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Movement of the circuit-breaker moving contacts is achieved by means of a stainless steel bellows. The technology was proven to work, but much refinement of contact design and materials was required before the technology became commercially available (see Figure 10.8.)

This refinement has continued ever since, to the stage where economic, reliable designs of vacuum interrupters and associated operating mechanisms are widely available and will be found in many 11 and 33 kV distribution switchgear applications.

The designs have been perfected to such an extent that their application can be found even in 415 V circuits.

Unfortunately, it is not physically and economically possible to produce a vacuum interrupter 'bottle' for voltages higher than 33 kV. Whilst vacuum interrupters have been used for high voltage applications, in particular at 132 kV, these concepts comprise a number of 33 kV interrupters in series, and in consequence vacuum technology at higher voltages is not economic.

10.5.2.8 Dual pressure SF_6 circuit-breakers

Where SF_6 was first used for circuit-breaker interruption it was used in a concept similar to that of an air-blast circuit-breaker. With this arrangement SF_6 was used at a relatively low pressure as an insulating medium across the open contacts and from the contacts to earth. For circuit interruption high pressure SF_6, stored in a separate pressure vessel, was allowed to blast through the interrupters and across the opening contacts to extinguish the arc in a similar manner to that of an air-blast circuit-breaker. The concept worked very well but it needed a dead tank construction of circuit-breaker with external bushings connecting to the

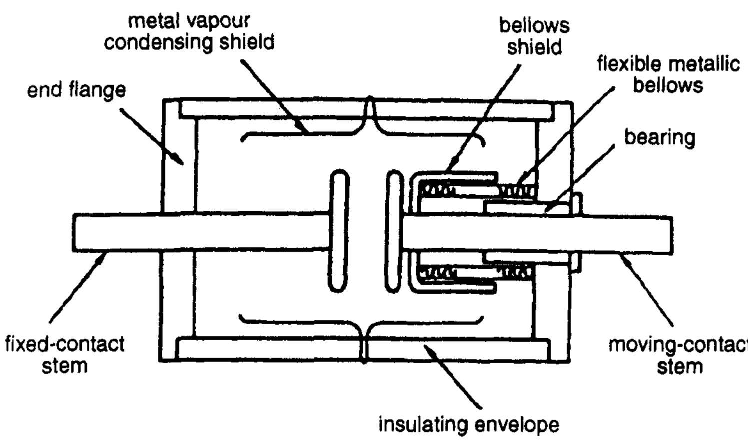

Figure 10.8 Cross-section of a vacuum interrupter

HV circuits. The design was, in consequence, costly and even more so as it required a separate high pressure SF_6 storage vessel. At the high storage pressure, of typically some ten bars, the SF_6 would liquefy at low ambient temperatures. To prevent this happening heater tapes were wound around the high pressure cylinder to ensure that the SF_6 was always in its gaseous state. Failure of the heater, however, could result in circuit-breaker failure, and hence heater monitoring circuits were required.

In view of these shortcomings, and in view of the rapid developments of other SF_6 interruption technologies, the dual pressure SF_6 circuit-breaker had only a short time of availability. The concept, however, has proven to be successful and, even now, some 132 kV dual pressure SF_6 circuit-breakers still remain on the system within the UK.

10.5.2.9 Self-generation gas blast (puffer) SF_6 circuit-breaker

The next generation of SF_6 circuit-breakers still employed the same principle of arc interruption as the dual pressure circuit-breaker, but in this case there was no requirement for storage of the high pressure SF_6. SF_6 within the interrupter was used at a slightly higher pressure than for the dual pressure circuit-breaker, typically 6 to 6.5 bar gauge. The high pressure blast was generated by means of gas compression from a piston within the interrupter during the opening stroke – hence the name self-generating blast or puffer.

There then followed rapid developments of designs of interrupter, nozzle and gas flow principles to the extent where the partial duo-blast concept was successfully developed, allowing higher interruption capabilities to be achieved with a very short arcing time. Such a typical interrupter is shown in Figure 10.9.

The puffer interrupter principle has been widely applied in both

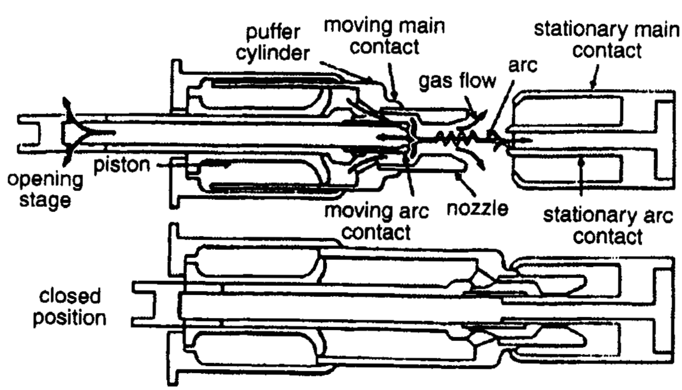

Figure 10.9 Typical partial duo-blast SF_6 interrupter

distribution and transmission circuit-breaker applications. Its main disadvantage is that it requires a large operating energy and long opening stroke to precompress the SF_6. This necessitates the use of large, costly, operating mechanisms, and it is for this reason that for transmission circuit-breakers hydraulic or pneumatically operated mechanisms have been developed. At distribution voltages spring operating mechanisms can still be used, but these are nevertheless relatively costly.

10.5.2.10 Self-pressurising SF_6 circuit-breaker

In view of the need for costly operating mechanisms for the puffer type of circuit-breaker, developments ensued to attempt to use the energy of the arc to create pressure to cause it to extinguish itself. This works very well for interruption of high fault current but does not work so well for interruption of lower levels of fault current where long thin arcs can be drawn out. To overcome this problem a low energy piston is still required to provide a flow of SF_6 across this low energy arc. Nevertheless, considerably reduced operating forces are required when compared with the puffer type of circuit-breaker. This has led to the development of significantly lower cost operating mechanisms such that spring operating mechanisms are widely being applied to this type of circuit-breaker at transmission voltages.

10.5.2.11 Rotating arc circuit-breaker

The puffer type of circuit-breaker proved to be costly compared with the rapidly developing vacuum circuit-breaker technology at distribution voltages and particularly where only low short-circuit rated currents were required. In consequence, an alternative form of SF_6 interruption was developed. The technology allowed the arc to move through the gas rather than the gas moving across the arc. The arc was caused to move by automatic insertion of a coil during the contact opening process. The current passing through this coil caused a magnetic field to be generated which led to rapid rotation of the arc (see Figure 10.10).

Rotating arc circuit-breakers tend to arc to the full length of their contact stroke and, in consequence, have relatively long arc durations, particularly at low levels of fault current. This is because the lower magnetic field generated by the lower fault current will not cause the arc to rotate so rapidly. At even lower currents arc rotation may cease altogether and arc interruption may be purely fortuitous. This may be particularly critical if the circuit-breaker is required to switch low energy reactive currents where very high values of transient recovery voltage may be encountered. Such reactor current switching breakers require to be proven by laboratory tests for this duty.

Notwithstanding this potential shortcoming, rotating arc circuit-breakers are very widely applied in distribution switchgear applications

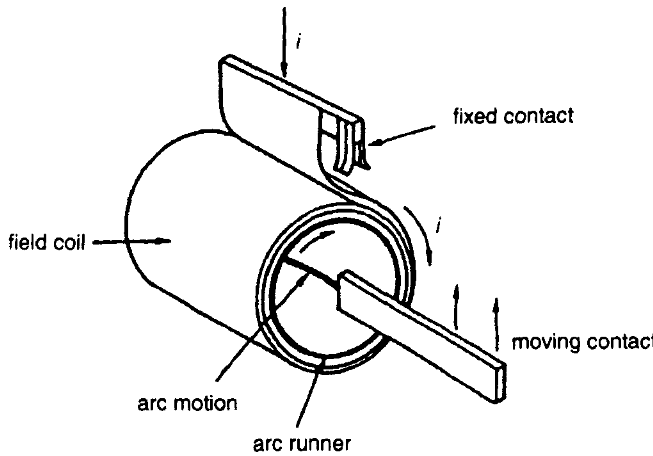

Figure 10.10 SF_6 rotating arc principle

and offer very economic solutions. Low energy cost effective operating mechanisms can be employed when compared with the puffer principle.

10.5.3 Disconnectors

Disconnectors (isolators) are used to connect or disconnect sections of the circuit to allow the facility for safe earthing of the disconnected circuits to enable maintenance or repair work to be undertaken. They are usually manually operated at distribution voltages but may, at high voltages, be motor operated to allow remote, or automatic, operation.

Disconnectors are not intended to interrupt circuit currents but will be required to interrupt small capacitive currents associated with either open circuit-breakers or adjacent live circuits.

Where they are used on multiple busbar circuits they may also be required to facilitate the live transfer of a circuit from one busbar to another. In such a case they will be required to break the parallel currents circulating in the different sections of the busbar.

When closed, the disconnector must clearly be capable of carrying its rated load current and also its rated short-circuit current. In its open position it must provide isolation both against the rated power frequency voltage and associated switching or lightning impulse voltages that may be superimposed thereon.

Disconnectors used in outdoor substations may be of various types - for distribution applications the most common type encountered is either the centre rotating post type or rocking post type. The general construction of such disconnectors is shown in Figure 10.11.

For metal enclosed switchgear, disconnection facilities are generally

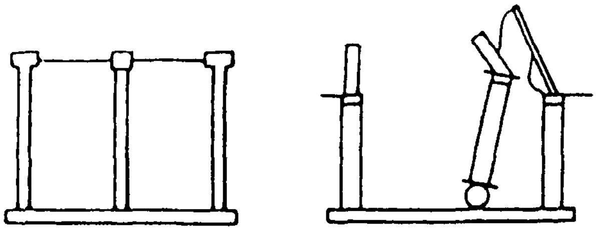

Figure 10.11 Disconnector types: outdoor substations

built into the equipment. For very many years such facilities have been provided but by allowing means of physically unplugging the circuit-breaker from its fixed position. The unplugging process provides a physical gap between circuit-breaker isolating contacts and the fixed contacts of both the circuit and busbar sides of the fixed panel. When isolation is completed metallic shutters automatically close the aperture to the fixed contacts (i.e. spouts). The shutters can then be padlocked or closed for safety purposes. Interlocks are provided to prevent physical damage on attempted reinstallation of an isolated section with padlocked shutters. It should be noted that whilst it has long been the practice to provide metallic shutters on all such equipment installed in the UK this has not necessarily been the case on switchgear utilised elsewhere.

Circuit-breaker isolation will be either by means of vertical or horizontal movement (see Figure 10.12).

In view of the potential high reliability of both SF_6 and vacuum circuit-breakers, and the considerably reduced need for maintenance, there has been a tendency in recent years to make the circuit-breaker fixed and nonwithdrawable. In such cases it is necessary to provide separately enclosed disconnectors. These may be provided on both the busbar and circuit sides but the modern tendency is for them to be provided solely on the busbar side. Such disconnectors usually incorporate an earthing switch such that the circuit side can be earthed via the circuit-breaker. Interlocks are required to ensure that the disconnection can only be achieved with the circuit-breaker in its 'off' position. A separate interlock prevents the disconnector from individually being moved to its 'earth on' position. Such an arrangement is also shown in Figure 10.12.

10.5.4 Earth switches

When work is required on outgoing circuits or on substation busbars or circuit-breakers it is necessary, subsequent to isolation, to apply an earth to the circuit to make it safe for work to commence. This may be facilitated by the provision of an earthing device or earth switch. For older

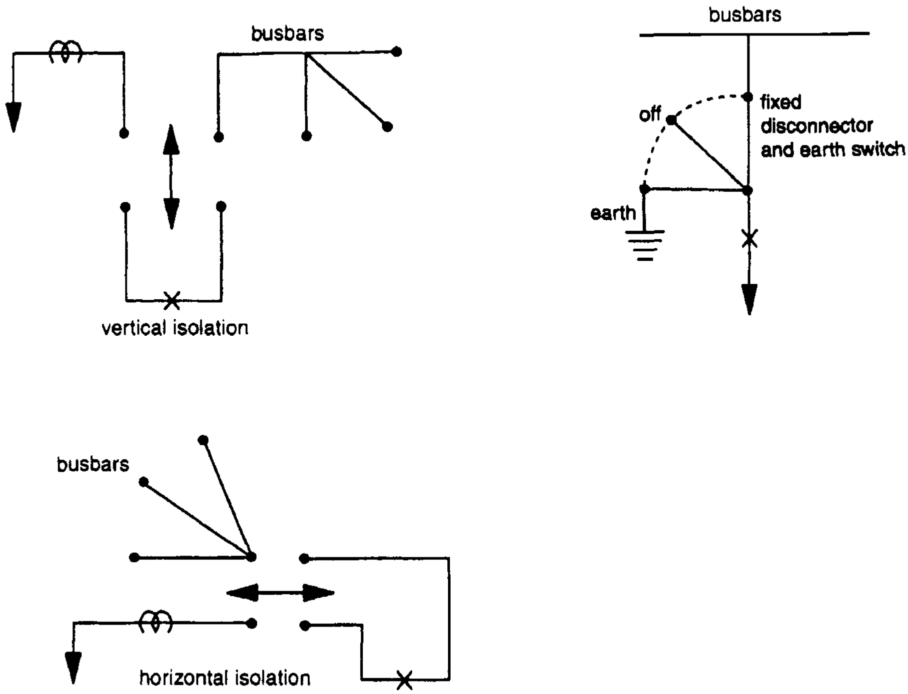

Figure 10.12 Metal enclosed switchgear: isolation facilities

metal-clad switchgear it was common practice to provide a separate device which could be plugged into a de-energised spout. Such devices could on occasions be inadvertantly plugged into a live circuit, with disastrous results. In consequence, this type of earth device was banned and a device which could be fitted to the circuit-breaker isolating contacts was utilised. This allowed earthing of the circuit via the circuit-breaker, i.e. a fault-making device. Such devices are widely employed on distribution metal-clad switchgear assemblies. They may also provide the facility via interlocks for checking the correct phase relationship and cable testing.

Earthing should only be applied to metal-clad distribution switchgear by means of a fault-making device.

In view of these inherent problems and the cumbersome nature of the earthing device, manufacturers built earthing features into the metal-clad equipment itself. This is often achieved via transfer earthing, i.e. the movement of the circuit-breaker from the circuit engaged position to be plugged into an additional two positions either to select circuit to earth or busbar earth. Incidentally, circuit-breaker tripping facilities must be locked off with the circuit-breaker in its earthing location to prevent inadvertent removal of the earth from the system.

For overhead line circuits earthing switches are generally not of the fault-making type. Earthing switches may be provided at either side of a disconnector. With such an arrangement isolation gaps are readily visible and the overhead circuit can be readily tested and checked to ensure that it is de-energised.

For higher voltages, 132 kV and above, the earthing switch may also be required to interrupt the capacitive and inductive currents induced into the earthed line from an adjacent live circuit on the overhead line towers.

10.5.5 Switches

A circuit-breaker is commonly incorrectly referred to as a switch. A switch is a device that must be capable of making and breaking load currents but not overload currents. It is not capable of breaking short-circuit currents but may, in certain circumstances, be required to have a rated short-circuit-making capacity. It must also carry in its closed position its rated short time current. It is generally power operated to ensure that consistent opening and closing speeds are achieved.

Switches may be air, oil or SF_6 insulated, and they will usually have some form of rudimentary arc control system. They are widely used on distribution networks in combination with either disconnectors or fuses. They have minimal use at transmission voltages.

10.5.6 Switch disconnector

This is a switch which provides in its open position an isolating distance. A typical outdoor switch disconnector arrangement is shown in Figure 10.13. Switch disconnectors, using SF_6 interruption technology, were first used at transmission voltages c. 1970, and still remain on the system.

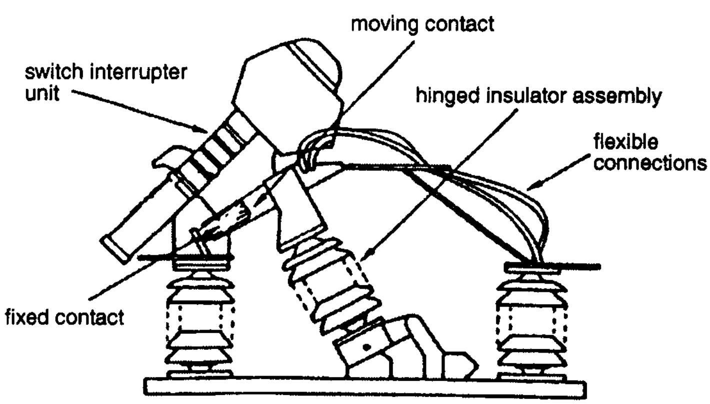

Figure 10.13 Outdoor pole-mounted switch disconnector arrangement

With the rapid development of SF_6 arc interruption technology for circuit-breakers, switch disconnectors no longer offered economic advantages and their use diminished. In the USA, however, more economic versions are again starting to appear and their use is again becoming viable.

10.5.7 Switch fuse

A switch fuse is a combination of one assembly of switch and fuse in series. It is widely used in LV applications but not so much so at distribution voltage applications. The reason for this is that the switch is not protected for a fault between the switch itself and the fuse.

10.5.8 Fuse switch

This is a device whereby the fuse is physically mounted on the moving contact assembly of the switch. This ensures that the switch will always safely close against its rated short-circuit-making current, with the fuse operating to clear the fault. As the fuse operation is very rapid, the fault-making current duty of the switch is considerably reduced and more economic designs can ensue.

Fuse switches are very widely used in distribution networks at 11 kV. Their application is limited at 33 kV and nonexistent at higher voltages.

10.5.9 Fuses

A fuse is a one-shot device capable of carrying its rated current, carrying defined circuit overloads for predetermined times, of clearing overloads in excess of predetermined times and of clearing short-circuit currents caused by system faults. Once operated its fuse-link must be replaced.

10.5.9.1 Expulsion fuse

An expulsion fuse is a semi-enclosed (rewirable fuse) which is widely used on 11 kV distribution overhead line networks. It has a reduced application at 33 kV. A typical arrangement is shown in Figure 10.14.

The fuse element assembly comprises flexible 'tails' with a small central region comprising the element itself. It is this portion that melts, or volatalises, on fault operation. The element is enclosed in a solid insulated tube, the end fittings of which are held by two spring loaded contacts. On operation, high pressure gases are developed within the bore of the tube. These expel the ends of the element flexible leads and at the same time assist in arc extinction. The top contact then releases and allows the fuse carrier to swing around its bottom, hinged assembly to give a visual sign of operation and to provide an isolation gap.

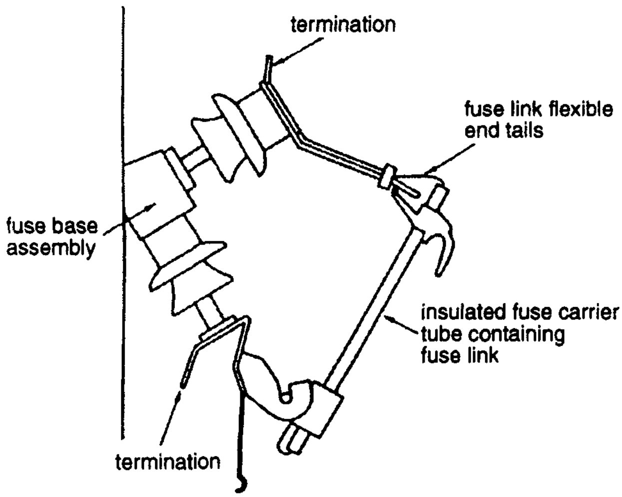

Figure 10.14 Circuit switching device: expulsion fuse type

Expulsion fuses are not current limiting in that they always require a current zero to clear. Arc durations are in consequence long and arc energies are high. The rated short-circuit-breaking currents are relatively low – typically no greater than 8 kA at 12 kV. When the expulsion fuse operates it expels hot gases from either end of its fuse carrier (hence its name). They usually give a very loud retort on fault operation. They provide a relatively economic means of protecting overhead line spur circuits.

10.5.9.2 Current limiting fuses

A current limiting fuse is a sealed device that does not expel any gases on operation. As it is sealed it can also be used, at 11 kV, under oil. Its mode of operation differs considerably from an expulsion fuse in that it will current limit, i.e. it will cut off a rising short-circuit current before the current reaches its full peak value.

The device comprises a fuse element, usually made from a silver strip. The element may be typically 2 m long at 11 kV and, to accommodate this length within the length of the 250 mm fuse body, it is necessary for it to be wrapped spirally around an insulated star core, usually of ceramic material with a central hollow bore. There may be two or more elements in parallel to increase the rated current capability of the fuse. Each element has numerous regular notches along its length. The purpose of these notches is to ensure that on operation under high short-circuit currents, each notch will volatalise and in so doing will produce a number of arcs in series to build up a back EMF to withstand the system applied and transient voltages. Very rapid arc extinction is achieved by energy being extracted from the arc by the surrounding medium. This medium is in the form of a very fine grained silica sand. Energy from the arc is used to fuse the sand into a glass-like substance known as fulgurite. This fulgurite also surrounds the arc to limit its spread.

For interruption of lower short-circuit currents a different interruption mechanism is used. This comprises a small deposit of lead tin alloy placed towards the middle of the element length. When the element overheats from an overload current the alloy melts and passes through the molecular structure of the silver to cause the silver to have a significantly lower melting point. This element will thus part at this point, which then allows a long low energy arc to slowly burn back along the element length until arc extinction occurs. This phenomenon is known as the 'Metcalf' effect or 'M' effect.

The HV current limiting fuse usually has a very thin parallel fuse wire passing through the bore of the star core which operates subsequent to main element operation. On such operation it causes a small gunpowder charge, located at one end of the fuse cap, to explode. This explosion forces a small pin through the end cap. This is referred to as a striker pin and is used to allow 3-phase switch operation on single-phase fuse operation.

A typical construction of an 11 kV current limiting fuse is shown in Figure 10.15, with diagrammatic representation of its mode of operation being shown in Figure 10.16.

These fuses are widely used under oil at 11 kV in ring main units, and are also widely used in LV applications. They are not generally used in applications above 33 kV.

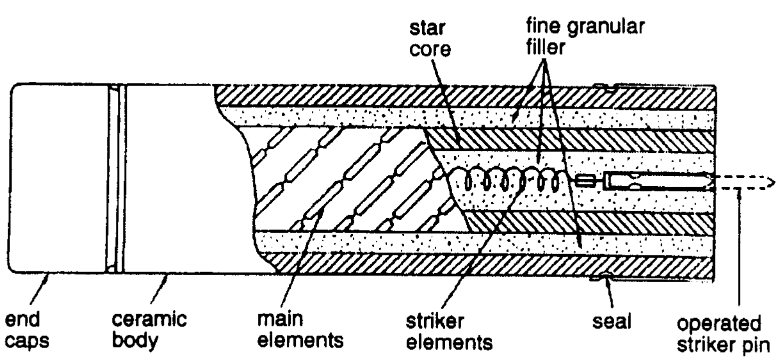

Figure 10.15 Current limiting fuse: HV construction

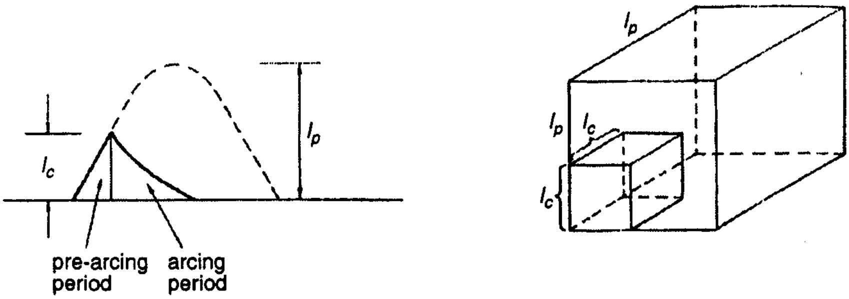

Figure 10.16 Current limiting fuse: fuse cutoff current

10.5.10 Contactors

A contactor performs much the same duty as a switch. The main difference is that it is designed to be capable of performing very frequent switching operations and is also capable of interruption of overload conditions and motor stall current conditions. It is widely used in industrial processes for motor operation. It is not generally used in HV distribution circuits but will be encountered in use, having rated voltages of up to 11 kV, in power station auxiliary switchgear applications.

10.5.11 Ring main units

A ring main unit is a metal enclosed construction of distribution switchgear which is widely used in urban ring circuits. By itself, and in combination with a transformer and LV switchboard, it forms a secondary distribution substation (see Section 10.2.2.3).

The metal enclosed ring main unit comprises a 'ring' busbar circuit with a switch disconnector in each side of the ring. Teed off from the central busbar is a fuse switch which invariably feeds to an 11 kV/415 V 3-phase transformer.

On the ring circuit side of each ring switch disconnector is an earth switch. This provides facilities for earthing the cable at either end to allow fault repair. Subsequent to repair it is common practice to subject the cable to HV tests. Testing facilities are achieved by means of a separate, loose, test device, commonly referred to as test prods. Once the cable circuit has been isolated and earthed at both ends it is then possible to release a padlocked, and interlocked, cover to allow the insertion of the test device. With the test device in position it is then possible to open the earth switch to its 'earth off' position. The remote end switch is then placed to its earth off position and the cable test voltage can be applied to the terminals of the device. On completion of the tests the device cannot be removed until the switch has been moved to its earth on position to reapply the circuit earth.

The earth switch cannot be operated until the test access cover has been correctly relocated and is secured in position. Both built-in mechanical interlocks and padlocking facilities allow safe operation to be achieved.

In practice, most ring main switch disconnectors are in fact three position devices which, in addition to the on and off position, can be moved, after appropriate interlock selection to the earth on position.

The tee-off circuit comprises, in general, a fuse switch whereby the HV fuse links are mounted on the moving portion of the switch. The HV fuse-links typically have rated currents of up to 80 A and are used to provide both overload and short-circuit protection to the HV side of the transformer.

A low rated earth switch is provided between the fuse switch and the transformer terminations to allow earthing of the transformer HV in the event of an LV backfeed.

Traditionally, ring main units have been of the oil filled type using HV fuses on the tee-off circuit, but more laterally these have been superseded by SF_6 insulated devices. An SF_6 insulated ring main unit may use an SF_6 interrupter (circuit-breaker) in its tee-off circuit or possibly a vacuum interrupter. Some still employ HV fuses, but these must be mounted externally in air, which leads to complication and added expense.

A typical ring main layout is shown in Figure 10.17.

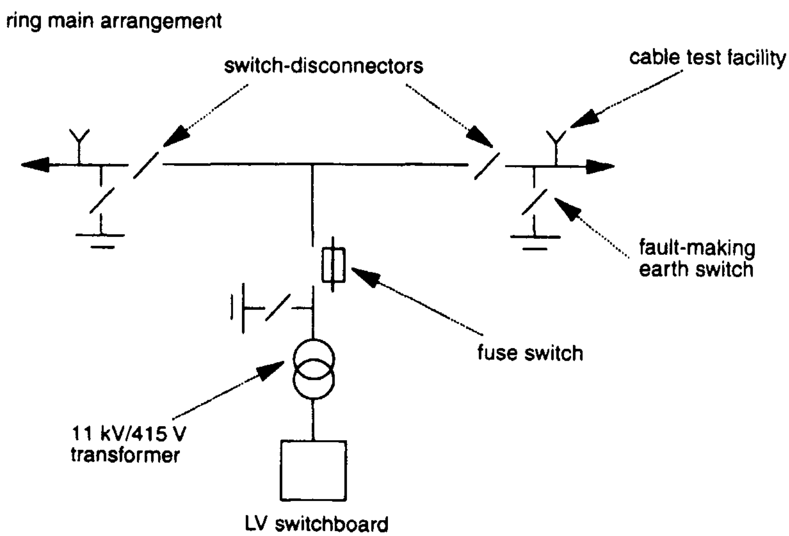

Figure 10.17 Typical distribution secondary substation layout

10.6 Circuit protection devices

10.6.1 Surge arresters

Surge arresters are devices which dissipate, to earth, a transient overvoltage to protect down line connected equipment from possible dielectric breakdown. There have been major developments in the design of surge arresters in recent years.

Traditionally silicone carbide arresters have been used. These are satisfactory for dissipating high over-voltages and high current surges, but are not suitable by themselves for withstanding continuous AC power frequency voltage since they would have to pass continuous current in the order of 100 A. To overcome this problem a number of series capacitive gaps are incorporated. These will reduce the value of the series current that flows to that of the capacitive current of the associated gaps. On operation from high transient overvoltages the series gaps will flashover to insert into the circuit the silicone carbide resistor blocks.

Such arresters require the fault current to pass through a current zero point before they will clear; hence operating times can be in the order of 10 ms, and also rapid deterioration of the gaps ensues.

A more recent development has been the zinc oxide surge arrester. This material passes a very low current at its normal operating voltage, typically less than 1 mA; hence series gaps are no longer required. This considerably reduces the costs of the arrester and improves its performance and reliability.

Zinc oxide surge arresters, as they do not require a series gap to operate, are very fast in operation, typically less than 1 ms, and do not require the passage of a zero current.

Sealing problems have been widely encountered on silicone carbide type arresters with resultant gap deterioration and eventual failure. Zinc oxide arresters are not so prone to this deterioration mechanism, and improvements in sealing techniques have been achieved such that high reliability devices can now be supplied.

Figure 10.18 shows the comparison between the characteristics of a silicone carbide arrester and a zinc oxide arrester.

10.6.2 Instrument transformers

Instrument transformers are devices which produce, at earth potential, a replica in magnitude and phase of the current flowing in the primary circuit and of the voltage across the primary circuit. The former are called current transformers and the latter are referred to as voltage transformers.

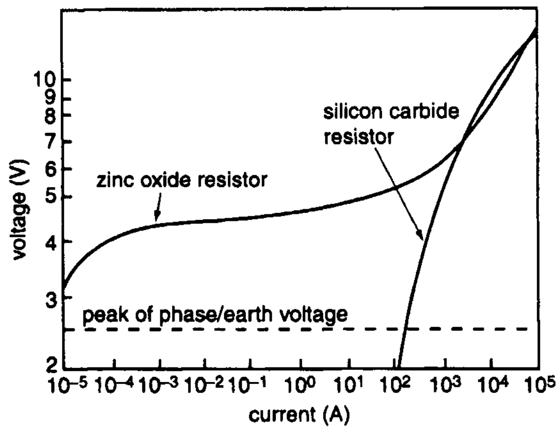

Figure 10.18 *Surge arresters: comparison of silicon carbide and zinc oxide resistor characteristics*

10.6.2.1 Current transformers

Current transformers (CTs) are usually in the form of a one-turn bar primary which passes through the centre of a toroidal core, and around the core is a multiturn secondary winding. As the bar primary is at line potential, insulation must be provided between it and the secondary winding/assembly. For 11 kV or 33 kV metal-clad switchgear this insulation is usually provided by means of an HV bushing which, at 33 kV, may be of the SRBP construction and more commonly at 11 kV it is of cast epoxy resin construction. It should be remembered that the outside of the HV bushings must be at earth potential to avoid the possibility of electrical discharges between this surface and the earthed CT assembly.

For distribution applications the CT secondary winding usually has a current rating of 5 A, but for applications involving long lengths of secondary leads the current rating may be 1 A to reduce the lead burden.

CTs must have a defined current ratio, i.e. 400/5 200/1, etc. As the primary circuit current rating decreases it may be that insufficient ampere turns are generated to provide the required secondary output to drive the associated protection equipment, in which case the primary winding may comprise two or more turns. This adds further complication to the insulation design between the primary and secondary windings, and care is needed to ensure long term integrity.

Secondary outputs are usually given in terms of volt-amperes, i.e. VA. A typical output is 15 VA. Various classes are defined for both protection and high accuracy tariff metering. For the latter conventional core material losses are too high and it is necessary to use a nickel alloy material commonly referred to as Mumetal.

For higher voltage applications, e.g. 132 kV and above, the construction is somewhat different and may be either of the hairpin dead tank design or, more latterly, of the bar primary live tank design. In either case insulation between the HV conductor and secondary assemblies is provided by multiple layers of oil impregnated paper, and the whole assembly is filled with insulating oil. However, detailed description of the construction of these CTs is beyond the scope of this chapter.

10.6.2.2 Voltage transformers

Voltage transformers (VTs) for 11 and 33 kV distribution applications are usually of the 3-phase type and have traditionally been of the oil insulated construction with the whole assembly being enclosed within its own metal enclosed oil-filled tank. HV connections are achieved via three protruding bushings. These bushings plug into associated spout and fixed contact assemblies on the metal-clad switchgear panel. VTs may be connected to either the circuit side connections or busbar side connections. The VT tanks are mounted on wheels which run on rails on the switchgear to allow them to be either rolled back to an isolated position or rolled inwards to engage the primary circuit contacts.

All such VTs are protected on each phase by an HV fuse often enclosed within the VT bushings. The fuses traditionally have a rating of 0.6 A and have a resistive fuse element to limit fault infeed in the event of VT failure. Without such a fuse dramatic VT failure and consequential substation disruption may result.

A recent trend, particularly at 33 kV, is to utilise single-phase VTs with one end of each winding connected directly to earth. This arrangement is used mainly on resistive earth systems where the single-phase earth fault current is limited to something in the order of 1000 A.

With such single-phase arrangements it is imperative to ensure that appropriate protection is provided both to the equipment and personnel in the event of VT failure.

Most modern day voltage transformers are insulated with cast epoxy resin. The manufacturing technique is, however, critical as any voids incorporated into the moulding process can lead to partial discharge activity and eventual VT failure.

VT secondary voltage outputs are typically rated at 110 V phase to phase, or 63.5 V phase to earth. Output ratings are similarly given in VA, and a typical rating would be 100 VA per phase. Again high accuracy devices can be provided for tariff metering purposes.

For outdoor substations weatherproof enclosures can be provided with associated HV bushings.

For higher voltage systems a different principle is used in that a series of capacitors are provided between the HV conductors and earth to form a capacitor divider. Voltage is tapped off from the lower capacitive assembly to feed an electromagnetic type of voltage transformer to provide the secondary voltage. CVT design is outside the scope of this chapter.

10.6.2.3 Alternative voltage and current transducers

Conventional current and voltage transformers occupy a relatively large amount of space on a metal-clad switchboard and by themselves are also relatively expensive. The provision of such devices therefore forms a significant cost contribution to the total panel cost. Conventional electromagnetic devices have been required for many years because large outputs are necessary to drive conventional protection relays. With the advent of modern electronics, or digital relays, significantly lower energy infeeds are required. In consequence, this has led to the development of new current and voltage transducer devices. For the low energy voltage requirement a conventional resistive voltage divider can now be utilised. With current transducers optical techniques are rapidly being developed, as are similar associated techniques for voltage transducers. The benefit of such techniques is that they can be made very small and are more readily accommodated than conventional devices, allowing significant potential cost reduction.

10.7 Switchgear auxiliary equipment

Auxiliary equipment, i.e. the low voltage part of the switchgear provided for control and monitoring of main components, has traditionally been provided by hard-wired components, conventional switches, terminations and electromechanical relays, with such secondary systems being supplied by the switchgear manufacturer.

There is a rapidly growing trend to the introduction of electronic technologies whereby the equipment and processes may be supplied by alternative suppliers.

The reliability of electronic components has improved significantly in recent years, and their performance is more and more deterministic. Such electronic facilities allow the provision of more automated operation and also provide diagnostic data on the performance of the primary plant.

Once concepts have been perfected significant advantages will be gained by the end user.

International standardisation of such approaches is rapidly occurring and indeed some manufacturers are already incorporating such concepts.

10.8 SF_6 handling and environmental concerns

Over recent years attention has been focused both on potentially hazardous breakdown products of SF_6 and on possible environmental concerns.

10.8.1 SF_6 breakdown products

SF_6 decomposes at high temperatures encountered during the arc interruption process into very many constituent products but, on gas cooling, these decomposition products tend to recombine to form SF_6. Any gaseous breakdown products remaining tend to be absorbed by desiccants placed within the gas enclosure. Hence for normal and short circuit switching operation SF_6 gas decomposition is of little concern and SF_6 gas filled interrupters can remain in service under normal operating conditions for very many years without the need to be opened up for examination.

In the event of very heavy fault arcing or long term partial discharge activity some of these breakdown products may remain and if chambers are to be opened up some care is necessary.

Typical breakdown products from sparking or from partial discharges are SF_4, WF_6, SOF_4, SOF_2, SO_2, HF, SO_2 and F_2. Contact erosion and internal arcing might also produce CuF_2, WO_3, WO_2, F_2, WOF_4 and AIF_3.

Most of the reactive decomposition products and their follow-up reactions have toxicities comparable with SO_2 and may constitute a health risk if present in too high a concentration.

Some reactive decomposition products are corrosive, particularly in the presence of moisture, and appropriate handling precautions should be followed on the opening up of such chambers.

The aluminium fluoride breakdown products will be evident by the presence of a white/grey powder lying on insulating and chamber surfaces. These powders are nonconducting and are not critical for insulation performance.

The gaseous breakdown products will be evident by a 'rotten egg' smell produced mainly by SO_2. However, SF_6 arced gas should never be deliberately smelt.

When opening up chambers it is necessary to wear disposable overalls, gloves, face mask or respirator if entering chambers, head protection and appropriate safety footwear. Arc products should be removed by means of a fine filter vacuum cleaner and contaminated surfaces should be neutralised to prevent acidic corrosion. Before entering chambers the SF_6 must be safely removed, filtered and stored.

SF_6 *must not be deliberately released to the atmosphere.*

There has been concern over recent years that electrical breakdown of

SF_6 may produce S_2F_{10}, a very toxic gas. Whilst this has been identified in laboratory experiments it has never, to date, been positively identified in faulted equipment in service. In any event it very rapidly recombines as the temperature drops to the normally found breakdown products. Three years of work by international experts in Canadian Laboratories concluded that S_2F_{10}, even if initially present, was of no practical consequence provided appropriate, normally accepted, handling procedures were followed.

10.8.2 SF_6 environmental concerns

High level balloon measurements of gases in the upper atmosphere over the last 20 years or so have identified the presence of SF_6. Estimates suggest that total quantities in the outer atmosphere could be of the order of 80 000T.

Work thus commenced to ascertain the possible effect on atmospheric contamination of this quantity of gas. Initial work showed that SF_6 was not an ozone depleting gas as it cannot initiate the ozone catalytic chain, i.e. SF_6 has no effect on ozone depletion.

Work also commenced to ascertain the ability of its molecule to reflect radiation in the infra-red spectrum. This showed it had a very high reflectability in this spectrum and, as such, constitutes a potentially major greenhouse gas. Work to ascertain its natural lifetime in the atmosphere estimates this to be between 800 years and 3200 years, i.e. it takes a very long time to naturally decompose.

The above two factors combined make SF_6 the worst known greenhouse gas. Efforts have since continued to assess the effect of the 80 000 tons of SF_6 on greenhouse warming. Figures produced in 1995 show that the anthroprogenic contribution, i.e. man-made greenhouse effect from SF_6, was less than 0.1%.

In earlier years this effect was not known and there was no restrictions, apart from cost, on the deliberate release of SF_6 to the atmosphere.

Clearly, deliberate release can now no longer be allowed. In addition, handling procedures must be improved to avoid losses during these processes. These issues are addressed in Reference 1, and Reference 2 discusses in more detail the environmental issues. Reference 3 is a further updated paper on environmental concerns.

10.9 The future

Deregulation of the electrical supply industry in many parts of the world is having a significant effect on the way utilities operate. They are now facing new pressures to deliver ever increasing quality and continuity of service, to reduce supply restoration times and to reduce electricity cost to the customer. In parallel with this the maintenance workload is increasing due to utilisation of a wide variety of lower cost plant and due to the ever increasing age of existing equipment. Further factors affecting utilities are increased cost constraints, difficulties in obtaining and justifying the stocking of spare parts and reductions in the numbers of experienced personnel, particularly those with expert knowledge on the equipment.

All utilities need to become more efficient. One way of achieving this is to reduce maintenance costs, which represent a significant part of operational costs, by effective techniques such as condition based maintenance where condition assessment is achieved by use of diagnostic monitoring techniques. Developments are such that automated monitoring will be the norm, with deviations from the norm being detected before failure occurs. We could thus end up with a fully automated self-monitoring distribution system.

All these factors are being driven by the customers' need for a high quality, highly reliable low cost supply of electricity. Competition between utilities will force these concepts even further.

There are yet two further additional pressures which will affect future concepts, the first being the environmental pressures and the second the pressures resulting from new technology developments.

The environmental pressures have arisen over the last 150 years or so as a result of industrialisation, and there are signs that even within this period of time considerable environmental deterioration has resulted. Clearly we cannot continue contaminating the planet to this extent. The public are becoming more and more aware of these issues and already environmental pressures can no longer be ignored.

Environmental aspects can be significantly improved in many areas of the electrical power industry. There is already pressure to minimise lifetime energy usage. This applies from mining raw materials, to manufacture of components, manufacture of assemblies, lifetime energy usage, and energy usage on final disposal. The greater energy usage is usually during the lifetime use of the equipment. At the end of the life of the equipment it must be possible to dispose of all components in an environmentally acceptable way. Energy usage losses can also be minimised by use of highly efficient local generators, and this is also a further trend that is already occurring.

Very many new technology developments are looming on the horizon. As mentioned earlier there are major developments in the case of magnetic materials; further major developments are also taking place in the use of polymers. These are having applications in energy storage devices, e.g. batteries, capacitor storage, etc. They are also allowing the fundamental development of new technologies, such as fuel cells, photovoltaic cells, heat pumps, etc. In parallel with this there are also major developments in superconductivity.

All these developments will have a major influence on the way in which we manufacture, deliver and use electrical energy.

In parallel with this, load patterns are tending to change much more rapidly than has been experienced in the past. This is due to inward investment of new technology industries, some of which are proving to be short lived, particularly due to the varying economic climate around the world.

With this background, what sort of systems might we have in 10 to 15 years' time? A possible scenario is shown in Figure 10.19. If such a scenario is probable, how do we move from where we are at present to the new concepts in the most cost-effective way?

Such requirements for future substations might be:

- must be relocatable
- must not require manual intervention
- must have a very high degree of reliability
- must have automated operation, only signalling when the system is in an incorrect state
- must have low losses
- must be recyclable
- must only use environmentally compatible components
- must not require maintenance
- must be compatible with communicating to other system nodes
- must maintain quality of supply.

A challenging time is ahead for younger engineers!

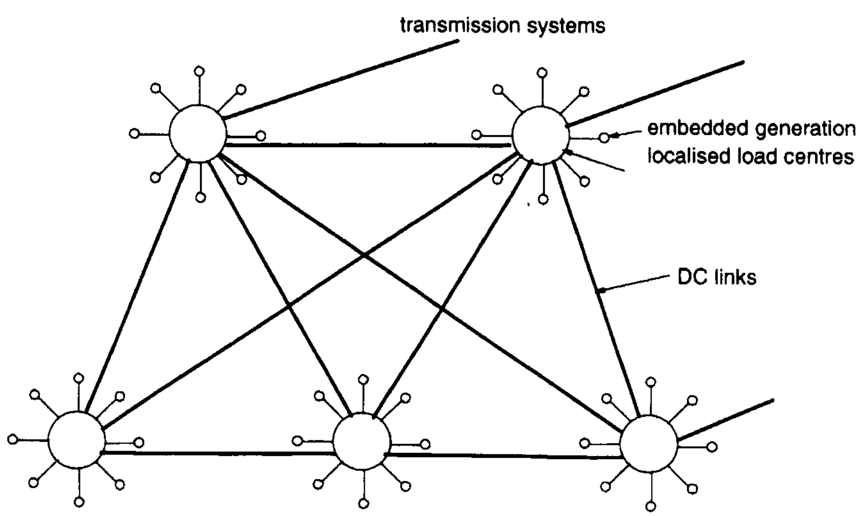

Figure 10.19 The future system

10.11 References

1 CIGRE WG23-10: 'SF_6 and the global atmosphere', *Electra*, 1996, **164**, pp. 121–131

2 CIGRE TASK FORCE 23.10.01: 'SF_6 recycling guide – re-use of SF_6 gas in electrical power equipment and final disposal'. CIGRE Brochure 117, August 1997

3 MAISS, M. and BRENNINKMEIJER, C.A.M.: 'Atmospheric SF_6: trends, sources and prospects, *Environ. Sci. Technol.*, 1998, **32**, pp. 3077–3086