission at higher voltages
- Have greater mechanical strength
- Longer life
- Permit the use of longer spans
- Can withstand most severe climatic conditions

NOTE: *Tower footings are usually solidly grounded*

SESSION 2-3 INSULATORS

Overhead line conductors should be supported on the poles and towers in such a way that current from conductors do not flow to earth through the supports, that is, the line conductors must be properly insulated from their support. This is achieved by securing line conductors to supports with the help of insulators. The insulators provide the necessary insulation between line conductors and supports.

The desirable properties of insulators are:

- High mechanical strength
- High electrical resistance
- High dielectric strength or relative permittivity
- Non-porous, free from impurities and cracks, so as not to lower the permittivity
- High ratio of puncture strength to flashover

The most commonly used material for insulation of overhead lines is porcelain, but glass steatite and special composition materials are also used to a limited extent. The most common types of insulators are;

(i) pin type
(ii) suspension type
(iii) strain insulators and
(iv) shackle insulator

2-3.1 Pin-Type Insulators

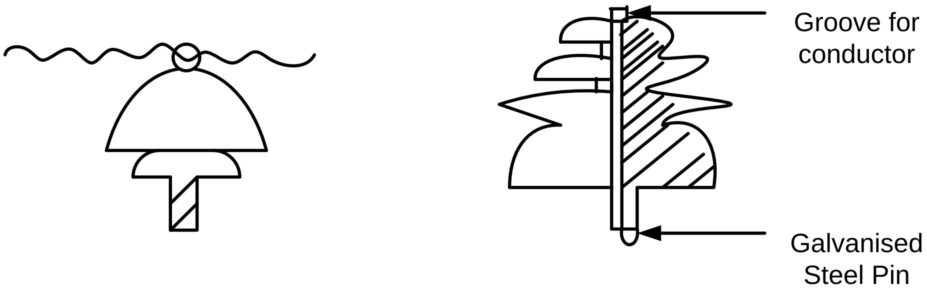


Fig 3.2: Pin-type Insulators

- Pin type insulators are used for voltages up to 33 kV.
- Pin type insulators have the disadvantage that the conductor runs on top of the insulator and is therefore exposed to lightning.
- Too bulky and thus uneconomical for higher voltages above 33 kV

2-3.2 Suspension-Type Insulators

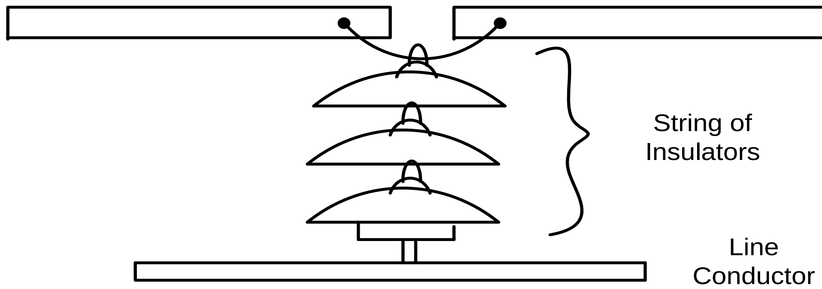


Fig 3.3: Suspension-type Insulators

Suspension type insulators are employed for higher transmission voltages (greater than 33 kV). Each disc in the string is usually designed for 11 kV. A number of them are connected in series to form a chain and the line conductor is carried by the bottom most insulator.

The main ***advantages*** of the **suspension type insulators** are:

- ❖ Suspension type insulators are cheaper than pin type insulators for voltages higher than 33 kV.
- ❖ They are generally used with steel towers. The conductors run below the earthed cross-arm of the tower, thereby providing protection against lightning
- ❖ Ease of selecting the number of discs for a particular voltage
- ❖ If any one disc is damaged, the whole string does not become useless because the damaged disc can be easily replaced
- ❖ The suspension arrangement provides greater flexibility to the line
- ❖ In the case of increased demand on the transmission line, it is found more satisfactory to supply the greater demand by raising the line voltage than to provide another set of conductors. The additional insulation required for the raised voltage can be easily obtained in the suspension arrangement by adding the desired number of discs.

2-3.3 Strain Insulators

They are employed at dead end corners or sharp curves, where the line is subject to greater tension. For low voltage lines, say up to 11 kV, shackle insulators are used as strain insulators.

2-3.4 Shackle Insulators

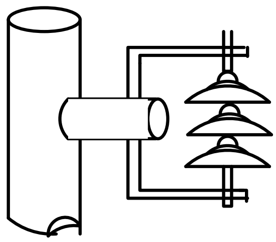


Fig 3.4: Shackle Insulator

2-3.5 Causes of Insulation Failure

Insulators are required to withstand both mechanical and electrical stresses. The latter type is primarily due to line voltage and may cause the breakdown of the insulator. *Electrical breakdown of the insulator can occur either by flashover or puncture*.

In flashover, an arc occurs between the line conductor and insulator pin (earth), and the discharge jumps across the air gaps, following the shortest distance. The insulator will, however, continue to act in its proper capacity unless extreme heat produced by the arc destroys the insulator. In the case of puncture, the discharge occurs from conductor to pin through the body of the insulator. Puncture breakdown permanently destroys the insulator due to excessive heat. The ratio of puncture strength to flashover voltage is known as *safety factor*, i.e., $Safety\ factor\ insulator = \frac{Puncture\ strength}{Flashover\ voltage}$. For pin type insulators, the value of safety factor is about 10.

SESSION 3-3 POTENTIAL DISTRIBUTION OVER A STRING OF SUSPENSION INSULATORS

A string of suspension insulators consists of a number of units connected in series through metallic links, the number of units depending on the transmission voltage. Each insulator units constitutes a capacitor. There exists therefore mutual or self- capacitance between different units. In addition, there exists capacitance to ground (tower) because of the nearness of the tower, cross-arm and line.

Due to this shunt capacitance to ground, the charging current is not the same through all the units. Consequently, the total system voltage is ***not equally distributed*** *over the different units of the string*. (See the Fig below).

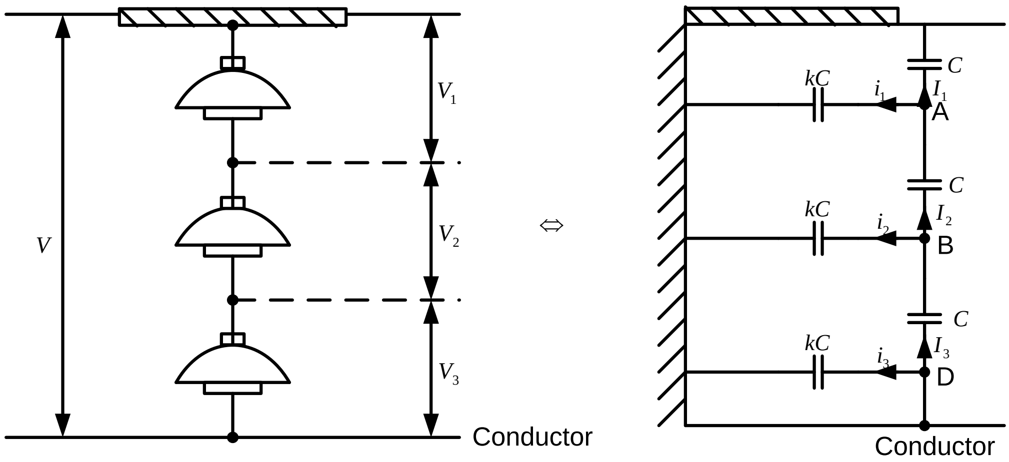


Fig 3.5: Suspension Insulator String and Voltage Distribution

Concerning the suspension insulator string, the following points must be noted:

- The voltage impressed on a string of suspension insulators does not distribute itself equally across the individual insulator units.
- The inequality of the voltage distribution between individual units becomes more pronounced as the number of insulator units increases, and it is also dependent on the ratio (capacitance of insulator/capacitance of earth).
- The unit closest to the line conductor carries the maximum percentage of the line voltage, the figure progressively decreasing as the unit nearest to the tower is approached.
- The unit nearest to the conductor is under maximum stress and is likely to be punctured first.

3-3.1 Calculation of Potential Distribution along Insulator Units

Suppose that the shunt capacitance to ground is a fraction k of the self-capacitance C of each insulator unit. That is;

C = *self capacitance of insulator unit*
kC = *shunt capacitance to ground (tower)*

It is seen that $I_1 = \dfrac{V_1}{1/\omega C} = \omega C V_1$ *(3.1)*

Similarly $i_1 = \dfrac{V_1}{1/\omega kC} = \omega Ck V_1$ *(3.2)*

Applying Kirchoff's current law (KCL) at node A,

$$I_2 = I_1 + i_1 = \omega C V_1 (k+1) \tag{3.3}$$

$$\Rightarrow \begin{aligned} V_2 \omega C &= V_1 \omega C + V_1 \omega Ck \\ V_2 &= V_1 (k+1) \end{aligned} \tag{3.4}$$

The shunt current i_2 is produced by the voltage combination of $(V_1 + V_2)$.

Appyling Kirchoff's Current Law at node B,

$$I_3 = I_2 + i_2 \tag{3.5}$$

$$\begin{aligned} V_3 \omega C &= V_2 \omega C + (V_1 + V_2)\omega Ck \\ V_3 &= V_1 k + V_2 (k+1) \\ &= V_1 k + \{V_1 (k+1)\}(k+1) \\ &= V_1 (k^2 + 3k + 1) \end{aligned} \tag{3.6}$$

Similarly, the voltages on the *nth* unit can be determined.

3-3.2 String Efficiency of String Insulators

If the string has *n* units, the total voltage across the string is given as:

$$V = V_1 + V_2 + V_3 + V_4 + ...V_n \quad (3.7)$$

The string efficiency is then given by;

$$\text{String efficiency } \eta = \frac{\text{total voltage across the string}}{n \times \text{voltage across the unit } \textit{closest} \text{ to the line}} \quad (3.8)$$

The string efficiency is an important consideration, since it decides the potential distribution along the string. The greater the string efficiency, the more uniform is the voltage distribution. Thus 100% efficiency is an ideal case for which the voltage across each unit will be exactly the same. Although it is impossible to achieve 100% string efficiency, it can be improved.

3-3.3 Improving the String Efficiency

The inequality of voltage distribution along the string increases with the number of units in the string. Therefore shorter strings have more efficiency. The greater the value of *k*, (i.e., the ratio of capacitance to earth/capacitance per unit), the more non-uniform is the potential distribution across the string, and hence the lesser is the efficiency.

If the insulation of the most stressed insulator unit is punctured or flashover takes place, the breakdown of the other units will take place in succession. There is therefore the need to equalize the voltage distribution across the various units, i.e., to improve the string efficiency.

The string efficiency can be ***improved*** by:

- Making the ratio of capacitance to earth/capacitance per unit as small as possible, through longer cross-arms.
- Use of *graded* insulators
- Providing a *guard ring* to surround the lowermost unit; this is connected to the metal work at the bottom. This ring increases the capacitance between the metal work and the line, and helps in equalizing the voltage distribution along the different units.

3-3.3.1 Longer Cross-Arms

The value of the string efficiency depends on the value of *k*, i.e., the ratio of shunt capacitance to self-capacitance. The lesser the value of *k*, the greater the string efficiency, and the more uniform is the voltage distribution. The value of *k* can be decreased by reducing the shunt capacitance. ***The shunt capacitance is reduced by increasing the distance of the***

conductor from the tower, i.e., the use of longer cross-arms. The extent of the reduction is, however, limited by cost and the mechanical strength. In practice, $k = 0.1$ is the limit achievable by this method.

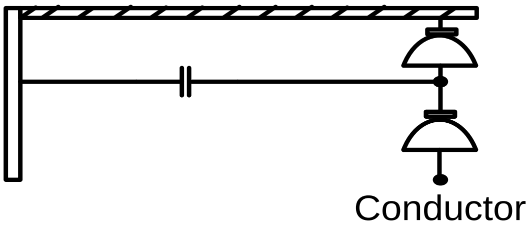


Fig 3.6: Cross-arm

3-3.3.2 Use of Graded Insulators

The insulators are capacitance graded, that is, they are assembled in the string in such a manner that the top unit has the minimum capacitance, increasing progressively towards the bottom unit that is nearest to the conductor. *Since voltage is inversely proportional to capacitance, this method tends to equalize the potential distribution across the units in the string*. The main problem is that it requires different-sized insulators.

3-3.3.3 Application of Guard Ring

Guard rings are metal rings electrically connected to the conductor and surrounding the bottom insulator. (See Fig below).

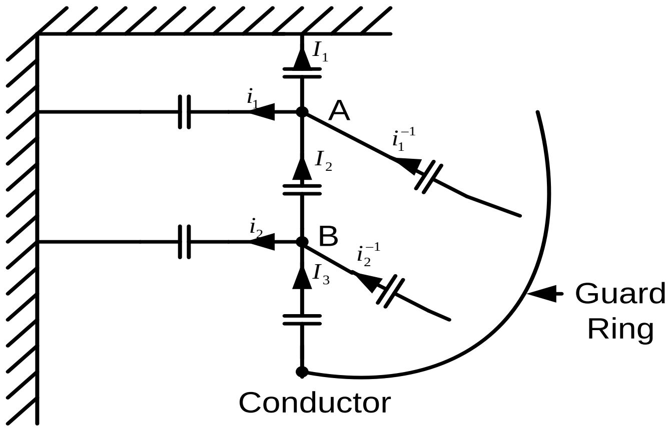


Fig 3.7: Use of Guard Ring For Uniform Voltage Distribution

The guard ring introduces capacitance between the metal fittings and the line conductor. The guard is contoured in such a way that the shunt capacitance currents i_1, i_2, i_3 etc., are equal to the metal fitting line capacitance currents. This results in the same charging current flowing through each unit of the string. Consequently, there will be uniform potential distribution across the units.

Example 3.1

Each line of a 3-phase 11 kV system is suspended by a string of 3 identical insulators. The self-capacitance of each disc is found to be 10 times the shunt capacitance to ground. Find the following:

1. voltage distribution across teach insulator
2. string efficiency

Solution 3.1

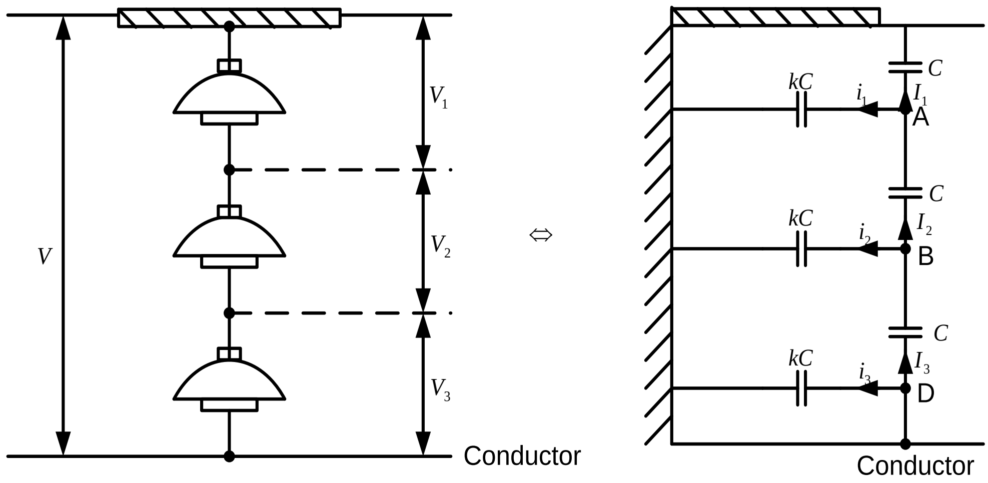


Fig: 3.8: String of suspended insulators

The phase voltage is given as $V_{ph} = \frac{V_L}{\sqrt{3}} = \frac{11}{1.732} = \underline{6.35\,kV}$

From Equations (5.4) and (5.6), $V_2 = V_1(k+1)$ and $V_3 = V_1(k^2 + 3k + 1)$

Where $k = \frac{C_{shunt}}{C_{self}} = \frac{1}{10} = \underline{0.1}$ But $V_1 + V_2 + V_3 = V_{ph}$, and hence

(a)

$$V_1 + V_1(k+1) + V_1(k^2 + 3k + 1) = 6.35$$
$$V_1 + V_1(0.1+1) + V_1\left[0.1^2 + 3(0.1) + 1\right] = 6.35$$
$$\Rightarrow V_1 = \underline{1.86\,kV}$$

Hence $V_2 = 1.1V_1 = 1.1 \times 1.86 = \underline{2.05\,kV}$

$$V_3 = 1.31V_1 = 1.31 \times 1.86 = \underline{2.44\,kV}$$

(b) String efficiency

$$\eta_{string} = \frac{V_{ph}}{n \times V_n} = \frac{V_{ph}}{3 \times V_3} = \frac{6.35}{3 \times 2.44} = 0.867 = \underline{86.7\%}$$

SESSION 4-3 SAG IN OVERHEAD LINES

The conductors of an overhead transmission line are attached to suitable insulators carried on supports of wood, steel or reinforced concrete. *The supports must be strong enough to withstand not only the dead weight of the conductors, but also the loads due to ice and other things that might adhere to them and to wind pressure*.

While erecting an overhead line, it is very important that conductors are under safe tension. If the conductors are too much stretched between supports in a bid to save conductor material, the stress in the conductor may reach unsafe value, and in certain cases, the conductor may break due to excessive tension.

In order to permit safe tension in the conductors, they are not fully stretched but are allowed to have *a dip or sag*. The difference in level between the points of supports and the lowest point on the conductor is called *sag*.

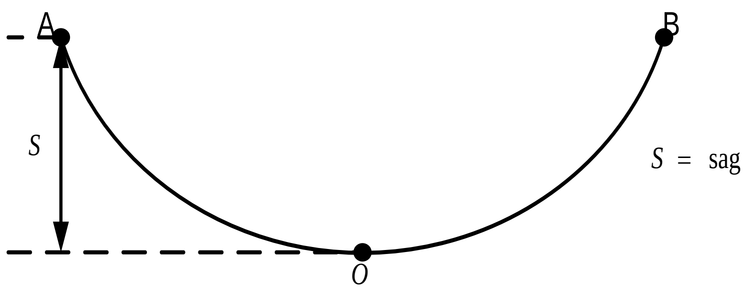


Fig 3.9: Sag in Overhead Lines

The following points about sag must be noted:

- ❖ Conductor sag and tension are important considerations in the mechanical design of overhead lines
- ❖ Sag should be kept minimum in order to reduce conductor material required, as well as avoid extra pole height for sufficient conductor clearance above ground level.
- ❖ Sag and stresses vary with temperature on account of thermal expansion and contraction of the line conductors.
- ❖ When a conductor is suspended between two supports at the same level, the sag-span curve approaches that of a parabola, if the sag is very small compared with the span.
- ❖ Tension in the conductor material must be low to avoid mechanical failure.

- The tension at any point on the conductor acts tangentially, and so the tension at the minimum point of sag is horizontal.
- The horizontal component of tension is constant throughout the length of the wire
- The tension at supports is approximately equal to the horizontal tension acting at any point on the wire.

We'll be treating sag calculation with supports at equal levels.

4-3.1 Sag Calculation When Supports Are At Equal Levels

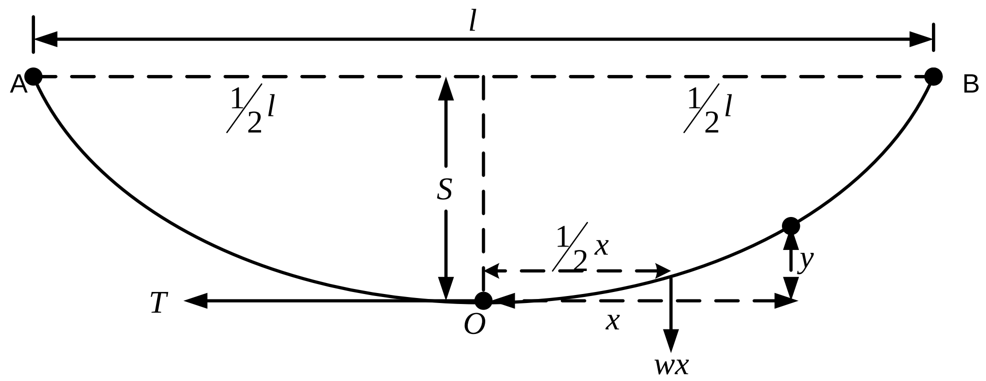


Fig 3.10: Sag Calculation For Supports at ***Same*** *Level*

It must be recalled that tension is governed by conductor weight, wind effects, ice loading (not applicable in Ghana) and temperature variations. A standard practice is to keep the conductor tension less than 50% of its ultimate tensile strength, i.e., a minimum factor of safety in respect of conductor tension is 2.

Let l = length of span

w_c = weight per unit length of conductor

T = tension in the conductor

O = reference point for measuring the coordinates of different points on the conductor.

Let us assume that the curvature is small, that is, the length of curved surface OP = x, the horizontal projection. Then the two forces acting on the portion *OP* of the conductor are:

- The weight $w_c x$ of the conductor acting at a distance $x/2$ from O.
- The tension T acting at *O*.

Mathematically, we have

$$T \cdot y = w_c x \cdot \frac{x}{2}$$
$$or \;\; y = \frac{w_c\, x^2}{2T} \qquad (3.9)$$

For the minimum sag, the coordinates are: $x = l/2$, $y = S$. Substituting these values into equation (3.9), we obtain:

$$Sag = S = \frac{w_c\, l^2}{8T} \qquad (3.10)$$

4-3.2 Effect of Wind and Ice Loading on Sag Calculation

The expressions derived for sag earlier are only true if the conductor was acted upon by its weight only. In practice, however, a conductor is always subjected to wind pressure and, in the temperate regions, to ice loading or coating.

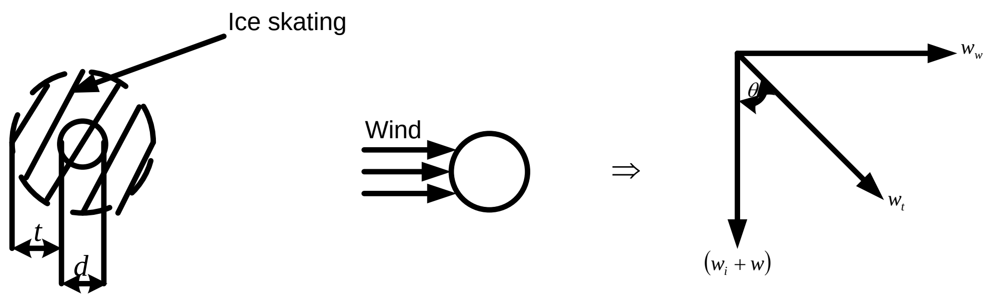


Fig 3.11: Effect of wind and ice loading on sag

- Ice coating acts vertically downwards
- Wind loading acts horizontally, i.e., at right angles to the projected surface of the conductor

If we denote w_i as the weight of ice per unit length, w_c the weight of conductor per unit length and w_t the total weight of conductor per unit length, then

$$w_t = \sqrt{(w_c + w_i)^2 + w_w^2} \qquad (3.18)$$

But

$$w_i = \text{density of ice } x \text{ volume of ice per unit length}$$
$$= \rho_{ice} x \frac{\pi}{4}\left[(d + 2t)^2 - d^2\right] x 1 \qquad (3.19)$$
$$= \rho_{ice} \pi\, t\,(d + t)$$

Also

$$w_w = \text{wind pressure per unit area } x \text{ projected area per unit length}$$

$$= p_{wind}\ x(d+2t)x1 \qquad (3.20)$$

$$= p_{wind}(d+2t)$$

NOTES:

- The conductor sets itself in a plane at an angle θ to the vertical, where

$$\tan\vartheta = \frac{w_w}{w_c + w_i} \qquad (3.21)$$

- The sag in the conductor is given by the relation

$$S = \frac{w_t l^2}{8T} \qquad (3.22)$$

  where S represents the "slant sag" in a direction making an angle θ to the vertical. If no specific mention is made of the problem, then the slant sag is calculated by using the above formula.

- The *vertical sag* = $S\cos\theta$

Length of Line Spans

Wooden poles:	40 – 50 m
Steel tubular poles:	50 – 80 m
Reinforced concrete poles:	80 – 100 m
Steel towers:	100 – 300 m

Example 3.2

The effective diameter of a line is 1.96 cm and it weighs 90 kg per 100 m length. If the line is subjected to a loading due to ice of radial thickness 1.25 cm and density 920 kg/m^3, as well as a horizontal wind pressure of 30 kg/m^2, and the maximum stress in the line is not to exceed ¼ of the ultimate strength of 4000 kg/cm^2, then calculate

a) additional loading due to the ice and wind pressure
b) total weight per metre run of the ice
c) maximum sag in still air
d) maximum vertical sag under additional loading due to ice and wind.

Solution 3.2

a) Additional loading due to ice and wind pressure

$$w_i = \pi \rho_i r_i (d + r_i) = \pi \times 920 \times 1.25 \times 10^{-2} \times (1.96 + 1.25) \times 10^{-2} = \underline{1.16\, kg/m}$$

$$w_w = \rho_w (d + 2r_i) = 30 \times [1.96 + 2(1.25)] \times 10^{-2} = \underline{1.34\, kg/m}$$

b) Total weight per metre run

$$w_r = \sqrt{(w_i + w_c)^2 + w_w{}^2} = \sqrt{(1.16 + 0.9)^2 + 1.34^2} = \underline{2.46\, kg/m}$$

d) Maximum sag in still air; Tension

$$T = \max imum\, stress \times area = \left(\frac{1}{4} \times 4000\, kg/cm^2\right) \times \left(\frac{\pi \times 1.96^2}{4}\right) = \underline{3017.58\, kg}$$

Hence $S_0 = \dfrac{w_c l^2}{8T} = \dfrac{0.9 \times 100^2}{8 \times 3017.58} = 0.373\, m = \underline{373\, cm}$

d) Maximum sag under additional ice and wind pressure loading

The sag under additional loadings is

$$S_r = \frac{w_r l^2}{8T} = \frac{2.46 \times 100^2}{8 \times 3017.58} = 1.02\, m$$

The vertical sag is

$$S_{vertical} = S_r \cos\theta = S_r \times \left(\frac{w_c + w_i}{w_r}\right) = 1.02 \times \left(\frac{0.9 + 1.16}{2.46}\right) = 0.854\, m = \underline{854\, cm}$$

SESSION 5-3 CORONA DISCHARGE

Introduction

When an alternating potential difference is applied across two conductors whose spacing is large compared to their diameters, there is no apparent change in the condition of the atmospheric air surrounding the wires, if the applied voltage is low.

However, when the applied voltage exceeds a certain value, called the *critical disruptive voltage*, the conductors are surrounded by a faint luminous glow of bluish colour called ***corona***.

The phenomenon of corona is always accompanied by;

(i) a hissing sound production
(ii) *production of ozone which is easily detected because of its characteristic odour and*
(iii) *radio interference*.

The higher the voltage is raised above the critical disruptive value, the larger and higher the luminous envelope becomes, and the greater the hissing sound, the power loss and the radio noise.

If the applied voltage is further increased to the breakdown value, the hissing and glow increase so much so that a ***flashover*** or ***spark*** will occur between the conductors due to the breakdown of air insulation. If the conductors are polished and smooth, the corona glow will be uniform throughout the entire length; otherwise the rough points will appear brighter.

If the transmission voltage is DC instead of alternating, there will exist a difference in the appearance of the two wires. The positive wire will have a uniform glow about it, whilst the negative conductor will have spotty glow.

5-3.1 Principles of Corona Discharge

Some ionization is always present in air due to cosmic rays, ultra-violet radiations and radioactivity. Thus under normal circumstance, the air around the conductor contains some ionized particles (i.e., free electrons and positive ions) and neutral molecules.

When voltage is applied between conductors, potential gradient is set up in the air, which will have maximum value at the conductor surfaces. Under the influence of potential gradient, the existing free electrons acquire greater velocities. The greater the applied voltage, the greater the potential gradient and the more is the velocity of the free electrons.

When the potential gradient at the conductor reaches about *30 kV/cm* (maximum value), the velocity acquired by free electrons is sufficient to strike a neutral molecule with enough force to dislodge one or more electrons from it. This produces an ion and one or more free electrons, which in turn are accelerated until they collide with other neutral molecules, thus producing other ions and free electrons. This process of ionization is cumulative; the result of which is that either corona is formed or spark takes place between the conductors.

5-3.2 Factors Affecting Corona Discharge

The phenomenon of corona is affected by the following:

- physical state of the atmosphere,
- conductor surface
- spacing between conductors
- line voltage

5-3.2.1 Atmospheric State

Corona is formed due to ionization of air surrounding the conductors, and is therefore affected by the physical state of the atmosphere. In stormy weather, the number of ions is more than in normal weather, and as such corona occurs at much less voltage as compared with fair weather.

5-3.2.2 Conductor Surface

The corona effect depends on the shape and conditions of the conductors. A rough and irregular surfaced conductor will give rise to more coronas, because unevenness of the surface decreases the value of breakdown voltage. Thus a stranded conductor produces more corona than a solid conductor. The potential gradient at conductor surface is given as:

$$g = \frac{V_{ph}}{r \log_e \left(\frac{r_o}{r_i} \right)} \qquad volt/cm \qquad (3.39)$$

Corona occurs when the value of g is equal to the breakdown strength of air, i.e., $30 kV/cm$ (maximum value) at *76 cm Hg* and 25^oC.

5-3.2.3 Spacing between Conductors

If the spacing between conductors is made very large as compared to their diameters, there may not be any corona effect. This is because the larger distance between the conductors reduces the electrostatic stresses developed at the conductor surface, thus avoiding corona formation. The spacing increase is limited by cost of supporting structure.

5-3.2.4 Line Voltage

The higher the line voltage, the greater the electrostatic stresses developed at the conductor surface, hence the higher the chances of corona formation.

5-3.3 Disruptive Critical Voltage V_c

Corona occurs when the electrostatic stress in the air surrounding the conductors exceeds *30 kV_{max}/cm or 21 kV_{rms}/cm*. The *effective disruptive critical voltage, which is the minimum phase voltage at which corona occurs,* is given by the relation:

$$
\begin{aligned}
V_C &= m_0 g_0 \delta\, r \log_e\left(\frac{d}{r}\right) \qquad kV / phase \\
&= 2.3 m_0 g_0 \delta\, r \log_{10}\left(\frac{d}{r}\right)
\end{aligned}
\qquad (3.40)
$$

where

m_0 = irregularity factor which takes into account the surface condition of the conductor

g_0 = breakdown strength or disruptive voltage gradient of air at *76 cm Hg* and *25°C.*

= *30 kV_{max} / cm or 21 kV_{rms} / cm.*

d = distance between conductors (in cm)

r = radius of conductor (in cm)

δ = air density factor

The value of the air density factor is given as

$$\delta = \frac{3.92b}{273+t} \qquad (3.41)$$

where b = barometric pressure in cm of Hg

t = temperature in degrees centigrade

The irregularity factor m_0 depends on the shape of cross-section of the wire and the state of its surface. Its value is unity for an absolute smooth wire of one strand of circular section and less than unity for wires roughened due to weathering. Typical values are given below:

Conductor type	**Irregularity factor**
Polished wires	1.0
Weathered wires	0.93 – 0.98
7-strand cables, concentric lay	0.83 – 0.87
Cables with more than 7 strands	0.80 – 0.85

5-3.4 Disadvantages of Corona

1. Corona is accompanied by *loss of energy (dissipation of power)*, although it is not so important except under abnormal weather conditions like storms, etc. This loss of energy affects the transmission efficiency of the line.
2. Ozone produced as a result of corona may react chemically with the conductor and cause *corrosion of the conductor*.
3. The current drawn by the line due to corona losses is non-sinusoidal, and hence non-sinusoidal voltage drop occurs in the line. This may cause *interference with neighbouring circuits* due to electromagnetic and electrostatic induction.
4. Such a shape of corona current tends to introduce a large third harmonic component.
5. Corona effects are intense for voltages of 35 kV and higher. Corona discharges ro busbars are extremely undesirable, because the intense ionization of the air *reduces its dielectric strength and makes it easier for flashover to occur in insulators and between phases*, particularly when the surfaces concerned are dirty or soiled with other deposits/impurities.
6. Ozone produced due to corona discharge aggressively attacks the metallic components in substations and switchgear, covering them with oxides.
7. Crackling sound of corona discharge in a substation masks other sounds like light crackling noise due to arcing in a loose contact, the sound of impending breakdown or creepage discharge in the equipment, the rattling noise due to loosening of steel in transformer core, etc. The timely detection of such sounds is very crucial for the prevention of any serious breakdown.

5-3.5 Merits of Corona

- Due to corona formation, the air surrounding the conductor becomes conducting and hence the virtual diameter of the conductor is increased. The increased diameter reduces the electrostatic stresses between conductors.
- Corona reduces the effects of transients produced by surges.

SESSION 6-3 EXERCISES ON OVERHEAD TRANSMISSION LINE DESIGN

Exercise 3.1

(a) Briefly explain what is meant by "string efficiency" of an insulator suspension system, and *state* the ways of improving it.

(b) Each line of a 3-phase, 11 kV system is suspended by a string of three identical insulators. The self-capacitance of each disc is 20 times the shunt capacitance to ground. Determine the following

(i) voltage distribution across each of the three insulators

(ii) string efficiency

Exercise 3.2

(a) Briefly **explain** (NOT define) what the "string efficiency" of an insulator suspension system means, and *state* THREE ways of improving it.

(b) Each line of a 3-phase, 66 kV system is suspended by a string of four identical insulators. The self-capacitance of each disc is 15 times the shunt capacitance to ground.

(iii) Sketch a diagram showing the capacitances and the current and voltage distributions.

(iv) Applying the appropriate network theorems, deduce equations for the voltage distribution across each of the four insulators

(v) Hence determine the voltage distribution across each of the four insulators, as well as the string efficiency of the system.

Exercise 3.3

(a) A 3-phase line has conductors 2 cm in diameter spaced equilaterally 1 m apart. If the dielectric strength of air is 30 kV (peak) / cm, for what critical value of the line voltage will corona commence? Take air density factor $\delta = 0.952$ and the irregularity factor $m_0 = 0.9$.

(b) State and explain the functions of the components of an overhead transmission line.

(c) An overhead transmission line conductor consists of hard drawn copper conductor of diameter 15 mm, having a dead weight of 1120 kg/km and spanning 200 metres. The supporting structures are at equal levels. The conductor has an ultimate tensile stress of 42.2 kg/mm^2 and allowable tension is not to exceed 1/4th of ultimate strength. Assume density of ice as 0.915 g/cm^3, find the vertical component of the sag under the following conditions:

(i) still air

(ii) a horizontal wind of pressure 60 kg/cm^2

(iii) an ice coating of 10 mm

(iv) a horizontal wind pressure of 60 kg/cm^2 **and** an ice coating of 10 mm.

Exercise 3.4

(a) Briefly explain how corona discharge takes place in overhead transmission line systems, and discuss the factors that influence corona.

(b) What are the common causes of failure in insulators?

(c) State and explain the functions of the components of an overhead transmission line.

(d) An overhead 240 mm^2 330 kV line at a river crossing is supported from two towers at heights 60 m and 120 m above water level. The horizontal distance between the towers is 400 m. If the tension in the conductors, which weigh 2.2 kg/m, is 2500 kg, find the clearance between the conductor and water level at a point midway between the towers in:

(i) still air

(ii) horizontal wind of pressure 80 kg/cm^2.

UNIT 4

UNDERGROUND CABLE DESIGN

Due to their greater installation costs, heavy time loss and costs in the localization and repair of cable fault (digging to have access to the buried cables), underground cables are employed in areas where it is impractical to use overhead lines. Such areas may be thickly populated areas where municipal authorities prohibit overhead lines for reasons of safety, or around plants and substations where maintenance conditions do not permit the use of overhead construction.

In urban areas with more heavily loaded MV systems, the main streets and roads may have one or more MV feeder cables buried below the pavements. In very heavily loaded areas, it may be necessary to lay cables below roadways, owing to lack of space under pavements because of the number of other services (such as gas, water, sewers, telephone, low-voltage cables etc.) already installed there, and/or the narrow width of the pavement.

An advantage of overhead system for distributors is that tapping can be made at any time without any disturbance, which is of great importance in rapidly developing areas. However, underground cables are more advantageous for feeders which are not likely to be disturbed for tapping purposes, because being less liable to damage through storms or lightning or even willful damage, they offer safer guarantee of supply. But this advantage may be offset by the cost of trenching and expensive jointing necessary in case of repairs. *Underground cables have greater urge over overhead lines in cases where voltage regulation is more important, because due to very small spacing of their conductors, they have very low inductance and hence experience low inductive drops*.

Learning objectives

On completion of this unit, you would be able to:

- Describe the types and construction of underground cables
- Explain electrical stress in cables
- Describe the thermal characteristics of the cables
- Explain charging and sheath currents of cables
- Describe methods of cable fault localization
- Undertake exercises on underground cable design.

SESSION 1-4 UNDERGROUND CABLES

1-4.1 Properties of Underground Cables

- Conductor used in cables should be thinned stranded Cu or Al of high conductivity. Stranding is done so that the conductor may be flexible and carry more current
- Conductor size should be such that the cable carries the desired load current without overheating and so as to have voltage drops within permissible limits
- The cable must have proper thickness of insulation, in order to give high degree of safety and reliability at the voltage for which it is designed
- The cable must have suitable mechanical protection so that it can withstand rough use when laying them.
- The materials used in the manufacture of cables should be such that there is complete chemical and physical stability throughout its length.

1-4.2 Construction of Cables

The main components of an energy cable are the following:

1. core
2. insulation
3. sheath
4. bedding
5. armouring
6. serving.

The Figure below shows the constructional details of a typical cable.

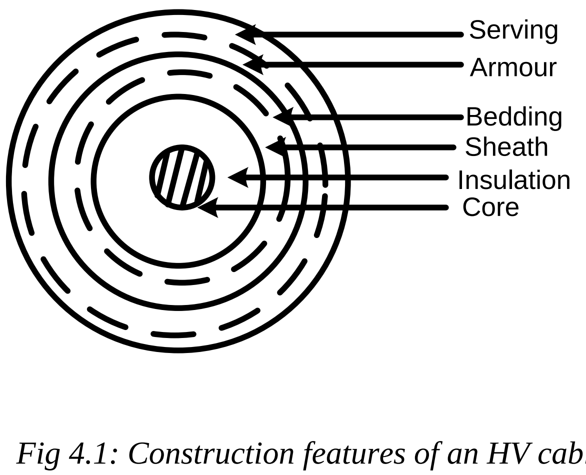


Fig 4.1: Construction features of an HV cable

1-4.2.1 Core or conductors

A cable may be single-cored (i.e. having one core) or multicored (having more than one cores or conductors), depending on the type of service for which it is intended. But generally, they are made of one, two, three or four cores.

Originally, the conducting cores of a cable were made of copper wire since this could be readily formed, and because copper has excellent electrical conductivity. But with the increase in the price of copper, attention was switched to the use of aluminium conductors both in stranded wire and solid form. For equal conductance, the required weight of aluminium is only half that of copper.

1-4.2.2 Insulation

Around each core or conductor is provided a suitable thickness of insulation, the thickness of the layer depending on the voltage to be withstood by the cable. Along with changes in conductor material have come changes in cable insulation. The commonly used insulating materials are:

(i) Oil-impregnated paper-laminated tapes
(ii) Rubber mineral compound
(iii) Varnished cloth, laminated tapes
(iv) Thermoplastic compounds, like polyvinyl chloride (PVC), polyethylene (PE), Nylon,
(v) Thermosetting compounds, like cross-linked polyethylene XLPE

As the electrical load on a cable varies, so does the conductor temperature, and the various component parts expand and contract until eventually gaps or voids may appear in the insulation. This can lead to local electrical discharges in the cable, depending on the electrical stress, with consequent deterioration of the insulation.

To overcome this problem at HV, the oil-filled cable has insulating oil fed into the center of each conductor under pressure from oil tanks along the cable route, to fill any voids that occur.

Thermoplastic insulants, like PVC, are liable to plastic flow at high temperatures, and create an added problem, in that dense black smoke is emitted from burning PVC, as well as poisonous acidic gases. In addition, the dielectric properties of PVC are limited, so that it is now mainly used in LV cables.

PE is suitable for all medium voltage levels, as is XLPE, which allows a longer short-time heat duration under fault conditions, and at a higher temperature in normal operation, than PE. XLPE cables are now available for use at working voltages up to 300 kV, with cross-sectional areas up to 200 sq. mm.

1-4.2.3 Metallic sheath

In order to protect the cable from moisture, gases or other damaging liquids (acids or alkalines) in the soil and atmosphere, a metallic sheath of lead or lead alloy or aluminium is provided over the insulation.

1-4.2.4 Bedding

Over the metallic sheath is applied a layer of bedding, which consists of a fibrous material like jute or hessian tape. The purpose of the bedding is to protect the metallic sheath against corrosion and from mechanical injury due to armouring.

1-4.2.5 Armouring

Over the bedding is provided an armoured layer, which consists of one or two layers of galvanized steel wire or steel tape. Its purpose is to protect the cable from mechanical injury while laying it and during the course of handling. Armouring and bedding may be combined in some cables.

1-4.2.6 Serving

This protects the armouring from atmospheric conditions using a layer of fibrous material (like jute) similar to the bedding.

NOTE: Bedding, armouring and serving are only applied to cables for the protection of conductor insulation and to protect the metallic sheath from mechanical injury.

1-4.3 Properties of Insulation Materials for Cables

The satisfactory performance of a cable depends to a great extent on the characteristics of the insulation used. Therefore the proper choice of insulating material for cables is of considerable importance. In general, the *insulating material used in cables should have the following properties*:

i. High insulation resistance to avoid leakage currents
ii. High dielectric strength to avoid electrical breakdown
iii. High mechanical strength to withstand mechanical handling
iv. Non-hygroscopic, that is, it should not absorb moisture from the air or soil, because moisture tends to decrease insulation resistance and hastens breakdown of the cable. In case the insulating agent is hygroscopic, the cable must be enclosed in a waterproof covering like sheath.
v. Non-inflammable
vi. Low cost

No single insulating material possesses all the above properties. Therefore the type of insulating material to be used depends on the purpose for which the cable is required, and the quality of the insulation to be aimed at. The principal insulating materials used in cables are rubber, oil-impregnated paper, rubber mineral compound, polyvinyl chloride (PVC), polyethylene (PE), cross-linked polyethylene (XLPE), etc.

1-4.4 Classification of Cables

Underground cables are classified according to the

i. Type of insulating material and
ii. Voltage for which they are manufactured.

The latter method of classification is more generally used, according to which cables are divided into the following groups:

Low-tension	LT cables:	-	up to 1000 V
High-tension	HT cables:	-	up to 33 kV
Super-tension	ST cables:	-	from 66 kV to 132 kV
Extra high-tension	EHT cables:	-	beyond 132 kV

(oil-filled under pressure and-gas pressured cables)

1-4.5 Laying of Underground Cables

For practical purposes, cables are installed in groups to avoid a multitude of routes. This enhances appearance in exposed runs, and minimizes the cost of fixings. Different cable designs are adopted for both high voltage and low voltage distribution systems, the choice depending largely on the load, type and requirement of the user.

For long above-ground routes subject to large loads, *armoured multicore cables* are the first choice, because they:

- are available with large current ratings
- have adequate mechanical strength for suspension purposes and
- have the further advantage that the armouring is usually suitable for use as a protective conductor

Although polyvinyl chloride (PVC) is the most commonly used insulation, it is gradually being replaced by cross-linked polyethylene (XLPE) insulation, although there are many alternatives available which are suitable for use in areas subject to arduous conditions such as high temperatures, corrosion and hazardous zones.

Armoured cables are equally suited for direct burial and installation in prepared ducts or trenches and at high level on tray, ladder rack or cable brackets. With the latter, it is advisable to consult the cable manufacturer about maximum suspension distances to avoid sagging.

The reliability of underground cable networks depends to a considerable extent on the proper laying and attachment of fittings, i.e., cable end bolts, joints, branch connectors, etc. The three main methods of underground cable laying are:

1. Direct laying method
2. Draw-in system
3. Solid system

1-4.5.1 Direct Laying Method

In this method, a trench of about *1.5 metres deep* and *45 cm wide* is dug. The trench is covered with about 10 cm of fine sand and the cable is laid over the sand bed. The sand bed prevents the entry of moisture from the ground and thus protects the cable from decay. After the cable has been laid in the trench, it is covered with yet another sand of about 10 cm thickness, before finally covering it with cement tiles, bricks or other materials to protect it from mechanical injury.

When more than one cable is to be laid in a trench, a horizontal or inter-axial spacing of at least 30 cm must be provided in order to reduce the effect of mutual heating and also to ensure that a fault in one cable does not extend to the adjacent cables. Cables to be laid directly must have servings of bitumised paper and hessian tape, so as to provide protection against corrosion and electrolysis.

Advantages of direct laying method:

- Simple and less costly
- It gives the best conditions for dissipating the heat generated in the cables
- It is clean and safe, as the cable is invisible and free from external disturbances

Disadvantages of direct laying method:

- Extension of load is possible only by completely new excavation which may cost as much as the original work
- Load redistribution within the network cannot be done so easily without extra cost
- Maintenance cost is very high
- Localization of fault is difficult
- It cannot be used in congested areas where excavation is expensive and inconvenient.

NOTE: *The direct method of laying is employed in open areas where excavation can be done conveniently and at low cost.*

1-4.5.2 Draw-in Method

In this method, conduit or duct of glazed stone or cast iron or concrete are laid in the ground with manholes at suitable positions along the route. The cables are then pulled into position from the manholes. Care must be taken where the duct line changes direction. *Cables to be laid this way need **not be armoured** but must be provided with serving of hessian and jute in order to protect them when being pulled into the ducts*.

Advantages of draw-in system:

- Repairs, alterations and additions to the cable network can be made without opening the ground
- As the cables are not armoured, the joints become simpler and maintenance cost is reduced considerably
- There are very less chances of fault occurrence due to strong mechanical protection provided by the system.

Disadvantages of draw-in system:

- ❖ High initial cost
- ❖ Derating of cables due to close grouping and unfavourable conditions for heat dissipation.

NOTE: *The draw-in method is suitable for congested areas where excavation is expensive and inconvenient. It is normally used for road crossings, workshops, etc.*

1-4.5.3 Solid System

In this method of laying, the cable is laid in open pipes or troughs dug out in the earth along the cable route. The troughing is of cast iron, stoneware, asphalt or treated wood. After the cable is laid in position, the troughing is filled with a bituminous or asphaltic compound and covered. Cables laid in this manner are usually plain lead covered because troughing affords good mechanical protection.

Disadvantages of solid system:

- ➢ More expensive than direct laying system
- ➢ Requires skilled labour and favourable conditions
- ➢ Due to poor heat dissipation facilities, the current-carrying capacity of the cable is reduced.

NOTE: *The solid system is seldom used nowadays*.

SESSION 2-4 CHARGING AND SHEATH CURRENTS IN CABLES

It is known that any two conductors that are separated by an insulating medium constitute a capacitor. When a potential difference is established across two such conductors, current flows in at one conductor and out at the other conductor, so long as the potential difference is maintained. The conductors of an overhead transmission line, as well as the cable construction, fulfill these conditions. Hence when an alternating potential difference is applied across a cable or transmission line, it draws a *leading current* even when it is unloaded. This leading current is in quadrature with the applied voltage and is known as the *charging current*. Its value depends on voltage, the capacitance of the system arrangement and the frequency of the alternating current.

SESSION 3-4 ELECTRIC STRESS IN CABLES

Usually an electrostatic field is set up in the insulating medium between two good conductors. The conductors have such a high conductivity that any voltage drop within the conductors (except at very high frequencies) is negligible compared with the potential difference across the insulator. *All points in the conductor are therefore at the same potential, so that the two conductors form the boundary potentials for the electrostatic field.*

A single-core cable with metallic sheath has the same electrostatic field as a pair of concentric cylinders. The electrostatic field between two concentric conducting cylinders (e.g. the field in the insulation medium between core and sheath) is illustrated in the Figure below:

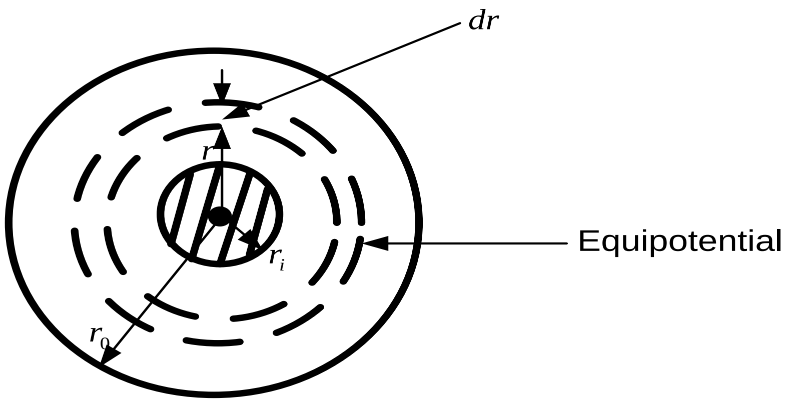


Fig 4.2: Electrostatic Field between Core and Metal Sheath of a Single-Core Cable

The boundary equipotentials are concentric cylinders of radii r_i and r_o, where

r_i = inner or core radius of cable

r_o = *outer* or internal sheath radius of cable = r_i + thickness of insulation

The *electric stress* E (also known as *electric field strength or electric intensity or potential gradient*) is given by the relation:

$$E = -\frac{dV}{dr} = \frac{Q'}{2\pi\varepsilon r} \qquad (in \quad V/m) \tag{4.1}$$

where V is the potential at the point r from the center of the cable, measured in the direction of the E and Q' is the charge per metre.

But the potential is given as

$$V = \frac{Q'}{2\pi\varepsilon}\ln\left(\frac{r_o}{r_i}\right) \qquad (in\ V) \tag{4.2}$$

Hence the capacitance per unit length between the concentric cylinders formed by the core and metal sheath with the insulation layer of the cable is

$$C' = \frac{Q'}{V} = \frac{2\pi\varepsilon}{\ln\left(\frac{r_o}{r_i}\right)} \qquad (in \quad F/m) \tag{4.3}$$

or

$$\frac{Q'}{2\pi\varepsilon} = \frac{V}{\ln\left(\frac{r_o}{r_i}\right)} \tag{4.4}$$

Substituting Equation (4.4) into (4.1), the electric stress in the cable is

$$E = \frac{V}{r\ln\left(\frac{r_o}{r_i}\right)} \tag{4.5}$$

It is seen from Equation (4.5) that the electric stress at any point r in the dielectric (i.e., insulating medium) varies inversely as r, and will have the maximum value at the minimum radius, that is, when $r = r_i$***.***

Thus the maximum electrical stress is

$$E_{\max} = \frac{V}{r_i\ln\left(\frac{r_o}{r_i}\right)} \tag{4.6}$$

When designing a cable, it is important to obtain the most economical dimensions. The greater the value of the permissible maximum electric stress, $E_{\max}$, the smaller the cable may be for a given voltage V. The maximum permissible electric stress, however, is limited to the safe working stress for the dielectric or insulating material.

With V and $E_{\max}$ both fixed, the relationship between r_o and r_i will be given by:

$$r_i \ln\left(\frac{r_o}{r_i}\right) = \frac{V}{E_{\max}} = k$$

$$\Rightarrow r_o = r_i e^{k/r_i} \qquad (4.7)$$

For the most economical cable, r_o will be a minimum (see Eqn 4.5), and hence

$$\frac{dr_o}{dr_i} = 0 = e^{k/r_i} + r_i\left(-\frac{k}{r_i^2}\right)e^{k/r_i}$$

$$\Rightarrow r_{i\,ideal} = k = \frac{V}{E_{\max}} \qquad (4.8)$$

and hence from Equation (4.7), the *ideal outer or sheath radius* is given as

$$\begin{aligned} r_{o\,ideal} &= r_{i\,ideal} \cdot e \\ &= 2.718\, r_{i\,ideal} \end{aligned} \qquad (4.9)$$

Example 4.1

A 33 kV single-core cable has a conductor diameter of 1 cm and a sheath of inside diameter 4 cm. Find the maximum and minimum stress in the insulation.

Solution 4.1

Maximum stress $E_{\max} = \dfrac{V}{r_i \ln\left(\dfrac{r_o}{r_i}\right)} = \dfrac{33}{0.5 \times \ln\left(\dfrac{2.0}{0.5}\right)} = \underline{47.6\, kV_{rms}/cm}$

Minimum stress $E_{\min} = \dfrac{V}{r_o \ln\left(\dfrac{r_o}{r_i}\right)} = \dfrac{33}{2.0 \times \ln\left(\dfrac{2.0}{0.5}\right)} = \underline{11.9\, kV_{rms} / cm}$

Alternatively, $E_{\min} = E_{\max} \times \left(\dfrac{r_i}{r_o}\right) = 47.6 \times \left(\dfrac{0.5}{2.0}\right) = \underline{11.9\, kV_{rms} / cm}$

Example 4.2

Find the most economic size of a single core cable working on a 132 kV 3-phase system if a dielectric stress of 60 kV/cm can be allowed.

Solution 4.2

Phase voltage of cable, $V_{ph} = \dfrac{132}{\sqrt{3}} = \underline{76.21\, kV}$

Peak value of phase voltage, $V_{peak} = V_{ph}\sqrt{2} = 76.21 \times 1.414 = \underline{107.78\, kV}$

Most economical size, $d_{i,\, ideal} = 2 \times r_{i,\, ideal} = \dfrac{2 \times V_{peak}}{E_{\max}} = \dfrac{2 \times 107.78}{60} = \underline{3.6\, cm}$

SESSION 4-4 ELECTRICAL SHIELDING OF HIGH VOLTAGE CABLES

As the need for electrical power grows, the use of higher voltages for distribution and utilization must be considered and the selection analyzed economically. For operating voltages below 2 kV, non-shielding constructions are common, and above 5 kV the standard cable designs are shielded. Shielded cables are more costly than unshielded, and so the conditions for application must be determined for the proper cable design to be selected.

Shielding of an electric power cable is briefly defined as the practice of confining the electric field of the cable to the insulation of the conductor by means of semi-conducting layers, closely fitting or bonded without voids to the inner and outer surfaces of the insulation. *The inner or strand stress control layer is at conductor potential and the outer or insulation stress control layer is at or near ground potential*.

The conductance of the insulation shield is determined by the area of the metal tapes or wires employed in conjunction with the semi-conducting layer, and should be adequate to drain away the *charging currents* and in some cases to carry fault currents.

The ***reasons for shielding*** are as follows:

- The *inner or strand stress control layer* is used to reduce voltage stress across voids between conductor strands and insulation, so as to eliminate ionization of the air in the void, which may be a causative factor in shortening cable life.
- The *outer or insulation shields* have several purposes –
    1. To confine the dielectric field within the cable
    2. To equalize voltage stress within the insulation, minimizing surface discharges
    3. To better protect cable connected to overhead lines or other induced potentials
    4. To limit electromagnetic interference (radio, TV)
    5. To reduce the hazard of shock

The Figure below shows the electrostatic field of a shielded cable and an unshielded cable

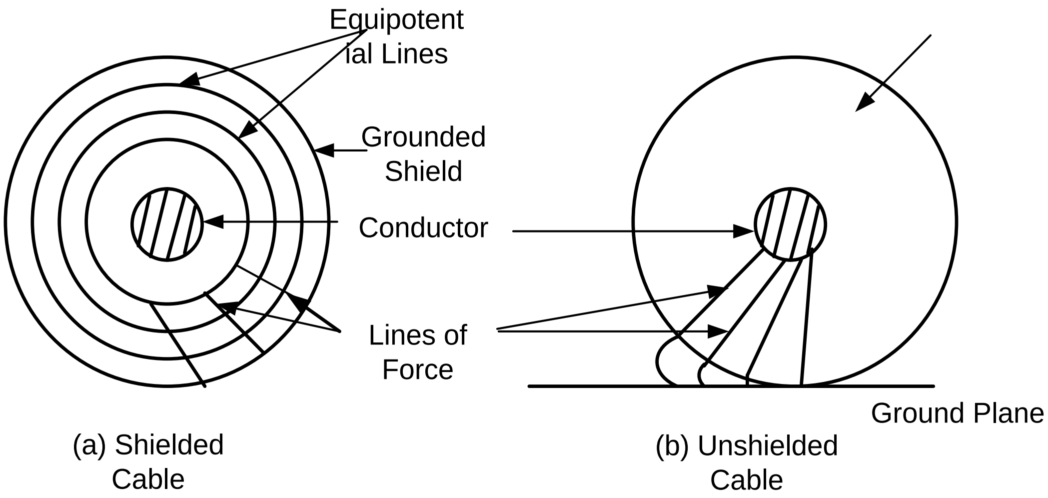


Fig 4.3: Electrostatic field of (a) Shielded cable (b) Unshielded cable

For the *shielded cable*, as in Fig (a), the equipotential surfaces are concentric cylinders between conductor and shield. The voltage distribution follows a simple logarithmic variation, and the electrostatic field is entirely within the insulation. The lines of force and ***stress are uniform*** and radial, and cross the equipotential surfaces at right angles, ***eliminating any tangential or longitudinal stress within the insulation or on its surface.***

For the *unshielded cable*, the voltage distribution between a 5 kV unshielded cable and a grounded plane is illustrated in Fig (b). The figure assumes the air to be the same, electrically, as the insulation, so that the cable is in a uniform dielectric above ground plane to permit illustration of the voltage distribution and electrostatic field associated with the cable.

SESSION 5-4 CABLE DESIGN AND RATINGS

The selection of power cables for particular circuits or feeders develops around the following considerations:

1. *Electrical* – Dictates conductor size, type and thickness of insulation, correct materials for LV and HV designs, consideration of dielectric strength, insulation resistance, specific inductive conductance, and power factor
2. *Thermal* – Compatibility with ambient and overload conditions, expansion and thermal resistance
3. *Mechanical* – Involves toughness and flexibility, consideration of armouring, and resistance to impact, crush, abrasion, and moisture
4. *Chemical* – Stability of materials on exposure to oils, flame, ozone, sunlight, acids and alkalis

The cable ratings depend on the working voltage, conductor size and load current.

5-4.1 Voltage Selection

LV power cables are generally rated at 600V. The selection of the cable insulation for medium (over 600 and up to 15 kV) and the high voltage systems involves a rating made on the basis of phase-to-phase voltage of the system in which the cable is to be applied. The general system category depends on whether the system is grounded or ungrounded, and the rapidity with which a ground fault on the system is cleared by relay protection.

A ground fault on an ungrounded cable system results in full line-to-line voltage stress across the insulation of the two ungrounded conductors. Therefore such a cable must have greater insulation thickness than a cable used on grounded systems, where it is impossible to impose full line-to-line potential on the other two unfaulted phases for an extended period of time.

5-4.2 Conductor Selection

In any installation, the importance of calculating and installing the correct size of cable for each circuit is paramount. This entails the correct formula and *correction factors* given in the IEE Wiring Regulations. The correction factor depends on the Grouping (G), Ambient temperature (A), Thermal insulation (T). By using the symbols G, A, T, a useful mnemonic, *GAT*, can be used.

The selection of *conductor size* is principally based on the following considerations:

- ***Load-current criteria*** – as related to loadings, code requirements, thermal effects of the load current, mutual heating, losses produced by magnetic induction, and dielectric losses. The selection of a cable size based on its thermal heating, both from the load current and from mutual heating from nearby cables, is considered. The standards give complete description of the calculation of ampacities and the constants on which they are based, including the losses taken into account, such dielectric losses and induced a.c. losses. The latter include skin effect and proximity losses in the conductors, and sheath losses.

- ***Emergency overload criteria*** – The increase in current due to the overload can raise the conductor's temperature to a level where the conductor's insulation can be damaged. Sustained operation over and above maximum rated operating temperatures or ampacities is not very effective or economical, because temperature rise is directly proportional to conductor loss, which increases as the square of the current. The greater voltage drop might also increase the risks to equipment and service continuity.
- ***Fault current criteria*** – Under short-circuit conditions, the temperature of the conductor rises rapidly. Then due to thermal characteristics of the insulation, sheath, etc., it cools off slowly after the short-circuit condition has been removed. Failure to check the conductor size for short-circuit heating could result in severe permanent damage to the cable insulation, due to disintegration of insulation material, which may be accompanied by smoke and generation of combustible vapours. These vapours will, if sufficiently heated, ignite, possibly starting a serious fire. Less seriously, the insulation or sheath of the cable may be expanded to produce *voids* leading to subsequent failure. This becomes especially serious in 5 kV and higher voltage cables. In addition to thermal stresses, there are mechanical stresses set up in the cable through expansion upon heating. As the heating is rapid, these stresses may result in undesirable cable movement. However, on modern cables, reinforcing binders and sheaths considerably reduce the effect of such stresses.
- ***Voltage drop limitations*** – Voltage drop to and in the final circuit must not be overlooked, as this can have bearing on the conductor size chosen. As far as voltage drop is concerned, it is important to obtain accurate route length for the cables, together with the maximum continuous current the conductors will have to carry, to enable the voltage drop in each cable to be calculated.

For a *single-phase system*, the *approximate* formula for the *voltage drop* per phase is:

$$\begin{aligned} \Delta V &\approx IR\cos\phi + IX\sin\phi \\ &\approx I_p R + I_q X \end{aligned} \qquad (4.10)$$

Where ΔV = voltage drop in circuit, line-to-neutral
I = load current flowing in conductor
R = line resistance for one conductor
X = line reactance for one conductor
$\cos\phi$ = load power factor
$\sin\phi$ = load reactive factor
$I_p = I\cos\phi$ = resistive component of load current
$I_q = I\sin\phi$ = reactive component of load current

NOTE: *In single-phase calculations, the resistance and reactance of the* <u>*return path*</u> *must be included in R and X.*

For *3-phase systems*, the line-line voltage drop can be calculated from:

$$\begin{aligned}\Delta V &= \sqrt{3}\left(I_p R + I_q X\right) \\ &= \frac{P}{V}\left(R + X \tan\phi\right)\end{aligned} \tag{4.11}$$

where V is the line-line voltage and P is the total 3-phase power.

SESSION 6-4 CABLE FAULT LOCALIZATION

In a commercial plant, a large variety of cable faults can occur. The problem may be in a communication circuit, or in a power circuit, either in the low-, medium-, or high-voltage class. Circuit interruption may result, or operation may continue with some objectionable characteristics. Regardless of the class of equipment involved or the type of fault, one common problem is to determine the location of the fault so that repairs can be made.

The vast majority of cable faults encountered in a commercial power system occur between conductor and ground. *Most fault-locating techniques are made with the circuit deenergized. In ungrounded or high resistance grounded low voltage systems, however, the occurrence of a single line-to-ground fault will not result in automatic circuit interruption, and therefore the process of locating the fault may be carried out with the circuit energized.*

6-4.1 Influence of Ground Fault Resistance on Cable Fault Location

Once a line-to-ground has occurred, the *resistance of the fault path* can range from almost zero up to a million ohms. The fault resistance has a bearing on the method used to locate the failure. In general, a low-resistance fault can be more readily located than one of high resistance. In some instances, the fault resistance can be reduced by the application of voltage sufficiently high to cause fault to break down and of sufficient amperage to cause the insulation to carbonize.

Some large utilities use a high-voltage alternating current supply of about 20A capacity for this *burn-down method*. This burn-down method is useful with paper and elastomeric cables, but generally of little use with plastic types.

The fault resistance, which exists after the occurrence of the original fault, depends on the type of cable insulation and construction, and the cause of the failure. A fault, which is immersed in water, will generally exhibit a variable fault resistance and will not consistently arc over at a constant voltage. Damp faults behave in a similar manner until the moisture has been vaporized. In contrast, a dry fault will normally be much more stable and consequently can be located more readily.

For failures that have occurred in service, the type of system grounding and available fault current, as well as the speed of relay protection, will be the influencing factors. Because of the greater carbonization and conductor vaporization, a fault resulting from an in-service failure can generally be expected to be of a lower resistance than one resulting from overpotential testing.

6-4.2 Equipment and Methods for Cable Fault Localization

A wide variety of commercially available equipment and a number of different approaches can be used to locate cable faults. Some of the techniques and procedures, which have application in the location of faulted cables, are considered briefly. The common *methods or techniques for cable fault localization* include:

1. Physical evidence of the fault
2. Megohmmeter instrument test
3. Conductor resistance measurement method
4. Clamp-on ammeter method
5. Capacitor discharge or impulse method
6. Tone signal

6-4.2.1 Physical Evidence of the Fault

Observation of a *flash, sound or smoke* accompanying the discharge of current through the faulted insulation will sometimes immediately locate a fault. This is more probable with an overhead circuit than with underground construction. The discharge may be from the original fault, or may be intentionally caused by the application of test voltage. The burnt or disrupted appearance of the cable will also serve to indicate the faulted section.

6-4.2.2 Megohmmeter Instrument Test

When the fault resistance is sufficiently low that it can reliably be detected with a megohmmeter, the cable can be sectionalized and each section tested to determine which contains the fault. This may require that the cable be opened in a number of locations before the fault is isolated to one replaceable section. This could involve considerable time and expense, and might result in additional splices. Since splices are often the weakest part of a cable circuit, this method of fault localization may introduce additional failure at a subsequent time.

6-4.2.3 Conductor Resistance Measurement Method

This method consists of measuring the resistance of the conductor from the test location to the point of fault using either the *Varley Loop or Murray Loop Test*. Once the resistance of the conductor to the point of fault has been measured, it can be translated into distance by using handbook values of resistance per unit length of the size and type of conductor involved, correcting for temperature if required.

Both of these methods give good results which are independent of fault resistance, provided fault resistance is low enough that sufficient current for the deflection of the meter can be produced with the available test voltage. For distribution systems using cables insulated with organic materials, relatively low-resistance faults are the type commonly encountered.

The conductor resistance measurement method has its major application on such systems. Loop tests on larger conductor sizes may not be sensitive enough to narrow down location of the fault.

6-4.2.4 Clamp-on Ammeter Method

Where the faulted circuit has broken down to a point that low voltage will cause current to flow when such a low voltage is applied, then an ordinary clamp-on ammeter can be used to find the fault. A low voltage is applied through any type of load which will limit the current to about 10 A. Then the clamp-on ammeter can be applied at various points of access, and at the first point where no current flow is determined, the tester will be downstream from the fault. Care must be taken to account for the return current flow on the shield or armour which will tend to cancel the test current.

6-4.2.5 Capacitor Discharge Method

This method consists of applying a high-voltage high-current impulse to the faulted cable. A high voltage capacitor is charged by a relatively low-current capacity source such as that used for high-potential testing. The capacitor is then discharged across an air gap into the cable. The repeated discharging of the capacitor provides a periodic pulsing of the faulted cable.

Where the cable is accessible, or the fault is located at an accessible position, the fault may be located simply by sound. But where the cable is not accessible, such as in duct or directly buried in soil, the discharge at the fault may not be audible. In such cases, magnetic detectors are available to trace the signal to the point of fault.

The magnetic detector generally consists of a magnetic pick-up coil, an amplifier and a meter to display the relative magnitude and direction of the signal. The direction indication changes as the detector passes beyond the fault. *Acoustic detectors* are also employed, particularly in situations where no appreciable magnetic field external to the cable is generated by the tracing signal.

In applications where relatively high-resistance faults can be anticipated, such as with solid-dielectric cables or through compound in splices and terminations, the impulse method appears to be the most practical method.

6-4.2.6 Tone Signal Method

This method may be used on energized circuits. A fixed-frequency signal, generally in the audio-frequency range, is imposed on the faulted cable. The cable route is then traced by means of a detector, which consists of a pick-up coil, receiver, and head set or visual display, to the point where the signal leaves the conductor and leaves enters the ground return path.

This class of equipment has its primary application in the low-voltage field and is frequently used for fault location on energized ungrounded-type circuits. On systems rated greater than 600 V, the use of a tone signal for fault location is generally unsatisfactory because of the relatively large capacitance of the cable circuit.

SESSION 7-4 HEATING IN CABLES

The sources of heat generation in cables are

1. Core losses
2. Dielectric losses
3. Sheath losses

7-4.1 Core Losses in Cables

The core losses are the copper losses in the core of the cable. To determine the core loss, the resistance is calculated as follows:

1. Let the resistance be known at 20^{o}C as R_{20}. Then assuming an operating temperature of 65^{o}C, we obtain $R_{65} = R_{20}(1 + \alpha_{20}\theta)$, where $\theta = 65 - 20$, and α_{20} = temperature coefficient at 20^{o}C.
2. The DC resistance obtained above 20^{o}C is multiplied by a factor of 1.02 to account for skin and proximity effect.
3. The length of the outermost strand is greater than the central strand, the length used to calculate the DC resistance. A factor of 1.02 is again applied to account for this.

7-4.2 Dielectric Losses in Cables

This is due to the leakage current and hysteresis effect in the dielectric. To obtain an idea of the dielectric loss, consider the simplified phasor diagram of the current in a dielectric shown in Fig below.

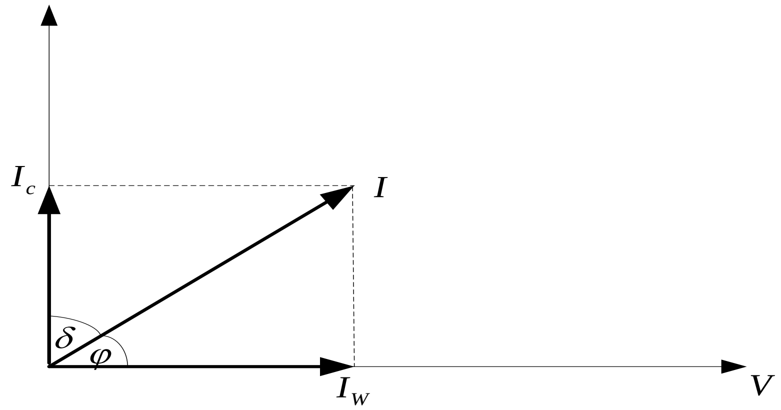


Fig 4.4: Dielectric Loss in cables

The dielectric loss (in watts) can be measured directly or it may be calculated by the formula:

$$P_{diel} = V^2 \omega C \tan\delta \qquad (4.12)$$

where P_{diel} = power loss in the dielectric, *(in watts W)*

V = applied voltage, *(in volts V)*

ω = angular frequency = $2\pi f$, f is the frequency of the applied voltage

C = capacitance of the dielectric , *(in Farads).*

$\tan\delta$ = dielectric or loss factor, $\tan\delta = \dfrac{I_c}{I_w}$

For paper-oil, $\tan\delta$ lies between 0.002 and 0.003, but this value increases rapidly with temperature above 20^{o}C in oil-filled cables. ***In lower voltage cables, the dielectric loss is negligible, but is very appreciable in cables above 275 kV and above***.

7-4.3 Sheath Losses in Cables

The current in the core of the cable sets up pulsating magnetic field which induces voltage in the metallic sheath. The induced voltage in turn sets up current in he sheath, and this results in sheath losses.

The sheath currents I_S are proportional to the cable core currents I_C. Therefore the sheath losses are also proportional to the conductor losses, i.e.,

$$I_S = kI_C \tag{4.13}$$

$$\text{Copper loss} = R_C \times I_C{}^2 \tag{4.14}$$

$$\text{Sheath loss} = R_S \times I_S{}^2 = k^2 I_C{}^2 R_S \tag{4.15}$$

Because the sheath losses are proportional to the conductor losses,

$$\begin{gathered} R_C \times I_C{}^2 = k' R_S I_S{}^2 = k'(k^2 I_C{}^2 R_S) \\ \Rightarrow R_C = k'k^2 R_S \end{gathered} \tag{4.16}$$

If λ is the ratio of sheath loss to the conductor loss, then the equivalent AC resistance of the cable will be

$$R_{eq} = R(1+\lambda) \tag{4.17}$$

where R is the resistance of the core of the cable.

SESSION 8-4 EXERCISES ON UNDERGROUND CABLES DESIGN

Exercise 4.1

(a) Draw a labelled diagram of a typical single-core concentric 161 kV power cable, indicating all the various layers.

(b) Using electrostatic equations, derive the formula for the electric stress distribution in a power cable having a core radius r_i, insulation thickness d and outer radius r_o.

(c) A single-core concentric cable operates at 161 kV in a 3-phase 50 Hz system, and has a conductor diameter of *5 cm* and an insulation thickness of *3.75 cm*. Calculate the maximum and minimum stresses in the cable.

(d) For the cable above, determine the most economical cable dimensions, if the insulation used has a maximum permissible stress of $10 MV / m$.

Exercise 4.2

(a) Draw a well-labelled diagram of a typical single-core concentric 220 kV power cable, indicating all the various layers.

(b) Using electrostatic equations, derive the formula for the electric stress distribution in a power cable having a core radius r, insulation thickness d and overall radius R.

(c) Hence show, by calculation, that the most economical size of conductor is obtained when $R = e$, where e is the base of natural logarithms.

(d) Find the overall diameter of a single-core concentric cable and its most economical diameter when working on a 220 kV 3-phase 50 Hz system. The maximum permissible stress in the dielectric is not to exceed 250 kV/cm.

Exercise 4.3

(a) The maximum and minimum stresses in the dielectric of a single core are 40 kV (rms)/cm and 10 kV(rms)/cm respectively. If the conductor diameter is 2 cm, find
   (i) thickness of insulation
   (ii) operating line voltage

(b) Mention the three methods of cable laying you know, and discuss relative the merits and demerits of each method.

(c) Explain the term *"shielding"* as applied in high voltage power cables, and outline the reasons why shielding is necessary in power cables.

(d) Briefly describe any FOUR methods or techniques that are employed in cable fault localization