Chapter 10

Distribution switchgear

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10.1 Introduction

Switchgear is a term used to refer to combinations of switching devices and their interconnection with associated control, measurement and protection equipment. It allows the interconnection of various parts of the electrical network by means of transformers, overhead lines or cables to allow control of the flow of electricity within that network from power station to customer. Switchgear is also designed to be able to safely interrupt any faults that might occur in any part of the network to protect the network itself, associated equipment and operational personnel. It also provides, by means of disconnectors, facilities for isolating sections of the network and, with the provision of earthing switches, to allow the safe application of devices to ensure that the isolated sections of the network are earthed and made safe for maintenance activities or possible fault repair.

A combination of busbar circuits, circuit-breakers, switches, fuse switches, disconnectors, earthing devices, terminations and associated control and protection equipment is referred to as a 'substation'. A substation may or may not include a means of voltage conversion, i.e. one or more transformers.

The typical electrical network may comprise generators feeding directly into part of the transmission system, and the transmission system itself may have interconnection to other transmission networks. Such systems are used to allow the flow of large amounts of power from the generating stations to the distribution load centres which may be many tens or hundreds of kilometers away.

Distribution of the power from the transmission system will be via bulk supply points which allow the means of tapping off power to feed local communities via a 'distribution' network.

Substations are used at all interconnecting node points, i.e. generator to transmission system, within the transmission system, transmission system to distribution networks and within the distribution networks themselves. A typical electricity supply network is shown in Figure 10.1.

Within the UK generators typically operate at 25 kV and their output is immediately transformed up to the transmission system voltage of either 400 kV or 275 kV. Tee-off points to feed distribution networks are typically rated at 132 kV or 33 kV. The local distribution network itself, almost universally, operates at 11 kV. Tee-off feeds to customers are transformed from 11 kV to 415 V, with local LV networks operating at 415 V 3-phase.

The foregoing relates to typical power supply networks; however, with deregulation of the electrical power utilities and introduction of greater competition, there is a growing trend to operate high efficiency small generating plants within the electrical distribution networks, and such networks are having to adapt to allow interconnection of these embedded generators. Interconnection, however, is still via local substations.

The subject of this chapter is to discuss the types and combinations of switchgear which may be encountered within the distribution networks. Whilst in this text the term 'distribution switchgear' will be used, a more recent trend is for it to be referred to as 'medium voltage (MV) switchgear'; the terms are synonymous.

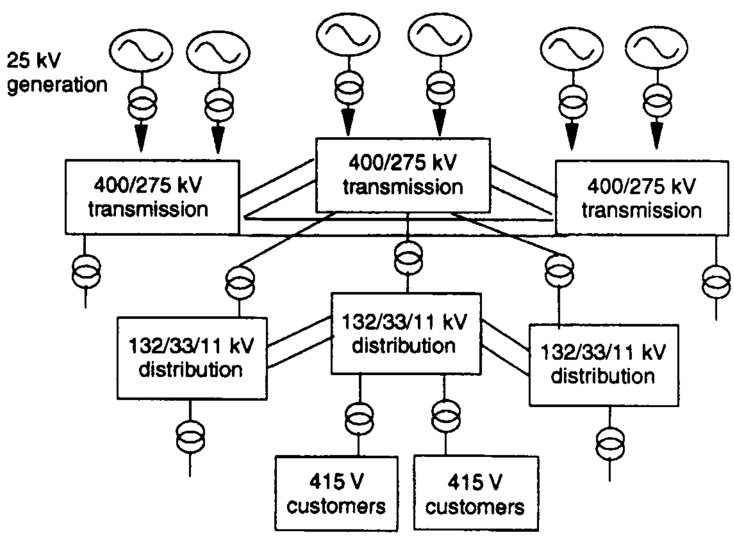

Figure 10.1 Electricity supply network
Interconnection of circuits is by means of substations

10.2 Substations

There are a number of methods of construction of substations (supplementary information is provided in Chapter 9). Common types are described below.

10.2.1 Substation types

10.2.1.1 Open air

These comprise separately mounted interconnected switching devices and components, e.g. busbar support insulators, current transformers, voltage transformers, cable sealing ends, etc., where atmospheric air provides the main insulation path to earth. The solid insulators clearly have to be designed to be capable of withstanding, for many years, all encountered environmental conditions, e.g. rain, ice, snow, wind loading, temperature variations, pollution, lightning activity and associated switching activity to ensure that dielectric breakdown to earth or between phases is improbable. This generally requires relatively large clearances and, in consequence, open air substations tend to cover large ground areas and may also be unsightly if located near local communities. Some degree of landscaping is normally required to minimise the visual impact.

10.2.1.2 Metal enclosed

With this arrangement all switching devices and associated components are enclosed in a metallic earthed structure on a per-bay basis and are cable connected. This arrangement has the disadvantage that there is no segregation within the panel; hence, a fault in an instrument transformer, for example, could readily spread to encompass the switching device and panel interconnecting busbars. Such arrangements are not generally used where high reliability and high availability systems are required, i.e. at bulk supply points or at primary distribution substations. They are, however, widely used for distribution secondary substations, e.g. ring main units (see Section 10.5.11). Such arrangements have the advantage that they may be physically small in size and only require a fraction of the land area required by an equivalent open air substation. Metal enclosed substations may be either of the outdoor type, in which case the enclosure must protect the internally connected equipment against all prevailing environmental conditions, or alternatively the substation may be enclosed within a building or low cost weatherproof housing.

10.2.1.3 Metal-clad

This is a derivative of the metal enclosed switchgear where all major components per bay are physically segregated from one another by means of earthed metalwork such that a fault in any one compartment cannot readily spread to adjacent compartments. It is vitally important that busbars are unaffected by a fault in any particular circuit panel such that adjacent panels can safely remain in service until appropriate repairs can be executed. Typical segregation is between cable box and instrument transformers, instrument transformer chambers and circuit-breaker and circuit-breaker and busbars. Such arrangements allow the achievement of higher reliability and higher availability systems than may be achieved with metal enclosed concepts. Most primary switchboards are of the metal-clad type. For economic reasons many such switchboards were originally designed for outdoor use; however, in harsh environmental climates environmental deterioration may readily occur and maintenance costs may be high. It is now common policy for such metal-clad switchgear to be housed in appropriate weatherproofed buildings. A further modern trend is for them to be housed in transportable containers such that, as systems and local load patterns change, they can readily be transferred to more appropriate locations.

10.2.1.4 Insulation enclosed

With this type of construction all HV components are enclosed within insulation without external metallic screens. The insulation is generally of the solid moulded form with components interfaced by atmospheric air. Correct dielectric stressing is vital with such combinations of components. Whilst the equipment may generally be physically smaller than metal-clad types of switchgear the high dielectric stress, under varying humidity conditions, can, if not properly controlled, lead to early failure mechanisms.

Such equipment is not generally utilised within the UK but is, however, employed quite widely within some European countries.

10.2.1.5 Gas insulated substations (GIS)

A further form of metal-clad substation which is used mainly at transmission voltages is the gas insulated substation. With this concept SF_6 provides the main dielectric medium between the primary conductor and earth. In view of the very high dielectric strength of SF_6 the dimensions can be made very small. There are two basic concepts: the first is where each phase is physically enclosed within earthed metalwork, and the other is where the three phases are enclosed within one chamber. The former has a higher degree of integrity as phase-to-phase faults cannot occur. The latter, however, provides a more economic and more compact concept. Both arrangements are widely used, with the phase isolated concept being used mainly at higher voltages and the 3-phase in one tank concept being used at the lower transmission, or high distribution, voltages, i.e. 132 kV. Some manufacturers have, however, utilised the phase isolated concept down to voltage levels of 33 kV, and there are a number of such installations within the UK.

10.2.1.6 Insulation considerations

Correct insulation design is vital for all substations; this applies not only for open-air types and insulation-enclosed types but also for metal-enclosed and metal-clad types, which employ many insulating components. For example, with metal-clad equipment connections must be provided to connect one compartment to adjacent compartments; such connections are usually by means of bushings (see Chapter 8). Insulation has also to be provided between phases and between phase and earth. Typical insulating materials that may be employed are atmospheric air, insulating oil, bitumous compound, oil impregnated paper (OIP), synthetic resin bonded paper (SRBP) epoxy resin or SF_6. The correct design of insulating interfaces between components and different insulation materials is vital for the long term service integrity of the equipments.

10.2.2 Substation layouts

10.2.2.1 Primary distribution substations

Primary distribution substations within the UK typically operate at 11 kV and are utilised to supply a relatively large number of consumers within a local area. They may be interconnected with other primary substations or fed directly from a 33 kV/11 kV bulk supply point. Outgoing circuits may feed either rural or urban networks. A primary substation feeding a rural network is commonly of the open terminal air-insulated design, whereas a primary substation feeding urban networks is more commonly of the indoor meta-clad design.

A common electrical arrangement for either substation is of the single busbar design but with the busbar being split into two sections and interconnected via a bus section circuit-breaker. There are usually two incoming circuits – one feeding each section of busbar. There may be typically five outgoing circuits feeding either multi-radial networks for overhead rural systems or ring circuits for urban cable connected networks.

To enable isolation from the system for maintenance purposes it is common for disconnection facilities to be provided on either side of the circuit-breaker. Facilities will also be provided for earthing outgoing or incoming circuits and for earthing each section of busbar. Current transformers will invariably be fitted within the outgoing circuit for either protection or, less commonly, for tariff metering purposes, the latter facilities usually being provided for large single customers.

A typical single busbar primary layout is shown in Figure 10.2.

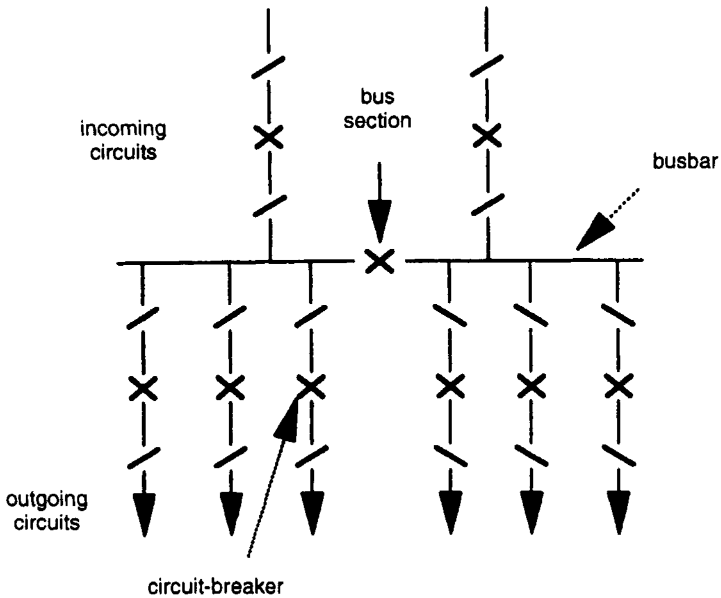

Figure 10.2 Typical distribution primary substation layout: single busbar

10.2.2.2 Bulk supply points

For large important supplies, i.e. as at bulk supply points, which in the UK typically operate at 132 kV/33 kV, or perhaps for large industrial customers, higher security may be built into the substation design. This is usually achieved by means of the provision of a duplicate busbar system. Such an arrangement is shown in Figure 10.3.

This allows the option of four separate sections of busbar to be utilised such that if any one busbar fails, supplies could generally be maintained via the other three busbars. All circuits can be selected to either of the two main busbar sections. Busbar protection is usually provided to ensure very rapid clearance of any faulted section of busbar. Such arrangements are, however, very costly. In addition, modern day equipment is very reliable such that the same degree of availability can usually be achieved without the need to resort to a second busbar system. It is also necessary to ensure that each section of busbar is normally kept energised. If a section remains de-energised for any period of time then deterioration may occur such that possible busbar failure may result on re-energisation.

10.2.2.3 Secondary substations

Secondary substations are almost universally used in urban networks and are usually connected into ring circuits. The purpose of the secondary

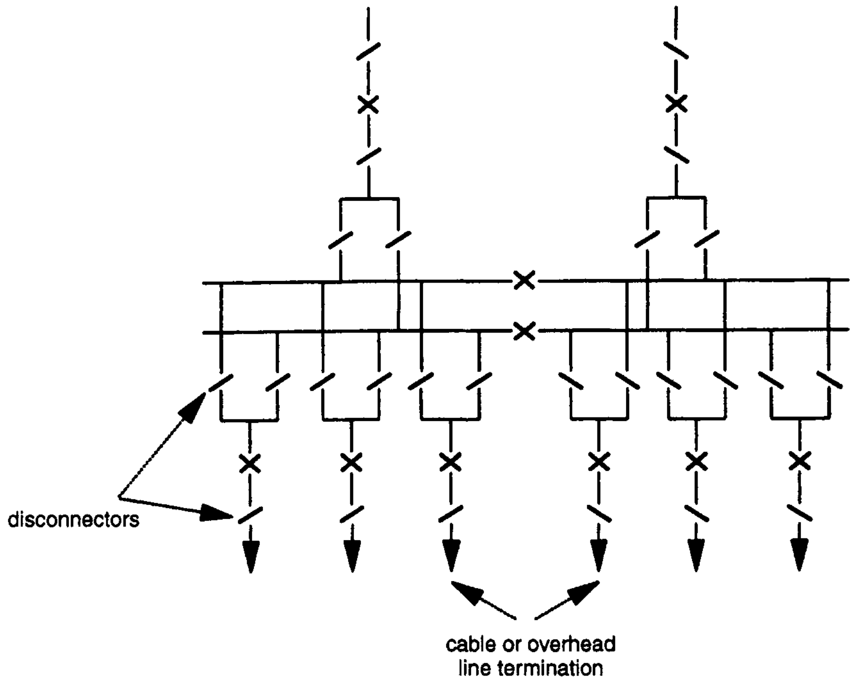

Figure 10.3 Typical distribution primary substation layout: double busbar

substation is to provide a feeding point to local customers at low voltage – typically 415 V 3-phase or single phase. Hence they always employ an 11 kV/415 V 3-phase transformer which may have ratings of typically up to 1000 kVA. The transformer HV is fed from a tee-off from the 11 kV ring main circuit. This ring main equipment is usually of the metal-enclosed form and, whilst built to be weatherproof, they are now usually enclosed within a small prefabricated weather resistant housing. The complete substation is usually enclosed within a fenced off area. It should be noted that the main purpose of the weatherproof housing is to reduce the maintenance requirement otherwise needed for environmentally exposed equipments. The weatherproof housing is not intended to provide safety to the operator or to third parties. Safety is built into the ring main unit itself. The ring main unit is described in more detail in Section 10.5.11

10.3 Distribution system configurations

10.3.1 Urban distribution systems

A typical urban distribution system is shown in Figure 10.4.

The system is fed from a primary distribution switchboard as

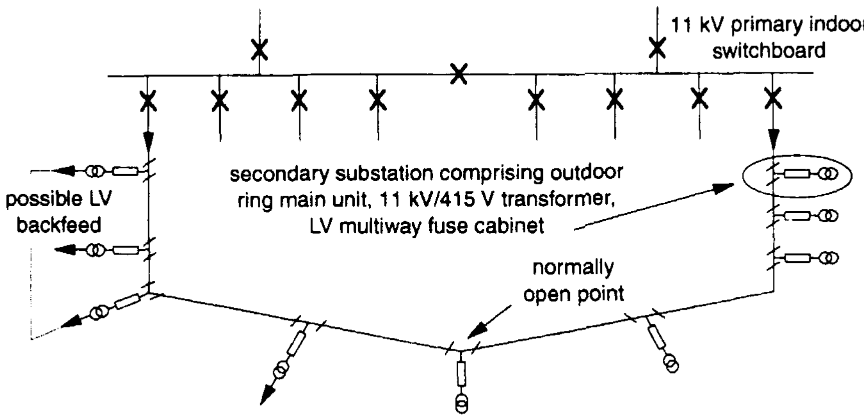

Figure 10.4 Urban distribution system

described earlier. Each outgoing feeder on one section of the busbar feeds via an 11 kV cable network to typically 10 to 12 secondary distribution substations which are electrically connected within the ring circuit. This ring circuit is connected back to a feeder on the adjacent section of busbar at the same substation. The ring circuit usually has a normally open point. The purpose of this is to minimise the number of customers affected by the faulted section of the ring circuit. Once the faulted circuit has been located it can be isolated and earthed, via the ring main units, to allow safe repair work. In the meantime the normally open point can be closed to re-energise the maximum possible number of customers. The ring system normally operates with the primary switchboard bus-section circuit-breaker in the open position.

Ring main switches need to be manually operated; hence, fault location and customer re-energisation can be time-consuming. A modern tendency is for the ring main switches to be fitted with remotely operable mechanisms such that switching times can be reduced by allowing remote substation facilities or, with modern intelligence systems, to allow automatic de-energisation and isolation of a faulted section and re-energisation up to the point of the fault.

The tee-off point of the ring main unit feeds via an 11 kV/415 V 3-phase transformer to an LV fuse board, typically having up to five outgoing circuits which feed directly to large customers or groups of customers. In most of these LV circuits it is possible to achieve an LV backfeed from an adjacent ring main unit, thus maximising the number of customers on supply whilst fault repairs are in progress.

The general network principles described here operate in most industrialised countries, although some may employ radial as well as ring circuits. Typical distribution voltages used elsewhere may range from 10 kV to 20 kV. 6.6 kV systems were common at one time within the UK but these have now largely been phased out.

10.3.2 Rural distribution systems

A typical rural distribution system is shown in Figure 10.5. The primary switchboard will usually comprise two sections of busbar connected via a bus-section circuit-breaker as described earlier. The number of outgoing feeders tends to be less than with an urban network with typically six panels. The primary switchboard in this case may be of the open terminal form or in the outdoor weatherproofed form. However, for reasons given earlier it is now more common for these primary switchboards to be enclosed within a brick type enclosure, in which case conventional indoor metal-clad type switchgear is more commonly used. Most 11 kV rural primary switchboards are of the metal-clad type whereas at 33 kV open-type busbar connected switchgear is more common.

Most rural networks in the UK feed overhead line distribution circuits, hence there is usually a short connection of cable connecting from the switchboard to the terminal pole of the overhead line. It is also common for surge arresters to be fitted at the cable sealing end and mounted physically at the top of the pole at the junction between the cable and overhead line. Surge arresters reduce the probability of transient induced overvoltages resulting from lightning strikes to the overhead line affecting either the cable or associated switchgear.

The overhead line feeders are generally of a radial form, although in some more densely populated rural areas interconnection from radial circuits may be achieved to effectively produce a combination of both ring and radial circuits. The radial circuits will usually have numerous

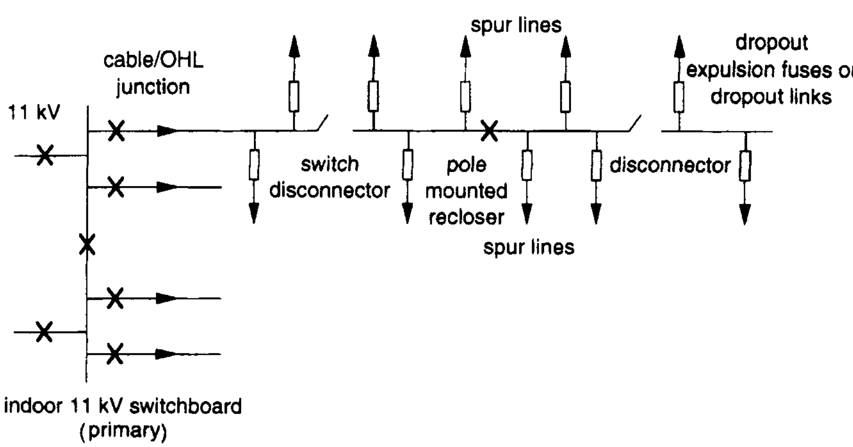

Figure 10.5 Rural distribution system

spur lines feeding to local small communities. Whilst the radial circuits will comprise a 3-phase system, spur circuits often constitute a 2-phase (single-phase) supply. It is necessary to ensure that all customers do not lose supply for a fault on any of the radial or spur circuits.

Traditionally most spur circuits have been protected by a device known as an expulsion fuse (see Section 10.5.9.1). This comprises an 11 kV rewirable fuse in which, when it operates, its fuse-carrier hinges about a bottom bracket to fall to its operated position whilst at the same time providing a visual indication of isolation. However, many faults on 11 kV overhead line networks are transient in nature, e.g. a tree blowing on to a line, a foreign object on the line, a bird between lines, etc., and once the transient fault has been cleared it is often safe to re-energise the line. With expulsion fuses this can take some time, typically up to 1 h, for engineers to be notified, arrive on the site to locate the operated fuse and repair and replace it to reinstate supplies. A more recent development to overcome this problem has been what is referred to as an 'intelligent link'. This is mounted in the expulsion fuse base and counts the passage of fault current to allow the substation primary circuit-breaker to trip and reclose; after three pulses of fault current it will assume that the line has a permanent fault, and an electrically charged circuit will fire a release pin to allow the carrier to drop to an isolated position within the de-energisation time of the primary circuit-breaker.

For particularly long lines it is of concern if all customers experience the temporary loss of supply whilst the feeding primary circuit-breaker auto-recloses. For this reason it is then more common for a pole-mounted auto-reclosing circuit-breaker to be located some half-way along the overhead line feeder. Such devices used to derive their closing energy from a falling weight type of operating mechanism; such a system clearly needed rewinding after it had completed its charge of typically ten closing operations. Modern versions of pole-mounted auto-reclose circuit-breakers are solenoid operated and receive their closing energy from the feeding primary circuit at 11 kV. Pole-mounted auto-reclosing circuit-breakers were traditionally of the oil-filled type and were protected against transient overvoltages by means of 'duplex' spark gaps, i.e. two gaps in series to minimise breakdown by the presence of birds or foreign objects. Modern types of pole-mounted auto-reclosers are either of the vacuum-type circuit-breaker or SF_6-type circuit-breaker and require to be protected against internal breakdown by metal oxide surge arresters. (See Chapter 2).

Another device which is commonly fitted in series with the main rural feeder is a disconnector. This is generally manually operated from the bottom of the pole by a long metallic operating drive rod and series connected insulated rod. The disconnector has no breaking capacity and should therefore be operated only at a time when the line is de-energised to provide a point of isolation such as to allow work to be safely undertaken downstream of the disconnector. A further device which may be fitted is a switch-disconnector. This is a device for interrupting load current but not fault current. The switch disconnector usually has some form of rudimentary arc control device to enable it to interrupt the load current flowing in the line, i.e. a switch disconnector can be operated with the line energised. Its interrupting medium is usually atmospheric air and gases produced within its arc control device. (See Section 10.5.6).

10.4 Ratings

All switching devices have 'Ratings' and it is necessary to understand how equipment is rated. A brief description of some of the typical ratings encountered is given below.

10.4.1 Rated current

This is the continuous current that equipment is capable of passing without exceeding its temperature rise limits. Such limits are defined in the appropriate international specifications.

Typical rated currents encountered for older equipment would be 400 A, 800 A, 1200 A and 2000 A.

Newer equipment is rated on the basis of preferred numbers, which are related to the 'Reynold' series, with the R10 series being the most commonly used for switching equipment.

Typical current ratings encountered for newer equipment would thus be 630 A, 800 A, 1250 A and 2500 A, etc.

10.4.2 Rated short-circuit-breaking current

The rated short-circuit-breaking current is the RMS value of the short-circuit current that a circuit-breaker is capable of breaking at its rated voltage to the prescribed conditions of the appropriate international specification, which for circuit-breakers is IEC 62271–100.

Typical values of rated short-circuit-breaking current to be found on older switchgear equipment are 7.9 kA, 13.1 kA, 18.4 kA and 26.2 kA. For newer equipment the appropriate R10 ratings are 8 kA, 12.5 kA, 16 kA and 25 kA, 31.5 kA.

It should be noted that older equipments were commonly rated in terms of their MVA capability. The MVA rating is equivalent to the rated voltage × the rated short-circuit-breaking current × $\sqrt{3}$.

10.4.3 Rated short-circuit-making current

The rated short-circuit-making current is the peak value of the rated short-circuit current that the circuit-breaker is capable of closing against, at 0.1 power factor, i.e. it has to close against the maximum current asymmetry.

The asymmetrical factor commonly used was 1.8. This would thus give a making current of $1.8 \times \sqrt{2} = 2.55 \times$ RMS value of current. For more modern equipment a 'rounded' value of 2.5 is used.

10.4.4 Rated asymmetrical breaking current

This is the value of asymmetrical breaking current that a circuit-breaker is capable of interrupting under typical system asymmetric conditions. Whilst traditionally a value of a DC component offset equivalent to 50% of the RMS value of the rated short-circuit-breaking current has been used, the modern tendency is to specify the asymmetric current in terms of the system X/R ratio. A ratio of typically 14.5 has been used, but IEC 62271–100 recognises that more onerous conditions may exist and in such cases it is necessary for the user to specify the required value.

10.4.5 Rated short time current

This is the rated short circuit through current that a switching device and its assembly is capable of safely withstanding for a rated time. The peak value of the rated short time current must be equivalent to the value of the rated short-circuit-making current.

In the UK for distribution switchgear the rated time is normally 3 s. For transmission switchgear and for distribution switchgear used elsewhere a rating of 1 s might only be required.

10.4.6 Rated voltage

The rated voltage of an item of equipment is the RMS voltage that the equipment is capable of withstanding continuously, and it is the value used to verify all performance criteria. The rated voltage relates to the maximum permissible system voltage, e.g. 10 kV or 11 kV systems equipment would have a rated voltage of 12 kV, similarly for 33 kV systems the equipment rated voltage would be 36 kV.

10.4.7 Rated insulation withstand levels

These are the values of overvoltage that the equipment is capable of withstanding for a short duration. They are usually defined in terms of two criteria for distribution switchgear, i.e. the 1 min power frequency withstand voltage and the rated lightning impulse withstand voltage. For 11 kV equipment, for example, the rated power frequency overvoltage might be 27 kV RMS for 1 min and the rated lightning impulse voltage may be 75 kV peak, or alternatively 95 kV peak.

The rated lightning impulse voltage comprises a double exponential waveshape having a rise time to its peak value of 1.2 μs and a time to half-life of 50 μs. Electrical power equipment is required to withstand 15 such lightning impulses of both positive and negative polarities. Such tests are clearly intended to simulate lightning induced overvoltages entering into the switchgear. For transmission switchgear switching overvoltage tests are also required. These are similar to lightning impulse tests but have a waveshape of 250/2500 μs.

10.4.8 Rated transient recovery voltage

When a circuit rapidly changes from one steady-state condition to another it cannot do so without inducing transient overvoltages and associated current surges. Since circuit-breakers invariably clear at zero current the overvoltage produced at that point will be dependent on the rate of change of current, the circuit inductance and stray capacitance. For 11 kV equipment, for example, the rated transient recovery voltage would have a peak value of 20.6 kV with a time to its peak value of 60 μs. The rate of rise of voltage is particularly critical and for the values quoted this would equate to a rate of rise of 0.34 kV/μs.

There are many other rated values for switchgear but the ones described above are typical of the information that might be encountered on an equipment rating plate. For further information the reader is referred to IEC 62271–100 High Voltage Alternating Current circuit-breakers.

10.5 Switching equipments

The foregoing sections have described distribution networks and some of the electrical switching equipments which may be encountered together with typical equipment rated values which may be encountered on the equipment rating plates. These describe the performance criteria. It should be noted that, by themselves, these ratings do not necessarily ensure safety. Safety provisions must be built in to equipment, firstly in accordance with local regulations and then in accordance with the utilities' own requirements. Similarly it might be necessary for the utility to specify the operational features that are required to be incorporated.

A variety of terms are used to describe such equipment, and it is important that the power engineer fully understands the meaning of these terms and the performance and operational differences between the different types of equipment which may be encountered.

A brief description of such equipment follows.

10.5.1 *Circuit-breakers*

A circuit-breaker is a device which, in addition to carrying, and making and breaking, its rated load current, is also capable of interrupting, when energised via suitable protection relays, its rated short-circuit-breaking current. It is also capable of closing against its rated short-circuit-making current.

Extremely large magnetic forces are set up when a circuit-breaker attempts to close against the system short-circuit current, and it is essential that the operating mechanism has sufficient stored energy to impart into the moving contact system to ensure that it fully closes and is 'latched' closed. There are a number of different types of operating mechanisms that may be encountered, these being typically as follows.

10.5.1.1 Manually operated mechanisms

Many older circuit-breakers required direct manual operation where the closing energy and operating force was entirely dependent on the strength and skill of the operator. Failure to close with sufficient force to overcome the short-circuit throw-off forces results in the circuit-breaker contacts opening, or being held in a partially open position, and circuit-breaker failure is inevitable. This is an extremely dangerous situation for the operator. In consequence, manually operated circuit-breakers should be removed from the system or operated only when the system is de-energised. Alternatively, it may be possible for the direct manual operating mechanism to be replaced with a stored energy type of operating mechanism, but in this case further type test verification will be required.

Direct manually operated circuit-breakers should not be closed with the primary system energised.

Incidentally, virtually all circuit-breaker operating mechanisms employ an arrangement of mechanical linkages, toggles and latches. With the circuit-breaker in a closed position, a latch engages within the mechanism toggle arrangement to mechanically hold the circuit-breaker closed. Tripping is achieved by means of a DC operated coil supplied from the substation battery. The tripping energy is most commonly derived from springs which are charged during the closing operation of the circuit-breaker.

10.5.1.2 Independent manual spring operated mechanisms

In view of the inherent problems with manually operated mechanisms manufacturers found ways of producing a low cost operating mechanism that was still manually operated but where, during the early part of the closing operation, a closing spring is charged; halfway through the operation the charged springs travel over-centre and closing is achieved by the energy imparted into the springs such that the closing force and speed is independent of the operator. Such mechanisms are generally only used at 11 kV and where the equipment short-circuit rating does not exceed 12 kA.

10.5.1.3 Dependent spring operated mechanisms

Circuit-breaker closure by manual means with an operator standing in front of the circuit-breaker is not always desirable, particularly as it requires an operator to have to travel to site to close the circuit-breaker. Hence, an operator independent means of closing was required.

This is achieved in a number of ways, the cheapest and often the most preferred way of closing being to prestore energy into closing springs. This can either be achieved manually or by means of a motor gear drive arrangement. The operating mechanism is then held in a 'charged' position by means of a latch which can be released to allow the circuit-breaker to close on operation of a DC operated closing coil. When the springs have been released to allow circuit-breaker closure the operating mechanism is mechanically latched in its closed position such that the closing springs can again be recharged, either manually or by remote operation. It is thus possible to 'store' a charge within the closing springs such that if the circuit-breaker trips it is immediately ready for reclosure to provide an auto-reclosing feature.

Spring charged operating mechanisms are widely used in all circuit-breakers and there is now a modern tendency for them to be used for higher short-circuit ratings and even on transmission circuit-breakers.

10.5.1.4 Solenoid operated mechanisms

For many years an alternative to spring operated mechanisms was a solenoid operated mechanism. This comprises a very large DC operated solenoid coil whereby the solenoid moving plunger directly drives the operating mechanism linkage to close the circuit-breaker. Closing times are generally slow and large battery drains ensue particularly if the circuit-breaker is used for an auto-reclosing duty. Such mechanisms are rarely used these days but may well be encountered on older switchgear up to 132 kV.

With most solenoid operating mechanisms the circuit-breaker can be 'slow' closed by means of a manual lever operating on the solenoid plunger. There are usually no facilities to prevent such a manual operation on a live circuit.

It is vitally important that a solenoid operating mechanism should not be used to allow manual closure of a circuit-breaker onto a live circuit.

10.5.1.5 Magnetically operated mechanism

Over recent years there have been very rapid developments in the technologies and manufacturing processes for magnetic materials such that magnetically operated circuit-breakers are returning into fashion. These are being applied particularly for vacuum circuit-breakers where small contact travels are encountered. In this case the closing and hold-on force is derived from a permanent magnetic pole. To achieve closing or opening a small coil is used to bias the pole in one direction or the other. Such mechanisms alleviate the need for toggle linkages and can be produced very economically.

10.5.1.6 Hydraulically operated mechanisms

With this type of operating mechanism the closing energy is stored in an accumulator which comprises a high pressure cylinder with a centrally located piston. On one side of the piston is a gas which is usually nitrogen and on the other side is hydraulic oil. The oil can be fed via a pump to move the piston to compress the nitrogen. Closing energy is thus stored in the compressed nitrogen. A series of valves is provided, the first of which is operated by a closing coil. The first stage valve then allows high pressure oil into a second stage valve, which in turn typically operates a third stage valve to allow large quantities of high pressure oil to flow to an actuator piston. The piston then moves under the pressure of the oil to drive the circuit-breaker contacts to their closed position. The circuit-breaker is usually held closed by a differential pressure piston. To trip, a valve is operated via the circuit-breaker trip coil to allow the high pressure oil to be dumped to the low pressure reservoir. Typically two close-open operations can be stored within the accumulator.

Such operating mechanisms tend to be expensive and whilst widely used at transmission voltages are seldom encountered at distribution voltages.

A simpler variant is sometimes found at distribution voltages whereby a hydraulic ram is used to charge the springs of a spring operated mechanism.

10.5.1.7 Pneumatically operating mechanisms

This type of mechanism is similar to the spring operated mechanism but uses a pneumatically operated piston to drive a conventional toggle/linkage mechanism to close the circuit-breaker. A pressurised air receiver is required to store the energy, which typically is released to the closing piston via a closing coil operated three stage valve assembly. Whilst such mechanisms may occasionally be encountered in distribution applications, they are nevertheless widely utilised within transmission switchgear applications.

10.5.2 Distribution circuit-breaker types

The types of distribution circuit-breaker encountered will briefly be described, but detailed description of arc extinction mechanisms are given in Chapter 6.

10.5.2.1 Bulk oil plain break circuit-breaker

This was an early design of circuit-breaker in which all three phases were enclosed within a tank of oil. The circuit-breaker contained no specific means of arc control. Arc extinction was determined solely by the oil characteristics and the pressure rise within the circuit-breaker tank. For three phase rated short-circuit currents of up to 12 kA such circuit-breakers operated satisfactorily since high pressures were built up within the circuit-breaker tank to assist in the arc extinction process. Under single phase or low current fault conditions, however, insufficient pressure may be built up to extinguish the arc. This results in long spindly arcs being produced which may continue until the circuit-breaker contacts reach the end of their travel, after which interruption is solely fortuitous and failure may result. In consequence, plain break circuit-breakers should be removed from the system or should only be operated in a de-energised state, i.e. to be used solely as a disconnector.

Plain break circuit-breakers should be removed from power systems.

10.5.2.2 Bulk oil arc control circuit-breaker

The shortcomings of plain break bulk oil circuit-breakers were soon realised and solid insulated assemblies were developed to enclose the arc produced at each set of interrupter contacts. These are referred to as arc control devices whereby for high short-circuit currents very high pressures are built up in the top section of the arc control device as a result of vaporisation of the oil. The high pressure results in rapid arc extinction. Pressure is released usually via two or more apertures in the region where the high pressure is developed, towards the top of the device. For lower fault currents insufficient pressure is produced in the upper section of the device to extinguish the arc, and much longer arcs are drawn out into the lower, more constrained, region of the device. This allows a higher pressure to result in this lower region. There are usually interconnecting chambers within the device which allow a flow of oil upwards and across the upper region of the arc to assist in cooling and arc extinction. This cross jet flow of oil lends its name to the arc control device, which is commonly referred to as a 'cross jet pot'. Such devices allow satisfactory high short-circuit current ratings to be achieved and at the same time allow safe interruption of both single phase and low current fault conditions (see Figure 10.6).

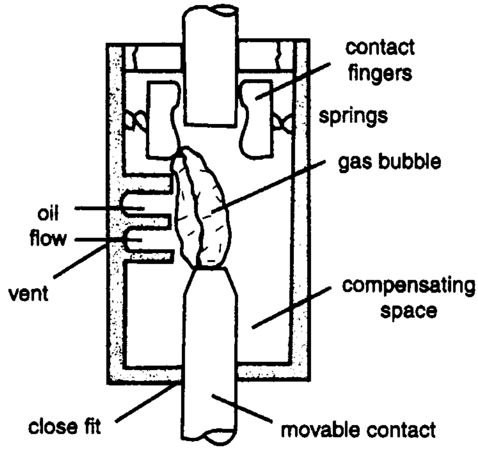

Figure 10.6 Oil circuit-breaker arc control device

Notwithstanding the satisfactory development of such arc control devices, even in the mid-1930s, plain break circuit-breakers continued to be manufactured up until the early 1960s. This was due to their significantly lower costs.

10.5.2.3 Minimum oil circuit-breaker

The development of the 'cross jet pot' allowed development of an alternative lower cost form of oil circuit-breaker. This is referred to as a minimum oil circuit-breaker where each phase has its own independent oil chamber which is of a relatively small volume. As the chamber is at line potential it must be supported from earthed metalwork by some form of insulator and, similarly, its outgoing HV terminal must be insulated. Such devices are referred to as live tank minimum oil circuit-breakers. Whilst for distribution purposes they can be made to be small and enclosed in metal-clad switchgear constructions they have one significant disadvantage. In view of the small oil volume, oil carbonisation rapidly occurs on fault interruption and, in consequence, more frequent maintenance is required than would be necessary for a bulk oil type circuit-breaker. If maintenance is not undertaken at the appropriate time, internal electrical tracking and deterioration can occur on insulating surfaces within the oil chamber which, if not corrected, will lead to catastrophic failure. For this reason minimum oil circuit-breakers have not been widely applied within the UK. They are, however, widely utilised within many European countries.

10.5.2.4 Air blast circuit-breaker – sequentially operated

Air blast sequentially operated circuit-breakers are devices that require a blast of high pressure air to cause extinction of the arc across the opening circuit-breaker contacts. The high pressure air is usually stored in an air receiver on which is mounted the insulator support and interrupter assemblies. On being required to trip, the operating mechanism will mechanically open a valve which allows the high pressure air to enter the contact chamber. This high pressure air operates a piston connected to the moving contact assembly which causes the contacts to open and at the same time allows a blast of air to flow across the opening contacts to clear the fault. Following the passage of the flow of air the contacts reclose under the influence of a spring compressed during the opening operation. Such circuit-breakers cannot provide permanently open contacts, and during the arc extinction process it is necessary for a mechanically driven sequential disconnector to operate to provide an open gap before the contacts reclose. Closure of the circuit-breaker is achieved solely by closing the sequential disconnector.

The advantages of such circuit-breakers is that they provide rapid fault clearance under all fault conditions, clearance is usually achieved within one cycle of arcing. They are also ideal for, more economically, providing a means of clearing both high fault levels and low inductive fault currents. Such circuit-breakers are rarely found on distribution networks but may occasionally have been utilised at 11 kV, or more commonly 33 kV, for shunt reactor switching duties.

10.5.2.5 Pressurised head air blast circuit-breaker

These are devices whereby the contacts are held open by pressurised air and the circuit-breaker does not, in consequence, require a series sequential disconnector. These circuit-breakers are used only at transmission voltages where very rapid fault clearance times are required. They will not be found in distribution circuits, but may be encountered at 132 kV bulk supply points.

10.5.2.6 Free air circuit-breaker

This is a device that is used solely at 11 kV and below. It can generally achieve very high current ratings, i.e. 4000 A and very high short-circuit ratings of typically 50 kA. In consequence it is seldom used in distribution applications and also tends to be very costly. Its main advantage is that it uses nonflammable components and, with its high ratings, is ideally suited for use in auxiliary circuits of power stations. In most older UK power stations this is the only form of circuit-breaker that will be found for auxiliary circuits.

Its contacts operate in free air; on opening, an arc is pulled out for the full length of the open contacts. The arc is then transferred to runners which cause it to rise; it then enters an arc chute, which is a device comprising a large number of vertically rising steel plates each being physically separated by a distance of 6 mm or so. As the arc enters the arc

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chute, it is split up into numerous small arcs in series, each of which is cooled by the plates. The arc rises within these plates and is extinguished by the time it reaches the top of the arc chute. Such circuit-breakers tend to have relatively long fault clearance times but have been proven to be very reliable (see Figure 10.7).

A further version of this device is commonly found in LV networks, and such devices can be designed to achieve very rapid fault clearance times by chopping the current to zero even before it reaches its first peak value. These free air circuit-breakers are additionally referred to as 'current limiting' circuit-breakers. Current chopping features, however, cannot be achieved for voltages above 1000 V.

10.5.2.7 Vacuum circuit-breaker

Up until the 1960s there was no real economic alternative to the use of bulk oil circuit-breakers for distribution applications. It had long been known, even from the 1920s, that contacts opening in a vacuum would not sustain an arc. This feature was never employed for circuit-breakers due to the difficulties of providing a sealed chamber that could hold a vacuum, without leakage, for the circuit-breaker lifetime of at least 30 years.

Post World War II saw very rapid developments in television technology, which required the tubes to be operated with a sustained vacuum. Television tube technology was thus applied to produce a sealed insulation enclosure for opening the contacts of a vacuum circuit-breaker.

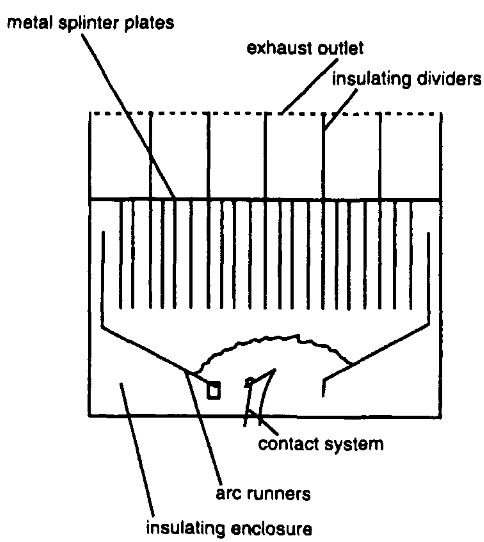

Figure 10.7 Arc chute interrupter