Power and Energy Series 21

Electricity Distribution Network Design

2nd Edition

E. Lakervi and E.J. Holmes

IET POWER AND ENERGY SERIES 21

Series Editors: Prof. A.T. Johns
J.R. Platts

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Other volumes in this series:

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The Institution of Engineering and Technology

Published by The Institution of Engineering and Technology, London, United Kingdom

First published 1989 (0 86341 151 7)
Second edition hardback 1995 (0 86341 308 0)
Second edition paperback 1995 (0 86341 309 9)
Reprinted with revisions 2003
Reprinted 2007, 2008

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Six Hills Way, Stevenage
Herts, SG1 2AY, United Kingdom

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British Library Cataloguing in Publication Data
A catalogue record for this product is available from the British Library

ISBN (10 digit) 0 86341 309 9
ISBN (13 digit) 978-0-86341-309-4

Printed in the UK by Short Run Press Ltd, Exeter
Reprinted in the UK by Lightning Source UK Ltd, Milton Keynes

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Preface and acknowledgements

Whilst there have been a number of publications specifically covering the generation and transmission of electricity, distribution systems seem to have received less attention. The quality of supply received by the vast majority of customers is directly related to the reliability of the distribution systems supplying them, which itself is a function of the design of these networks. The lower level of load growth experienced in the 1980s requires that the accuracy of distribution network design should be improved in order to optimise capital investment programmes. In addition, technical innovations in the past decade present the design engineer with the opportunity to improve operational efficiency and reduce customer outage times due to network faults and maintenance requirements. The book includes those theoretical and practical aspects which the authors consider are particularly relevant in designing distribution networks; in particular the increasing use of computers in the design and operation of distribution networks.

In writing this book the authors have been grateful for the help received from many sources. Thanks are due to the Tampere University of Technology and Nokia Oy, Finland, for financial support, and to Midlands Electricity plc for the considerable amount of secretarial assistance during the preparation of the manuscripts. We wish to thank our many colleagues and friends for their helpful criticism and technical advice; in particular, staff from Tampere University of Technology, especially Associate Professor J. Partanen and Mr. A. Mäkinen, and from Midlands Electricity plc; also Mr. H. Hammersley, UK, M. Persoz of Electricité de France, Mr. Rudasill of VEPCO, USA; and Mr. J. E. D. Northcote-Green of Advanced Systems Technology, Westinghouse Electric. Finally we acknowledge the considerable understanding and support we have received from our wives Sirpa and Maggie and our families during the four years of work on the book.

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Preface to 2nd edition

The six years since this book was first published have seen a number of developments in the area of distribution network design.

Market conditions are exerting stronger pressures on the design engineer, the structure of electrical utilities is changing or under review in a number of countries, and increasingly national or international legislation is adding further constraints. While many of the techniques of earlier decades are still in use, the increasing penetration of computers has significantly affected the manner in which distribution networks are being designed and operated.

As a consequence, Chapter 14, covering computer-based planning, has been re-written, as has Chapter 4 on reliability. Advantage has been taken to add material on international recommendations affecting network design and to discard some outdated and less relevant material. Also, a number of the revisions are based on students' comments arising when the first edition was being used for teaching international university and short courses.

Once again, we acknowledge the help of our friends and colleagues in the electrical industry with the updating of the book; in particular Mr. J.-H. Etula, Espoon Sähkö Oy, Mr. A. Mäkinen, Dr. K. Kauhaniemi and many others from Tampere University of Technology; Mr. H. Salminen of the Association of Finnish Electric Utilities; Professor J. Partanen, now at Lappeenranta University of Technology, and Mr. R. Hartwright of Midlands Electricity plc.

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Chapter 1

The supply system

1.1 Generation, transmission and distribution

The primary aim of the electricity supply system is to meet the customer's demands for energy. Power *generation* is carried out wherever it gives the most overall economic selling cost. The *transmission* system is used to transfer large amounts of energy from the main generation areas to major load centres. *Distribution* systems carry the energy to the furthest customer, utilising the most appropriate voltage level. Thus an electricity supply system contains three different functions. Often individual supply organisations cover only one of these functions within a particular area or region.

Electricity is produced from a number of energy sources. Plant with a high capital cost, such as hydro and nuclear stations, is economic only if operated for most of the year at maximum output. On the other hand, plant which has a relatively low capital cost but high operating costs, such as gas turbines, may be more economic for short periods of operation to meet peak loads. Fossil-fuelled steam power stations, together with nuclear power plants and hydro stations, provide the majority of electrical energy. This is illustrated in Table 1.1, covering energy consumption in 1992 in some European countries, and in Figure 1.1 which shows the amounts of energy produced by these three sources in the European Community countries, the USA, the former USSR and Japan in 1991. Combined heat and power stations are favoured in some countries. In a combined heat and power station the energy normally lost in the condensation process is utilised by heat consumers. Thus the overall efficiency of the power station can be markedly increased. Diesel engines, wind and wave machines, and solar cells provide only a marginal amount of electricity on a world-wide basis, although their output may be significant locally. This kind of dispersed generation is rapidly increasing in some countries, however.

In any one country it is essential that resources be channelled into constructing generating plant which results in the lowest possible energy costs, taking into account the capital investment, and operating and maintenance

Table 1.1 Sources of electrical energy (TWh) in European countries (1992)

Country	Net generated	Steam	Nuclear	Hydro	Net import	Total
Austria	43·4	10·4	—	33·0	0·7	44·1
Belgium	68·4	26·1	41·1	1·2	—	68·4
Denmark	28·2	27·4	—	0·8	5·7	33·9
Finland	55·0	21·8	18·2	15·0	8·2	63·2
France	434·7	45·7	321·3	67·7	−53·2	381·5
Germany	393·6	227·3	149·2	17·1	−3·7	389·9
Great Britain	295·7	222·7	68·4	4·6	16·7	312·4
Greece	31·2	28·8	—	2·4	0·6	31·8
Ireland	14·6	13·9	—	0·7	—	14·6
Italy	214·2	169·1	—	45·1	5·2	249·4
Luxembourg	1·2	0·6	—	0·6	3·9	5·1
Netherlands	60·3	56·7	3·6	—	8·6	68·9
Portugal	26·3	21·3	—	5·0	1·3	27·6
Spain	140·5	67·8	53·4	19·3	0·6	141·1
Sweden	141·0	7·5	60·8	72·7	−2·1	138·9
Switzerland	57·3	1·5	22·1	33·7	−3·7	53·6
Former Yugoslavia	62·8	37·5	3·8	21·5	−1·7	61·1

costs, subject only to proper environmental safeguards. The facility to operate power stations utilising different types of generation plant enables the load pattern to be matched better and gives more flexibility to achieve the lowest overall cost of electrical-energy production in the uncertainties of the future. For example, in Finland nuclear and combined heat and power stations each produce approximately one-third, hydro stations one-fifth and conventional condensate power stations only one-tenth of the total energy requirements.

To obtain maximum overall efficiency, combined heat and power stations should be located within a town, where the houses can be heated from the station hot water output, or within a factory requiring steam. Large rivers, where the drop in water level makes it possible to construct and operate larger hydro power stations, are often located in remote locations at considerable distances from the main areas of electricity demand. Similar considerations apply to geothermal stations and, for safety reasons, to nuclear stations. It is essential to have an adequate electrical system to transport electrical power from these large power stations to the main load centres. The demand can then be met by running the precise amount of power plant, wherever situated, operating at the most efficient loading to give the minimum overall cost under all credible system conditions. A strong transmission system is often justified economically because the difference in cost between different methods of generation is usually higher than any additional transmission cost.

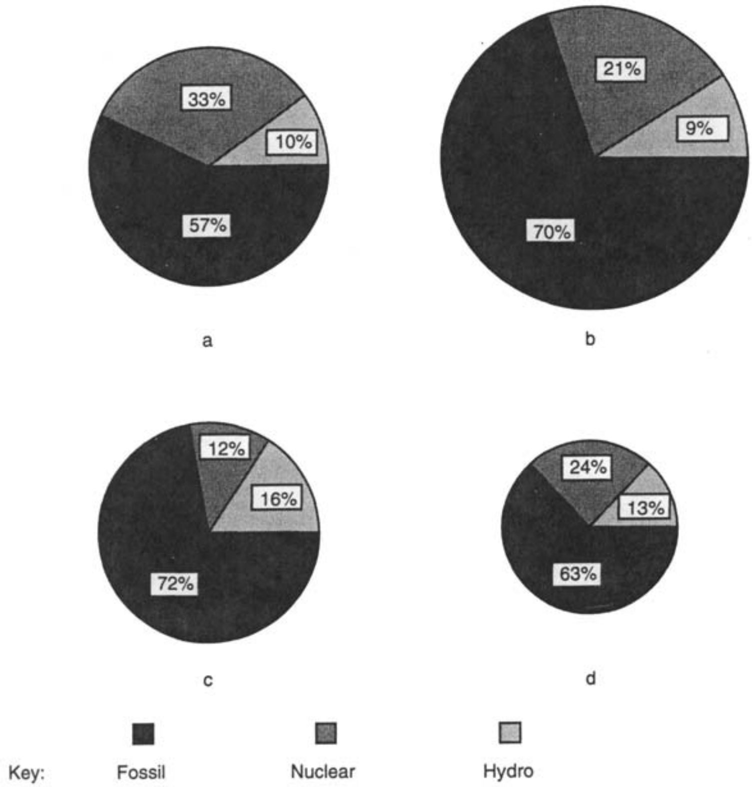

Figure 1.1 *Generation of electricity by energy source in 1991*

a EC countries, 1846 TWh
b USA, 3025 TWh
c Former USSR, 1680 TWh
d Japan, 838 TWh

Where the transport of very large amounts of power over large distances is involved, a very high-voltage system, sometimes termed major or primary transmission, is required. Such systems operate in the 300 kV plus range, typical values being 400, 500 and 765 kV. When transmission systems operating at lower voltage levels (110 or 132 kV) become overloaded, a higher-voltage system can be added as an overlay. An example of this is the 275/400 kV supergrid system established in Great Britain in the 1950s when the existing 132 kV system became incapable of coping with the large power transfers from the north to the south of England.

The following definitions for various voltage levels are used in the book. Low voltage (LV) is below 1 kV, while medium voltage (MV) covers voltage levels generally lying between 1 and 36 kV, used particularly in distribution systems, with high voltage (HV) being used for systems over 36 kV. In any electrical

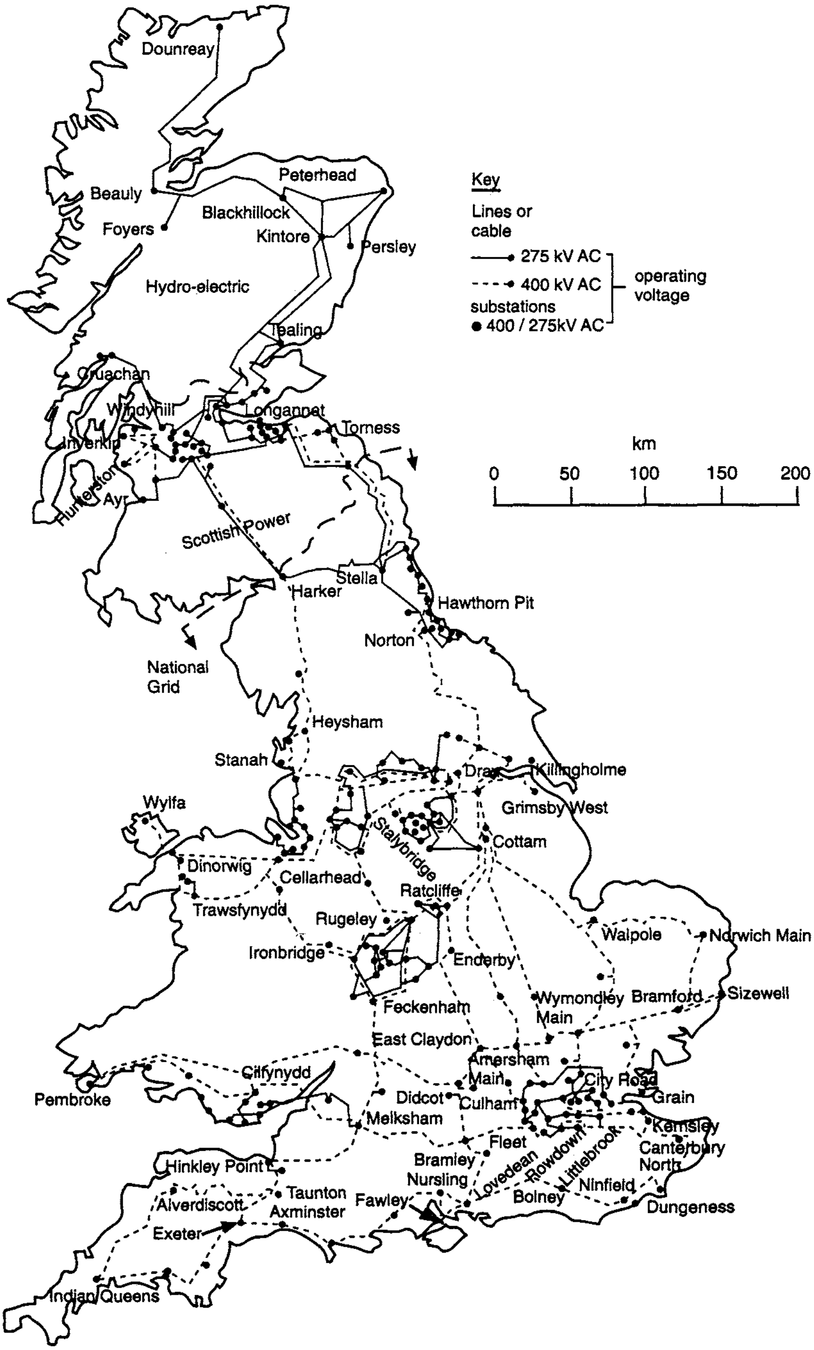

Figure 1.2 Map of UK Supergrid (Courtesy National Grid, Scottish Power and Scottish Hydro-Electric)

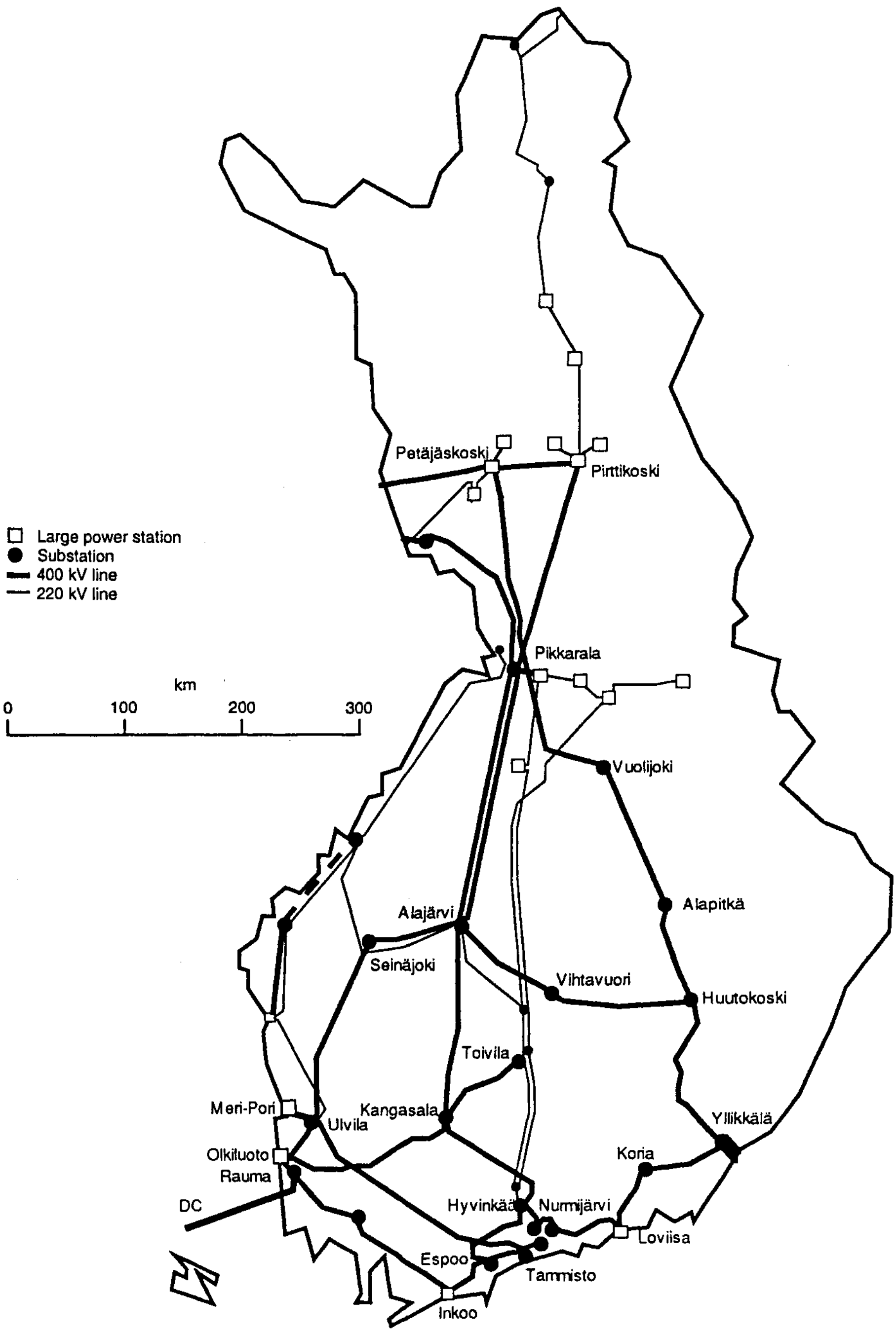

Figure 1.3 Map of Finnish main grid 1993 (Courtesy IVO Transmission Services Ltd.)

system the concept of LV, MV and HV has a relative meaning and does not necessarily comply with national safety or other regulations. The term EHV is used in this book to signify voltage levels above 300 kV.

EHV interconnections have been constructed between regions and countries in order to achieve the most economic use of generation and transmission plant overall, and to cater for temporary shortages of plant in any one region. In Europe the largest of such arrangements operates under the auspices of the Union for the Co-ordination of the Production and Transmission of Electrical Energy (UCPTE). This is shown schematically in Figure 1.4, where the width of the lines indicates the relative energy transfers between the various countries and the size of the circle indicates roughly the amount of electrical energy consumption in 1992. Owing to the political situation in former Yugoslavia in the 1990s, parts of the Yugoslavian network and Greece were not synchronised to the UCPTE network. Power exchanges with Nordic countries are co-ordinated via the NORDEL organisation. As will be seen from Figure 1.4, further interconnection facilities exist with Russia, the Czech Republic, Hungary and Romania. Owing to the former political situation in Europe and the many technical differences between the western and eastern power systems, DC links have been used to interconnect these systems. A DC link is in operation on the interconnection between NORDEL and UCPTE and HV DC links also interconnect Great Britain and France. Similar EHV interconnectors link various regions in the USA and Canada to pool generation capacity. The political changes in eastern Europe and the increasing activities in the whole

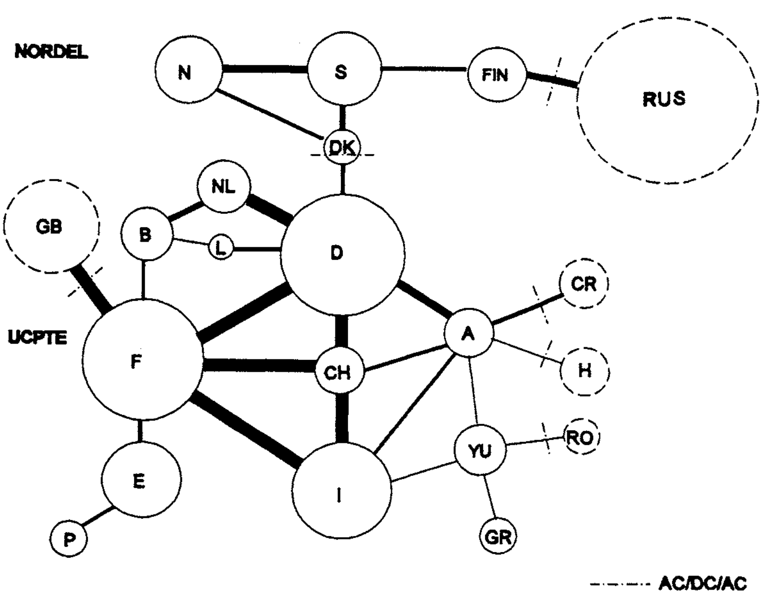

Figure 1.4 The Western European UCPTE and NORDEL interconnection ties

world towards new and larger interconnected systems have also raised the question of the need for, and technical possibilities of, connecting the western and eastern electric power systems.

Depending on the number, and size, of conductors per phase and the distance involved, a single 400 kV transmission circuit could carry the output of a 2000 MW power station. If this output were lost for just one hour, the resultant costs of any disruption of supply could run into millions of pounds, thus justifying a high level of security – for example installing parallel circuits to improve reliability and stability. It is also possible that an industrial load of, say, 20 MW supplied from the HV system would need to be secured against a single fault if this would detrimentally affect the customer's production or equipment. EHV and HV systems are therefore planned so that single-circuit faults rarely result in loss of supply to any customer. This assumes effective protection systems and adequate alternative back-up connections.

The HV networks may be operated as interconnected systems or discrete groups. When operating as interconnected systems these networks may then be used to provide back-up capacity to the higher-voltage networks.

Below the transmission system there can be two or three distribution voltage levels to cater for the variety and demands of customers requiring electricity supplies. In general, the MV and LV networks are operated as radial systems. The theoretical and technical aspects of planning and operating these systems, as well as the supporting HV systems, form the major part of this book.

1.2 Supply organisations

Since the activities associated with the three functions of electricity supply, i.e. generation, transmission and distribution, are so widely different, this provides a basis for splitting these activities between different supply organisations. Usually the main generation and transmission activities are carried out by the same undertaking, although combined heat and power stations are often owned by industrial companies or municipal authorities.

In the 1990s there has been a strengthening trend towards breaking up the vertical integration in the electric power industry by separating the generation, transmission and distribution of electricity into separate business areas. This trend includes the increasing demand towards opening up transmission and distribution networks to producers and customers and the appearance of independent power producers. Until now, many electricity undertakings have been considered to be 'public services' rather than commercial businesses. The ultimate goal in the ongoing 'deregulation' process is to consider electricity as a product that can be sold in a free market without any restrictions from official authorities.

In the European Community, as part of the deregulation process, the first legislative action with the objectives of increased integration, removal of barriers to trade, improved security of supply, reduced costs and enhanced competitiveness was the adoption in 1990 of two Directives. The Transit Directive gives the right to electricity utilities to import or export energy across a third country, and the Price Transparency Directive aims to ensure that the energy market is not distorted by hidden subsidies.

In some countries electricity distribution supply organisations form part of a nationalised energy authority, controlled via a government department. Distribution systems may also be owned and operated by the local town administration or council. Additionally, distribution systems may also be owned by private companies and others have a mixture of public and private ownership. A distribution supply company could have a monopoly of supplying electricity within a given area which, in the extreme, may encompass a whole country, while at the other end of the scale it may cover only a small town. The strengthening trend towards separating electricity generation from transmission and distribution and the demands of opening a free market for electricity, however, will lead to the reorganisation of power utilities.

In Europe deregulation of the electricity supply industry is most advanced in the United Kingdom and in some NORDEL countries. In Norway, electricity transmission has been separated from generation and a free market has been opened for electricity, while a similar development is taking place in Finland and Sweden in 1995 and 1996, respectively. In the power distribution sector, deregulation means that customers are allowed to buy their energy from any generating or selling organisation. Thus a traditional distribution company or utility must now divide its activities between the energy and network business areas, with the energy business deregulated and operating under normal commercial competition, while the network activities will remain more or less monopolistic. In addition, it is foreseen that new companies will be set up in the energy business area. In the network business area regulations are required to ensure that the power transfer through any distribution network is reasonably priced.

In Finland one state-owned company accounts for nearly one-half of the country's generation, with private industry, power companies and municipalities providing the rest of the generation. A separate state-owned company is responsible for the main part of the 400 kV transmission system, while the 220 kV and 110 kV systems are owned by several organisations. Electricity distribution is provided by some 100 private or municipal companies, with rural parish communities often being the main share owners in the private companies supplying their area.

Of the EC countries only Great Britain has reorganised its electricity supply industry by transferring it to private ownership; it now consists of companies formed from the previously state owned organisations plus a number of other smaller single station generating companies. In England and Wales, with the exception of nuclear energy production which is still in public ownership, electricity is mainly generated by two private companies. One organisation is responsible for electricity transmission, and 12 regional electricity companies have a responsibility for distribution within their authorised areas. In Scotland the two public organisations are now privatised, operating as vertically integrated companies covering generation, transmission and distribution. Here, also, nuclear generation remains in state ownership.

In the Federal Republic of Germany some 1000 electricity supply companies are involved in electricity generation, transmission and distribution for public supplies, with joint-stock companies predominating. The nine interconnected power companies cover 80% of the public supply demand. Some industrial companies generate electrical energy for their own demand, with any surplus energy being made available to the public network. 90% of the transmission line network (the EHV network) is owned by the nine interconnected power companies, with 55 regional companies being responsible for regional transmission and distribution.

At the time of writing, Italy was moving towards privatisation of its generation, transmission and distribution systems. Elsewhere Argentina, Colombia, New Zealand and several eastern European countries have already taken significant steps to open their markets.

In France generation, transmission and distribution of electricity are still covered by the nationalised organisation Electricité de France (EdF). Some independent generation takes place outside EdF, for example associated with the French railways and coal mines, and a few distribution networks operated by certain public and co-operative organisations have also been left out of the nationalised industry.

Within the USA there is a wide spread in the size and type of electricity utilities. There are more than 3000 individual undertakings engaged in the generation, transmission and distribution of electricity, or combinations of these. Just under 200 private-investor-owned utilities form the largest segment of the electricity supply industry, serving about 75% of the retail customers. There are also some 2700 municipal, state or county utilities. Approximately 900 co-operatives are owned by groups of people who have organised joint ventures for the purpose of supplying energy to specified rural areas. The US Federal Government operates seven big utilities, two examples being the Tennessee Valley Authority (TVA) and the Bonneville Power Authority (BPA).

1.3 The distribution system

The function of an electricity distribution system is to deliver electrical energy from the transmission substations or small generating stations to each customer, transforming to a suitable voltage where necessary.

Figure 1.5 illustrates the interrelation of the various networks. The HV networks are supplied from EHV/HV substations which themselves are supplied by inter-regional EHV lines. HV/MV transforming substations situated around each HV network supply individual MV networks. The HV and MV networks provide supplies direct to large customers, but the vast majority of customers are connected at LV and supplied via MV/LV distribution substations and their

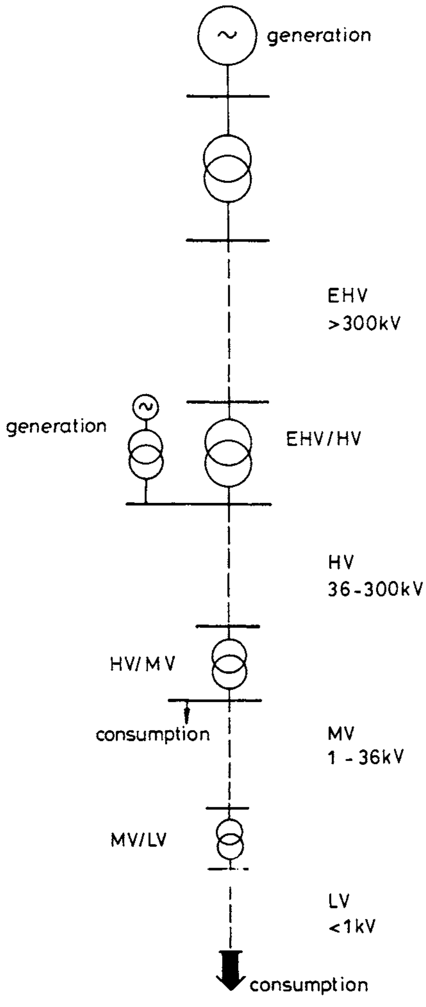

Figure 1.5 Block schematic of transmission and distribution systems

associated LV networks as indicated by the larger arrow at the LV busbar in Figure 1.5. The Figure indicates the voltage ranges in general use on the different networks from LV, through MV and HV, to EHV. In some countries an additional HV or MV voltage level is present, often for historical or geographical reasons. Figure 1.6 shows in more detail the use of various components on these networks. For simplicity EHV and HV disconnectors are not included, and the Figure can only indicate general system arrangements since design practice varies from country to country, and between supply utilities within a country. Some of these practices are discussed in subsequent chapters.

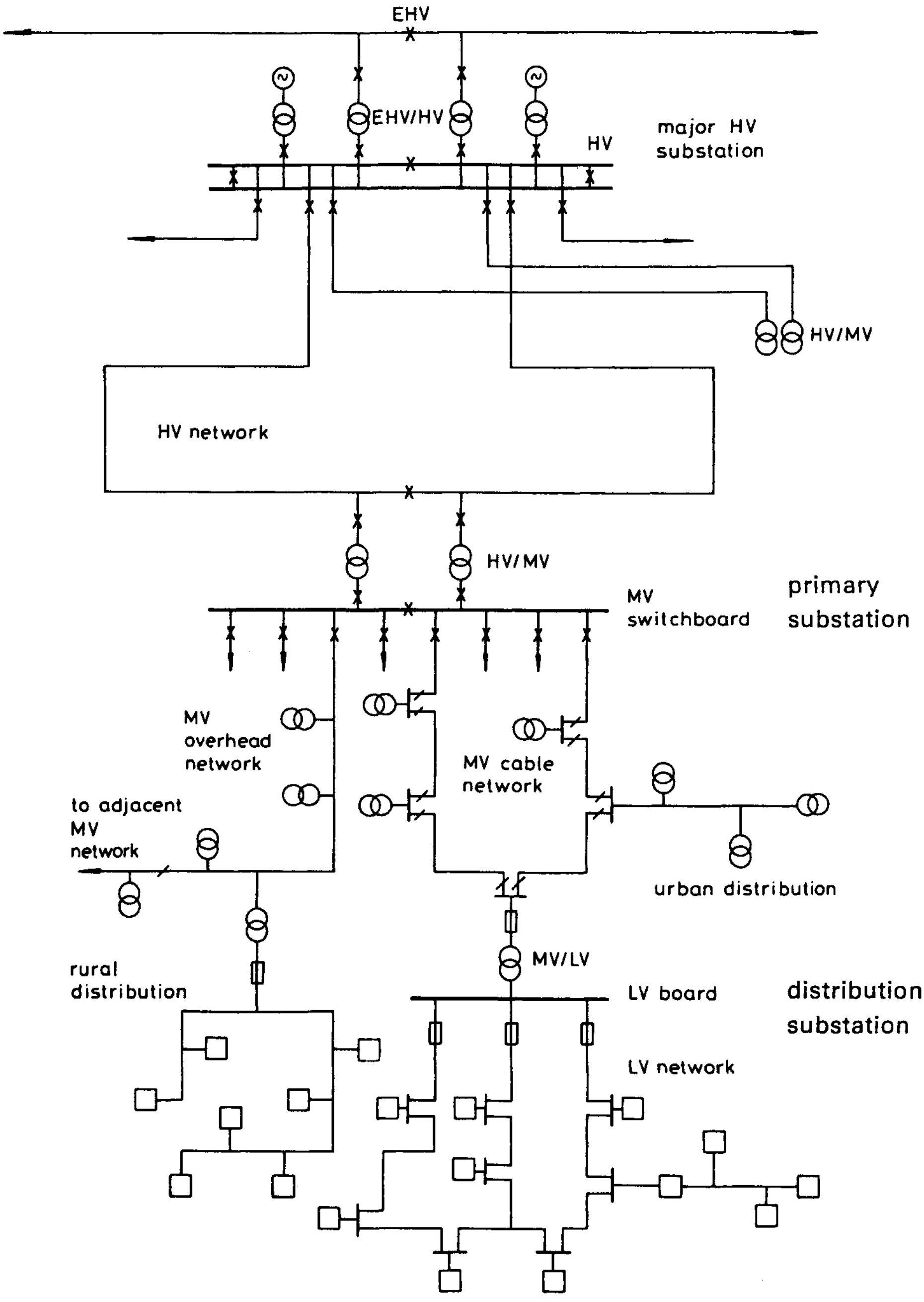

Figure 1.6 EHV/HV/MV/LV network arrangements

Generator
Transformer
X Circuit breaker
/ Disconnector
Feeder
Fuse
☐ LV Customer

In rural areas overhead MV lines are in general use. While some earlier installations using copper conductors remain, it is now common practice to use 25–100 mm^2 steel-cored-aluminium conductors and wooden poles. Aluminium-alloy conductors now account for about 10% of the total length of conductor installed each year. Concrete and steel poles are used in regions where wood is not readily available or climatically suitable. Insulated conductors are more reliable and also environmentally more acceptable and are tending to be used increasingly. Of necessity underground cables are being installed more frequently in urban areas, but they are only used in rural areas for environmental reasons, e.g. to avoid a wirescape effect close to a substation.

Pole-mounted transformers, with ratings from 5 to 315 kVA, form the rural distribution substations. The smaller sizes are sometimes single-phase units. In urban areas supplied by MV underground cables the substation can be at ground level, in brick, steel or concrete enclosures, or placed in the basements of office or housing blocks with transformer sizes varying from about 200 to 2000 kVA.

Low-voltage distribution in rural areas is by means of overhead lines with bare or insulated conductors. The use of aerial bunched conductors is becoming dominant, particularly in villages, small towns and forested areas. The length of new LV lines is usually limited to around 500 m or even less, depending on such factors as the voltage, the number of phases used and the load. In town centres underground cables predominate. In urban areas back-up supplies are often available from neighbouring distribution substations.

In those countries where the provision of electricity supply has just started, it is essential that the choice of system design philosophy be appropriate to the local social and economic conditions. In any 'green field' situation the design engineer has the opportunity of introducing the most suitable technology available for equipment, automation, telecontrol and microprocessor applications, which can have considerable advantages in sparsely populated areas with long distances between substations, and often over difficult terrain. Changing from one practice to another, even if technically better, is seldom economic, at least in the short term. It is particularly important that a suitable supply organisation be set up, and that a system design philosophy which is most suited to an individual country's own conditions be developed. Those factors which have an influence on the choice of voltage levels, system earthing, the use of three-phase or single-phase supplies, and operational and protection arrangements are discussed in subsequent chapters.

1.4 Supply requirements

With the increasing dependence on electricity supplies the necessity to achieve an acceptable level of *reliability*, *quality* and *safety* at an economic price becomes even more important to customers. The price that a customer has to pay for electrical power is dictated by the costs of the associated generation, transmission and distribution systems. Particularly for those customers whose energy demand is high, the tariff level is a vital component of their overall costs and may well influence whether electricity or some other form of energy is used.

Virtually all customers consider the reliability of the electricity supply to be of major importance, affecting as it does the working, domestic and social aspects of their life. Whilst the customer would like to have total reliability and never to lose supply even for a brief period, supply authorities are aware that technically and financially this would be an impossible target. The customer is concerned about any financial loss or inconvenience he or she may suffer as a consequence of a supply interruption. The effects of loss of supply vary with the customer group. A number of studies carried out indicate the wide range of values that customers place on loss of supply (outage). Figure 1.7 gives one example of such studies.

Figure 1.8 indicates the costs incurred by customers as a result of loss of supply. With 100% availability, i.e. total reliability, these costs would be zero. An electricity utility incurs additional expenditure as the reliability is improved. Eventually these costs increase dramatically for each additional percentage-point improvement, so that to try to achieve 100% reliability would be economically impracticable. On the basis that the total minimum cost to the

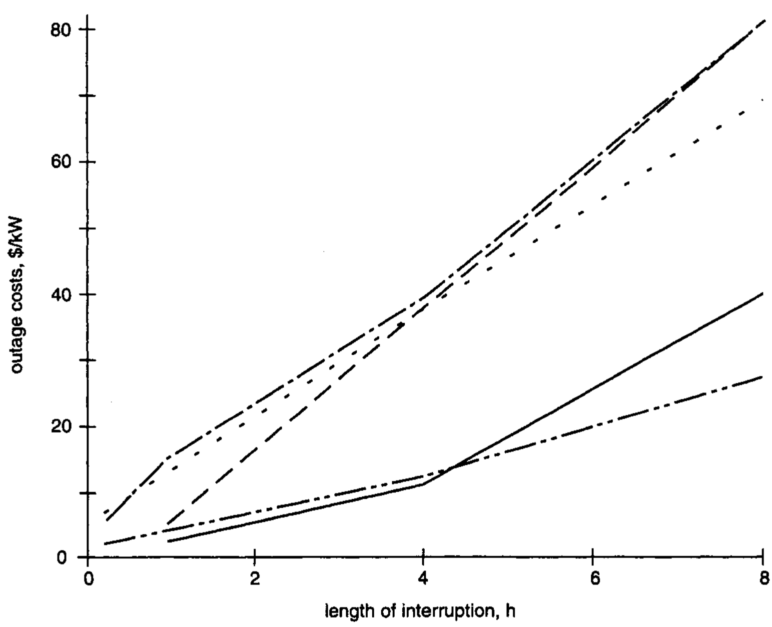

Figure 1.7 Estimated values of outage costs for different customer groups (courtesy VTT Energy)

———	residential	- - - -	industry	..——..—	public sector
— —	agriculture	..——.——	commercial		

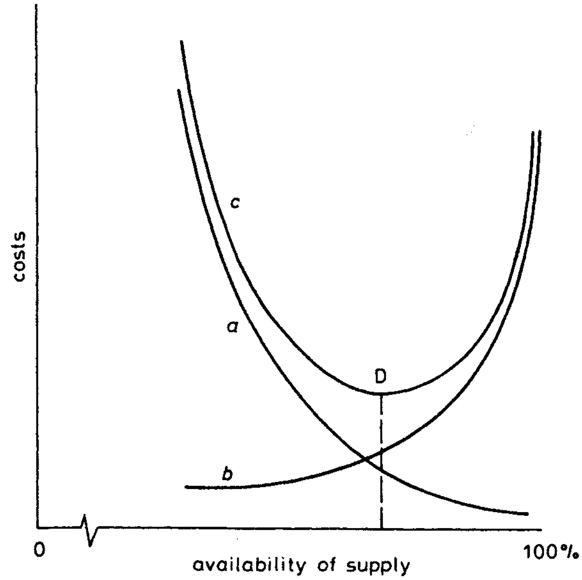

Figure 1.8 *Balance between utility and customers' costs*

a Cost incurred by customers as a result of loss of supply
b Cost incurred by utility in providing the availability of supply
c Total cost $= a + b$

community should determine the level of availability, this would be at point D on curve c.

As the costs of unreliability tend to be related to the electrical demand not supplied, and to the length of the interruption, recommendations concerning standards of security should perhaps best be related to these factors. The combined load of a group of customers or substations affected by a fault on the distribution system could be used as an indicator against which to set down various levels of system security. Without specific recommendations the tendency would be that 'good supplies' get better and 'poor supplies' get worse.

Network reliability can be considered as a cost factor, similar to investment or losses. If estimated outage times and loss of demands were calculated for each customer, then, using the costs in Figure 1.7 or some equivalent cost factor, it would be possible to obtain a measure of reliability. In practice this type of reliability calculation can be carried out using computers; these topics will be covered in Chapter 4; and Sections 9.5 and 14.6.

Another factor affecting the quality of supply is the actual value of the supply voltage, which 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 a voltage generally results from excessive voltage drops on the distribution networks. In addition to variations in the actual value of voltage being supplied, the voltage waveform may vary from a pure sine wave and thus cause improper operation of utility equipment or customers' appliances. Some of the causes of waveform distortion and other phenomena in respect of user voltages are discussed in more detail in Chapters 12 and 13.

The third requirement highlighted at the head of this Section is the safety of the electricity supply. The power-distribution systems themselves may cause danger to people, animals and property in a number of ways unless suitable precautions are adopted. Customers' appliances must be constructed and operated in such a way that they do not lead to accidents involving, for example, electric shock, or fires caused by overcurrents or faults. Safety can be improved in various ways, e.g. by ensuring that adequate clearances are maintained between conductors and earth (ground), using an appropriate method of earthing the power network, and by providing suitable reliable protection on all circuits and electrical equipment. Some of the safety requirements may be dictated by public authorities but the codes of practice adopted by utilities, including those for design, generally ensure that actual safety standards are better than the minimum required by law. Nonetheless, absolute safety cannot be achieved, so that efforts for improved safety must all be co-ordinated with other supply requirements.

Problems of limited finance and other resources can lead to strategies being adopted to extend supplies as fast as possible whilst accepting some tolerances on the quality and standards of supply. The standards can then be improved as the electricity system develops and additional finance becomes available.

1.5 Network configurations

In designing distribution 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. Various arrangements of mesh and interconnected networks are illustrated in Figure 1.9 where individual substations are represented by circles. The interconnecting circuits of the mesh arrangement can provide increased security of supplies to individual substations, and this arrangement is therefore frequently used in HV systems. While this arrangement requires more substation equipment overall, for example switchgear and electrical connections, it is usually more efficient in terms of total circuit costs. The mesh arrangement is easier to extend and has a higher utilisation of circuits when fully developed than a ring system, although this can result in higher network losses. Rings and mesh systems may be operated split with normally open points, or closed to improve security, although the latter require more circuit breakers and more sophisticated protection.

By interconnecting and operating a number of infeed substations in parallel as shown in Figure 1.9*b* it is possible to reduce the total transformer capacity into

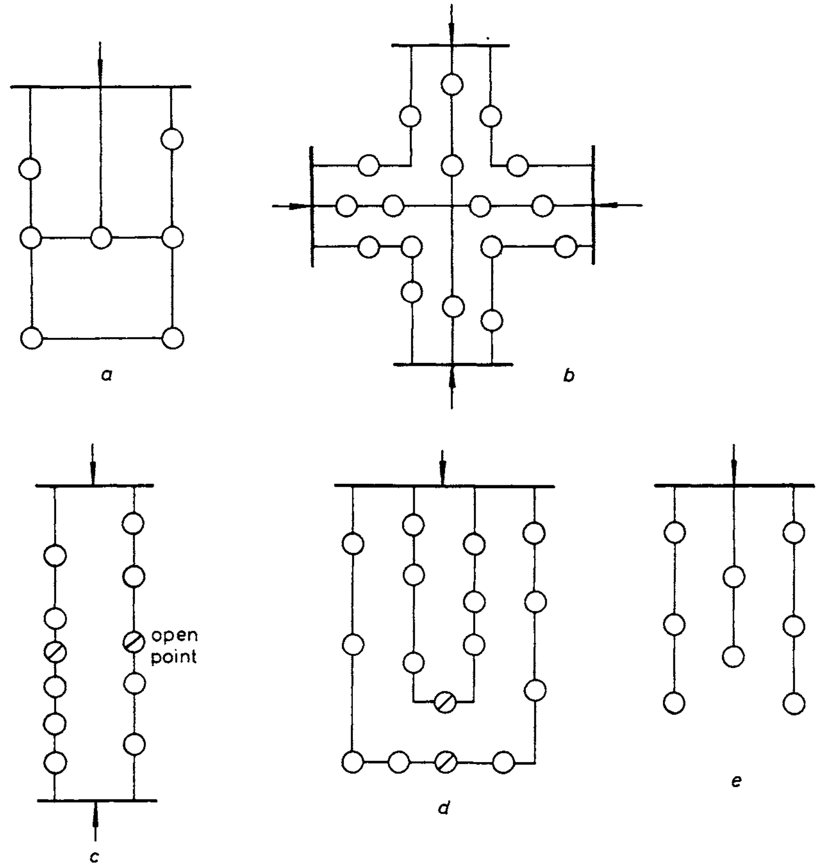

Figure 1.9 *Types of network configuration*

a Mesh network
b Interconnected network
c Link arrangement
d Open loop
e Radial system

the group. Subject to satisfactory network circuit loadings such an arrangement can accept the loss of one infeed without interruption of supplies within the network. Care must 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 infeed points can result in reverse power flows through the infeed transformers under outage conditions on the higher-voltage system.

A similar interconnection between infeed points can be provided by the link arrangement shown in Figure 1.9*c*. However, by opening the interconnectors as indicated, the system can operate as radial feeders with closure of the open points restoring supplies if one of the infeed substations is out of service. A common option at MV and LV is the open-loop arrangement shown in Figure 1.9*d*. Under normal operating conditions the network is operated as a number of radial feeders. On the occurrence of a fault between the busbar and the sectionalising open point, once the faulted section has been isolated the normally open disconnector can be closed to provide back-up supplies. In addition, purely radial networks without the facility of back-up interconnection, as indicated in Figure 1.9*e*, are in common use, particularly for LV rural systems.

In all these arrangements it should be noted that the optimum number of substations which can be connected to a feeder depends on the network voltage and the distances, and average demand supplied, from each substation. The application of such configurations to HV, MV and LV networks is discussed in Chapters 8, 9 and 10, where network arrangements, and protection and operating facilities, are covered in more detail.

The configuration of an individual network is also affected by the topography of the countryside through which its circuits pass. Flat rural areas are more amenable to interconnected configurations while valleys tend towards radial or spur arrangements. Existing networks will have been influenced by the philosophies and policies of earlier planners and designers. It is not uncommon for networks to be a mixture of practices. For operational reasons networks are equipped with switchgear, automatic disconnectors and reclosers to provide day-to-day flexibility to cover all likely network problems. Whatever system arrangement is used, the design engineer must ensure that a practical arrangement has been achieved at the lowest cost, with some flexibility to cater for as yet unknown future developments.

1.6 Auxiliary systems

Associated with the distribution networks themselves, various ancillary systems are needed to assist in meeting the requirements for economy, reliability, quality and safety of supply. Although certain internal administrative systems, e.g. transport, specialised machinery and the accountancy function, belong in this category, only those electrical systems which assist in the operation and maintenance of the main distribution networks are discussed here.

Protection systems are installed to prevent faults caused by abnormal currents or overvoltage from damaging distribution equipment. Protective relays initiate isolation of faulted sections in order to maintain continuity of supply elsewhere on the system while lightning arresters bypass the excess energy of voltage surges to earth. Microprocessor-controlled relays also provide facilities to monitor system performance and permit adjustment of relay settings by remote control – a facility not available with the more conventional electromechanical or electronic relays.

Telecontrol systems enable real-time information to be obtained from the supply system and permit remote-control operation of various switching equipments. Such systems thus actively assist in improving fault clearance times and the overall security of 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, and public and utility-owned telephone networks, radio links, power-line carrier systems as well as optical-fibre arrays now offer alternative data-transmission paths. Applications of *distribution automation* are expanding rapidly. Typical conventional examples of these at substations are alarm centre, transformer voltage-control units, tuning systems of Petersen coils, interlocking systems and sequence control of switchgear. These can also be integrated into the telecontrol system. Network information systems, which traditionally have been used for computer-aided design of distribution networks, are now capable of introducing useful support to automation applications and are being used more and more, for example in providing facilities for automatic fault location and restoration. Load management systems have been developed to reduce the peak loads on distribution network equipment, although the major benefit of such systems is in reducing the peaks of generation output. Various forms of signalling are in use to switch customers' loads on and off as necessary, including coded ripple signals injected into the distribution network and radio transmitted signals to tuned receivers in customers' premises.

By using or introducing some or all of these auxiliary systems the design engineer has the facility for improving network utilisation, reducing customer supply interruptions, and ultimately reducing capital and revenue expenditure.

Chapter 2

Planning distribution networks

2.1 Overall philosophy

The planning and design of electricity distribution networks can be divided into three areas. Strategic or *long-term planning* deals with future major investments and the main network configurations. *Network planning* or design covers individual investments in the near future while *construction design* includes the structural design of each network component taking account of the various materials available. The object of this chapter is to introduce those factors which should be taken into account when designing electricity distribution systems. The emphasis will be on general planning guidelines. Later chapters are devoted to more detailed considerations of technical and economic aspects, and specific engineering topics.

Long-term planning of the distribution system is an essential part of the planning activities of an electricity supply utility. Its main purpose is to determine the optimum network arrangements, what investments would be required, and the timing of these to obtain maximum benefits. At each stage the appropriate regulations covering such matters as quality of supply, safety and amenity should always be met while keeping the total costs over the life of the system as low as possible. To achieve this all the cost components – not just capital investments and their timing but also continuing annual costs such as system losses and maintenance expenditure – must be taken into account.

In industrialised countries the existing supply system covers virtually all the inhabited areas. In these areas the existing network usually provides a good starting point for planning future system arrangements. The need for further investment is usually to cater for load growth, or to replace ageing assets on the network. Uprating existing overhead lines and other plant, where technically feasible, can often be more economic than installing new circuits or equipment when the costs of obtaining new line routes or new substation sites are taken into account. However, the longer-term cost of developing the network must also be examined. The above objectives may be modified as time passes. In addition, it will be necessary to consider the effect of future changes in such factors as the growth of load in different areas, variations in the relative levels of the costs of materials and energy, as well as the increasing use of technical innovations.

From these planning studies it is possible to draw up lists of expected major annual investments and also to allocate sums of money to cover future undefined technical schemes. The total investment requirements must then be compared with an associated financial plan which takes account of assumptions made concerning the bulk purchase prices of electricity, load growth, system losses, existing loans, new borrowing requirements and any changes in salary costs, safety requirements etc. Over the period of the financial plan a balance should be achieved so that both the technical and financial objectives are reached within a stable and acceptable energy-sales tariff level.

The planning activity often includes not only determining major future network requirements, e.g. additional primary substations or the major revision of a telecontrol scheme, but also producing planning guidelines. These are usually intended to cover the smaller and more common types of investment for which it would not be economic to carry out individual technical and economic appraisals in detail; e.g. the replacement of distribution transformers or overhead-line conductors, or the design of housing-estate supplies. In this way common policies can be more easily implemented. Economic aspects often play an important role in determining such guidelines since, in addition to any technical factors, the costs of alternative policies also have to be taken into account when drawing up these guidelines. The written guidelines used by utilities are increasingly being transferred to network information systems, which are discussed in Chapter 14.2.

2.2 Planning objectives

A large variety of regulations, guidelines and recommendations are produced to ensure that electricity supply systems can be properly operated for the benefit of society. In most countries regulations concerning safety, the supply arrangements and the proper use of electricity form part of governmental legislation and in Europe, especially in the EC countries, efforts are being made to bring regulations together in a unified manner. Rules or recommendations for including economic optimisation in design procedures, for example, or for obtaining a suitable level of income to cover future investments are best determined by the utility management or owners. Although supply utilities have some degree of monopoly within their distribution areas, their economy should be balanced in such a way that the unit tariff level and profit margin are satisfactory to customers and owners, respectively. Whether the utilities are owned privately, or by municipal or state authorities, or by any combination of

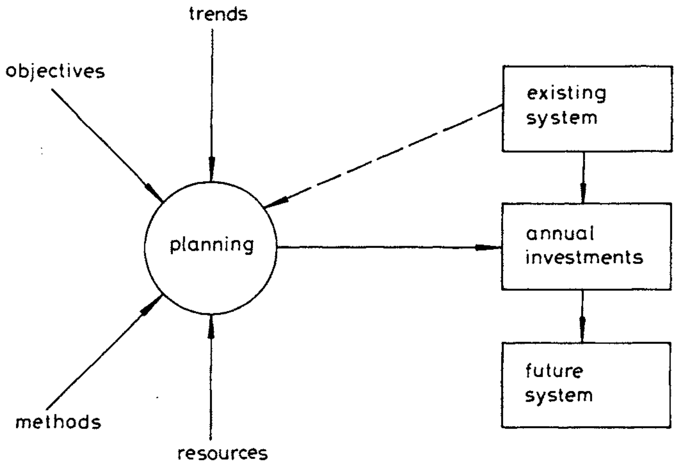

Figure 2.1 Planning as part of the distribution-system development process

these, does not in principle affect the situation, although municipal and state authorities are often more subject to political influence.

Planning objectives concerning the quality of supply, tariff price levels and stable employment are in common use in industrialised countries. There are still large variations from one country to another regarding the level at which regulations are formulated, and whether these are mandatory or obligatory, and also in the degree of detail of the regulations. This applies whether or not the regulations are laid down by local or state authorities or by the utilities themselves.

The detailed requirements of individual technical regulations may have a significant effect on such matters as the quality of supply, safety and the costs of providing electricity supplies to customers. For example, regulations setting out the minimum acceptable ratio of the lowest single-phase short-circuit current to the rating of a protection fuse on the low-voltage network will tend to increase costs, especially in rural areas. On the other hand this requirement improves safety to the system and customers, and reduces voltage fluctuations. This therefore encourages more rational investment than would, for example, occur if an extreme value were chosen for the minimum voltage to be received by any customer.

The number of national regulations and recommendations plus the internal design policies and engineering recommendations of a utility can be large. Considerable effort is required to ensure that all these documents are regularly updated to take account of improved techniques or changes in policy. It is nevertheless essential for a utility to ensure that everyone involved in the design of its supply networks has the most up-to-date information and tools and uses them correctly.

2.3 Combining engineering and economics

Both in long-term planning and in the detailed design work of an individual project the main aspects to be considered are technical performance and total costs. In order to carry out quantitative assessments of system design problems suitable tools must be developed for three main tasks:

(i) Defining a technically feasible solution. This includes calculations for deciding whether the appropriate regulations will be fulfilled, e.g. the maximum permissible voltage drop or the minimum fault current.
(ii) Estimating the cost of each circuit or item of equipment. Often this will be based on a unit length of cable, or trench excavation, or the cost of buying and installing a particular circuit breaker or transformer.
(iii) Ensuring that different types of costs can be sensibly compared. This requires that the costs of the various options being considered are in a form which enables acceptable comparisons to be made. To do this the various annual costs and individual capital investments are converted to annuities, or preferably to present worth values, to obtain total costs which can then be compared in order to decide on an agreed course of action. These aspects are discussed in Chapter 5.

In some cases it may be necessary to consider some deviation from standards set down in an engineering or financial recommendation, provided that statutory regulations are not broken. For example, a slight excursion outside the planning limit for voltage drop could be examined. Any consequential costs or savings of such an action, compared with remaining within the recommended limits, would be part of the cost/benefit studies necessary to arrive at the optimum solution.

Utilities usually plan their investment programme for a number of years ahead, and within this plan agree a detailed list of investments for the next year or two depending on their financial policy. In order to select the most advantageous investments from a long list of proposals, cost/benefit studies must be carried out. It is possible that schemes involving safety to utility personnel and the public, for example, might be given priority. Then by comparing the investment required for a particular proposal against such factors as the variation in the future costs of system losses, the estimated non-distributed energy due to system faults and the annual maintenance costs, it is possible to determine an order of priority for the proposals.

When considering any single proposal, various methods of achieving the required objective must be compared, on both a technical and an economic basis.

2.4 Effect of the existing network

The present distribution-system network arrangement is a natural starting point for planning purposes. The various types of equipment, their location, electrical loading and mechanical conditions are all factors to be taken into account when considering future developments. It is not possible to assess the overall technical capability of any network unless studies have been carried out to determine its performance under load, or fault, conditions. Computer-based information systems are used for this purpose. If current or kVA load readings are not available then customers' annual unit sales (kWh) can be used to derive load data. However, the accuracy of this method is dependent on the information available, or assumptions made, about the load factor, diversity and power factor of the individual customer groups used to build up the total load figure. Load curve information collected for different customer groups offers the possibility of some reliable conversion factors being available.

Industrial countries operate against a background of over a hundred years of providing electricity supplies. As a consequence, their supply practices are well established although they may vary from country to country. Considerable technical or financial benefits are therefore necessary to justify the replacement of existing policies by new ones. However, such changes have been made, e.g. the move from DC to AC, the adoption of higher system voltages, the use of new types of cables or circuit breakers, and decentralising system operation control.

Since the engineering life of each system component may be different, it is difficult to decide on a time span in which to assess the effect of any major change in policy over the life of the various components. It is therefore acceptable to use simple cost/benefit analyses when considering the investment programme for one or two years within the period of a long-term plan, provided that suitable account is taken of future unknown factors by some form of sensitivity analysis.

2.5 Consideration of development trends

The various items of equipment installed in power systems have long useful lives with some items remaining in service for 40 or 50 years. Thus proposals affecting an existing network should not just cover present loads but be capable of meeting, or being readily reinforced to meet, future loads. Even though these cannot be predicted exactly, every effort should be made at the planning and design stage to produce a justifiable estimate of future load growth in the area under consideration.

Various sensitivity-analysis studies have shown that errors in forecasts of load levels at the planning stage are the major causes of wrong investment, although it should be noted that most over-investments in transmission and distribution systems are partially offset by the resultant reduction in system losses. Consideration should always be given to the possibility of incorporating technical innovations into the system, e.g. insulated overhead conductors, new types of circuit breakers, the use of microprocessor devices in protection, and local automation schemes and network telecontrol. It is often cheaper overall to make some provision for the possibility of more stricter regulations in the future than to have to make major revisions to distribution networks or their associated auxiliary systems at some later date.

If major variations can be foreseen in the cost relationships between various electrical components compared to their capability and energy losses, these should also be considered at the investment appraisal stage. One example is the introduction of low-loss transformers where it may not be possible to justify replacement solely on savings in losses, although the saving in losses may be a factor in determining any replacement of obsolescent or deteriorating transformers. The use of XLPE cable, with a higher conductor operating temperature, permits the use of a smaller cross-sectional area conductor than with the older cables. However, this reduced cross-sectional area results in an increased resistance, and therefore higher I^2R losses. It is therefore necessary to take account of the capitalised losses as well as the initial investment cost when comparing the economics of XLPE cables against those of existing cables when considering network reinforcement.

2.6 Production of long-term plans

At HV the technical studies can be complex, especially if generation is involved. The design and construction period often includes complicated negotiations to obtain routes for overhead lines and underground cables. Consequently the overall lead time for individual HV schemes, from the planning stage to completion, is so long that most of the work load and expenditure up to the end of the review period, say eight years ahead, can be reasonably accurately estimated. For MV networks it is usually possible in the earlier years of the review period to divide the future work programme into those required for specific projects and those to cater for general load growth. From this an assessment can be made of the engineering and financial resources required for at least half the review period. Thereafter it may be necessary to make provision for future schemes as yet unknown, in addition to any known large projects.

All these considerations will involve some combination of network reinforcement and extension by circuits and units of large capacity, and the addition of new substations and circuits. If the timing, and the size, of the investment in HV and MV projects are determined from cost/benefit analyses of the various options available for each project, the most cost-effective schemes can be included with some confidence in both the engineering and financial long-term plans. This is an important aspect when such schemes take up a considerable proportion of a utility's financial and manpower resources.

On the other hand, because of the short lead time usually given to a utility by customers and housing and industrial developers requiring new or additional supplies, low-voltage networks cannot be investigated in such detail over such a long time period. Nonetheless, studies based on estimated loads for the next few years ahead will indicate the number of feeders likely to require reinforcement, generally due to excessive voltage drop, and those cases where there could be insufficient short-circuit current to operate protective devices satisfactorily. Such studies will indicate particular requirements for some years ahead. For the later years of the programme some general provision will need to be made for the LV systems based on past experience, perhaps related to overall load growth, for example.

Allowance must also be made in such plans for the replacement of equipment at all voltage levels, together with offices, shops and vehicles, and miscellaneous equipment such as tools and computers. For equipment which has a long useful life, such as cables, allowance must be made to write off any equipment which becomes surplus to system requirements, e.g. owing to network reorganisation or loss of load, before such items reach the end of their useful technical life and require replacing. This may occur in a system having two voltage levels, where rationalisation results in one voltage level being removed, with redundant cables left in the ground which cannot be re-used in the revised network configuration designed for expected future developments. In some circumstances there may be an economic case for purchasing equipment at a cheaper capital cost whilst accepting that its useful life may be shorter. However, the economic assessment should then take account of any increased maintenance costs and losses, together with earlier replacement when the shorter technical lifespan is reached.

In addition to the estimated cost of reinforcing and maintaining a utility's electrical system, it is necessary to include other future costs such as the provision of an adequate transport fleet, and possible activities associated with combined heat and power systems. The production of long-term plans thus necessitates a financial plan requiring co-operation between all the main sections of a utility. The annual updating of these plans and the planning and design policy documents provide the necessary support system for the detailed designing of a utility's electricity supply system.

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Chapter 3

Technical considerations

3.1 General

Good system planning and design requires a sound knowledge of the existing electrical system to provide a firm base on which to assess projects for future network development. Technical factors such as those aspects which can influence future loads need to be considered. However, it is essential that any project under consideration by a planning engineer must not only be examined from the point of view of various technical aspects; a comprehensive economic assessment of each project must also be carried out at the same time, to ensure that any proposed development is technically sound and cost effective.

This chapter covers various technical aspects which should be considered for both normal and abnormal operating conditions. The planning engineer has to consider the effect of the loss of any item of equipment on the supplies to customers and on the quality of supply, e.g. voltage fluctuations, and the amount of time a customer may be off supply, as well as the safety of the public and the utility staff. It is also necessary to take account of the effect of transient and permanent system faults on both utility- and customer-owned equipment.

3.2 Modelling network components

3.2.1 Components

When carrying out technical calculations it is necessary to make use of 'equivalent circuits' for various components, and then combine these circuits in order to represent the interconnection of the components in the actual electrical network. The relatively short lengths of MV and LV distribution circuits enable simple modelling techniques to be used for lines. The radial network configurations usually used make it possible to simplify the network model, and large matrix models are seldom necessary. It is usually sufficient to represent a distribution circuit by a series impedance and ignore its capacitance, except when carrying out voltage calculations on a long cable for example, when a π or tee equivalent circuit with capacitive shunt branches should be used. In special cases such as an earth fault on a network operating with an isolated neutral, the phase–earth (ground) capacitances of short lines can also be significant and need to be included. Table 3.1 includes typical electrical parameters of a selection of overhead lines and underground cables for distribution systems.

Table 3.1 Typical electrical parameters of overhead lines and underground cables

Type	System voltage, kV	Phase conductor Al/Fe, mm^2	Resistance, Ω/km (+20°C)	Reactance, Ω/km (50 Hz)
Overhead line	0·4	25/0	1·06	0·30
Overhead line	0·4	50/0	0·64	0·28
Overhead cable	0·4	35/0	0·87	0·10
Underground cable	0·4	120/0	0·25	0·07
Overhead line	11	50/0	0·64	≃0·4*
Underground cable	11	185/0	0·16	0·08
Overhead line	20	54/9	0·54	≃0·4*
Underground cable	20	120/0	0·25	0·11
Overhead line	110	242/39	0·12	≃0·4*

* Value depends on spacing and crossarm construction

Transformers can be represented by shunt and series impedances. The smaller distribution transformers have a larger series resistance than reactance, while the larger power transformers have negligible resistance compared with reactance. In the latter case neglecting resistance has little effect on voltage-drop studies, but resistance should be taken into account when calculating real power and energy losses. The manner in which the phase windings are connected to each other and to earth has a significant influence on non-symmetrical fault currents. This aspect will be discussed in Section 3.7.

When modelling small generators and motors it may be necessary to take resistance into account. However, for most studies only the reactances of synchronous machines are used. Three values of positive sequence reactance are normally quoted: subtransient, transient and synchronous reactances, denoted by X_{st}, X_t and X_s. In fault studies the subtransient and transient reactances of generators and motors must be included as appropriate, depending on the machine characteristics and fault-clearance time. The subtransient reactance is the reactance applicable at the onset of the fault occurrence. Within 0·1 s the fault current falls to a value determined by the transient reactance and then decays exponentially to a steady-state value determined by the synchronous reactance.

Table 3.2 Typical per-unit reactances for three-phase synchronous machines

Type of machine		X_{st}	X_t	X_s	X_2	X_0
Turbine generators	2 pole	0·09	0·15	1·2	0·09	0·03
	4 pole	0·14	0·22	1·7	0·14	0·07
Salient pole	with dampers	0·20	0·30	1·25	0·20	0·18
generators	without dampers	0·28	0·30	1·2	0·35	0·12

X_{st} = sub-transient reactance
X_t = transient reactance
X_s = synchronous reactance
X_2 = negative sequence reactance
X_0 = zero-sequence reactance

Typical per-unit reactances for three-phase synchronous machines are given in Table 3.2. The 'turbine generators' cover steam and gas-turbine-driven generators and synchronous machines, and the values for salient-pole generators are appropriate for hydro-power-plant generators.

For both transformers and machines, with equipment rating S_n and system phase–phase voltage V_n, then the resistance and reactance of the equipment are given by

$$R = v_r \frac{V_n^2}{S_n} \tag{3.1}$$

and

$$X = v_x \frac{V_n^2}{S_n} \tag{3.2}$$

where v_r and v_x are the resistive and reactive components of the per-unit impedance voltage of the equipment.

3.2.2 Transforming impedances

In distribution-system calculations very often the network to be studied involves one transforming step plus the circuits at the two voltage levels. The values to be used for the resistance and reactance of a transformer depend on whether the higher- or lower-voltage side is being studied (V_n in eqns. 3.1 and 3.2). Similarly the impedance of lines and other components, or the voltages and currents, on the opposite side of the transformer must be converted before carrying out circuit calculations. To study the system on side 1 of the transformer the impedances on side 2 must be multiplied by $(V_{1n}/V_{2n})^2$. The equivalent transforming ratio for voltages is V_{1n}/V_{2n}, and for currents V_{2n}/V_{1n}. Here V_{1n} and V_{2n} are the nominal voltages of the transformer.

A simple example will be used to illustrate how these transformations are applied in distribution-system calculations. Consider the network in Figure 3.1

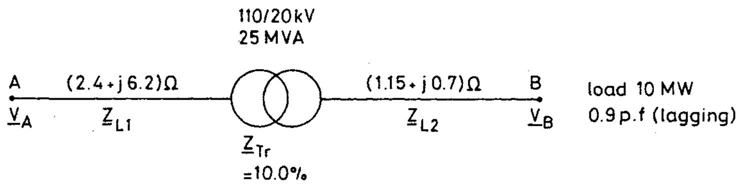

Figure 3.1 Example network

where the load at B is fed from source A via a 110 kV line, a 110/20 kV transformer and a 20 kV feeder. The load voltage is assumed to be 20 kV. It is required that the source voltage at point A be determined.

In the following calculations, transformed impedances and voltages to the 20 kV side have been marked by the symbol ′.

$$
\begin{aligned}
\boldsymbol{Z}'_{L1} &= \frac{(20)^2}{(110)^2}(2{\cdot}4 + j6{\cdot}2)\Omega = (0{\cdot}079 + j0{\cdot}205)\,\Omega \\
\boldsymbol{Z}_{Tr} &= j0{\cdot}10\frac{(20)^2}{25}\Omega = j1{\cdot}6\,\Omega \\
\boldsymbol{Z}'_{AB} &= \boldsymbol{Z}'_{L1} + \boldsymbol{Z}_{Tr} + \boldsymbol{Z}_{L2} = (1{\cdot}23 + j2{\cdot}51)\,\Omega = 2{\cdot}80\underline{/63{\cdot}89^\circ}\,\Omega \\
P &= \sqrt{3}VI\cos\phi \\
I &= P/\{\sqrt{3}V\cos\phi\} = 10\times 10^6/\{\sqrt{3}\times 20\times 10^3\times 0{\cdot}9\}\,\mathrm{A} \\
&= 320{\cdot}8\,\mathrm{A} \\
\boldsymbol{I} &= 320{\cdot}8\underline{/-25{\cdot}84^\circ}\,\mathrm{A} \\
V'_A &= V_B + \Delta V \simeq V_B + \sqrt{3}I\,(R'_{AB}\cos\phi + X'_{AB}\sin\phi) \\
&= 20\,000 + \sqrt{3}\times 320{\cdot}8(1{\cdot}25\times 0{\cdot}9 + 2{\cdot}51\times 0{\cdot}436)\,\mathrm{V} \\
&= 20\,000 + 1220 = 21\,220\,\mathrm{V} = 21{\cdot}220\,\mathrm{kV} \\
V_A &= (V_{1n}/V_{2n})V'_A = (110\,000/20\,000)\times 21{\cdot}220 = 116{\cdot}7\,\mathrm{kV}
\end{aligned}
$$

3.2.3 Per-unit values

In more complex networks, e.g. those including more than two voltage steps, the above impedance-transforming method can prove tedious. The use of per-unit values, e.g. ratios of actual values to certain base values, can be usefully employed in overcoming problems of transforming impedances across different voltage levels. The benefits of using per-unit values are:

- results for different systems are comparable, e.g. voltage drop v_d and power losses p_l
- transformer impedances are identical for both sides
- $\sqrt{3}$ factors are not needed in 3-phase calculations.

Usually the base value for the apparent power S is fixed to a typical transformer rating, and that for V to the nominal voltage. The base voltage V_b for other voltage steps is calculated by using the transformer ratios, while S_b is the same throughout the network being studied. I_b, Z_b and Y_b can be calculated from S_b and V_b.

The example in Section 3.2.2 is now used again in order to illustrate the use of the per-unit method. For calculating per-unit values the base power will be taken as the rated power of the transformer, i.e. $S_b = 25$ MVA, and is common to both voltage levels.

Calculating the base values of current for a 3-phase system:

$$\begin{aligned} \text{at } 110\,\text{kV}, \quad I_{bA} &= S_b/\sqrt{3}V_{bA} \\ &= (25 \times 10^6)/\sqrt{3} \times 110\,000 = 131{\cdot}22\,\text{A} \\ \text{and at } 20\,\text{kV}, \quad I_{bB} &= S_b/\sqrt{3}V_{bB} \\ &= 721{\cdot}7\,\text{A} \end{aligned}$$

and similarly the base values of impedance are:

$$\begin{aligned} \text{at } 110\,\text{kV}, \quad Z_{bA} &= V_{bA}^2/S_b \\ &= (110\,000)^2/(25 \times 10^6) = 484\,\Omega \\ \text{and at } 20\,\text{kV}, \quad Z_{bB} &= V_{bB}^2/S_b \\ &= (20\,000)^2/(25 \times 10^6) = 16\,\Omega \end{aligned}$$

The line ohmic values are then converted to per-unit values:

$$\boldsymbol{z}_{L1} = \frac{(2{\cdot}4 + j6{\cdot}2)}{484} = 0{\cdot}05 + j0{\cdot}013$$

$$\boldsymbol{z}_{L2} = \frac{1{\cdot}15 + j0{\cdot}7)}{16} = 0{\cdot}072 + j0{\cdot}044$$

The transformer reactance, given as 10% on 25 MVA, is thus 0·1 p.u. on the chosen base of 25 MVA, so that the total per-unit impedance between A and B is $0{\cdot}077 + j0{\cdot}157$.

A load of 10 MVA at 0·9 power factor, at 20 kV, equates to current $\boldsymbol{I}$, where

$$\begin{aligned} \boldsymbol{I} &= (10 \times 10^6)/(\sqrt{3} \times 20 \times 10^3 \times 0{\cdot}9) \\ &= 320{\cdot}8\underline{/-25{\cdot}84^\circ}\,\text{A} \\ &= 288{\cdot}7 - j139{\cdot}8\,\text{A} \\ &= I_p + jI_q \end{aligned}$$

Therefore the per-unit value of load current is

$$\boldsymbol{i} = \boldsymbol{I}/\boldsymbol{I}_{bB} = (288{\cdot}7 - j139{\cdot}8)/721{\cdot}7 = 0{\cdot}400 - j0{\cdot}194$$

The per-unit voltage drop v_d at busbar B is

$$\begin{aligned} v_d &\simeq i(r\cos\phi + x\sin\phi) \\ &= i_p r + i_q x \\ &= (0{\cdot}400 \times 0{\cdot}077) + (0{\cdot}194 \times 0{\cdot}157) \\ &= 0{\cdot}061 \end{aligned}$$

equivalent to

$$\begin{aligned} V_d &= v_d V_b \\ &= (0{\cdot}061 \times 20\,000) \\ &= 1220\,\mathrm{V} \end{aligned}$$

Thus, referring to Figure 3.1, $V_A \simeq V_B + V_d$ and, relating this to the higher voltage level, is given by

$$V_A = (110\,000/20\,000) \times (20\,000 + 1220) = 116{\cdot}7\,\mathrm{kV}$$

In this simple example the impedance-transformation method has proved to be less laborious than the per-unit method. Which method should be preferred depends on the system being studied. For distribution networks having only one MV step, impedance transformation is generally more useful, while in double MV systems and transmission networks the per-unit method is usually preferred.

Sometimes the impedances of different equipment may be stated on various power (MVA) bases. Having calculated the per-unit impedance on one base this can be converted to any other base using the following formula:

$$Z_{pu1}/Z_{pu2} = S_{b1}/S_{b2} \tag{3.3}$$

3.3 Power flows and losses

3.3.1 Power flows

For distribution networks AC load-flow studies are necessary to determine the capability of a network under all loading conditions and network configurations. This includes taking account of the loss of one or more circuits or items of equipment including the infeed power sources, whether from generation within the network or from transformer substations where the infeed power is obtained from a higher-voltage network. Most MV and LV networks are operated radially. As a consequence studies on such networks are relatively simple. On the other hand, the number of load points per network is higher and the information on the individual points is often limited with only the annual unit consumption figures at low voltage being known.

The power flow through each section of a network is influenced by the disposition and loading of each node point, and by system losses. Maximum-demand indicators installed at MV network infeeds provide the minimum amount of load data required for system analysis. More detailed loading information of the incoming supply and the outgoing feeders is economically available through the use of microprocessor units and telemetry.

Sometimes the numbers and ratings of customers' equipment appliances, and thus their maximum possible demand, are known. However, in order to carry out power-flow studies on MV and LV networks it is necessary to apply correction factors to individual loads. This is because summating the maximum values of all the loads will result in too high a value for the total current flows, and therefore the overall voltage drop, if the loads do not peak at the same time. It is therefore necessary to derate each individual load so that the summation of the individual loads equals the simultaneous maximum demand of the group of loads. This is achieved by applying a *coincidence factor*, which is defined as the ratio of the simultaneous maximum demand of a group of load points to the sum of the maximum demands of the individual loads. The inverse of the coincidence factor is termed *diversity factor*.

If kWh consumption information is available then empirical formulas or load-curve synthesis can be used to determine demands at network node points. The derivation of load data, and the use of computers for network studies, are discussed in Chapters 11 and 14.

3.3.2 Power losses

When the maximum current or real and reactive power flows have been determined, the series active and reactive power losses in a 3-phase circuit or any item of equipment, P_l and Q_l can be calculated from the following equations:

$$P_l = 3I^2R_l \tag{3.4}$$

$$\text{or} \quad P_l = \left[\frac{P}{V}\right]^2 R_l + \left[\frac{Q}{V}\right]^2 R_l \tag{3.5}$$

$$\text{and} \quad Q_l = 3I^2X_l$$

$$= \left[\frac{P}{V}\right]^2 X_l + \left[\frac{Q}{V}\right]^2 X_l \tag{3.6}$$

where R_l and X_l refer to the circuit series resistance and reactance as shown in Figure 3.2.

Given that the circuit shunt impedance is $(R_s + jX_s)$, as indicated in Figure 3.2, the shunt losses can be calculated using the shunt current I_s instead of I:

$$I_s = \frac{V/\sqrt{3}}{\sqrt{R_s^2 + X_s^2}} \tag{3.7}$$

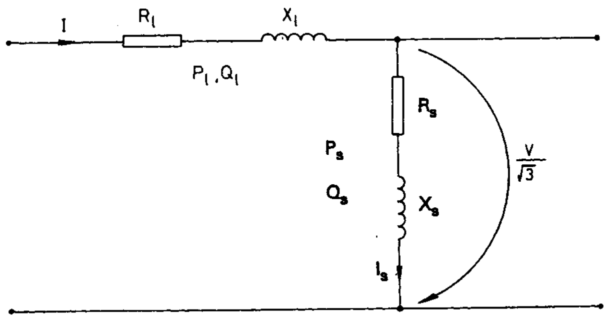

Figure 3.2 Calculation of circuit series and shunt losses

This circuit and method are most relevant for transformers and shunt capacitors, while parallel connection of the susceptance of the capacitance B and leakage conductance G is used when cables or high-voltage lines are concerned. Their shunt losses can be calculated using:

$$P_s = 3G\left[\frac{V}{\sqrt{3}}\right]^2 = GV^2 \tag{3.8}$$

$$Q_s = 3B\left[\frac{V}{\sqrt{3}}\right]^2 = BV^2 \tag{3.9}$$

The shunt resistive losses P_s for lines are usually very low while the reactive losses Q_s are negative; e.g. the shunt capacitance feeds reactive power to the system. Here V is the phase–phase voltage.

In the previous calculations it has been assumed that the system voltage was 3-phase. However, particularly at low voltage, single- or double-phase systems are sometimes used instead of the conventional 3-phase system because of their lower construction costs, even though the losses are higher.

Example

The ratio of losses between a single-phase and a symmetrical 3-phase line is derived. It is assumed that the same total real power P is delivered by both circuits, that all conductors are similar and have resistance R, and also that the phase–earth voltages are equal.

Single-phase line: The load P represents a certain current I. The current flows through the phase line, load and neutral conductor, and thus the system losses are

$$P_{l1} = I^2(2R) = 2I^2R \tag{3.10}$$

3-phase system: The load P is divided between three phases and the current in all of these is $I/3$. Because the load is symmetrical the phasor sum of these 3-phase currents is zero, and thus no current flows in the neutral conductor:

$$P_{l3} = \left(\frac{I}{3}\right)^2 (3R) = \frac{I^2 R}{3} = \frac{1}{6} P_{l1} \tag{3.11}$$

Thus, when the same real power is being delivered, the losses in a single-phase line are six times the losses in a balanced 3-phase line. In practice not all loads will be balanced 3-phase loads and the resulting imbalance will reduce this ratio.

When making economic comparisons, it is not sufficient just to compare the losses. In the above example the investment required for the 3-phase system is larger than that for the alternative single-phase arrangement. If the alternative of a four-conductor 3-phase line operating at single phase is considered, this would result in two wires in parallel being used for the phase and also the neutral conductors. Under this mode of single-phase operation the losses would be

$$P'_{l1} = 2I^2(R/2) = I^2 R$$

which is three times the losses at 3-phase operation of the same line.

3.3.3 *Load and loss load factors*

In economic comparisons it is often necessary to take account of the recurring annual system losses. System losses can be separated into so-called fixed losses and variable losses. The fixed losses are those due to the magnetisation currents of such items as transformers and reactors, which are often referred to as iron losses. For simplicity it is assumed that these losses occur for the full 8760 hours per annum, neglecting outages owing to maintenance or faults. Where more accuracy is required, the effect of the variation of voltage on the losses may need to be taken into account.

The variable losses are those caused by the flow of current through the different items of equipment on the network, and are also termed copper losses. Power losses in a component having resistance R are proportional to the square of the current flowing through it, i.e. $P_l = I^2 R$. For example, in Figure 3.3, the ratio P_l/P is much higher for high values of P than for low P values. The annual energy losses W_l can be determined by integrating the squared time function or duration curve of the current or of the power flow:

$$W_l = R \int_0^T I^2(t)\,\mathrm{d}t = \int_0^T P_l(t)\,\mathrm{d}t \tag{3.12}$$

This integration can be applied alternatively to the load curve shown in Figure 3.3*a* or to the duration curve in Figure 3.3*b*.

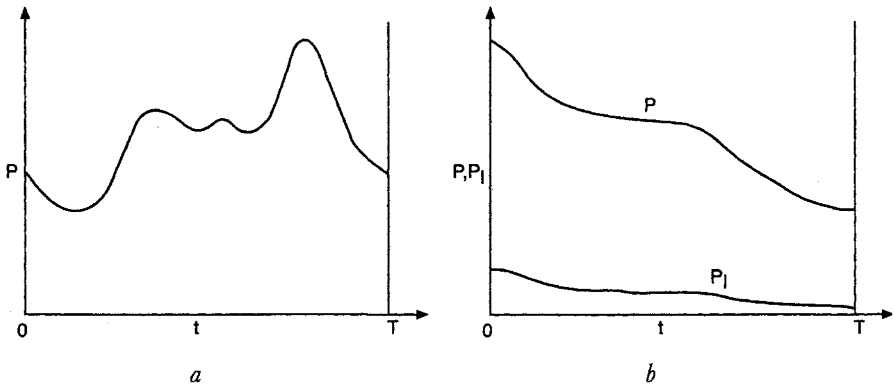

Figure 3.3 Load and load-duration curves

a Load curve
b Duration curves for power (P) and power losses (P_l)

The *load factor F* is defined as the ratio of the average power divided by the maximum demand, and can be expressed as $W/P_{max}T$. The *loss load factor* is defined as the ratio of the average power loss divided by the losses at the time of peak load, expressed by $(W_l/P_{lmax}T)$. The load factor can be determined by integrating the duration curve for P, and the loss load factor by integrating the $P_l(t)$ curve. The quadratic relationship between P_l and P is shown in Figure 3.3*b*.

Where only the load factor F is available, various formulas have been developed to obtain a quick approximation of loss load factor (LLF), generally based on the expression LLF $= aF + (1 - a)F^2$. Two examples are given below:

$$\text{Loss load factor} \simeq 0{\cdot}1F + 0{\cdot}9F^2 \tag{3.13}$$

$$\simeq 0{\cdot}3F + 0{\cdot}7F^2 \tag{3.14}$$

3.3.4 Heating effect

The energy from electrical power loss is converted to other energy forms, almost entirely heat. This heat energy thus tends to increase the temperature of the associated electrical component. High temperatures can result in premature ageing of insulation, while excessive temperature can result in conductors or insulation melting, with dangerous situations possibly occurring. The heating characteristic of a component depends on its material and construction, and there may be considerable temperature differentials throughout any item of equipment. In a large multimaterial piece of equipment the speed of heating and cooling differs in the various components. The transformer, with different winding, core and tank metals, plus conductor insulation and insulating oil, is a good example of this.

In this section the simple case of conductor heating will be considered. The effect of heating on transformers and cables is discussed in Chapter 6.

At any point in time the heat flow into a conductor due to losses is balanced by heat emission from the conductor plus heat retained in the conductor, in accordance with:

$$P_l \, \mathrm{d}t = mc \, \mathrm{d}\theta + a\alpha\theta \, \mathrm{d}t \tag{3.15}$$

where P_l = heating power

m = mass of conductor

θ = (conductor temperature) − (ambient temperature)

$\mathrm{d}\theta$ = temperature rise during time $\mathrm{d}t$

a = surface area

c = specific heat

α = heat emission constant

In the case of a short circuit the period involved is very short and the last term in eqn. 3.15 covering emission can be omitted, giving

$$\theta_{sc} \simeq (P_l t)/(mc) \tag{3.16}$$

Given that $P_l = I^2R$, the final temperature just before the clearance of a short circuit can be taken as being proportional to the protection operating time and to the square of the fault current, assuming the resistance to be independent of the temperature over the short period of time involved.

In the case of a steady load current the term ($mc\,\mathrm{d}\theta$) of eqn. 3.15 describing the retention of heat, is zero. Thus the difference between the final conductor temperature and the ambient temperature is given by

$$\theta_f \simeq P_l/(a\alpha) \tag{3.17}$$

and this is also proportional to the square of the load current.

In load-change conditions the time function of the temperature is obtained by solving the complete eqn. 3.15. When studying cooling $P_l = 0$. The solution leads to attenuating exponential curves. Their approximate equations are:

$$\text{heating:} \quad \theta_t = \theta_f(1 - \mathrm{e}^{t/\tau}) \tag{3.18}$$

$$\text{cooling:} \quad \theta_t = \theta_f \mathrm{e}^{-t/\tau} \tag{3.19}$$

where θ_t = temperature rise at time t from switching on or off

θ_f = final temperature rise

τ = time constant depending on material, size and shape of the conductor, given by

$$\tau = mc/a\alpha \tag{3.20}$$

The general shapes of the heating and cooling functions are illustrated in Figure 3.4.

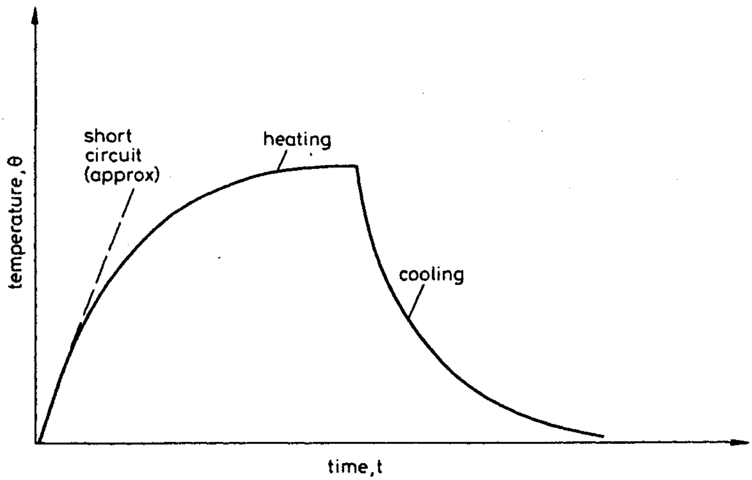

Figure 3.4 Heating and cooling curves for a conductor

3.4 Voltage drop

One of the most important constraints on distribution system design is the voltage level at the customer intake point. This is particularly important for the vast majority of customers taking supplies at low voltage with no means of adjusting the voltage received. A knowledge of the voltage at different locations can indicate the strong and weak parts of a network, and this is discussed in Chapter 13.

The voltage-drop phasor $\boldsymbol{V}_d$ for a section of line having an impedance $\boldsymbol{Z}$ and carrying current $\boldsymbol{I}$ is given by

$$\boldsymbol{V}_d = \boldsymbol{IZ} \tag{3.21}$$

In distribution systems it is the arithmetic difference between the sending- and receiving-end voltages which is the more useful voltage-drop value. A close approximation to this can be obtained from the simplified equivalent circuit shown in Figure 3.5. The circuit has resistance R, reactance X, sending-end voltage V_s and receiving-end voltage V_r. It carries current I lagging on V_r. The equivalent phasor diagram is given in Figure 3.6

During normal load-flow conditions the angle between the receiving- and sending-end voltages $\boldsymbol{V}_r$ and $\boldsymbol{V}_s$ is only a few degrees. For most practical cases the approximation $\phi \simeq \phi'$ is acceptable, so that the scalar relationship can be written as

$$V_s = V_r + IR\cos\phi + IX\sin\phi \tag{3.22}$$

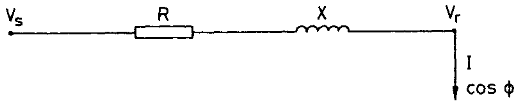

Figure 3.5 Single-phase equivalent circuit for a section of line

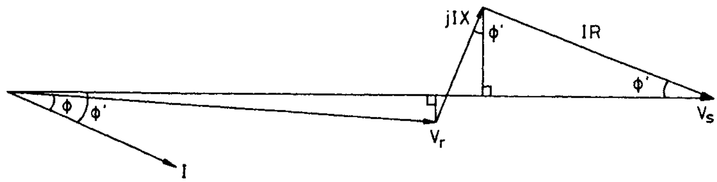

Figure 3.6 Phasor diagram for the line represented in Figure 3.5

The voltage drop V_d in the line is given by

$$\begin{aligned} V_d &= |\boldsymbol{V}_s| - |\boldsymbol{V}_r| \\ &\simeq IR\cos\phi + IX\sin\phi \\ &= I_pR + I_qX \end{aligned} \tag{3.23}$$

In eqn. 3.23 I_p and I_q represent the resistive and reactive components of the load current $\boldsymbol{I}$. In single-phase calculations the resistance and reactance of the return path must be included in R and X. For 3-phase systems the line–line voltage drop can be calculated from

$$\begin{aligned} V_d &\simeq \sqrt{3}(I_pR + I_qX) \qquad (3.24) \\ &= \frac{P}{V}(R + X\tan\phi) \end{aligned}$$

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

While eqns. 3.22–3.24 have been defined for flows along a line they are also appropriate for determining the voltage drop through any item of equipment in a network, knowing the equipment resistance and reactance and the load current and power factor. Referring back to the example of a line, the above study covered the case where the load was concentrated at the receiving end of a line section. Practical situations with several load points along the line can be solved by a series of similar calculations, obtaining the voltage drop due to each load point in turn. The total voltage drop is then the sum of the individual voltage drops due to each load point, assuming $\phi = \phi'$. If the loads do not peak at the same time it is necessary to apply a coincidence factor, defined in Section 3.3.1, to the loads to avoid obtaining too high a value for the voltage drop due to the simultaneous demand of the group of loads.

In some cases the load can be assumed to be distributed homogeneously along the line. In this situation the resultant voltage drop along the line will be one-half of the voltage drop obtained with a load equal to the total loading and concentrated at the end of the line. A single radial lightly loaded circuit presents conditions analogous to the above load distribution. Here the homogeneously distributed phase–earth capacitance feeds reactive current to the circuit and $I_q X$ thus has a negative value proportional to the square of the circuit length. If the resistive load is small enough, there can be a rise in voltage in moving from the sending end to the receiving end of the circuit.

In single-phase systems the voltage drop is higher than in a symmetrical 3-phase system, for the same conductor sizes, as shown in the following example.

Example

It is assumed that the same total real power P is delivered, and that all conductors are similar, having resistance R. In both cases the same phase–earth voltage V_p is applied, with the power factor $\cos\phi$ assumed to be unity.

Single-phase line: The load represents a current $I = P/V_p$ in a single-phase line. Considering that the neutral conductor is also loaded, the voltage drop is given by $V_{l1} = 2IR$.

3-phase line: In a 3-phase line the load P is divided between the three phases, each carrying current $I/3$. Again in this symmetrical case there is no load in the neutral conductor. The voltage drop in each phase is given by $V_{l3} = (I/3)R$.

Comparisons: In a two-wire single-phase line the voltage drop can be six times that of the 3-phase line.

3.5 System earthing

3.5.1 General

The main purpose in earthing the metallic frames of electrical equipment is to improve safety to the general public, operational staff, property in general and to system electrical equipment. The topic of protective earthing will be discussed in Section 3.5.8 for LV systems. The main emphasis in this Section will be on neutral-point earthing practices for MV systems, and also HV systems.

Different policies for earthing the star point or neutral of a system affect 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. Major national differences appear in the neutral earthing practices of MV systems. In this section consideration of the effects of various neutral earthing practices is introduced.

3.5.2 Hazard voltages

On the occurrence of a fault to earth, the value of the resultant fault current will depend on the phase voltage, the neutral earthing arrangement of the system, and the local earthing resistance R_e between the metallic frames and earth. The earth-fault current I_e (Figure 3.7*a*) causes a so-called hazard voltage $V_e = I_e R_e$ between the frames of the faulted equipment and earth. In practice the full voltage V_e seldom completely affects the person, as shown in the Figure, 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, which can be some considerable distance away from that person.

Figure 3.7*b* shows the variation in hazard voltage 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. 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. Ring-type earthing electrodes can also be used for the same purpose.

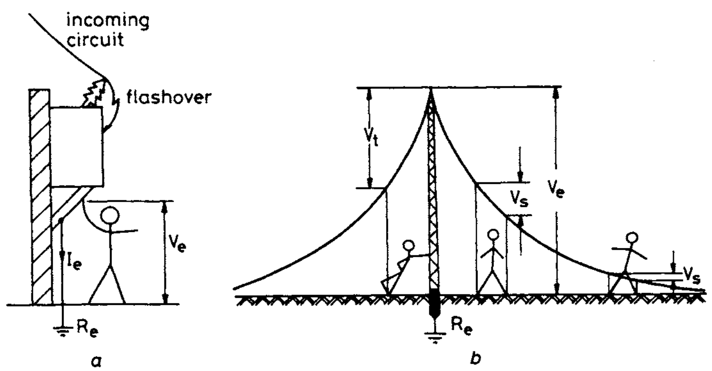

Figure 3.7 Hazard voltages

V_e = maximum earth fault voltage
V_t = touch voltage
V_s = step voltage
R_e = resistance to earth

3.5.3 Neutral earthing arrangements

In general, four methods of earthing the neutral points of electrical systems are employed:

(i) Solidly earth the neutral point (direct earthing)
(ii) Earth the neutral via an impedance
(iii) Earth the neutral via a suppression coil
(iv) Isolate the neutral entirely.

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 infeed HV/MV transformers. In addition, the metal frames of all transformers and other equipment are solidly earthed in HV and MV systems, whichever neutral earthing practice is adopted.

When applying methods (i), (ii) and (iii) the appropriate earth connection is made on to the neutral point of the transformer winding, e.g. at the neutral point of the star windings of a transformer, where the neutral of the network is directly available. Various earthing arrangements are shown in Figure 3.18 (page 57), which also shows the current distribution in the transformer windings under earth-fault conditions. With a delta winding an auxiliary transformer with star-interstar or zigzag windings is connected to the terminals of the delta winding to provide a neutral point. Consideration of the current flows for the various windings and earthing combinations is covered in Section 3.7.

3.5.4 Direct earthing

HV systems are often directly earthed. The earth-fault current may then exceed the 3-phase fault current. If not all of the neutrals of an HV system are earthed, the earth-fault currents and hazard voltages can be reduced to acceptable levels. In a directly earthed system power-frequency phase–earth overvoltages are the lowest, typically below 1·4 p.u.

3.5.5 Impedance earthing

MV networks often use different types of impedance earthing. Impedance earthing involves connecting a resistor or reactor between the system neutral point and earth. When a resistor is used its resistance is often of such a value that the earth-fault current passing through the transformer windings is limited to the rating of each winding. With an impedance earthed system the phase–earth voltage of an unfaulted 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 not cause problems with system equipment since the insulation level in MV systems is based on much higher lightning overvoltages. Further consideration of system overvoltages is given in Section 3.8.

3.5.6 Arc-suppression-coil earthing

A specific example of a neutral earthing reactor is the arc-suppression, or Petersen, coil, whose inductance can be adjusted to match closely the network phase–earth capacitances, depending on the system configuration, so that the resultant earth-fault current is small. Thus the resultant touch or step voltage is small, so that most systems could be operated for long periods with a sustained fault until the fault can be cleared. The arrangement is shown in Figure 3.22.

Experience with MV systems has shown that it is possible to depart from the ideal tuning value by about 25% before operational problems with protection and high fault current appear. Instead of one large controlled coil at the HV/MV substation, in rural networks it is possible to place inexpensive small compensation equipments, each comprising a star-point transformer and arc-suppression coil with no automatic control, around the system. If these equipments are properly located on individual feeders around the distribution network, no additional automatically operating arc-suppression-coil compensation is required. The disconnection of the compensation equipment when the associated feeder is isolated from the network ensures that the overall network compensation is retained regardless of the switching arrangements on the network. With this system the uncompensated residual current remains somewhat higher than in automatically tuned compensation systems, but experience has shown that arc-quenching is not substantially worsened and is operationally acceptable.

3.5.7 Isolated neutral systems

Operating a system with the neutral isolated results in low values of earth-fault current equal to the system capacitance current (see Figure 3.19, page 58). The voltage between faulted equipment and earth is small, which improves safety. For the same hazard voltage, relatively higher protective earthing resistances are acceptable compared with most other neutral earthing systems. On the other hand, transient and power-frequency overvoltages can be higher than those obtained, for example, with resistance earthed systems. Figure 3.8 gives the phasor diagram for an overvoltage condition. Here the phase–earth voltage V_A has increased to V_{Af} due to a single-phase fault on phase B.

3.5.8 Low-voltage-system protective earthing

At low voltage the earthing arrangements should be such that, on the occurrence of a fault on any appliance, the potential on any exposed conducting part likely to be touched by an individual should not reach a dangerous level. Many different practices are applied, especially in buildings.

When dealing with this subject the following IEC codes have been applied.

First letter = the relationship of the power system to earth:

T = direct connection of one point to earth,

I = all live parts, including the star point, isolated from earth, or one point connected to earth through an impedance.

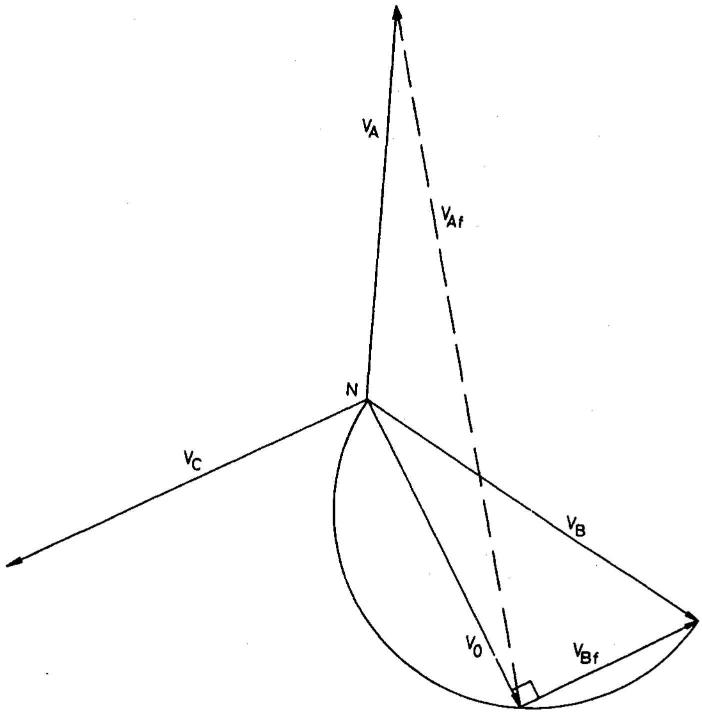

Figure 3.8 Phasor diagram for a power-frequency overvoltage
$V_{Bf} = I_f R_f$

Second letter = relationship of the exposed conductive parts of the electrical installation to earth:
T = direct electrical connection of the exposed conductive parts to earth, independently of the earthing of any point of the power system,
N = direct electrical connection of the exposed conductive parts to the earthed point of the power system (in AC systems the earthed point is normally the neutral point).

Where neutral and protective functions are provided by separate conductors the reference S is used. Where these functions are combined in a single conductor, referred to as a PEN conductor, the code C is used.

In Figure 3.9*a* the equipment frameworks are connected to the neutral conductor, which also includes the protective function, thus resulting in the coding TN-C. It is usual to bond the metallic water and gas pipes within the customer's installation to the earth connection, as well as the conducting frame of any appliance, to prevent excessive potential differences occurring between the non-electrical equipment and the earth system. A drawback of the TN-C system is that the load current flowing through the PEN conductor causes potential differences between the parts of the installation connected to the PEN

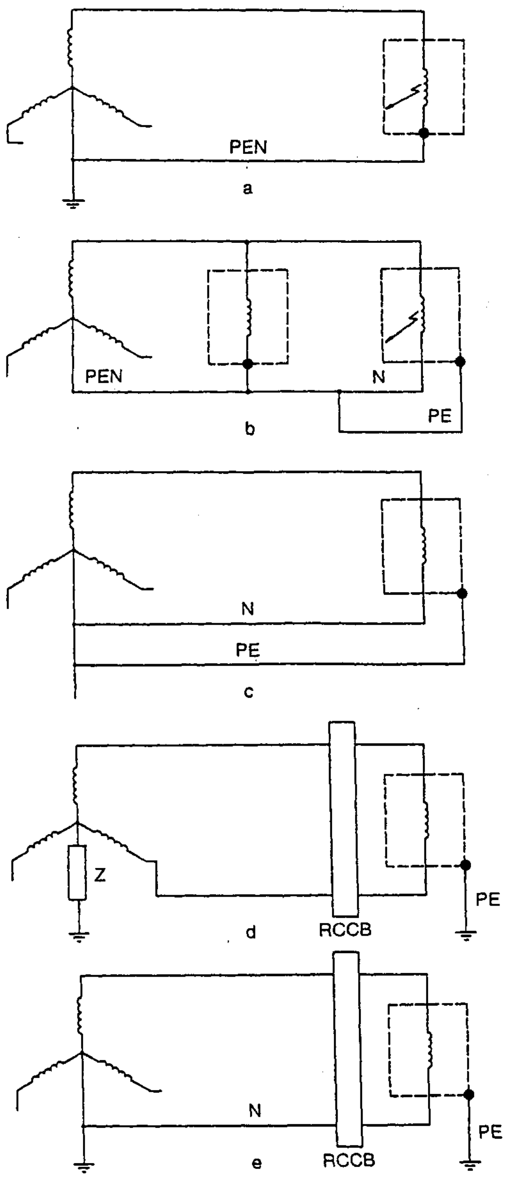

Figure 3.9 *Methods of earthing low-voltage systems*

RCCB: residual-current circuit breaker
Z: a high, or infinite, impedance
a Common neutral (N) and protective earth (PE) conductor (TN-C)
b Separate neutral and protective earth conductor in part of the system (TN-C-S)
c Separate neutral and protective earth conductors (TN-S)
d No direct connection between neutral and earth; separate protective earth electrode (IT)
e Electrically independent neutral and protective earth electrodes (TT)

conductor. Furthermore, the discontinuity in the PEN conductor is dangerous, since the section beyond the broken conductor may become live. The risk of accidents may be reduced by protective multiple-earthing, e.g. by connecting the PEN conductor to earth at several points.

In the system shown in Figure 3.9*b*, coded TN-C-S, neutral and protective functions are combined in one conductor in some parts of the system and provided by separate conductors in other parts. All the exposed conductive parts are connected together by either PE or PEN conductors and to the neutral point of the MV/LV transformer. The TN-C-S system is currently the one most commonly used in public LV systems, although it has some of the same drawbacks as a TN-C system. For example, the fact that the combined PEN conductor is loaded may not be acceptable in some cases owing to the risk of accidents or interference problems.

These problems can be avoided by the arrangement shown in Figure 3.9c, coded TN-S, which has become more and more popular especially in in-house systems. Here the neutral and protective conductors are separated and the neutral conductor is earthed at the MV/LV substation only. The protective conductor PE may have multiple earthing. TN systems are often used in countries like Sweden and Finland, where the poor conductivity of the earth makes it difficult to achieve low earthing resistance. Usually in public LV networks outside buildings, however, there is a combined PEN conductor with the whole system thus approaching the TN-C-S system described above.

When no earthing point is provided at the customer's premises by the supply utility, customers can provide their own earthing arrangements, as indicated in Figure 3.9*d*, and coded IT. In the IT system the neutral point or the neutral conductor is isolated from earth or earthed through an impedance. The exposed conductive parts are connected directly to earth. Whilst it may be possible for the utility to install a sufficiently sensitive earth-leakage detection device at the MV/LV substation, this would result in loss of supplies to all LV customers when a fault occurs on one customer's installation. Consequently, it is more usual for the customer to install a suitable device, the so-called residual-current circuit breaker (RCCB) as indicated in the figure, since a high earth-loop impedance may result in insufficient current to operate the normal overcurrent protection on the MV/LV transformer quickly enough. The RCCB is normally current operated, tripping when the leakage current reaches a preset value. The IT system is widely used in installations to avoid the first fault causing an interruption in the power supply. Thus the IT system is found in use, for example, at industrial plants, hospitals and in various reserve or safety systems. In some countries, like Norway, it has also been used in household and commercial installations.

In Figure 3.9*e*, coded TT, the exposed conductive parts of electrical equipment are connected to an earthing electrode separate from the earthing electrode of the MV/LV transformer. Owing to the high earth-loop impedance, the overcurrent protection must be implemented in a similar manner to the IT system. TT systems are widely used in central Europe.

3.6 Fault calculations

The design of a power system is influenced by the currents and voltages which are present under fault conditions. Information on these can determine, for example:

(i) the fault-breaking and -making capacity of circuit breakers, switches or fuses
(ii) the choice of the power-system equipment, including overhead lines and underground cables, to ensure that they are capable of withstanding the appropriate through-fault currents
(iii) the type of protective equipment at each point on the system, and the range of settings required
(iv) the design of network earthing systems.

Some, or all, of the following information may be required for a fault at any specified point on the system:

(a) the total maximum, and minimum, fault currents at the point of the fault and the values of fault current at other points on the system
(b) the voltages at the different points on the system, and also the phase angle between voltage and current. If the neutral is isolated or earthed via an arc-suppression coil, knowledge of the star-point-earth voltage, the earth-fault current and the phase angle between them, is useful.

Various types of system circuit faults are shown diagrammatically in Figure 3.10. The most common is the phase–earth fault. Any fault often results in an arc having some resistance, and the effects of this, plus the earth-loop impedance, on fault currents are covered in Section 3.7.

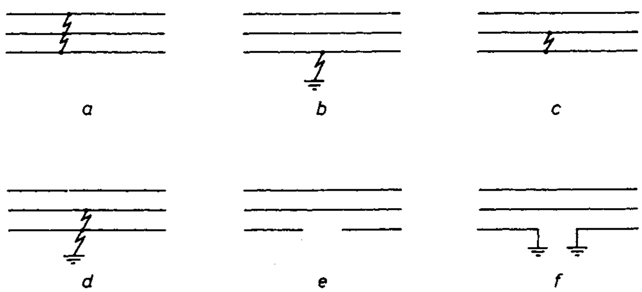

Figure 3.10 Examples of system faults

a 3-phase
b Phase–earth
c Phase–phase
d Phase–phase–earth
e Broken conductor
f Broken conductor to earth

Very often two assumptions can be made to simplify the calculations. It can be assumed that the pre-fault voltage at the point of fault is the same as the nominal system voltage at that point, and also that any load currents circulating around the system can be neglected since they will be small in comparison with the size of the fault currents.

Referring to Figure 3.11, the fault current of a 3-phase fault can be calculated using Thévenin's theorem by the equation $\boldsymbol{I}_f = \boldsymbol{V}/(\boldsymbol{Z}_{th} + \boldsymbol{Z}_f)$. Here $\boldsymbol{V}$ is the phase–earth voltage at the fault location prior to the fault, and $\boldsymbol{Z}_{th}$ is the total impedance seen from the fault, based on a single-phase equivalent network and including generator and motor impedances as well as circuit and equipment impedances. $\boldsymbol{Z}_f$ is the fault impedance. In the simpler distribution systems the reduction of the network to determine $\boldsymbol{Z}_{th}$ can often be carried out using simple network transformations.

Reference has already been made in Section 3.2 to the need to convert network impedances to a common base so that they can then be combined directly for network modelling. When calculating symmetrical 3-phase faults on a network, an equivalent single-phase network representation can be used. In addition to series and parallel reductions, star/delta and delta/star transformations may be required to obtain the equivalent impedance between source and fault.

Referring to Figure 3.12, the following relationships can be obtained and utilised in network reductions:

$$\boldsymbol{Z}_A = (\boldsymbol{Z}_{AB}\boldsymbol{Z}_{AC})/(\boldsymbol{Z}_{AB} + \boldsymbol{Z}_{AC} + \boldsymbol{Z}_{BC}) \tag{3.25}$$

$$\boldsymbol{Z}_B = (\boldsymbol{Z}_{AB}\boldsymbol{Z}_{BC})/(\boldsymbol{Z}_{AB} + \boldsymbol{Z}_{AC} + \boldsymbol{Z}_{BC}) \tag{3.26}$$

$$\boldsymbol{Z}_C = (\boldsymbol{Z}_{AC}\boldsymbol{Z}_{BC})/(\boldsymbol{Z}_{AB} + \boldsymbol{Z}_{AC} + \boldsymbol{Z}_{BC}) \tag{3.27}$$

$$\boldsymbol{Z}_{AB} = \boldsymbol{Z}_A + \boldsymbol{Z}_B + (\boldsymbol{Z}_A\boldsymbol{Z}_B)/\boldsymbol{Z}_C \tag{3.28}$$

$$\boldsymbol{Z}_{AC} = \boldsymbol{Z}_A + \boldsymbol{Z}_C + (\boldsymbol{Z}_A\boldsymbol{Z}_C)/\boldsymbol{Z}_B \tag{3.29}$$

$$\boldsymbol{Z}_{BC} = \boldsymbol{Z}_B + \boldsymbol{Z}_C + (\boldsymbol{Z}_B\boldsymbol{Z}_C)/\boldsymbol{Z}_A \tag{3.30}$$

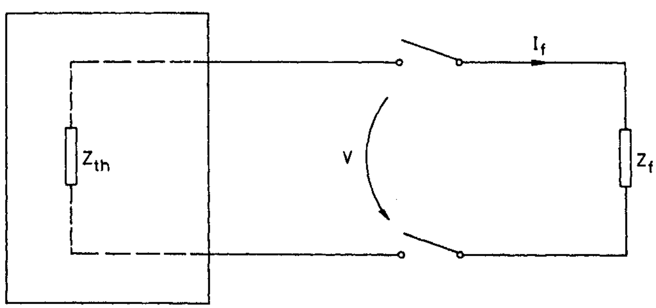

Figure 3.11 Calculation of fault current

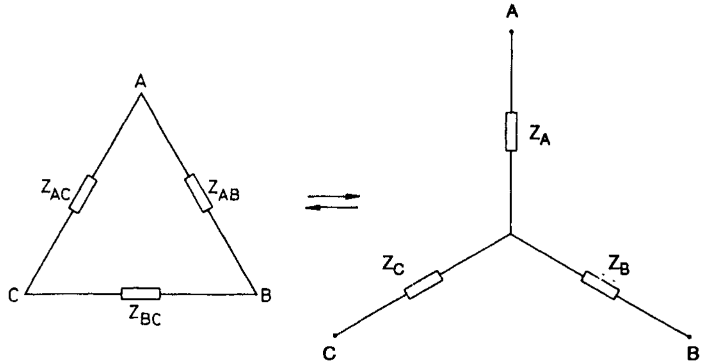

Figure 3.12 Star/delta and delta/star transformation

Figure 3.13 shows a small mesh network with two generation infeeds. It is required to find the fault level at point F. For simplicity only reactance values have been given, calculated as per-unit quantities on a 100 MVA base as described in Section 3.2. This is based on the assumption that circuit and generator resistances can be neglected since the generator reactances will predominate in any network reduction. The above assumption is used in the reduction of the reactances to a single value in order to calculate the fault level at F.

In order to calculate the fault level at F it is necessary to determine the total equivalent reactance between F and the reference node R, R being the point in the 3-phase system relative to which the phase voltages are expressed. When applying Thèvenin's method to this type of fault, R usually represents earth. R is also on of the notes for the sequence network used for building up the appropriate combination of sequence networks for unbalanced faults as described in Section 3.7. Thus, from the arrangement shown in Figure 3.13*a*, the equivalent network (Figure 3.13*b*) is obtained. Converting the delta reactances between busbars A, B and C to a star array Z_A, Z_B, Z_C, by use of eqns. 3.25–3.27, gives $Z_A = 0{\cdot}022$, $Z_B = 0{\cdot}017$ and $Z_C = 0{\cdot}025$ as shown in Figure 3.13*c*. Combining and redrawing the reactances to the arrangement shown in Figure 3.13*d*, a further transformation of the delta reactances at the top of the diagram results in the network of Figure 3.13*e*.

Then follows a number of series/parallel reductions resulting in an overall source-fault reactance of 0·246 p.u. on 100 MVA as shown in Figure 3.13*h*. Since the reactances have all been calculated on a 100 MVA base an overall source-fault reactance of 1·0 p.u. would result in a 3-phase fault level of 100 MVA. With the calculated source-fault reactance for this example of 0·246 p.u. the resultant 3-phase fault level at point F is thus 100(1·0/0·246) = 406·5 MVA. If the network nominal system voltage were 33 kV, the fault level of 406·5 MVA would be equivalent to a fault current of $(406{\cdot}5 \times 10^6)/\{\sqrt{3} \times 33000\} = 7{\cdot}11$ kA.

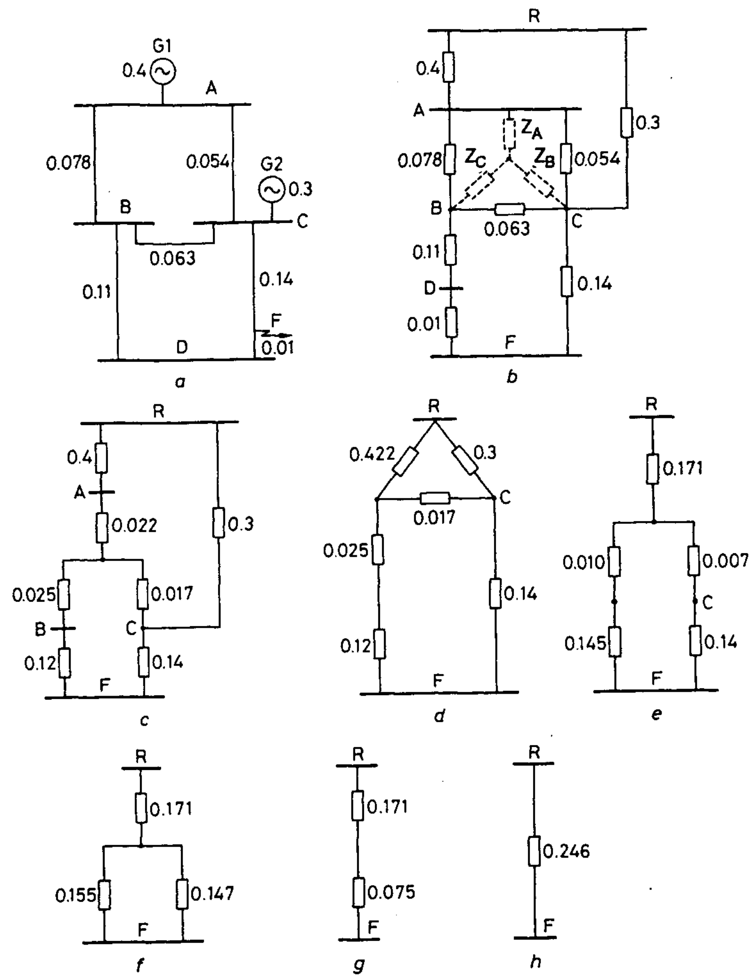

Figure 3.13 Small mesh-network reduction example

3.7 Unsymmetrical faults

3.7.1 Sequence networks

The simple single-phase equivalent circuit representation used in the previous section cannot be used directly when considering unsymmetrical faults since similar conditions do not apply to all phases of the faulted power system. Different methods of solving such problems have been developed, the most popular being the symmetrical-component system. This method is derived from an arrangement of three separate 'phase sequence' networks which, when suitably combined, provide the conditions for the unbalanced fault situation under consideration.

The three sequence networks do not actually exist within the power system but are purely a mathematical device to permit an easier solution of unbalanced system conditions. The detailed background to this method is given in many textbooks, and reference to some of these is included in the bibliography (Section 3.9). The use of symmetrical components is based on the fact that any combination of unbalanced 3-phase voltages and currents can be broken down into three separate systems of symmetrical phasors as illustrated in Figure 3.14 and comprising:

(i) a positive-sequence system made up of three phasors having the same magnitude, spaced 120° apart and rotating in the same direction as the phasors for generated voltages in the power system under consideration, i.e. the positive direction;
(ii) a negative-sequence system with three phasors of the same size spaced 120° apart, rotating in the same direction as the positive-sequence phasors, but in the reverse sequence;
(iii) a zero-sequence system where all three phasors are of the same magnitude and in phase with each other, rotating in the same direction as the positive sequence phasors.

Since each phase value is the sum of its sequence components, then, taking current values as an example,

$$\boldsymbol{I}_a = \boldsymbol{I}_{a1} + \boldsymbol{I}_{a2} + \boldsymbol{I}_{a0} \tag{3.31}$$

$$\boldsymbol{I}_b = \boldsymbol{I}_{b1} + \boldsymbol{I}_{b2} + \boldsymbol{I}_{b0} \tag{3.32}$$

$$\boldsymbol{I}_c = \boldsymbol{I}_{c1} + \boldsymbol{I}_{c2} + \boldsymbol{I}_{c0} \tag{3.33}$$

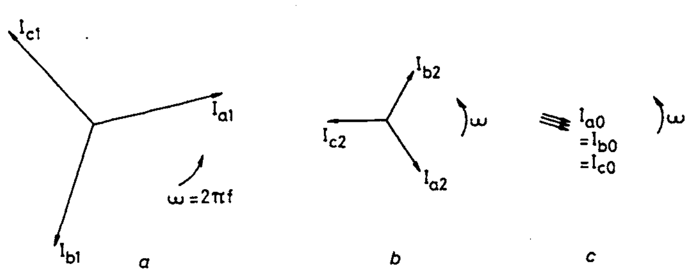

Figure 3.14 Sequence-component phasors

a Positive sequence
b Negative sequence
c Zero sequence

The sequence components can be written as follows using the operator a to indicate relative phasor positions:

$$\begin{aligned} &\boldsymbol{I}_{a1}; \quad \boldsymbol{I}_{b1} = \boldsymbol{a}^2\boldsymbol{I}_{a1}; \quad \boldsymbol{I}_{c1} = \boldsymbol{a}\boldsymbol{I}_{a1} \\ &\boldsymbol{I}_{a2}; \quad \boldsymbol{I}_{b2} = \boldsymbol{a}\boldsymbol{I}_{a2}; \quad \boldsymbol{I}_{c2} = \boldsymbol{a}^2\boldsymbol{I}_{a2} \\ &\boldsymbol{I}_{a0}; \quad \boldsymbol{I}_{b0} = \boldsymbol{I}_{a0}; \quad \boldsymbol{I}_{c0} = \boldsymbol{I}_{a0} \end{aligned}$$

where $\boldsymbol{a} = 1\underline{/120^\circ}$

The phase values can now be indicated in terms of the sequence components of one phase only as given below, and as determined geometrically in Figure 3.15:

$$\boldsymbol{I}_a = \boldsymbol{I}_{a1} + \boldsymbol{I}_{a2} + \boldsymbol{I}_{a0} \tag{3.34}$$

$$\boldsymbol{I}_b = \boldsymbol{a}^2\boldsymbol{I}_{a1} + \boldsymbol{a}\boldsymbol{I}_{a2} + \boldsymbol{I}_{a0} \tag{3.35}$$

$$\boldsymbol{I}_c = \boldsymbol{a}\boldsymbol{I}_{a1} + \boldsymbol{a}^2\boldsymbol{I}_{a2} + \boldsymbol{I}_{a0} \tag{3.36}$$

or in matrix notation

$$\begin{bmatrix} \boldsymbol{I}_a \\ \boldsymbol{I}_b \\ \boldsymbol{I}_c \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ \boldsymbol{a}^2 & \boldsymbol{a} & 1 \\ \boldsymbol{a} & \boldsymbol{a}^2 & 1 \end{bmatrix} \begin{bmatrix} \boldsymbol{I}_{a1} \\ \boldsymbol{I}_{a2} \\ \boldsymbol{I}_{a0} \end{bmatrix} \tag{3.37}$$

$$\begin{bmatrix} \boldsymbol{I}_{a1} \\ \boldsymbol{I}_{a2} \\ \boldsymbol{I}_{a0} \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & \boldsymbol{a} & \boldsymbol{a}^2 \\ 1 & \boldsymbol{a}^2 & \boldsymbol{a} \\ 1 & 1 & 1 \end{bmatrix} \begin{bmatrix} \boldsymbol{I}_a \\ \boldsymbol{I}_b \\ \boldsymbol{I}_c \end{bmatrix} \tag{3.38}$$

The derivation of the formulas to calculate the phase currents for a line–earth fault will be used as an example of the interrelation of phase and sequence components, since this is the most common system fault.

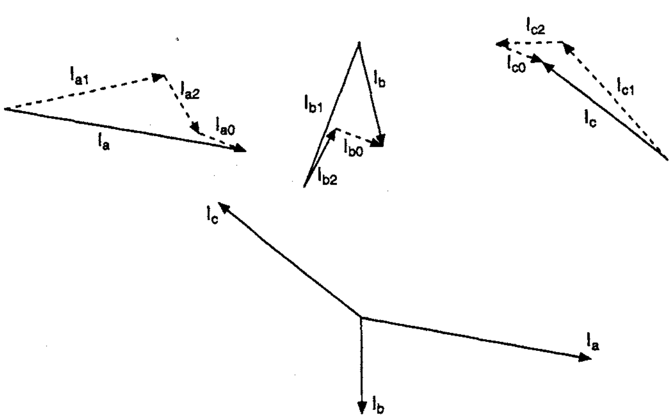

Figure 3.15 Determination of phase values from sequence components

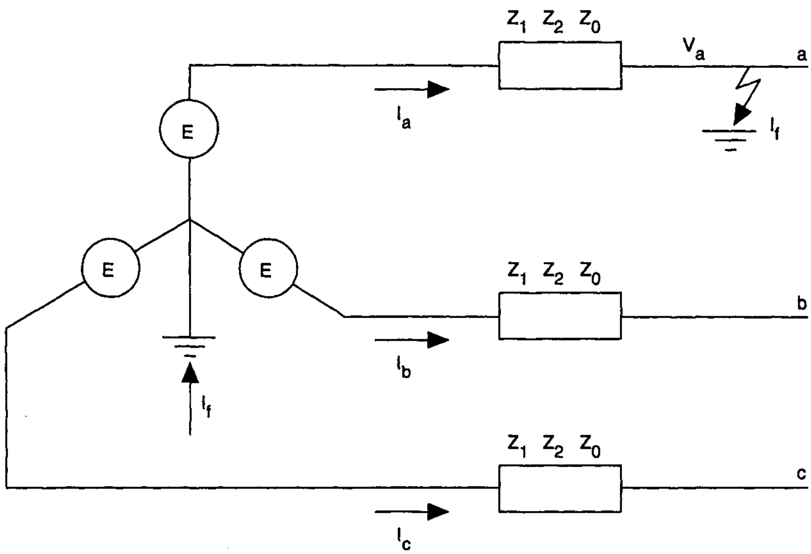

Figure 3.16 Single line–earth fault

Let the fault be on phase a (Figure 3.16). Assuming a radial system and no fault or earthing impedance, then, at the point of the fault,

$$\boldsymbol{V}_a = 0 \quad \text{and} \quad \boldsymbol{I}_b = \boldsymbol{I}_c = 0$$

Thus, from eqn. 3.38, the symmetrical components of the fault current are

$$\begin{bmatrix} \boldsymbol{I}_{a1} \\ \boldsymbol{I}_{a2} \\ \boldsymbol{I}_{a0} \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & \boldsymbol{a} & \boldsymbol{a}^2 \\ 1 & \boldsymbol{a}^2 & \boldsymbol{a} \\ 1 & 1 & 1 \end{bmatrix} \begin{bmatrix} \boldsymbol{I}_a \\ 0 \\ 0 \end{bmatrix} \tag{3.39}$$

from which it can be seen that:

$$\boldsymbol{I}_{a1} = \boldsymbol{I}_{a2} = \boldsymbol{I}_{a0} = \frac{1}{3}\boldsymbol{I}_a \tag{3.40}$$

From Figure 3.16, $\boldsymbol{E}$ is the pre-fault phase–neutral voltage at the point of fault on the reference phase a, so that

$$\boldsymbol{V}_a = \boldsymbol{E} - \boldsymbol{I}_{a1}\boldsymbol{Z}_1 - \boldsymbol{I}_{a2}\boldsymbol{Z}_2 - \boldsymbol{I}_{a0}\boldsymbol{Z}_0 \tag{3.41}$$

and, from eqns. 3.40 and 3.41,

$$\boldsymbol{I}_{a1} = \boldsymbol{I}_{a2} = \boldsymbol{I}_{a0} = \frac{\boldsymbol{E}}{\boldsymbol{Z}_1 + \boldsymbol{Z}_2 + \boldsymbol{Z}_0} \tag{3.42}$$

and, referring to eqn. 3.40,

$$\boldsymbol{I}_a = \frac{3\boldsymbol{E}}{\boldsymbol{Z}_1 + \boldsymbol{Z}_2 + \boldsymbol{Z}_0} \tag{3.43}$$

If $\boldsymbol{Z}_{fn}$ is the sum of the phase–earth fault impedance $\boldsymbol{Z}_f$ and the neutral–earth impedance then eqn. 3.43 is modified to

$$\boldsymbol{I}_a = \frac{3\boldsymbol{E}}{\boldsymbol{Z}_1 + \boldsymbol{Z}_2 + (\boldsymbol{Z}_0 + 3\boldsymbol{Z}_{fn})}$$

In a similar manner the following formulas for symmetrical 3-phase, line–line, and line–line–earth faults can be determined.

3-phase fault

$$\boldsymbol{I}_a = \frac{\boldsymbol{E}}{\boldsymbol{Z}_1 + \boldsymbol{Z}_f} \tag{3.44}$$

Phase currents $\boldsymbol{I}_b$ and $\boldsymbol{I}_c$ can be obtained from $\boldsymbol{I}_a$ by multiplying by $\boldsymbol{a}^2$ and $\boldsymbol{a}$, respectively.

Line–line fault

$$\boldsymbol{I}_a = 0; \quad \boldsymbol{I}_b = \frac{-j\sqrt{3}\boldsymbol{E}}{\boldsymbol{Z}_1 + \boldsymbol{Z}_2 + \boldsymbol{Z}_f} \tag{3.45}$$

$$\boldsymbol{I}_c = -\boldsymbol{I}_b$$

Line–line–earth fault

$$\boldsymbol{I}_a = 0$$

$$\boldsymbol{I}_b = \frac{j\sqrt{3}(\boldsymbol{a}\boldsymbol{Z}_2 - \boldsymbol{Z}_0 - 3\boldsymbol{Z}_{fn})\boldsymbol{E}}{\boldsymbol{Z}_1\boldsymbol{Z}_2 + (\boldsymbol{Z}_0 + 3\boldsymbol{Z}_{fn})(\boldsymbol{Z}_1 + \boldsymbol{Z}_2)} \tag{3.46}$$

$$\boldsymbol{I}_c = \frac{-j\sqrt{3}(\boldsymbol{a}^2\boldsymbol{Z}_2 - \boldsymbol{Z}_0 - 3\boldsymbol{Z}_{fn})\boldsymbol{E}}{\boldsymbol{Z}_1\boldsymbol{Z}_2 + (\boldsymbol{Z}_0 + 3\boldsymbol{Z}_{fn})(\boldsymbol{Z}_1 + \boldsymbol{Z}_2)} \tag{3.47}$$

The interrelation of the phase-sequence networks for various system fault conditions is shown in Figure 3.17.

If the 3-phase fault current is assumed to have a value of 1 p.u. then the equations for the other types of fault can be defined as per-unit values of the 3-phase fault current at the same point, as set out below. Here $\boldsymbol{Z}_f$ and $\boldsymbol{Z}_{fn}$ are assumed to be zero:

Line–line fault current $= \sqrt{3}/(1 + \boldsymbol{Z}_2/\boldsymbol{Z}_1)$per unit

Line–earth fault current $= 3/(1 + (\boldsymbol{Z}_2 + \boldsymbol{Z}_0)/\boldsymbol{Z}_1)$ per unit

Line–line–earth fault current $= \sqrt{3}(\boldsymbol{a}\boldsymbol{Z}_2/\boldsymbol{Z}_0 - 1)/(1 + \boldsymbol{Z}_2/\boldsymbol{Z}_1 + \boldsymbol{Z}_2/\boldsymbol{Z}_0)$ per unit

For lines and cables the positive- and negative-sequence impedances are equal. Thus, on the basis that the generator impedances are not significant in most

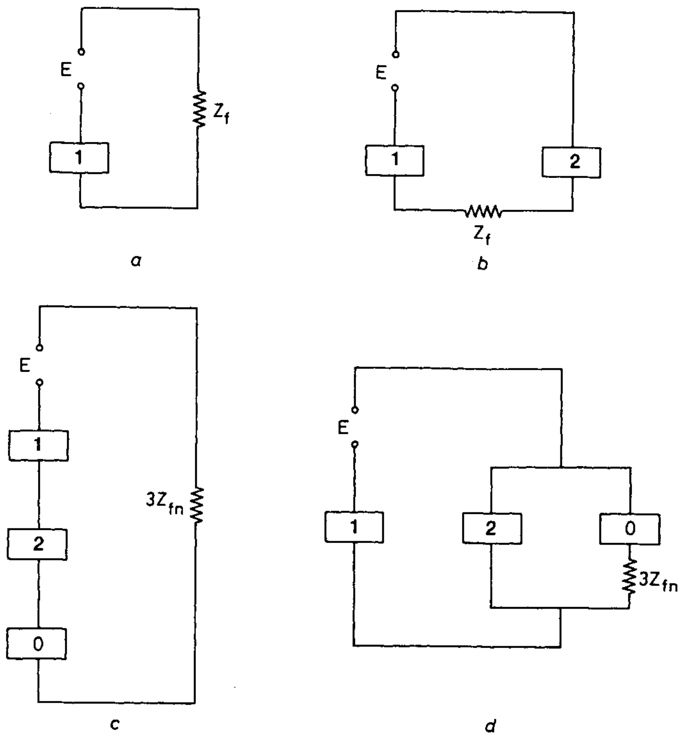

Figure 3.17 *Connection of sequence networks*

a 3-phase fault
b Line–line fault
c Line–earth fault
d Line–line–earth fault

distribution-network fault studies, it may be assumed for simplifying the calculations that overall $\boldsymbol{Z}_2 = \boldsymbol{Z}_1$. From the above formulas the fault current for a line–line fault is $\sqrt{3}/2$ times that for a 3-phase fault at the same point on the network. The relationship for a line–earth fault reduces to $3/(2 + \boldsymbol{Z}_0/\boldsymbol{Z}_1)$, and to $\sqrt{3}(\boldsymbol{aZ}_1 - \boldsymbol{Z}_0)/(2\boldsymbol{Z}_0 + \boldsymbol{Z}_1)$ for a line–line–earth fault.

3.7.2 System sequence impedances

Typical parameters for overhead lines and underground cables are given in Table 3.1 (page 28). The zero-sequence impedance of an overhead line depends on the presence, or otherwise, of a neutral conductor or any earth wire. The zero-sequence reactance of underground cables varies according to the spacing between the conductors, and between each conductor and any metallic sheath or screen.

As the resistive component of large machines is usually so small, the impedances of synchronous machines, including generators, are often quoted as reactance values. The negative-sequence reactance is about 15–25% lower than the positive-sequence value, and approximately equals the subtransient reactance X_{st}. The zero-sequence reactance depends on the winding arrangement and no zero-sequence currents can flow unless at least one generator neutral is earthed in some manner. Typical generator parameters are given in Table 3.2 (page 29).

The transformer zero-sequence impedance is dependent on whether or not the winding arrangements and neutral earthing connections will permit the flow of balancing zero-sequence currents in the windings. Figure 3.18 shows a number of transformer winding arrangements, and the current flows through the windings on the occurrence of a phase–earth fault on the primary or secondary system. Figure 3.18*a* represents a star/star transformer with primary and secondary star points earthed. For an earth fault on the secondary winding, zero-sequence currents are free to flow in both windings. In the delta/star arrangement shown in Figure 3.18*b* zero-sequence currents can circulate in the primary delta winding, balancing the ampere-turns produced by the zero-sequence currents in the secondary star winding.

Figure 3.18*c* covers the case of a star/star transformer with the secondary-winding neutral point earthed, and a delta tertiary winding. Here the tertiary windings provide a path for the circulation of zero-sequence current, and in theory this would not be possible if the delta tertiary winding were absent. In this case the transformer presents a high reactance to the zero-sequence current, of the order of the magnetising reactance. The current will be higher for a 3-leg core-type transformer because of its higher zero-sequence leakage flux compared with a five-leg shell-type transformer.

In the star/delta arrangement in Figure 3.18*d* zero-sequence currents circulate in the delta secondary windings for a primary phase–earth fault, but do not escape into the secondary network. If the neutral point of the auxiliary transformer is connected to earth via an impedance Z_g to limit the earth-fault current on the secondary side, the equivalent zero-sequence impedance of the neutral earthing impedance is $3Z_g$.

3.7.3 Earth faults

When considering earth faults it has so far been assumed that the network was earthed at some of the transformer neutral points, thus completing the earth-fault-current return path. With an unearthed system, or one earthed via an arc-suppression coil, the earth-fault current is small and often lower than the normal load current. Since this fault current is of the order of some tens of amperes it is unlikely to cause damage to lines, cables or other equipment.

Figure 3.19 represents an earth fault on an MV system having an isolated neutral. Here each line is modelled by a separate line–earth capacitance. Isolating all the neutral points on the system from earth causes the zero-phase-

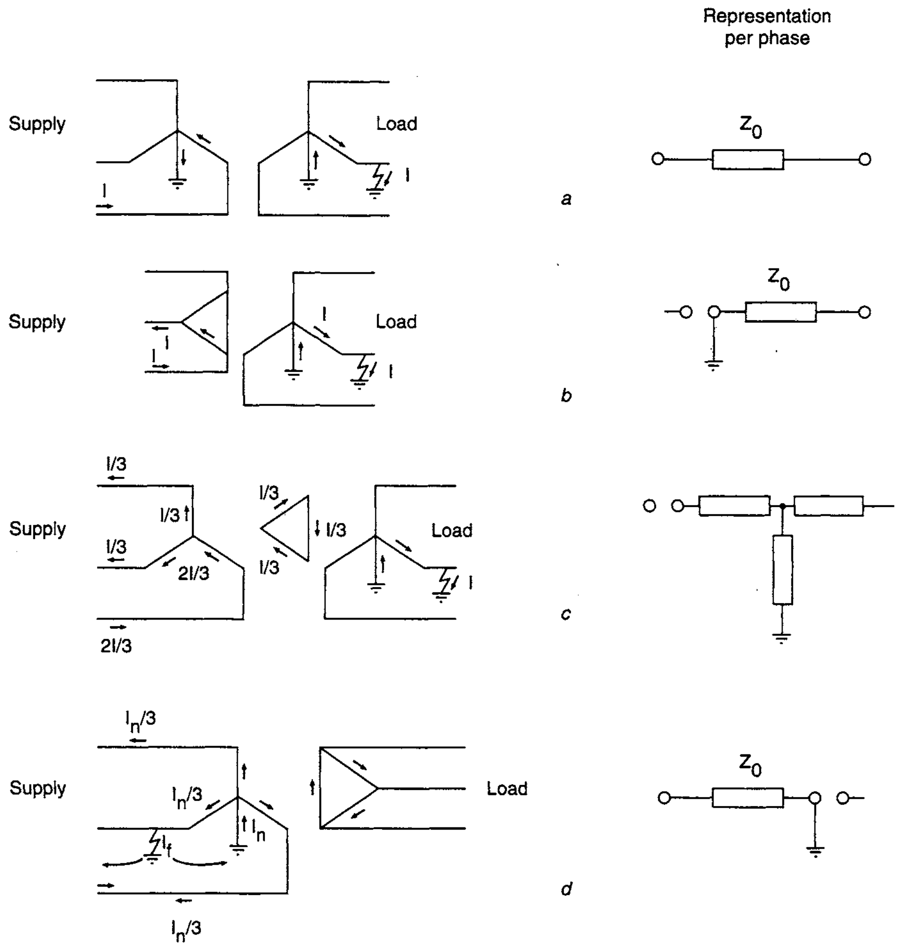

Figure 3.18 Earth-fault current flow for various transformer-winding arrangements

a Zero-sequence currents free to flow in both primary and secondary circuits
b Single-phase currents can circulate in the delta but not outside it
c Tertiary winding provides path for zero-sequence currents
d Single-phase currents can circulate in the delta but not outside it

sequence impedances between any point on the system and earth to appear as infinite. The series impedance of lines and equipment to zero-sequence current is essentially smaller than the shunt impedance represented by the earth capacitances of the lines, and can therefore be omitted. The earth-fault current path is completed via the line capacitances of each phase to earth.

Applying Thévenin's theory the circuit simplifies to Figure 3.20, with node *c* representing the neutral point of the MV winding of the HV/MV transformer. The line impedances have been omitted since they are small compared with that

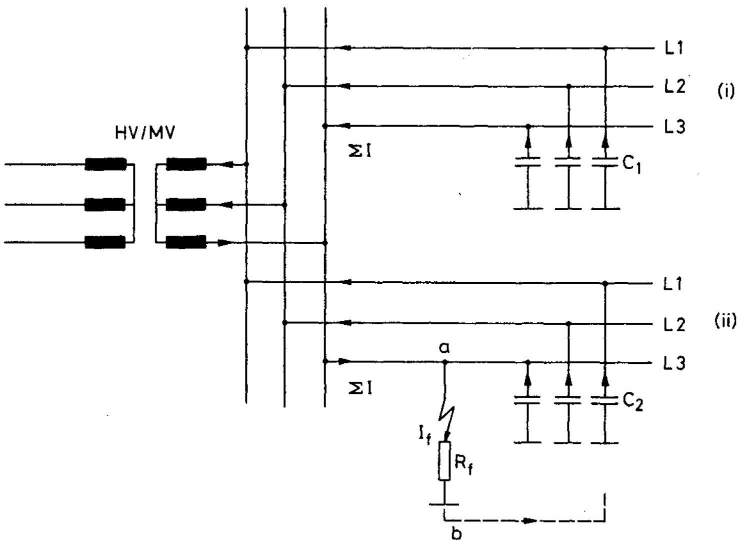

Figure 3.19 Single-phase–earth fault on an isolated system

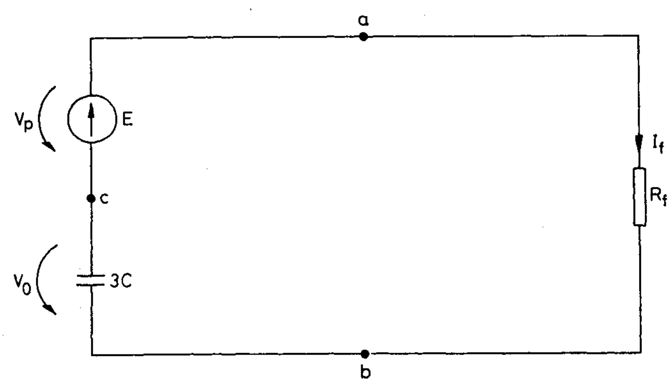

Figure 3.20 Equivalent circuit for the system shown in Figure 3.19

of the total capacitance to earth, 3C. From the equivalent circuit the equations for the earth-fault current $\boldsymbol{I}_f$ and the neutral-point voltage $\boldsymbol{V}_0$ can be determined in terms of the phase–earth $\boldsymbol{V}_p$ voltage before the fault.

$$\boldsymbol{I}_f = \frac{\boldsymbol{V}_p}{R_f + \dfrac{1}{j\,3\omega C}} = \frac{j\,3\omega C}{1 + j\,3\omega C R_f}\,\boldsymbol{V}_p \tag{3.48}$$

$$\boldsymbol{V}_0 = \frac{1}{j\,3\omega C}(-\boldsymbol{I}_f) = \frac{-1}{1 + j\,3\omega C R_f}\,\boldsymbol{V}_p \tag{3.49}$$

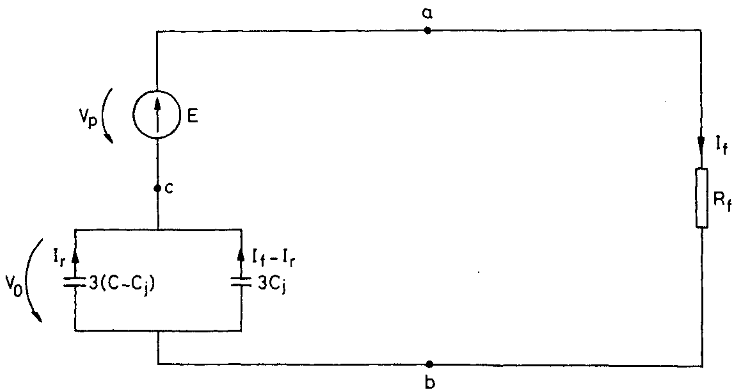

Figure 3.21 Equivalent circuit for Figure 3.19, with the two feeders separately identified

For relay and protection purposes it is essential to be able to determine the magnitude and direction of the fault current I_r in the faulted feeder at the substation. In Figure 3.21 $3C_j$ represents the earth capacitance of the faulted feeder. Equating the expressions for $\boldsymbol{V}_0$ for the two parallel branches in Figure 3.21 gives

$$-\boldsymbol{I}_r \frac{1}{j3\omega(C - C_j)} = -(\boldsymbol{I}_f - \boldsymbol{I}_r)\frac{1}{j3\omega C_j} \tag{3.50}$$

so that

$$\boldsymbol{I}_r = \frac{(C - C_j)}{C}\boldsymbol{I}_f \tag{3.51}$$

The direction of $\boldsymbol{I}_r$ is from the substation towards the faulted feeder.

For systems earthed via a Petersen coil it is necessary to take account of the coil resistance and reactance. Figure 3.22 shows the situation with an earth fault on a system earthed through a Petersen coil, with the equivalent circuit in Figure 3.23.

The inductance of the arc-suppression coil is adjusted so that the inductive current I_L approximately equals the current through the total earth capacitance $3C$. Neglecting feeder load current and system resistance, the phasor diagram for this arrangement is shown in Figure 3.24, with the resistive component of the coil current indicated by I_R. By applying the equivalent circuit of Figure 3.21, the following expressions for the total earth-fault current and neutral-point voltage can be determined as

$$\boldsymbol{I}_f = \frac{\boldsymbol{V}_p}{R_f + \dfrac{R}{1 + jR(3\omega C - 1/\omega L)}} \tag{3.52}$$

and $$\boldsymbol{V}_0 = \frac{-R}{R_f + R + jRR_f(3\omega C - 1/\omega L)}\boldsymbol{V}_p \tag{3.53}$$

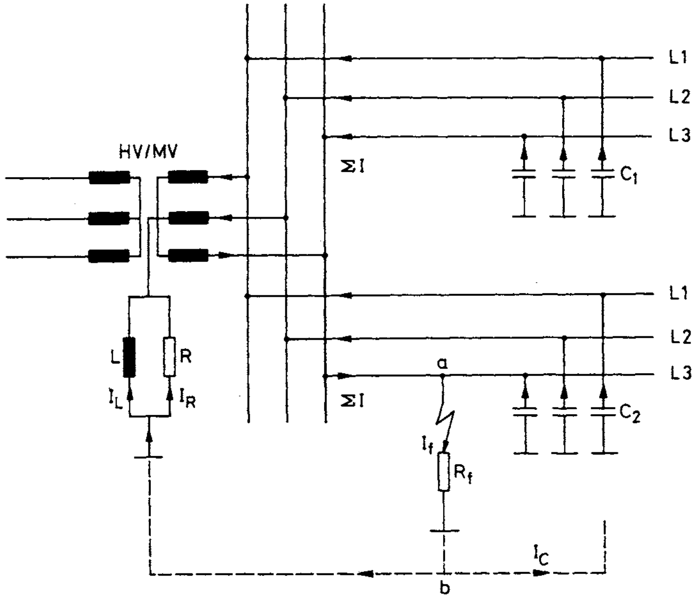

Figure 3.22 Single-phase–earth fault on a system earthed via an arc-suppression coil

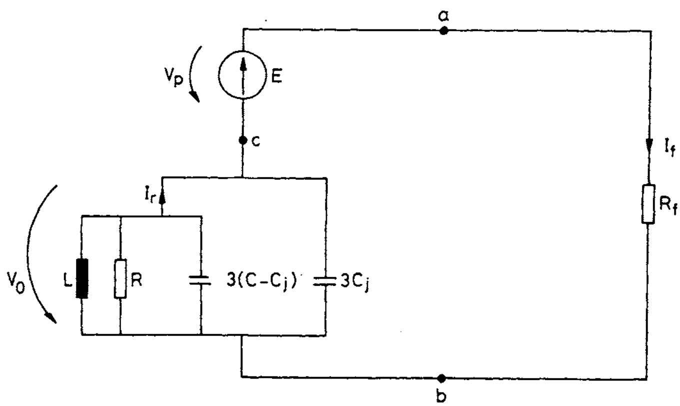

Figure 3.23 Equivalent circuit for the arrangement in Figure 3.22

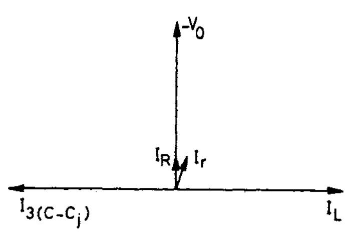

Figure 3.24 Phasor diagram for the Petersen coil

From the foregoing, voltage and current values and phase relationships can be calculated for different types of earth fault to assess stresses imposed on equipment, and for protection discrimination purposes, as in the following example.

An example of a phase–earth fault on a system with isolated neutral compared with one on an earthed system

In a phase–earth fault the three equivalent sequence networks are connected in series, as shown in Figure 3.16c. The magnitude of the zero-sequence impedance thus influences the nature of the earth-fault characteristics of the network. The zero-sequence network is the only one affected by the method of earthing.

The single-line diagram of the network used as an example is given in Figure 3.25. Both cases are calculated for this network, the only difference being that switch K is used to switch in or out the earthing resistor R_y. It is assumed that the 20 kV network supplied from the 110 kV substation is built up of lines having the same impedances and susceptances per unit length. The total length of lines is 200 km and the fault point F is located on line 1 10 km from the substation. The relevant electrical parameters of the system are shown in the figure.

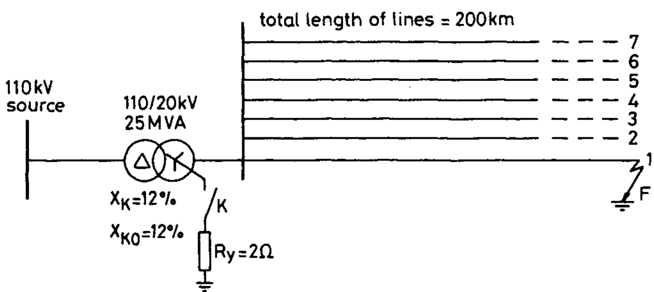

Figure 3.25 Example network for phase–earth fault on an isolated, and an earthed, system

a Isolated system: switch K open
b Earthed system: switch K closed
Source data: $Y' = 233\,\text{ms} \Rightarrow X_1' = 4{\cdot}3\,\Omega$; $Y_2 = 233\,\text{ms} \Rightarrow X_2 = 4{\cdot}3\,\Omega$
Fault point F is 10 km from transformer
Line data: $r = 0{\cdot}54\,\Omega/\text{km}$, $r_0 = 0{\cdot}69\,\Omega/\text{km}$, $x = 0{\cdot}38\,\Omega/\text{km}$
$x_0 = 1{\cdot}52\,\Omega/\text{km}$, $b = 3{\cdot}0\,\mu\text{s/km}$, $b_0 = 1{\cdot}9\,\mu\text{s/km}$, and $l_1 = 10\,\text{km}$

(a) Isolated network

Zero-sequence current cannot flow through the transformer since its neutral point is unearthed, so that calculation of the earth-fault is considerably simplified. 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. This capacitive impedance is some orders of magnitude higher than the positive- and zero-sequence impedances of the lines, which can therefore be neglected. The maximum value of the earth-fault current in the system being considered is thus virtually only dependent on the total capacitance to earth of the lines. This capacitance is proportional to the total line length and is much larger for underground cables than for overhead lines. The location of the fault does not have any significant effect on the magnitude of the fault current.

The earth-fault current in a phase–earth fault, from eqn. 3.48 is

$$\boldsymbol{I}_f = \frac{\boldsymbol{V}_p}{R_f + 1/(j3\omega C_0)} \tag{3.54}$$

where $\boldsymbol{V}_p$ = phase–earth voltage before the fault
$\omega = 2\pi f$ = angular frequency
C_0 = earth capacitance of one phase
R_f = fault resistance

Setting $R_f = 0$ in eqn. 3.54, the maximum value of fault current is given by

$$\boldsymbol{I}_{fmax} = 3\omega C_0 \boldsymbol{V}_p = 3\omega c_0 l \boldsymbol{V}_p = 3B_0 \boldsymbol{V}_p = 3b_0 l \boldsymbol{V}_p \tag{3.55}$$

where c_0 = earth capacitance per kilometre of line
l = total length of lines coupled together galvanically
$B_0 = \omega c_0 l = b_0 l$ = total earth susceptance of one phase
b_0 = earth susceptance per kilometre of line = ωc_0.

Using the values given in Figure 3.25, from eqn. 3.55, the earth-fault current I_{fmax} is

$$\begin{aligned} I_{fmax} &= 3\left[\{(1.9 \times 10^{-6}) \times 200\} \times (20\,000/\sqrt{3})\right] \\ &= 13{\cdot}2\,\mathrm{A} \end{aligned}$$

(b) Earthed system

With switch K closed the earthing resistor R_y provides a return path for the zero-sequence current. In this case the zero-sequence impedance of the transformer is typically about the same as its positive-sequence impedance. Figure 3.26 represents the connection of the three sequence-component networks in series for the phase–earth fault. In the zero-sequence network it will be seen that the resistor is represented as having a value of $3R_y$, and also that the equivalent transformer impedance is connected through that resistor to the reference point

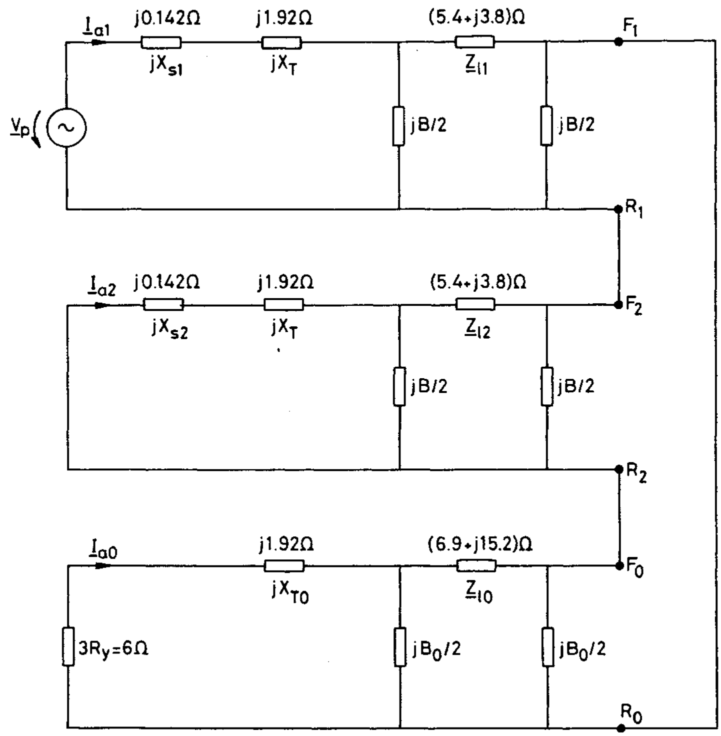

Figure 3.26 Connection of sequence networks for an example of a phase–earth fault on a system with an earthed neutral

$$\boldsymbol{Z}_{l1} = \boldsymbol{Z}_{l2} = l_1(r + jx); \quad B = l_l b;$$

$$X_{s1} = X_1'\left(\frac{V_2}{V_1}\right)^2; \quad X_{s2} = X_{s1}(X_2/X_1')$$

$$\boldsymbol{Z}_{l0} = l_l(r_0 + jx_0); \quad B_0 = l_l b_0; \quad X_{T0} = x_{K0}\frac{V_2{}^2}{S}$$

R. Thus a low-impedance path is provided for the circulation of zero-sequence current, and the impedances of the positive-, negative- and zero-sequence networks are of the same magnitude.

In Figure 3.26 the impedances have been expressed on the same voltage level, i.e. 20 kV. This network has been further simplified to produce the equivalent circuit shown in Figure 3.27 where the susceptances B and B_0 have been neglected without affecting the accuracy of the result to any great extent. Since these susceptances are much smaller than that represented by the transformer earthed through the 2 Ω resistance, the assumption that $B = B_0 = 0$ opens the shunt branches of the equivalent circuit. By way of example, the susceptance $B/2$ corresponds to a reactance of 66 kΩ. The parallel lines 2 to 7 (Figure 3.25)

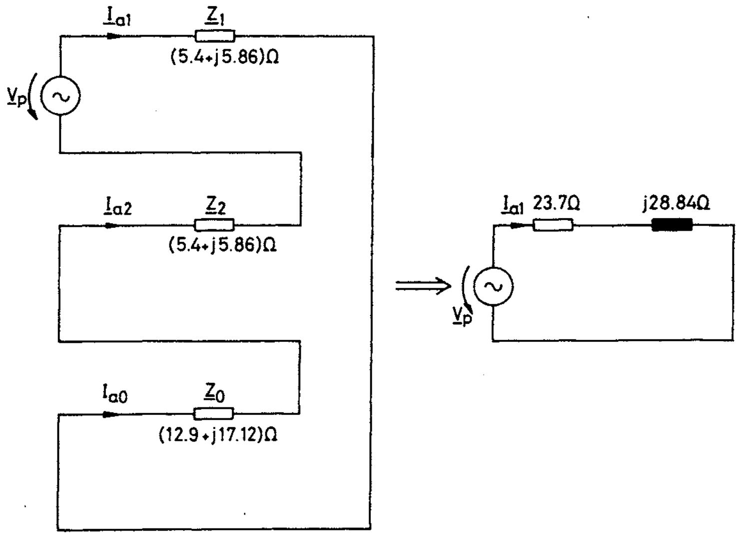

Figure 3.27 Simplified equivalent circuit for Figure 3.26

can now be omitted, and the earth-fault current is then dependent only on the distance of the fault point F from the substation. The zero-sequence impedance of the transformer now provides a low-impedance path for the zero-sequence current.

The earth-fault current can be calculated from eqn. 3.43, taking into account that R_f now is zero:

$$\begin{aligned} \boldsymbol{I}_{a1} &= \frac{20\,000/\sqrt{3}\underline{/0^\circ}}{\{(23{\cdot}7 + j\,28{\cdot}84) + 0\}} \\ &= 309{\cdot}3\underline{/-50{\cdot}6^\circ} \text{ amperes} \end{aligned}$$

From eqn. 3.40 $\boldsymbol{I}_{a1} = \boldsymbol{I}_{a2} = \boldsymbol{I}_{a0}$, and from eqn. 3.34, the phase–earth fault current is

$$\begin{aligned} \boldsymbol{I}_a &= \boldsymbol{I}_{fmax} = \boldsymbol{I}_{a1} + \boldsymbol{I}_{a2} + \boldsymbol{I}_{a0} \\ &= 3\boldsymbol{I}_{a1} = 3(309{\cdot}3)\underline{/-50{\cdot}6^\circ} \\ &= 928\underline{/-50{\cdot}6^\circ} \text{ amperes} \end{aligned}$$

It will be noted that the fault current in a resistance-earthed system is considerably higher than that in the isolated system.

3.8 Overvoltages

The production of overvoltages, and protection against these phenomena, are well researched for UHV and EHV systems, and adequately covered in many other books and papers. In this Section the effects of overvoltages on MV systems relevant to network design will be considered. This involves consideration of insulation levels, overvoltage protection and those system features influencing the production of overvoltages in order to achieve an economic balance. Usually manufacturers are required to meet standards which dictate items such as the test voltages required for MV equipment.

Air gaps, lightning arresters, or in some cases capacitors, are used for protecting the system against overvoltages. In addition, means of limiting the initiation of any overvoltage is available. These policies and equipments are discussed further in Section 7.6. This section will discuss the more important aspects of overvoltage generation on MV systems.

On MV networks, overvoltages produced by atmospheric conditions have a significant impact owing to the relatively low system-voltage level. The average peak value of lightning discharges is about 30 kA. The surge impedance of a medium-voltage line is about 500 Ω, so that a direct strike can cause surges with amplitudes of 7.5 MV to flow in both directions down the line, which can cause flashovers even on wooden poles with unearthed crossarms. Lightning strikes in the vicinity of a medium-voltage overhead line can also produce overvoltages due to electromagnetic and electrostatic induction. A 30 kA strike 100 m away from a line would lead to a surge of almost 100 kV being induced in the line, and these induced voltages form the majority of the recorded overvoltages. When travelling along a line the voltage waves are attenuated and distorted, but, compared with other forms of system overvoltages, these waves have steep fronts, of the order of hundreds of kilovolts per microsecond.

The shape of a standard smooth lightning impulse is given in Figure 3.28. The virtual front time T_1 is defined at 1.67 times the time interval T between the instants when the impulse is 30% and 90% of the peak value (points A and B in the Figure). If oscillations are present on the front, points A and B should be taken on the mean curve drawn through these oscillations. The virtual time to half-value, T_2, of a lightning impulse is the time interval between the virtual origin and the instant on the tail when the voltage has decreased to half the peak

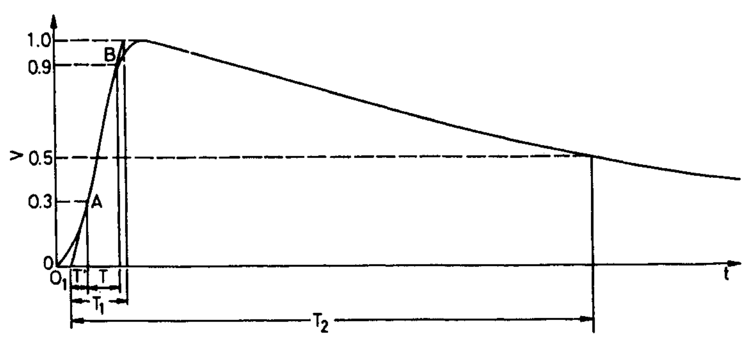

Figure 3.28 Lightning-impulse waveform

value. The standard test-voltage lightning impulse is a full lightning impulse having a virtual front time of 1·2 µs, and a virtual time to half value of 50 s, both within a given tolerance. If the surge voltage V_1 travels along a line with surge impedance $Z_1 = \sqrt{(L_1/C_1)}$, where L_1 and C_1 are the inductance and capacitance of that line, and arrives at a point where the surge impedance changes to Z_2, then the transmitted onward surge voltage V_2 is given by

$$V_2 = \frac{2Z_2}{Z_1 + Z_2} V_1 \tag{3.56}$$

The major increase in the transmitted surge is where Z_2 is considerably greater than Z_1. Thus if an overhead line feeds direct to a transformer having a surge impedance of several thousand ohms, then, from eqn. 3.56, the voltage surge introduced into the transformer will be almost twice the surge transmitted along the line. The appropriate method of protection is highly dependent on the local keraunic level, based on the average annual number of lightning strikes on a given area, which can vary by a factor of 100:1 for different regions of the world.

As well as externally produced overvoltages, transient or short-lived overvoltages can be produced within a network; for example due to a switching operation or a fault on the network. Owing to the system parameters, on MV systems such overvoltages may not reach the high values associated with lightning-induced overvoltages.

Earth faults may cause overvoltages between a healthy phase and earth. The maximum value of the earth-fault current $\boldsymbol{I}_f$ for a system in which the neutral points are isolated is obtained from eqn. 3.48 as

$$\boldsymbol{I}_f = -j\,3\omega C \boldsymbol{V}_p \tag{3.57}$$

where $\boldsymbol{V}_p$ is the highest phase–earth voltage.

The scalar value of the neutral-earth voltage V_0 is given by

$$V_0 = \frac{1}{\sqrt{\left\{1 + (3\omega C R_f)^2\right\}}} V_p \tag{3.58}$$

Thus

$$V_p^2 = V_0^2 + V_0^2 (3\omega C R_f)^2 \tag{3.59}$$

Eqn. 3.59 is the equation for a circle and, using eqns. 3.57 and 3.59, the phasor diagram shown in Figure 3.8 can be constructed. The Figure illustrates that, if the fault impedance is zero, the phase–earth voltage can have a value $\sqrt{3}$ times the normal voltage, and some fault-resistance values may even lead to slightly higher values of overvoltage.

In systems where the neutral points are earthed directly or via a small impedance overvoltages may occur during faults, but these are usually smaller than for the isolated neutral system described above. The maximum value of overvoltage depends on the ratios between different component resistances and reactances on the system as seen at the fault point. Figure 3.29 sets out

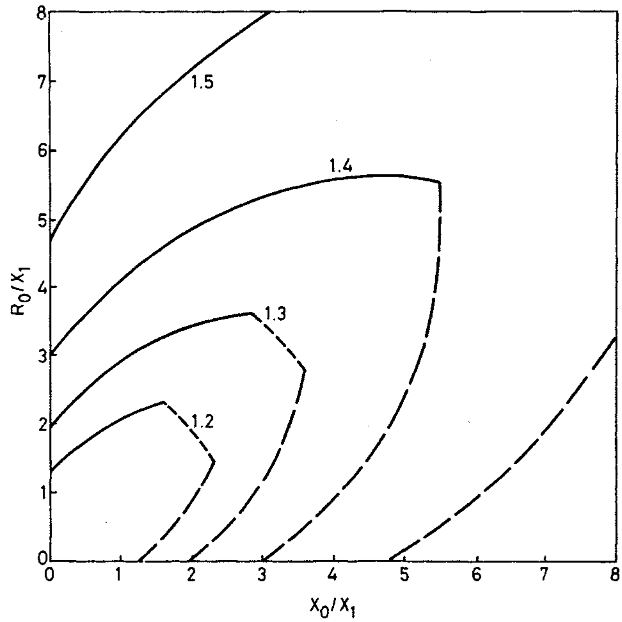

Figure 3.29 *Maximum value of the earth-fault coefficient V/V_p with varying network parameters*

graphically the dependence of the maximum value of the *earth-fault coefficient* V/V_p with varying network parameters.

In Figure 3.29 it has been assumed that the ratio between system resistances and reactances to the fault is given by $R_1 = R_2 = X_1$. The numbers on the curves indicate the maximum phase–earth voltage of any phase for any type of fault, in per-unit values of the nominal phase–earth voltage. In producing these curves the effect of fault resistance has been taken into account, using the value which results in the maximum voltage to earth. The discontinuity in the curves is caused by the effect of a change in the type of fault being assessed. The acceptable operating area, to avoid excessive high voltages being present on a network, is between the appropriate curve for the maximum acceptable per-unit ratio of V/V_p and the x and y axes.

The individual resistances and reactances which influence the maximum overvoltage are associated with the type of earthing, the network components, the transformer primary–secondary winding arrangements and the network configurations. Networks where the earth-fault coefficient is lower than 1·4 are called 'effectively earthed'. With the assumptions of Figure 3.29 that requirement is met if $X_0/X_1 \leqslant 5{\cdot}5$ and $R_0/X_1 \leqslant 5{\cdot}5$. In partially earthed networks, where only some of the star points are earthed, the earth-fault coefficient is approximately 1·7, which means that the maximum phase–earth overvoltage can reach the level of the system phase–phase voltage.

Under certain resonant conditions internal overvoltages can be produced within a network. For normal system arrangements the system capacitances and inductances do not result in series resonance at 50 or 60 Hz. However, in exceptional fault conditions at time of low load, such resonance is possible. For example, when one phase conductor is broken, the line capacitances and the no-load impedance of a transformer may produce resonance at harmonic frequencies, resulting in overvoltages.

Further examples of resonant overvoltages are ferroresonance and jump resonance. Ferroresonance can occur when a transformer is energised via a lightly loaded, i.e. capacitive, circuit. The inrush magnetising current contains a series of harmonics, one of which may cause resonance between the circuit capacitance and the transformer inductance. For a voltage transformer connected to an unearthed system, the resonant circuit may be formed by the earth capacitance of the system and the non-linear inductance of the voltage transformer connected between phase and earth. Owing to the nonlinearity effect the inductance can operate at a lower impedance under certain conditions, giving resonant conditions at the basic frequency, or multiplies or subharmonics. At resonance the voltages and currents may jump from one state to the other, thus resulting in the term 'jump-resonance', and current overloading of the voltage transformer, leading to thermal damage, may occur. Modern voltage-transformer construction techniques and the use of suitable damping resistors effectively inhibit these types of overvoltages.

The various arrangements used to protect system equipment against damage from overvoltages are described in Section 7.6.

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Chapter 4

Reliability

4.1 General

Reliability is an essential factor with regard to the quality of supply. The main factors used to judge reliability of supply to customers are the frequency of interruptions, the duration of each interruption and the value a customer places on the supply of electricity at the time that the service is not provided. These factors depend on variables such as the reliability of individual items of equipment, circuit length and loading, network configuration, distribution automation, load profile and available transfer capacity. Associated aspects are referred to in Chapters 7, 9 and 14.

Reliability analysis can be used to evaluate the reliability of individual system configurations – not only to compare relative levels of reliability, but also to assess the costs of providing a particular level of reliability. Cost/benefit studies then enable a decision to be made on whether to adopt a specific configuration to solve an individual problem. They can also be used to formulate policy decisions on the level of reliability to be afforded to groups of customers, or to support a given load level, for example.

4.2 Reliability investment appraisal

In many regions of the world customers have come to expect a high level of reliability to their supplies. The value to customers is determined by the benefits which they can derive from using it; e.g. the production of goods, lighting and heating at home and in shops and offices, improvement in their standard of living and the use for entertainment purposes in theatres, cinemas etc. Consequently their valuation of financial losses incurred owing to failure of supply will be based on this loss of usefulness and the timing of such loss, rather than upon the charges they pay for a unit of electricity. This valuation should reflect not only the direct effect of any loss of supply such as loss of production whilst having still to meeting employees' salaries and business overheads and the resultant direct loss of profit, but also secondary effects such as a lack of return on investment.

A customer receives a supply via low-, medium- and high-voltage networks. The reliability of this supply depends on the reliability of the component parts of each network supporting the customer, and on the configurations of the networks and the ability to provide back-up supplies under outage conditions. When a utility invests in order to improve the reliability of supply it does this for the benefit of customers, and the cost is passed on to them as a component of the electricity bill. In making any 'incremental reliability investment', the aim of the utility should be to match its marginal costs of preventing loss of supply to the marginal benefit consequently obtained by customers. In practice, investments on supply networks are seldom justified on a single factor such as reliability, but costs, such as investment, losses, maintenance and energy not supplied, all need to be considered when assessing various investment options.

Reference has already been made in Chapter 1 to the fact that, whilst customers would like total reliability and never to lose supply even for a brief period, technically and financially this would be an impossible target for supply authorities. Thus if a customer requires a virtually 100% secure supply, e.g. at a hospital or a complex computer installation, it may have to consider providing its own back-up supplies, such as by in-site generation, in order to secure some or all of the load against total loss of the electricity supply. Such an arrangement may be cheaper than requiring a sufficient number of electricity-supply infeeds from different substations in order to reduce the likelihood of total loss of the electricity supply to a very small value.

While each component added to the network can increase the network capability and may reduce system losses, the new component is also subject to failure. The necessary statistical information to determine the average failure rate of each component, and its down time due to repair and maintenance, is usually based on data collected, and averaged, over a number of years. This requires an efficient fault-recording system listing such facts as the time and location of each fault, which component in an item of equipment failed, possible cause of failure, the age of the component, any previous failures on the component and the influence of external factors such as weather, and the action of third parties such as utility staff, the general public and animals and birds. Regular updating of the long-term average fault-data information is necessary to take account of factors such as any improvements achieved in maintenance procedures, and the effects of removing from the system equipment which is prone to failure.

Some method of relating the net cost of the work involved to any improvement in reliability is a useful guide to the value and timing of such investments. One easy way to do this is to note that the costs of the power and energy not supplied can be directly related to the total costs of reinforcing the system. This would require that the summation of the associated costs, i.e. $C = \sum(C_i + C_l + C_m + C_o)$, should be minimised when planning the reinforcement scheme, where suffixes i, l, m and o refer to the costs of investments, losses, operation and maintenance, and outages, respectively.

An alternative approach is to determine a cost/benefit ratio, with the total costs associated with any project being calculated on an annual basis. These can be expressed as:

$$C = C_a + C_m - C_e \tag{4.1}$$

where C = total costs

C_a = capital component of bringing forward the work by one year to achieve reduced NDE

$$= \frac{C_c \times (p/100)}{1 + p/100} \tag{4.2}$$

p = annual interest rate

C_m = annual cost of maintaining and operating the network extension

C_e = reduction in the annual cost of system power and energy losses

C_c = the capital cost of the project

If the annual amount of non-distributed energy is reduced by W as a result of the network reinforcement, the cost/benefit ratio can be defined as $(C_a + C_m - C_e)/W$. This ratio has units of cost for each kWh improvement in non-distributed energy per annum. The lower its value the more justified is the proposed capital investment.

Table 4.1 Calculation of cost of non-distributed energy per annum

	Year 1	Year 2	Year 3	Year 4
1 Non-distributed energy; present system, MWh	5·05	10·48	15·00	17·20
2 Non-distributed energy; proposed system, MWh	0·12	0·18	0·21	0·23
3 Saving in non-distributed energy = (1) − (2), MWh	4·93	10·30	14·79	16·97
4 Annual capital charge, C_a, £	9090	9090	9090	9090
5 Operation & maintenance costs, C_m, £	2000	2000	2000	2000
6 Reduction in system losses, C_e, £	190	250	260	280
7 Net annual cost = (4) + (5) − (6), £	10900	10840	10830	10810
8 Cost per kWh saved = (7) ÷ {(3) × 1000}, £/kWh	2·21	1·05	0·73	0·64

Table 4.1 summarises a cost/benefit exercise carried out to determine the cost per kWh saved. The capital cost of the proposed scheme is £100 000. From eqn. 4.2, using an annual interest rate of 10%, the annual capital charge C_a is (£100 000 × 0·1)/(1 + 0·1), say £9090. Operation and maintenance costs are assumed to be 2% of the capital cost. The non-distributed energy with the existing system is shown in line 1, with line 2 showing the lower value of NDE obtained with the proposed system reinforcement, resulting in the reduction in NDE given in line 3. The estimated saving in the cost of system losses with the proposed reinforcement is given in line 6. The annual cost of the scheme is therefore as shown in line 7, giving the cost per kWh saved as line 8.

It is necessary to adopt a threshold value for this cost/benefit ratio below which schemes are considered to be justified, and above which they are not justified. In the example in Table 4.1 if the threshold value was £1/kWh saved, the proposed reinforcement would hardly be justified in year 2 but would be well justified in year 3.

The value given to non-distributed energy, or 'energy not supplied', is not its cost, or the profit margin and interest charges included in its cost, but its value to the user when it is not available – in theory how much customers would pay in an emergency to have supply restored. Studies carried out internationally have shown that there are wide differences between the prices that individual customer groups put on the value of non-distributed energy, as shown in Figure 1.7. It is therefore difficult to assign a precise single threshold value for all customers. Various options are available, but in the end the threshold value will be a matter of judgment for any supply utility.

Additionally, such a cost/benefit assessment could take account of the savings obtained in kW not supplied, as well as the savings in energy not supplied, as considered in the example above. The cost/benefit equation could then be of the format $(C_a + C_m - C_e)/(aW + bP)$, where P is the saving in kW not supplied and a and b are coefficients, their values being dependent on the importance customers place on both the amount of load lost and the length of time they are without supply.

For some specific customers having a low power demand for their appliances, e.g. a computer installation or a radio transmitter, the factors a and b may have extremely high values. In addition, when modelling the inconvenience due to very short outages, the energy involved is not a relevant factor.

4.3 Basic reliability theory

4.3.1 Components

Every component in a power system has an inherent risk of failure. In addition, outside factors influence the possibility of component failure; e.g. the current loading of the component, damage by third parties (human and animal), trees and atmospheric conditions – temperature, humidity, pollution, wind, rain, snow, ice, lightning and solar effect.

Given that λ_i is the average outage rate, and r_i the average outage duration of a component i, the expected annual outage time U_i is given by

$$U_i = \lambda_i r_i \tag{4.3}$$

One of the main assumptions in developing the following theory and associated equations is that failures of individual components are independent of each other. When carrying out reliability calculations it is essential that the units used for λ, r and U are compatible. Thus, for example, λ would be quoted in units of per annum, r in hours and U as hours per annum.

4.3.2 Radially operated systems

In the quantitative reliability analysis of a distribution system, the most important factors are the expected outage rates and times, and hence the outage demands and energies for individual customers and their total value for a specified network alternative. The latter implies a certain configuration and combination of network components based on a defined operation and maintenance policy.

An electrical circuit is composed of a number of components, such as lines, cables, transformers, circuit breakers, disconnectors etc. The solution is aimed primarily at estimating the influence of the unavailability of each component on the outages at each customer. Both the reliability data for the components used, and their location in relation to the paths from the feeding points to the customers, must be taken into account. For radially operated meshed networks, the relatively simple formulas in eqns. 4.4–4.7 can be used to calculate the reliability indices for a given load point j when considering failures. In studies of medium voltage networks, a load point involves those customers fed by a particular distribution substation. The calculation parameters considered here are their average or expected values. In deriving these formulas it is also assumed that outage periods are much shorter than the mean time between outages.

The average outage rate or the number of outages per year for the load j is given by

$$\lambda_j = \lambda_1 + \lambda_2 + \ldots \lambda_i + \ldots \lambda_n = \sum_{i \in I} \lambda_i \tag{4.4}$$

where λ_i is the failure rate of component i (per year), and I is the set of the components whose failure results in an outage at the given load point j.

The expected annual outage time, sometimes referred to as 'unavailability', is given by

$$U_j = \sum_{i \in I} \lambda_i t_{ij} \tag{4.5}$$

where t_{ij} is the outage time at the given load point j caused by a failure of component i(h).

The average outage duration is then given by

$$r_j = U_j/\lambda_j \tag{4.6}$$

Outages occurring on a power system could result in some loss of the electrical energy being supplied. This load is usually termed 'energy not supplied' or 'non-distributed energy' (NDE), and is given by

$$E_j = \lambda_j r_j P_j \tag{4.7}$$

where P_j is the outage power at the load point j.

The costs of the power and energy not supplied are given by

$$C_j = \sum_{i \in I} \lambda_i \{a_j(t_{ij}) + b_j(t_{ij})\, t_{ij}\} P_j \tag{4.8}$$

where $a_j(t_{ij})$ and $b_j(t_{ij})$ are the per-unit cost values for the demand and energy not supplied for the load point j when the outage time is t_{ij} (e.g. £/kW and £/kWh).

For permanent failures, the outage times t_{ij} caused by a given component can include either equivalent switching times or repair time. At the end of the switching time the faulty component is isolated and the supply is restored to the given load point. The repair time is the time from failure until the supply is restored by repairing or by replacing the faulty component.

The equivalent switching time caused by any component depends on how the faulted component, the load point, network protection, locally and remote controlled disconnectors, and reserve connections are situated in relation to each other.

Seasonal variations and correlations between loads, failure rates, outage durations etc. can also be taken into the account by calculating each season separately or by considering respective correlation factors.

The formulas for temporary failures and maintenance outages are basically similar to those outlined above. Only the reliability and cost data are different.

4.3.3 Parallel or meshed systems

For two circuits or components in parallel, the outage rate due to overlapping outages on parallel circuits λ_p is given by

$$\lambda_p = \lambda_1 U_2 + \lambda_2 U_1 \tag{4.9}$$

which from eqn. 4.3 can be written as

$$\lambda_p = \lambda_1 \lambda_2 (r_1 + r_2) \tag{4.10}$$

For two circuits or components in parallel the average outage duration r_p is

$$r_p = \frac{r_1 r_2}{r_1 + r_2} \tag{4.11}$$

To enable outage rates to be calculated, the outage rate λ_i and average outage duration r_i are required for each component. These are usually average values based on a long-term collection of fault information.

The outage rate λ_{ff} due to a fault occurring on a circuit during the duration of a fault on a parallel circuit is obtained from eqn. 4.9, i.e.

$$\lambda_{ff} = \lambda_1 U_2 + \lambda_2 U_1 \tag{4.12}$$

Should a fault occur on one circuit while another circuit is out of service for maintenance, it is usual to return the maintained circuit back to service as soon as possible. Let urgent restoration time be denoted by the suffix u; suffix f refers to the fault situation; suffixes 1 and 2 refer to the two circuits; suffix a refers to the period of time when a circuit can be released for maintenance from a system operational point of view; while suffix m refers to the period of time when maintenance is carried out. The outage rate due to a fault occurring on one circuit during maintenance on a second circuit λ_{fm} is given by

$$\begin{aligned}\lambda_{fm} &= \lambda_1 U_{m2} + \lambda_2 U_{m1} \\ &= \lambda_1(\lambda_{m2} r_{m2}) + \lambda_2(\lambda_{m1} r_{m1})\end{aligned} \tag{4.13}$$

and the relationship for the expected annual outage time U_{fm} is

$$U_{fm} = \lambda_1(\lambda_{m2} r_{m2}) \frac{1}{(1/r_{a2} + 1/r_{u1})} + \lambda_2(\lambda_{m1} r_{m1}) \frac{1}{(1/r_{a1} + 1/r_{u2})} \tag{4.14}$$

from which

$$U_{fm} = \frac{(\lambda_1 \lambda_{m2} r_{m2} r_{a2} r_{u1})}{(r_{a2} + r_{u1})} + \frac{(\lambda_2 \lambda_{m1} r_{m1} r_{a1} r_{u2})}{(r_{a1} + r_{u2})} \tag{4.15}$$

Where there are no back-up supplies, a fault will result in the same outage time for all customers, since the reconnection time equals the repair time plus reswitching time. If back-up supplies are available, the interruption times to various customers can be different, owing to the different reconnection times for each back-up route.

In many outage situations some load may be lost, but it is possible to restore some of the lost load by switching and reconfiguring the network. In general, a given network will be supplied by a number of circuits, and there will also be some interconnection at a lower voltage to neighbouring networks, supplied from other supply points. The amount of lower-voltage transfer capacity available between the different networks will depend on the network operating arrangements and the loadings on the various networks.

The annual outage time for those loads which can be transferred to other networks after a fault is

$$U_t = \lambda_t t \tag{4.16}$$

where t is the time taken to transfer part of the load by switching and λ_t is the average annual outage rate for those loads restored by transfer switching under emergency outage conditions.

The basic approach presented relates to a process involving independent outages between components. Although this might be generally sufficient for radial networks, it can frequently be extended to cope with more complex failure/restoration processes when meshed systems are considered. In addition, more complicated reliability calculation techniques are sometimes needed. The analysis requires a thorough understanding of how each load point can actually lose supply and how the supply can be restored. Also, for example, the effect of overloading of parallel circuits might have to be considered. Only some of the principal aspects are discussed briefly below, and more detailed techniques can be found in the Bibliography at the end of this Chapter.

Weather conditions can have a significant influence on the failure rate of equipment, especially on overhead lines. This influence increases the possibility of overlapping outages of two or more components, but can be taken into account by using, for example, a so-called two-state weather model. Also a common-mode outage can occur when a single failure causes the simultaneous outages on two or more components, and this mechanism can have a significant influence on the behaviour of the system.

4.4 Reliability calculation example

Most distribution systems are radial systems or, if meshed systems are constructed, they are operated as radial systems by using normally open points in the mesh. For this reason the network chosen as an example for the following reliability calculations, and shown diagrammatically in Figure 4.1, is a radial system.

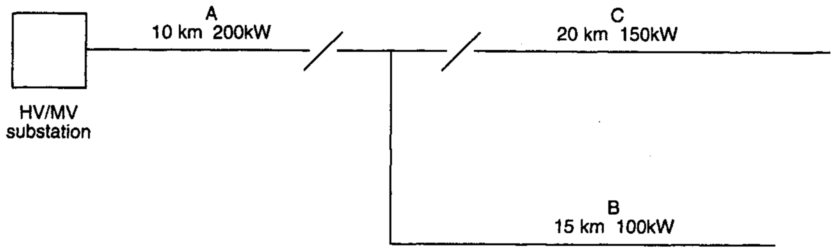
By way of example Figure 4.1a shows one MV feeder supplied from an HV/MV substation. In Figure 4.1b a backup circuit from a neighbouring substation is available. The system is divided into three sections A, B, and C, as shown. The target is to calculate the expected annual outage time and outage costs for customers in the different sections and for the whole system.

The following assumptions have been made:

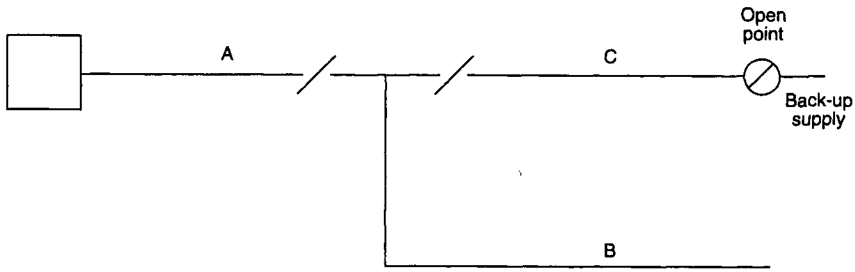
(i) the risk of failure is approximately proportional to the length of line, and failure rate is 0·07 per km per annum
(ii) the outage cost parameters are £0·6/kW and £3/kWh
(iii) the switching time is 1 hour and the repair time is 3 hours.

The solution:

Reliability indices can be evaluated using the principles of a series system. The expected annual outage time U can be calculated from eqn. 4.5, and outage costs C from eqn. 4.8. The values of U and C for each load section caused by faults on the different sections have been calculated separately and are shown in



a



b

Figure 4.1 Example network for reliability calculation

Table 4.1 Results for basic radial system (Figure 4.1a)

Load section	Fault section	λ_i (1/year)	t_{ij} (h)	U_j (h/year)	$\lambda_i(a + bt_{ij})P$ (£/year)	C (£/year)
A	A	0·7	3	2·1	0·7(0·6 + 3 × 3)200 =	1344
	B	1·05	1	1·05	1·05(0·6 + 3 × 1)200 =	756
	C	1·4	1	1·4	1·4(0·6 + 3 × 1)200 =	1008
	Subtotal	3·15		4·55		3108
B	A	0·7	3	2·1	0·7(0·6 + 3 × 3)100 =	672
	B	1·05	3	3·15	1·05(0·6 + 3 × 3)100 =	1008
	C	1·4	1	1·4	1·4(0·6 + 3 × 1)100 =	504
	Subtotal	3·15		6·65		2187
C	A	0·7	3	2·1	0·7(0·6 + 3 × 3)150 =	1008
	B	1·05	3	3·15	1·05(0·6 + 3 × 3)150 =	1512
	C	1·4	3	4·2	1·4(0·6 + 3 × 3)150 =	2016
	Subtotal	3·15		9·45		4536
					Total =	9828

Table 4.1, from which it will be seen that the annual outage times for the three different zones are 4·55 h, 6·65 h and 9·45 h, with the total costs of outages being £9828 per annum.

Let us then consider the possibility of arranging backup connection. This produces the results shown in Table 4.2. In this case the reliability indices of sections B and C are improved while those for section A remain unchanged. The difference compared with the situation without backup connection is £1995/year.

Table 4.2 Results for radial system with a backup connection (Figure 4.1b)

Load section	Fault section	λ_i (1/year)	t_{ij} (h)	U_j (h/year)	$\lambda_i(a+bt_{ij})P$ (£/year)	C (£/year)
A	A	0·7	3	2·1	$0{\cdot}7(0{\cdot}6+3\times 3)200=$	1344
	B	1·05	1	1·05	$1{\cdot}05(0{\cdot}6+3\times 1)200=$	756
	C	1·4	1	1·4	$1{\cdot}4(0{\cdot}6+3\times 1)200=$	1008
	Subtotal	3·15		4·55		3108
B	A	0·7	1	0·7	$0{\cdot}7(0{\cdot}6+3\times 1)100=$	252
	B	1·05	3	3·15	$1{\cdot}05(0{\cdot}6+3\times 3)100=$	1008
	C	1·4	1	1·4	$1{\cdot}4(0{\cdot}6+3\times 1)100=$	504
	Subtotal	3·15		5·25		1767
C	A	0·7	1	0·7	$0{\cdot}7(0{\cdot}6+3\times 1)150=$	378
	B	1·05	1	1·05	$1{\cdot}05(0{\cdot}6+3\times 1)150=$	567
	C	1·4	3	4·2	$1{\cdot}4(0{\cdot}6+3\times 3)150=$	2016
	Subtotal	3·15		5·95		2961
					Total =	7833

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Chapter 5
Economic principles

5.1 Introduction

Asset management is a key issue in network business. It is essential in network desing to consider not only the technical aspects but also the associated economics, since decisions based on both technical and economic assessments can have a significant impact on the financial stability of the utility. The necessary economic studies are normally an integral part of the overall appraisal carried out by the planning engineer.

Since the majority of customers are supplied at low voltage a considerable proportion of a utility's annual investment will be required for the connection of low-voltage customers and reinforcement of the MV and LV networks. The necessary work will generally take only a short time from planning through to commissioning, usually less than one year when cables and equipment to common standards are used. An assessment of various options may be based on the *capital investment costs* alone if the additional network capacity provided by each option is comparable, and if system losses and maintenance costs are effectively the same. Where loss and maintenance costs are not the same it is necessary to carry out an individual appraisal for each option. This usually involves consideration of the *costs of losses*, the expected *maintenance costs*, and *outage costs* based on the loss of demand and energy during supply interruptions.

In many cases, working to design procedures which have been determined by economic appraisals associated with the choice of standard cables and other equipment is in practice a more appropriate means of taking account of the most relevant cost components, as well as the technical aspects. However, when considering various options of major system reinforcements or extensions involving expenditure or income over a period of time, some other method of economic assessment is required which takes account of the *timing* of these items. Economic studies are also essential when determining acceptable network tariffs or the market value of a company.

5.2 Present worth

It is generally accepted that it is better to hold a sum of money now rather than have the money at some time in the future. This is because money held elsewhere may be unavailable in the future or inflation will make the money worth less in real terms of purchasing power. Also money available now could be invested to realise a greater sum in the future. The present-worth, or present-value, concept takes account of only the last of the above mentioned three factors. The method converts all cash flows to equivalent amounts at a common date which need not necessarily be the present time, based on a given interest rate. A sum of money S_0 invested at an interest of $p\%$ per annum will produce S_t at the end of t years in accordance with the formula

$$S_t = S_0(1 + p/100)^t$$

or

$$S_0 = S_t \frac{1}{(1 + p/100)^t} \qquad (5.1)$$

In eqn. 5.1 the term $1/(1 + p/100)^t$ is the *present worth factor* used to obtain the present-day value S_0 of a sum of money S_t available at year t in the future at an annual interest rate of $p\%$. Table 5.1 provides examples of present worth factors for six different interest rates over a number of years. More detailed lists can be found in accountancy-type textbooks.

An example of the use of present-worth assessment is set out in Table 5.2, where the various costs associated with two network investment options are considered. The capital investment for each year is shown in column 2, followed by the annual system losses and annual maintenance costs. The net cash flow in each year is the sum of these three costs. Here the usual accountancy practice has been used whereby capital expenditure and other outflows are recorded as negative, with any benefits and inflows being positive. Using an interest rate of 5% the present-worth factors in column 6 are used to derive the present worth of the costs of each year. It is assumed that the capital expenditure of both option A and option B results in the same annual loss and maintenance costs after year 10.

With option A capital expenditure is deferred, resulting in increasingly higher annual system losses and routine maintenance costs. With option B, system losses and maintenance expenditure are reduced as new equipment replaces old equipment in the earlier years. It is common practice to consider that the initial capital expenditure is made in year 0 using a present-worth factor of 1·00, and that annually recurring income or expenditure such as the cost of system losses or routine maintenance should commence in year 1, as illustrated in Table 5.2.

From the example in Table 5.2 over a ten-year period, using the appropriate present-worth factors for a 5% interest rate, on a pure net cash cost basis

Table 5.1 Present-worth factors for various annual interest rates

Year	Annual interest rate, p%					
	5	7.5	10	12.5	15	20
0	1·000	1·000	1·000	1·000	1·000	1·000
1	0·952	0·930	0·909	0·889	0·870	0·833
2	0·907	0·865	0·826	0·790	0·756	0·694
3	0·864	0·805	0·751	0·702	0·658	0·579
4	0·823	0·749	0·683	0·642	0·572	0·482
5	0·784	0·697	0·621	0·555	0·497	0·402
6	0·746	0·648	0·564	0·493	0·432	0·335
7	0·711	0·603	0·513	0·438	0·376	0·279
8	0·677	0·561	0·467	0·390	0·327	0·233
9	0·645	0·522	0·424	0·346	0·284	0·194
10	0·614	0·485	0·386	0·308	0·247	0·162
11	0·585	0·451	0·350	0·274	0·215	0·135
12	0·557	0·420	0·319	0·243	0·187	0·112
13	0·530	0·391	0·290	0·216	0·163	0·093
14	0·505	0·363	0·263	0·192	0·141	0·078
15	0·481	0·338	0·239	0·171	0·123	0·065
16	0·458	0·314	0·218	0·152	0·107	0·054
17	0·436	0·292	0·198	0·135	0·093	0·045
18	0·416	0·272	0·180	0·120	0·081	0·038
19	0·396	0·253	0·164	0·107	0·070	0·031
20	0·377	0·235	0·149	0·095	0·061	0·026
21	0·359	0·219	0·135	0·084	0·053	0·022
22	0·342	0·204	0·123	0·075	0·046	0·018
23	0·326	0·189	0·112	0·067	0·040	0·015
24	0·310	0·176	0·102	0·059	0·035	0·013
25	0·295	0·164	0·092	0·053	0·030	0·010
30	0·231	0·114	0·057	0·029	0·015	0·004
35	0·181	0·080	0·036	0·016	0·008	0·002
40	0·142	0·055	0·022	0·009	0·004	0·001

option A is £9600 more expensive than option B. But since the majority of the net cash outflow in option B occurs in the earlier years, then on the present-worth basis, option A is £37410 cheaper and would be the preferred scheme. If the difference between any options were considered to be small, it might be necessary to look at the technical aspects of the options, possibly carry out a sensitivity analysis as described in Section 5.6, or consider other relevant factors as discussed in Section 5.8.

Table 5.2 Present-worth example

(a) Option A

(1) Year	(2) Capital, £10^3	(3) Losses, £10^3	(4) Maintenance, £10^3	(5) Net cash flow, £10^3	(6) Present-worth factor $p = 5\%$	(7) Present worth, £10^3
0	0	—	—	0	1·000	0
1	0	−1·0	−0·5	−1·50	0·952	−1·43
2	0	−1·2	−0·75	−1·95	0·907	−1·77
3	0	−1·4	−0·6	−2·00	0·864	−1·73
4	0	−1·6	−0·6	−2·20	0·823	−1·81
5	−10	−1·9	−0·8	−12·70	0·784	−9·96
6	−40	−2·1	−1·0	−43·10	0·746	−32·15
7	−70	−2·4	−1·0	−73·40	0·711	−52·19
8	−60	−2·6	−0·8	−63·40	0·677	−42·92
9	−20	−1·5	−0·7	−22·20	0·645	−14·32
10	0	−0·8	−0·4	−1·20	0·614	−0·74
Totals	−200	−16·5	−7·15	−223·65		−159·02

(b) Option B

(1) Year	(2) Capital, £10^3	(3) Losses, £10^3	(4) Maintenance, £10^3	(5) Net cash flow, £10^3	(6) Present-worth factor $p = 5\%$	(7) Present worth, £10^3
0	−20	—	–	−20·00	1·000	−20·00
1	−75	−1·0	−0·5	−76·50	0·952	−72·83
2	−80	−1·2	−0·6	−81·80	0·907	−74·19
3	−20	−1·4	−0·6	−22·00	0·864	−19·01
4	−5	−1·05	−0·5	−6·55	0·823	−5·39
5	0	−0·8	−0·4	−1·20	0·784	−0·94
6	0	−0·8	−0·4	−1·20	0·746	−0·90
7	0	−0·8	−0·4	−1·20	0·711	−0·85
8	0	−0·8	−0·4	−1·20	0·677	−0·81
9	0	−0·8	−0·4	−1·20	0·645	−0·77
10	0	−0·8	−0·4	−1·20	0·614	−0·74
Totals	−200	−9·45	−4·6	−214·05		−196·43

From Table 5.2 it will be noted that at the end of the review period the equipment installed under option B would be about five years older than that installed under option A. Where the present-worth values of the options are close, say within 10%, this difference in asset age can be taken into account by determining the *residual value* of the assets of each option at the end of the review period. These aspects are considered further in Section 5.4.

The annual cash flow can often be assumed to be made up of components which can be considered as constant over a number of years, incresing by a fixed percentage each year, or as increasing quadratically. These factors then modify eqn. 5.1 as follows.

If the annual cash flow is a constant S_c,

$$S_0 = S_c(100/p)\{1 - (1/\alpha^t)\} \tag{5.2}$$

where $\alpha = (1 + p/100)$

t = review period in years

When the load and costs increase by a fixed percentage r% each year,

$$S_0 = S_1\gamma(\gamma^t - 1)/(\gamma - 1) \tag{5.3}$$

where S_1 =costs in year 1 and

$$\gamma = (1 + r/100)^2/(1 + p/100)$$

Eqn. 5.2 was obtained from the sum of a geometric series with a multiplier for the ratio of successive terms of $1/\alpha$, and in eqn. 5.3 the multiplier used was γ. Eqn. 5.3 is particularly useful when modelling the costs of outages.

For the situation where costs have a quadrature relationship to the annual load growth r, the variable γ is modified to γ_1, where $\gamma_1 = (1 + r/100)^2/(1 + p/100)$.

This modified version is suitable for loss calculations, particularly when considering the costs of the series, or copper, losses which have a quadrature relationship with loading.

5.3 Discounted cash flow

The example in Table 5.2 indicates one method used to compare schemes on an economic basis at a specified interest rate. However, in this case only capital expenditure and variations in the cost of losses and maintenance were considered. There was no reference to income, so that it was not possible to assess the *rate of return* on the capital employed in order to determine if the option with the lower present-worth value had an acceptable rate of return to the utility.

Both privately owned utilities and state supply authorities need to ensure that projects earn a *required rate of return* (RRR) in order to be considered economically worthwhile. The choice of minimum RRR is usually linked to the actual interest rate paid by a utility on capital borrowed and/or the degree of risk entailed in the project. State-supported authorities generally consider investment in distribution systems as low risk, and may therefore operate at RRRs around 5%. In this context it may be inappropriate to assess the rate of return of installing a supply to a single house, provided that the planning and design arrangements, and any capital contribution from the customer, meet criteria determined on a utility basis. Alternatively the rate of return may be calculated on the costs of providing supplies to a group of houses, again taking account of the expected income from sales of electricity plus the capital contribution from the housing-estate developer. On the other hand, schemes required to meet specific safety requirements, say, may not earn the RRR, and policy criteria on RRR must take account of such schemes.

An alternative method of assessing a project is to determine the *internal rate of return* (IRR). This is defined as the annual interest rate at which the discounted values of the cash inflows and outflows have the same gross present-worth value over a specified period; i.e. it is the discount rate at which the net present worth is equal to zero. It is normal to determine the IRR by an iterative process using various 'test discount rates' as in the following example.

Consider the situation where an investment of £6000 results in various financial benefits. These could be additional income, or savings in maintenance costs, or reduced system losses. In general, the benefits would be a mixture of these sums and the overall benefit for each year is shown under 'cash flow' in item (2) of Table 5.3 over the 10–year period. The present value of the benefits over the period are calculated using present-worth factors based on different test discount rates.

The computation of the calculations to determine the IRR of the above investment is set out in Table 5.3. Using the rules of present-worth practice the investment is allotted to year 0, and the annual benefits to years 1–10. The summation of the present worth of the benefits is compared with the present worth of the investment for each test discount rate. This is calculated as a ratio for expenditure/benefit. The IRR is the test discount rate when this cost/benefit ratio equals unity. The ratios from Table 5.3 are plotted graphically in Figure 5.1. The break-even point is at a test discount rate of 10·54%, which is thus the internal rate of return. A further column in Table 5.3 repeats the calculations at this rate to confirm the IRR. If the required rate of return is 8% then the expenditure of £6000, given the financial benefits quoted, is justified.

Such studies are amenable to desk-top-computer calculation. Subroutines can calculate the present-worth of salaries, system losses, maintenance work and income to arrive at a total present-worth of any option, including capital investment, enabling the IRR to be obtained. By deriving the IRR for various projects, then, if there is any limitation on the amount of capital investment in a particular year, i.e. capital rationing, optional projects can be placed in order of priority with preference being given to the projects with the higher rates of return.

Table 5.3 Calculations to determine internal rate of return

Year	Cash flow, £	Test discount rate							
		5%		10%		15%		10.54% IRR	
		Present-worth factor	Present worth, £	Present-worth factor	Present worth, £	Present-worth factor	Present worth, £	Present-worth factor	Present worth, £
(1)	*Cost*								
0	6000	1·000	6000	1·000	6000	1·000	6000	1·000	6000
$\sum(1)$	6000		6000		6000		6000		6000
(2)	*Benefit*								
1	750	0·952	714	0·909	682	0·870	653	0·905	679
2	800	0·907	726	0·826	661	0·756	605	0·818	654
3	900	0·864	778	0·751	676	0·658	592	0·740	666
4	1000	0·823	823	0·683	683	0·572	572	0·670	670
5	1050	0·784	823	0·621	652	0·497	522	0·606	636
6	1100	0·746	821	0·564	620	0·432	475	0·548	603
7	1150	0·711	818	0·513	590	0·376	432	0·496	570
8	1200	0·677	812	0·467	560	0·327	392	0·449	539
9	1250	0·645	806	0·424	530	0·284	355	0·406	507
10	1300	0·614	798	0·386	502	0·247	321	0·367	477
$\sum(2)$	9900		7919		6156		4919		6001
$\frac{\sum(1)}{\sum(2)}$	0·606		0·758		0·975		1·220		1·000

For schemes where expenditure is over a short period of time, and a high rate of return is involved, the *payback* approach is often used. In this method the time taken for the summated income plus savings in annual maintenance costs, system losses and staff levels to equal (i.e. payback) the sum of the capital invested is calculated; i.e. incomings equal outgoings. No present-worth calculations are carried out, the actual values of cash inflows and outflows for each year being used. When summated inflow equals summated outflow the payback time for the project has been reached. Normally utilities would use this method when expecting a payback period of around two to three years. If future economic conditions could be reasonably assumed to be stable, a longer payback period of up to five years may be considered acceptable. Payback suffers from the drawback that income (cash inflow) after payback has been achieved is ignored, and the incidence of cash payments and receipts is not taken into account as in the present-worth method.

A further method considers the *annuity* required to provide for the capital investment. If the investment, i.e. the original capital and annual costs, are

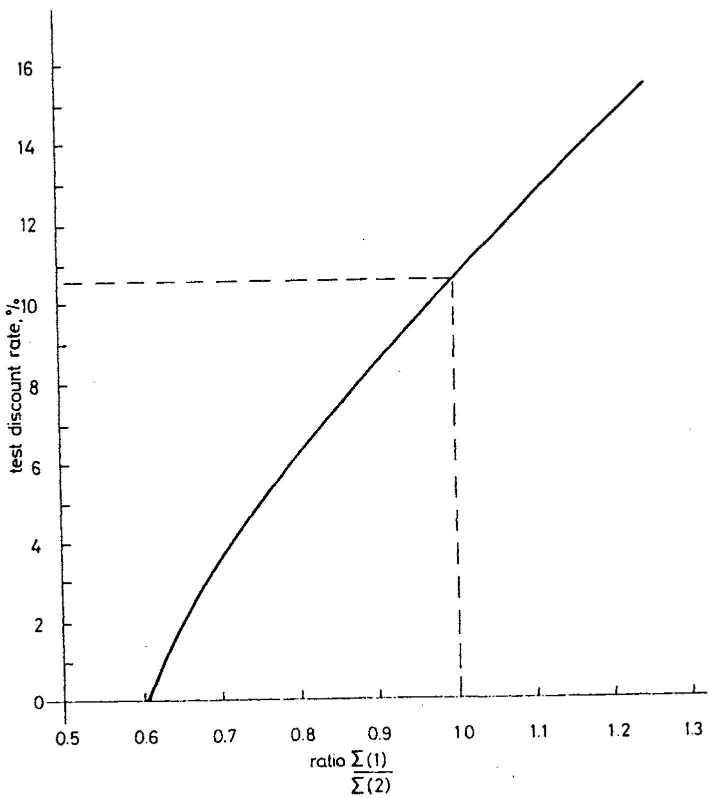

Figure 5.1 Relative costs versus test discount rate to determine internal rate of return

divided evenly across the review period and added to the appropriate cash flows, the annual payment S_a for a single investment S_0 is given by

$$S_a = S_0 \frac{p}{100} \quad \frac{1}{1 - \{1/(1 + p/100)^t\}} \tag{5.4}$$

Each method has its particular area of application. For example, when selecting the optimum size for a new feeder the present-worth method is suitable. On the other hand, the optimum year for replacing a conductor by one of larger cross-sectional area can be determined by comparing the annuity of the necessary investment with the annual savings in losses. When these are equivalent the optimum time has been reached provided that loadings do not decrease in the future.

An example involving capital investment and loss costs is indicated in Tables 5.4*a* and *b*. With the given load growth at one HV/MV substation, let it be assumed that there are two alternative methods of providing transformer capacity. The first is immediately to purchase a 16 MVA transformer, and add a similar-sized unit at a later date when necessary owing to load growth. The second method is immediately to purchase a 25 MVA unit which will meet the load over the 10 year study period.

The price of a 16 MVA unit is taken as £170 000, and a 25 MVA unit as £230 000. The no-load losses of the two transformers, P_0, are 16·1 and 21·8 kW, respectively, and the full-load series losses, P_l, are 88 and 121 kW. The cost of the no-load losses is taken as £170/kW, and the series losses £70/kW. The transformers are assumed to have a useful life of 20 years, and an 8% interest rate has been used in the present-worth and annuity calculations.

From eqn. 5.4, the factor by which a single investment should be multiplied to obtain the annuity can be calculated to be 0·102. By utilising the present-worth factor calculated from eqn. 5.1 the final columns in Tables 5.4*a* and *b* for the two strategies can be determined. In the first option the second transformer would have to be purchased in year 7. It will be noted that the difference in total costs is very small, so that any technical differences would dictate the final choice.

5.4 Time scale of studies and residual values

Electricity-distribution-system investment and operational costs are such that in practice the maximum period of assessment should be between 10 and 15 years. If any of the options being considered show similar rates of return, the period can be extended or a sensitivity analysis carried out. In these studies the capability of the various alternatives should be approximately the same at the end of the period being considered. If there is a significant difference in system capacity, some allowance should be made for this. This can be done by crediting any such scheme with a sum related to the value of the additional capacity, multiplied by the present-worth factor for the final year of the assessment period.

Table 5.4 Summary of two alternative strategies for providing transformer capacity

a

Year	Load, MVA	Losses, £/year P_0	P_l	Annuity of investments, £/year	Σ£ = (3) + (4) + (5)	Discounted present-worth value, £
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	11	2700	2900	17 340	22 940	21 240
2	12	2700	3500	17 340	23 540	20 170
3	13	2700	4100	17 340	24 140	19 170
4	14	2700	4900	17 340	24 940	18 330
5	15	2700	5600	17 340	25 640	17 460
6	16	2700	6300	17 340	26 340	16 590
7	17	5400	3500	34 680	43 580	25 410
8	18	5400	3900	34 680	43 980	23 750
9	19	5400	4300	34 680	44 380	22 190
10	20	5400	4800	34 680	44 880	20 780
Total		37800	43800	242 760	324 360	205 090

b

Year	Load, MVA	Losses, £/year P_0	P_l	Annuity of investments, £/year	Σ£ = (3) + (4) + (5)	Discounted present-worth value, £
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	11	3700	1600	23 460	28 760	26 630
2	12	3700	1900	23 460	29 060	24 900
3	13	3700	2300	23 460	29 460	23 390
4	14	3700	2700	23 460	29 860	21 950
5	15	3700	3100	23 460	30 260	20 610
6	16	3700	3500	23 460	30 660	19 320
7	17	3700	3900	23 460	31 060	18 110
8	18	3700	4400	23 460	31 560	17 040
9	19	3700	4900	23 460	32 060	16 030
10	20	3700	5400	23 460	32 560	15 080
Total		37000	33700	234 000	305 300	203 060

Since electrical equipment has a finite life owing to the normal process of deterioration, provision has to be made in the accountancy procedure of any organisation to 'write off' the equipment at the end of a given number of years, usually earlier than the expected average physical life. If before the end of this period it is necessary to remove equipment from the system because it has become obsolescent, or because of rapid technological development or changes in regulations, the equipment removed should be accorded a *residual value.* This should be the money which could be obtained from disposing of that asset even if the amount only reflects the value of the metal content of the equipment. An alternative approach is to include as a residual credit a discounted value for future cash inflows from the project.

Where an item of equipment is replaced, and the recovered equipment can be removed for use elsewhere on the system, the scheme covering the equipment replacement should be credited with the present-worth of the residual value of the released equipment at that time, having regard to the unexpired portion of its average life expectancy.

The present worth of the residual value can be determined in the same way as that of any single annual cost. The appropriate present-worth factors in Table 5.1 should be applied to residual values in order to obtain equivalent present values. It will be noted that the residual value of equipment reaching its accountancy age, usually between 25 and 40 years, can be quite small. However, where equipment is changed relatively soon after installation, the residual value can have a significant influence on the economic assessment.

5.5 Inflation and interest rates

The question of whether to include the effect of inflation in economic assessments has long been a matter of debate and conjecture. The simplistic view is that any rise in the costs of the resources for any project will generally keep in step with the average annual inflation rate over the period of years involved. When items of cost are fixed, e.g. via a maintenance contract or rental, such items should be discounted in order to include the cost at current price levels.

Equally the selling price of electricity, which mainly provides the income to finance capital investment projects, can be presumed to keep roughly in line with general price levels. By improving operational efficiency, the cost of electricity relative to other goods and services can, however, be reduced over a number of years, and this aspect should also be considered. Most capital-scheme investment appraisals cover a similar period of time. Given that the costs of the various options are comparable, then ignoring inflation will not significantly distort the economic comparisons provided that inflation remains at a modest level, say 5% per annum. Equally the vast majority of distribution network projects are mostly at MV/LV, so that economic appraisals over a period of five years or so are the most common. In this context inflation will only have a minor effect.

It should be recognised that periods of inflation at the 20–25% per annum level have occurred over the past 15 years, while inflation levels considerably in excess of 100% per annum have been experienced in some countries. On the assumption that all income and expenditure are equally affected by inflation, the effect of inflation will be to increase the present-worth in year t by $(1 + a/100)^t$ where a is the annual rate of inflation. Thus in year t the effective present-worth factor then becomes $\{(1 + a/100)/(1 + p/100)\}^t$ where p is the annual interest rate.

The relationship between the market interest rate of loans and inflation has an influence on the optimum RRR of the utility, and therefore on its investment policy. Inflation is the only factor which tends to reduce the required RRR below the interest rate. If inflation is relatively high, say 15%, and market interest moderate, say 10%, the real interest rate becomes negative. An RRR of a few percent can then be applied, so that it may be economic to borrow large sums of money for earlier capital investment. In low inflation conditions, say 2%, and with interest rates around 10% for example, there is then a fairly high positive real interest rate and the RRR has to exceed the interest rate to be economically viable. This tends to a much lower level of investment than in the previous example.

Where items of the investment appraisal calculation are being forecast to increase at differing levels of inflation, then the discounted cash flow can be carried out by using anticipated 'out-turn' prices. These prices should then be discounted at a rate which is equal to the sum of the required rate of return and the average inflation rate in order to eliminate the differing inflation rate. Such differing rates could apply to various fuels such as coal, gas etc., or costs related to the price of fuels, or salaries if these did not keep in line with inflation.

When utilities have to raise loan capital on the open money market, the minimum RRR, assuming negligible inflation, is influenced by the market interest rate. In such circumstances, the minimum RRR for economic studies needs to be a few per cent higher to provide a margin of profit and to acknowledge the uncertainties of forward forecasting. If optional capital is available, this should be invested where it can earn the highest return, with the return being used in economic studies. This situation is more applicable to developing countries particularly if capital-loan raising is on a national basis. On the other hand, state-supported utilities may be able to obtain capital at reduced interest rates.

5.6 Sensitivity analysis

The use of capital-investment appraisal techniques is intended to increase the confidence with which investment decisions are made. While there is no particular difficulty in using the techniques, it is more difficult to ensure that the forecast figures used are correct for all the possible changing circumstances during the economic life of a project. A sensitivity analysis measures the variation in return by considering the effect of a variation in each of the factors affecting the investment appraisal.

For example, it would be possible to assume that construction costs for a new project are variable to the extent of ±10%. Sometimes the possible variation may not be symmetrical, but skewed, so that it may not be possible to estimate future demands or energy sales to a greater accuracy than, say, between +10% and −20% of the estimate. Owing to the possibility of rapid technological changes, or other factors, it may be necessary to assume that the useful life of the scheme could have been overstated by 25% or even 50%. The relative competitiveness of other energy fuels, and changing government and worldwide economic policies will also influence long-term projects. Taking all such factors into account the range of profitability can be calculated.

For larger projects it is usual to consider a number of different scenarios involving variations in the assumptions made on load growth, investment costs, benefits obtained, plus the effect of other factors which cannot be specifically defined. A range of optimum optional measures or investments can then be determined as well as the effect of selecting a wrong option. It is essential to know which items of data are most critical in respect of moving towards a bad decision on a particular investment. Effort should be directed towards these items in order to obtain a better understanding of the investment situation. Studies have shown that the estimates of load level and load growth are two of the most critical parameters in these assessments.

Apart from the sensitivity-analysis method described earlier, another method of allowing for uncertainties in forecasting future strategies is to add a 'risk %' to the basic rate of return required, the 'risk %' being a matter of judgment or policy, depending on the various factors involved. However, this approach does not take account of the usual situation in which risk or uncertainty occurs at a point in time rather than continually over a period of time. To weight the RRR to allow for uncertainty is a crude approach. It requires a project to make a greater profit in order to reduce the likelihood of loss and this distorts the cash flows, leading to an incorrect evaluation of the results.

5.7 System losses

Part of the energy flowing through a distribution system, is lost in various ways in lines and components. Methods for determining the technical power and energy losses have been discussed in Sections 3.3.2 and 3.3.3. Network information systems, introduced in Chapter 14, are also efficient for loss calculations. Generally speaking, losses affect a utility's economics in two ways. Firstly they increase the power and energy demands, and thus increase the overall cost of purchasing and/or producing the total power requirements of the utility. System losses also increase the load flows through individual system components, which then leads to addtional cost being incurred owing to the extra losses associated with the increased load flows. Extra costs can also be incurred in having to increase some component ratings to cater for the additional current throughput caused by these losses.

The annual costs of the losses are usually based on the cost of generating, transmitting and distributing electricity taking account of the variations in costs throughout the year depending on the proportion of high-, medium- and low-merit plant in use at any one time. If complex time-of-day and time-of-year charges are in force, suitable computer programs are required to determine the total cost of system losses. The cost of losses depends on the part of the network in which they originated. For example, losses on the LV networks have to be fed through the whole supply system, via the HV and MV systems, and thus involve the highest cost per kW of loss. On the other hand, the loss load factor of LV loads is usually low, and there will be some diversity between the time when these loads peak compared with the utility's peak demand, which tends to reduce the overall cost of LV losses.

Table 5.5 Annual cost of losses

Annual load factor, %	10	20	30	40	50
Cost of series losses, £/kW of loss at time of maximum demand	10	15	30	50	100
Cost of shunt losses, £/kW			170		

To avoid complex loss-cost calculations on simple distribution networks it is convenient to produce tables of the total cost of the series losses (kW + kWh), relative to the series kW losses at time of peak demand and the annual load factor. Some typical figures are given in Table 5.5, based on Finnish tariffs for 1994.

From this Table the cost of the annual power and energy losses can be calculated, to an acceptable degree of accuracy in many cases, when the peak demand and the annual load factor are given. For example, at 30% annual load factor the total cost of the kW and kWh charges for 1 kW of series losses at time of maximum demand would summate to £30 per annum. This takes account of the variation in the kW and kWh components of the series losses with load throughout the year. The shunt kW losses are calculated for equipment in service at the time of maximum demand, and these losses are assumed to continue for 8760 h per annum. Again the overall cost is calculated on the resultant kW demand and energy consumed over the year.

These annual average values take some account of the very different costs of energy at different load levels and also the effect of the increasing power demand. They can therefore be applied to long-term studies such as feeder planning or the selection of the size of a transformer. It should be pointed out that these values are highly dependent on the distribution of power generation within a power system and on market conditions, and thus will vary from one country to another and, especially in open market conditions, the instantaneous value of energy often fluctuates over a wide range.

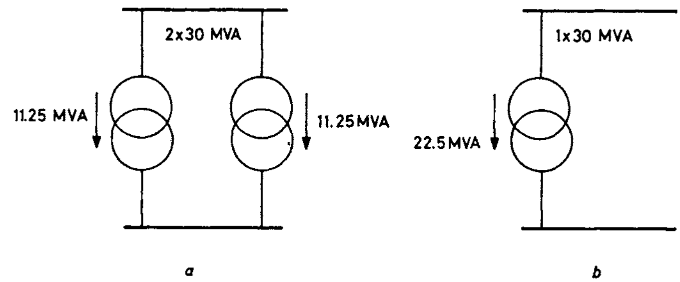

Figure 5.2 Transformer-loss studies

Annual average values for losses must not be used for operational studies since the variation of instantaneous energy prices is high. In these cases it is more appropriate to carry out a more detailed consideration of the different prices at different load levels. Such a situation is indicated in Figure 5.2 where consideration is being given to determining under which load conditions one transformer, or two, should be switched in and loaded. In high load conditions the cost of losses for two transformers will be lower than those for a single transformer. This is because the series losses vary as the square of the current so that the costs of the series losses with two transformers are one-half of those with one transformer and, at a particular load level, this more than offsets the higher cost of the shunt losses for the two units. Because the instantaneous values of losses, per kW, under high load conditions are typically high, this crossover point may be reached at considerably lower load levels than conventional calculations with average annual loss values might indicate.

5.8 Other factors

Economic comparisons relating to electricity-supply networks are usually confined to the financial and technical aspects of various options. It will probably also be necessary on occasion to take account of any additional costs involved in minimising the impact of any work on the amenity of an area. As a consequence of such constraints, the possibility of extra expenditure, such as diverting overhead lines or undergrounding sections of individual circuits, must be taken into account, either in the costing of the scheme or in a sensitivity analysis. It may well be that some other option, previously considered too expensive, may then prove more cost-effective than the originally preferred scheme plus the added amenity expenditure.

The question of state or municipal taxes and duties has not been covered, as these vary considerably from one country to another and generally act as an additional cost to be borne by the utility. Compensation for obtaining overhead line or underground cable routes will, however, form part of the costing exercise for any system extension proposal.

The social requirements of providing electricity supplies to remote areas may result in the investments not meeting the minimum RRR in some cases. Such schemes may even be installed at a loss or require financial supply from outside the supply authority from government, local communities or international sources.

It may also be necessary to carry out work on an electricity supply system to meet revised safety or technical regulations, and provision should always be made in any long-term financial plan for some such additional expenditure. The introduction of electricity supplies into an area can have additional spin-off in an improved economy not directly related to energy sales. All or some of the factors mentioned here, and other relevant ones, may need to be taken into account to arrive at a fair and reasonable economic assessment.

Notwithstanding all the procedures and aspects mentioned in this Chapter there will always be the overriding consideration that the supply utility must remain economically viable. This may lead to cutbacks in proposed projects in some years or the possibility of additional money becoming available as energy sales expand, and the planning engineer should always have these aspects in mind.

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Chapter 6

Equipment

6.1 General

In all other Chapters the objective has been to present the various theoretical, technical, economic and operational factors to be considered when planning and designing electrical distribution systems. This chapter is intended to provide some background information on the construction and operating characteristics of the main components installed on distribution networks, in order to provide the design engineer with basic data on the equipment which will be used to build up a functional system. With rapidly changing technologies affecting in some way the design of virtually all equipment, specific examples have not been illustrated; only general aspects of the main features of transformers, lines, cables and equipment are covered in this chapter. Protection aspects are covered in Chapter 7 and switchgear arrangements in Chapter 8.

From the commencement of manufacturing electrical equipment, various local and national standards have been used as the basis of individual equipment design. This has led to some non-uniformity of approach, and difficulties in reconciling equipment built to different specifications. The introduction of the International Electrotechnical Commission (IEC) standards provided a common base for the reliability and safety of equipment, interchangeability and mutual compatibility of equipment made by different manufacturers worldwide, plus the elimination of the unnecessary diversity of components used in the construction of electrical equipment. As a consequence, the IEC standards are used as the basis for regional and national standards, and in preparing specifications for international trade. They thus represent essential reference works for planning and design engineers.

Subject to network operating conditions permitting their retention, service experience has shown that equipment on electricity supply systems can have long engineering lives. HV/MV transformers are still giving good service over 50 years after being installed, as are MV cables, some of them now operating at twice their original design voltage. Examples are known of MV switchgear being replaced 90 years after installation and still in serviceable condition. The operating principles used in their construction were somewhat simple, using the traditional conductors, insulation and magnetic materials of that time. Many new applications have been developed using devices from outside the power-engineering sector, such as microelectronics, computer science, telecommunications and material technology – all well proven before being applied to power-distribution practice.

New equipment can, however, be more economic in operation with lower losses, better reliability and longer intervals between maintenance servicing; and these factors often motivate equipment replacement, as discussed in Section 6.6. In many cases replacement of equipment has been implemented because of changes in governmental or utility safety rules, or the lack of suitable spare parts as manufacturers have combined and rationalised their products, plus technological advances, rather than because of an inherent deterioration of ageing equipment.

6.2 Transformers

6.2.1 General

The transformer provides the facility for interlinking systems operating at different voltages. Thus voltage levels can be stepped up at power stations and transmission substations for supplying inter-regional power tie lines, and then reduced in stages through the HV, MV and LV networks in turn as indicated schematically in Figure 1.5. HV/MV and the larger MV/LV transformers are ground-mounted on concrete pads. Figure 6.1 shows an outline drawing of a typical HV/MV arrangement, identifying the major components. These transformers may also be located in 'indoor' installations within a suitable building for environmental reasons, particularly in urban areas.

In the so-called underground residential distribution (URD) system, which has found most favour in the USA, the MV/LV transformers are located in special underground enclosures. Smaller-sized units are often mounted on a platform constructed between two or four poles, with the smallest-sized transformers attached directly to a pole. Further reference to these pole-mounted transformers is given in Chapter 10.3. It is not uncommon for a cluster of three units to be attached to one pole, especially in the USA where single-phase units are preferred.

6.2.2 Losses

Transformer losses can be divided into two components: no-load losses and load losses. No-load losses result from hysteresis and eddy-current losses in the iron core, which depend on the type of steel used to fabricate the core. These losses are independent of the load current passing through the transformer, but increase with increasing voltage.

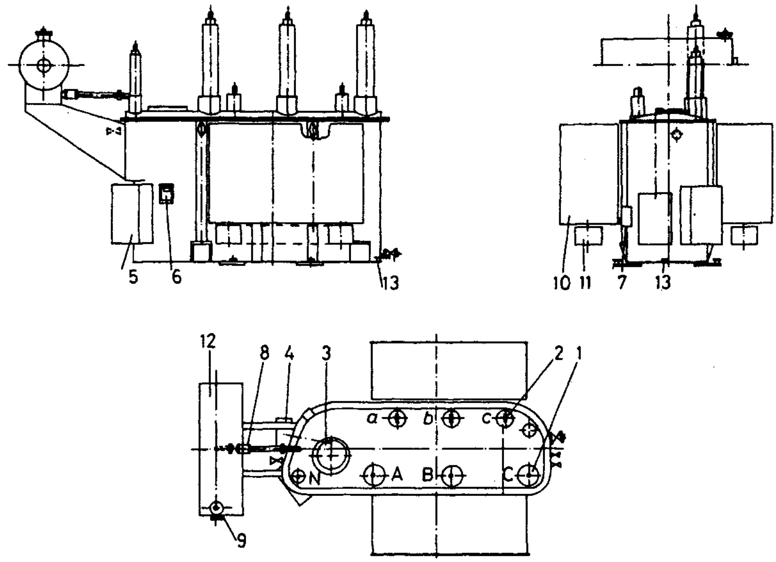


Figure 6.1 Outline drawing of HV/MV transformer (Courtesy ABB Finland)

1 High-voltage bushings
2 Medium-voltage bushings
3 On-load tap changer
4 Motor-drive mechanism for tap changer
5 Terminal and control cabinet
6 Oil thermometer
7 Dehydrating breather
8 Buchholz gas-detector relay
9 Oil-level indicator
10 Coolers
11 Fans
12 Oil conservator
13 Earthing terminal

Load losses include the losses due to passage of current through windings, the so-called I^2R or copper losses, plus eddy-current losses in the windings and the core, tank and other metallic parts of the transformer caused by the leakage flux.

When the overall efficiency of operation is assessed the energy taken by the motors pumping the transformer oil, or forcing air through the radiators, must also be taken into account. When HV/MV or MV/LV transformers made by different manufacturers to standard specifications are compared, the capitalised cost of the losses over the expected life of the transformer must be added to the capital cost to derive the overall cost during the lifetime of the transformer, in order to assess the most economic choice. The development of transformers using amorphous steel cores may soon result in economical designs being commercially available. The new core material will eliminate up to 75% of iron losses.

6.2.3 *Insulation life*

Most transformer cores and windings are contained within a tank filled with insulating oil. The transformer losses produce a rise in temperature in both core and windings which is transferred to the surrounding oil. Where the oil circulates by natural convection this is designated by ON (oil natural). Where the oil circulation is forced past the windings and then through the radiator banks connected to the transformer tank this is designated OF (oil forced). When a proportion of the forced oil is directed through the windings themselves, the designation OD (oil forced-directed) is used. The transformer tank, and radiators where fitted, can transmit the heat to the ambient air by natural convection (AN) or the radiator banks can be further cooled by motor-operated fans forcing air across the radiators, i.e. air-forced (AF). The more efficient the heat removal from the transformer windings via the oil to the outside air the higher the rating that can be applied to a given transformer-winding arrangement. Typically moving from an ONAN cooling system to ONAF and on to OFAF can result in a 1:1·5:2 improvement in throughput capability.

The maximum loading which a transformer can carry under normal loading conditions without impairing the insulation depends on the daily loading cycle and the ambient temperature. The life of a transformer will be determined by the rate of deterioration of the winding insulation. It is generally agreed that the highest temperature at any point in any winding, the 'hot spot' temperature, should not exceed 140°C, and that in temperate zones any increase in hot-spot temperature of the order of 5–8°C doubles the rate of deterioration of the insulation. Under emergency conditions short-time peak hot-spot temperatures up to 180°C can be accepted.

The hot-spot temperature at which there is no excess deterioration is quoted as 90–98°C. If the normal rate of deterioration is assumed to occur at 98°C, and to double for every 6°C increase in hot-spot temperature, the relative ageing of the transformer insulation with hot-spot temperature will be as shown in Figure 6.2.

Because the relationship between load and the hot-spot temperature is complex, and also depends on the construction of the transformer, various approximate formulas are applied. A commonly used formula is as follows:

$$T_{hs} = T_{ot} + k(T_{wa} - T_{oa}) \tag{6.1}$$

where

T_{hs} = hot-spot temperature

T_{ot} = top-oil temperature

T_{wa} = average winding temperature

T_{oa} = average oil temperature

k = coefficient with values between 1·1 and 1·3

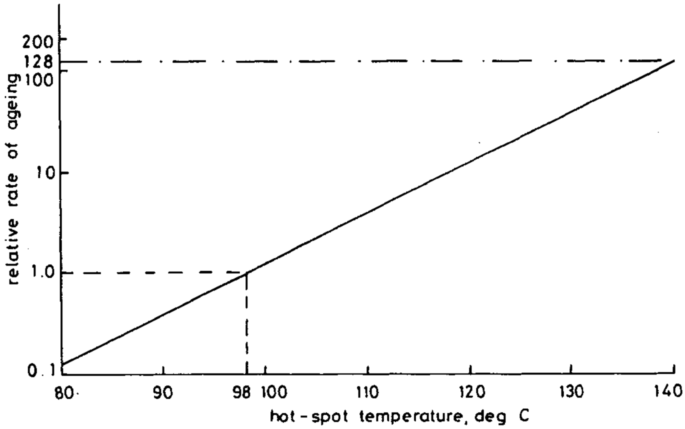


Figure 6.2 Relative ageing of transformer insulation with hot-spot temperature.

Figure 6.3 shows the amount of overload that can be carried by an ONAN transformer depending on the ambient temperature, and the loading cycle. Curve *c* covers the situation of continuous loading for 24 hours per day. It will be seen that full load can be carried at an ambient temperature of 20°C, rising to 1·3 times full load at −20°C and falling to 0·85 times full load at +40°C. Curve *d* shows the limit of loading which would lead to rapid deterioration and damage to the insulation if the load were applied continuously.

Curves *a* and *b* cover conditions where the maximum load occurs for 2 and 8 h continuously each day. Suffix 1 is where the previous loading is 0·25 times the transformer rating, while for suffix 2 the previous loading is 0·9 times the transformer rating. If high loadings are being considered, studies should be carried out to ensure that associated components such as the bushings and the transformer tap changer can carry the overloads in each daily load cycle. There are other factors besides ageing which affect the service life of a transformer, for example uprating the distribution voltage, increased loads, or reduced losses of new transformers, will mean that transformer replacement will generally occur well before the electrical or mechanical life span due to ageing has been reached.

6.2.4 Reactance of large supply transformers

The chosen design impedance of a transformer is basically determined by two factors which oppose each other. The first is to keep the fault level on the lower-voltage side to an acceptable value. This can result in somewhat high impedances which can then produce too high a voltage drop through the windings, so that a balance has to be struck between these two constraints. Linked to the voltage-drop aspect is the range of tappings provided on the transformer to adjust the winding ratio. On the assumption that the power flow is from the higher-voltage to the lower-voltage busbar, the tapping range must be such as to obtain an acceptable voltage at the lower-voltage busbar at any transformer loading for any likely variation in the higher-voltage busbar voltage.

It is possible that other considerations may restrict the maximum reactance. These include the need to minimise step change in voltage on the loss of one transformer, or on the loss of load, where two or more transformers may be operating in parallel on the lower-voltage side. In addition, the through-fault current must be adequate to operate protective relays, and the fault level at the lower-voltage busbar must be high enough to minimise the voltage elasticity ($dV/dP, dV/dQ$) and thus the effect of disturbing loads. The maximum value of reactance should be derived for the most limiting condition. In determining the tapping range, only sufficient taps need to be provided to cover variations in the primary and secondary busbar voltages, and the loading on the transformer.

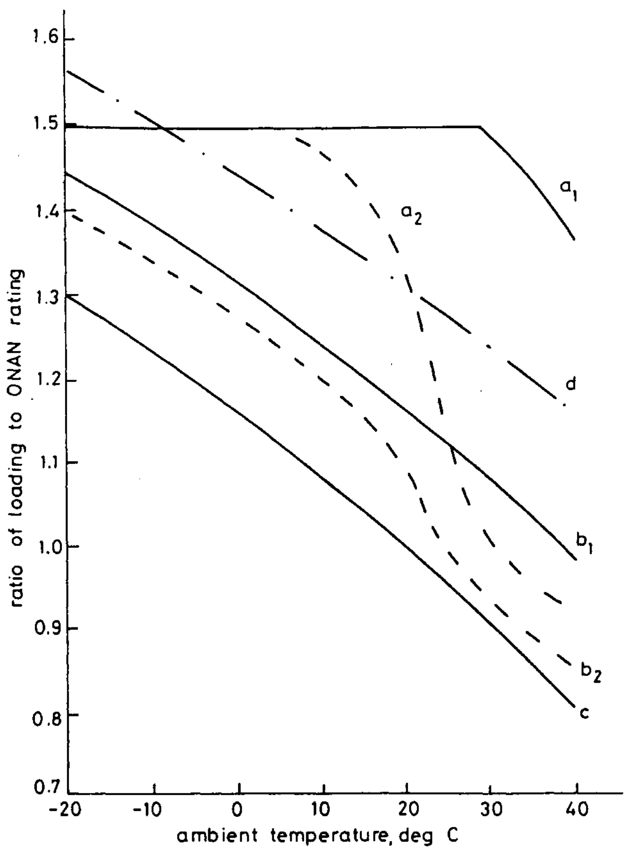


Figure 6.3 Typical maximum loadings on an ONAN transformer, dependent on ambient temperature and previous loading

6.2.5 Unsymmetrical loads

In low-voltage networks most customer appliances are single phase, and therefore tend not to be evenly distributed across the phases of a 3-phase supply. In addition, where only single-phase supplies are provided, this can result in unsymmetrical loadings. The smallest distribution transformers (MV/LV) in some countries are single-phase units. The primary side of the distribution transformer may be connected between phase and earth or across two phases of the MV line. Thus both voltage and current asymmetry can appear on 3-phase MV circuits.

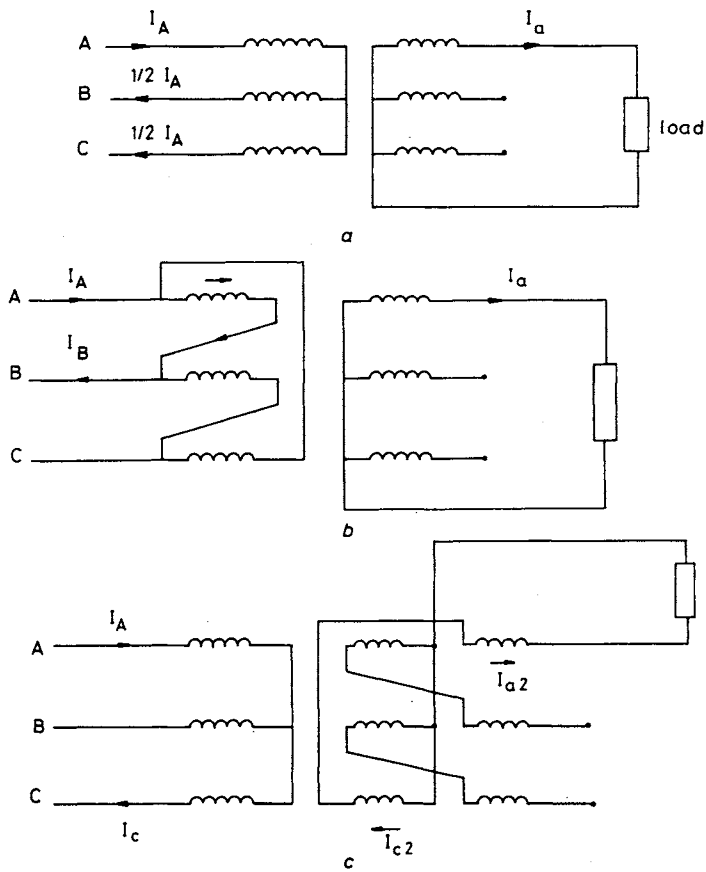


Figure 6.4 Distribution of unbalanced load currents for different winding arrangements

a Star/star
b Delta/star
c Star/zigzag

The degree of asymmetry transferred to the MV system depends also on the winding arrangements of the MV/LV transformers. Two types of winding connections are used in 3-phase distribution transformers: either the delta/wye (*Dy*) or the wye/zig-zag (*Yz*), shown in Figure 6.4.

If a 3-phase star/star-connected bank of three single-phase units has its primary star point connected to that of a *YNyn* supply, the load on each primary phase is proportional to that on the corresponding secondary phase, and the degree of unbalance is therefore the same on both sides of the transformer. When the primary star point is not connected, as in the *Yyn* arrangements shown in Figure 6.4*a*, the voltage of the primary neutral N approaches the voltage of phase A while voltages B–N and C–N increase. Since the voltage of the loaded phase is low, the result is that the secondary phase voltages are also unbalanced. To prevent this, star/star connections are not used in distribution transformers.

In order to avoid the above-mentioned voltage asymmetry the delta/star connection shown in Figure 6.4*b* can be used. The delta-connected primary will permit single-phase unbalanced secondary loading even though a primary neutral return is now absent. The secondary load current will cause a primary current flow from phase A to phase B.

Another suitable arrangement is the *Yz* connection shown in Figure 6.4*c*. The single-phase load current now flows through two sub-windings. This causes the MMFs on the different core limbs to maintain their balance so that no great voltage asymmetry will appear. The *Yz* connection is frequently used, especially in small transformers.

6.3 Overhead lines

An overhead line utilises air to insulate bare conductors for the majority of its length, apart from the very small sections connected to insulators on the line supports. The absence of further insulation and the relative ease of construction result in an inexpensive method of providing an electric circuit compared with an underground cable, particularly at MV and the higher voltages. Table 6.1 compares the costs of providing a circuit by overhead line or underground cable at different voltage levels. An appropriate average circuit rating, which is different for each of the four voltage levels, has been used for comparison purposes.

Table 6.1 Ratio of underground-cable to overhead-line costs, at each voltage level

EHV	HV	MV(a)	MV(b)	LV(a)	LV(b)
15 to 25:1	10:1	5:1	2:1	5:1	1.5:1

(a) in built up areas
(b) in normal soil conditions

These ratios can only be taken as very broad values, since, for both types of construction, overall costs are considerably influenced by labour and material costs and the topography and type of terrain involved. For example, in favourable conditions when special ploughs can be used for cable laying, as in fields, the cost of LV cable can be very close to or even lower than that of an LV overhead line. This may also be the case for MV under certain soil conditions when all life-time costs, including capital investments plus costs associated with reliability, are considered. In areas of difficult terrain, e.g. mountainous or involving large river crossings, there is often a clear cost advantage with overhead lines. It will be apparent that the cost of constructing any network will be affected by the ratio of overhead line to underground cable, particularly at the higher voltage levels.

Table 6.2 Relative values of lines and cables in England and Finland in 1993

(*a*) England

	EHV	HV	MV	LV	Total
Overhead lines, %	1·2	3·4	27·5	9·8	41·9
Underground cables, %	0·1	0·5	20·0	37·5	58·1
Ratio overhead/underground	16	7	1·4	0·3	0·7

(b) Finland

	EHV >300 kV	HV 36–300 kV	MV 1–36 kV	LV <1 kV	Total
Overhead lines, %	1·0	5·2	33·1	43·4	82·7
Underground cables, %	0·0	0·1	2·8	14·4	17·3
Ratio overhead/underground	>100	>50	11·7	3·0	4·8

Apart from these considerations other factors influence the ratio of lines to cables. In the more sparsely populated areas of the world there is more opportunity to obtain overhead-line routes, even though in some circumstances construction may be difficult owing to the distances involved in getting materials to site, and the nature of the terrain. This is illustrated by Table 6.2*a*, which shows the percentage of overhead and underground cable-circuit kilometres, by voltage levels, in service in 1993 in England, where the majority of customers are in cities and other built-up areas, and supplied via medium- and low-voltage cable networks. On the other hand, the majority of the HV and EHV routes are predominantly overhead because of the large cost difference referred to in Table 6.1.

Table 6.2*b*, covering similar statistics for Finland in 1993, also shows the effects of a much lower average population density and the early adoption of overhead (insulated) cables, particularly at low voltage, making the overhead alternative even more preferable.

Overhead conductors must be installed at a height which provides adequate electrical clearance from the ground, from nearby buildings or trees, and over roads and railways etc. National or utility regulations set out the minimum clearances allowing for factors such as the swing of conductors with winds blowing across the line at prescribed speeds. The line height is determined by the maximum conductor sag between towers, which itself is influenced by the span length, the conductor type, the maximum permissible conductor stress, the maximum conductor temperature and the ambient air temperature. When mechanically dimensioning a line, the design engineer must ensure that all the above criteria are met under all load conditions. The extremes of expected weather conditions must also be considered. At high current loading and high ambient temperatures the sag is greatest, while in cold temperatures and with low load the stress in the conductors is at its highest. Where snow and ice are likely to be encountered allowance should be made for this. Snow and ice on the conductors effectively increase the area exposed to wind, and the extra weight imposes additional mechanical loading on the 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 (ACSR) conductor.

Overhead lines are carried on a variety of supports. Wood poles predominate at low and medium voltage, but at high voltage steel towers are more usual. Concrete poles are also frequently used for LV and MV lines. Diagrams of a number of tower and pole designs are given in Figure 6.5.

Figure 6.5*a* shows an HV double-circuit steel tower. The use of two wooden poles with a steel crossarm, as in Figure 6.5*b*, provides an HV single-circuit design of relatively low height. A typical arrangement at medium voltage is the single wooden pole with steel cross-arm, shown in Figure 6.5*c*. The bare conductor and overhead-cable arrangements used at low voltage are shown in Figures 6.5*d* and *e*. The dimensions given indicate the general sizes of the various towers and poles but do not necessarily apply to any one utility, or where special conditions exist.

Bare overhead conductors require adequate clearance to be observed to avoid any physical contact which would initiate a fault. In heavily wooded areas it is necessary to clear an area on either side of the overhead line to avoid conductors being blown by wind into contact with the trees. Various forms of insulated overhead lines and cables are in service. The insulation prevents faults developing should the cable touch a branch of a tree, or from conductor clashing. Safety clearance can be reduced, as can the width of the cleared area around the line. This type of construction is thus electrically safer than the bare wire conductors.

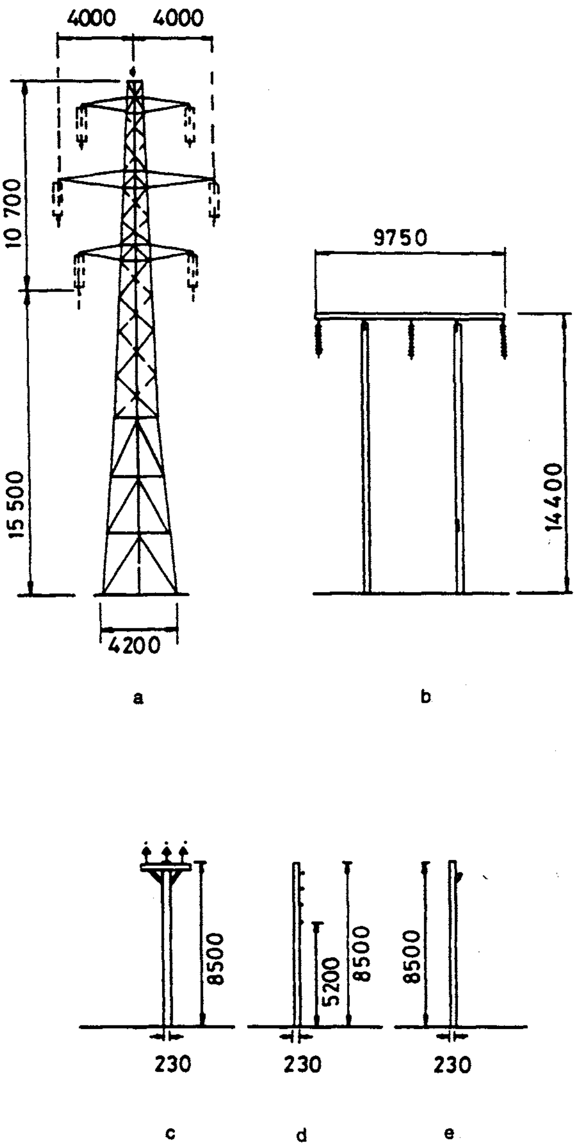
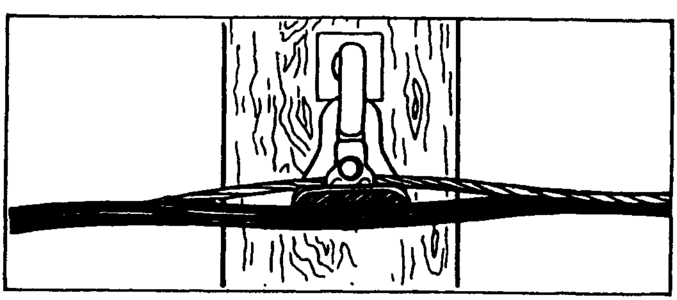


Figure 6.5 Towers and poles for overhead lines
Dimensions are in mm

For LV networks three main types of construction are in general use. Separately covered conductors are widely used for distributors and services in the UK and USA. Aerial bunched cables are used in Finland and France, for example, while self-supported aerial cables are in common use in Italy. Other constructions involve an insulated neutral, rather than the neutral wire being bare. A typical LV aerial bunched cable is shown in Figure 6.6. Experience in Nordic and tropical countries has shown that minimal tree trimming is necessary to erect and operate aerial bunched cables.

Similar types of insulated line are also used in MV systems. At medium voltage the insulation costs are much higher, so that the last two constructions mentioned in the previous paragraph are only economic under special circumstances. A 20 kV double-circuit line with covered conductors is shown in Figure 6.7. In this type of arrangement the conductor insulation does not meet IEC standards for full line or cable insulation, but it is nevertheless satisfactory for preventing a power fault occurring with clashing conductors or when conductors strike trees in high winds. The conductor insulators, however, have to cope with the same voltage stresses as occur with bare overhead conductors. At medium voltage, covered conductors provide a more economical arrangement than overhead cables.

a



b

Figure 6.6 Typical LV aerial bunched cable

a Section of self-supporting overhead cable
b Cable suspended from a pole.

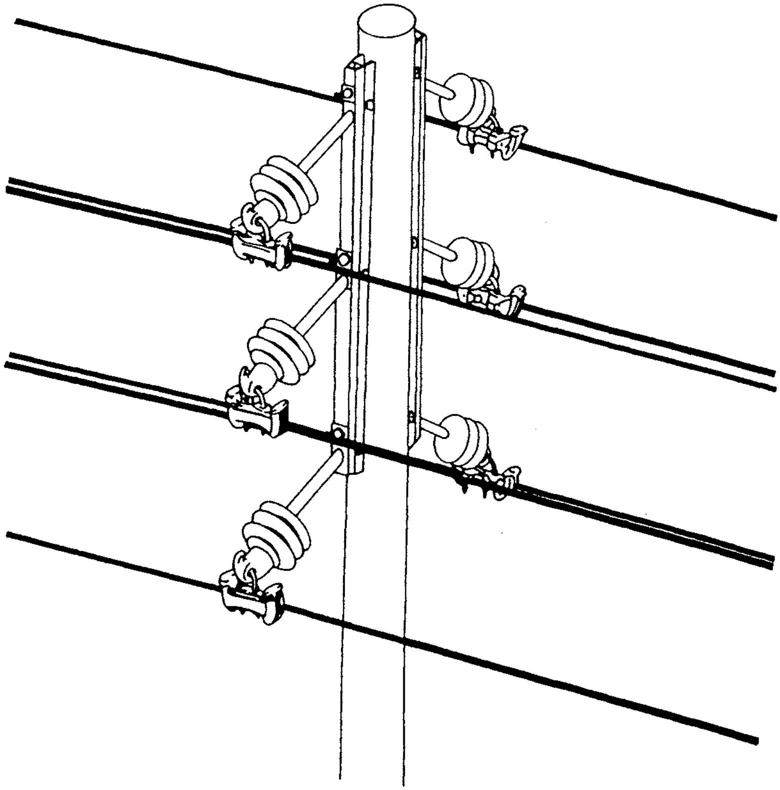


Figure 6.7 20 kV double-circuit line with covered conductors.

6.4 Underground cables

When supported by insulators from poles or towers an electrical conductor can utilise the air surrounding it as the insulating medium. In placing a conductor underground, buried directly, or in ducts or pipes, the first consideration is to insulate each conductor from the other conductors, and from earth (ground).

An early form of cable-conductor insulation, introduced in the late 1880s, was the use of layers of oil-impregnated paper tape wound round each conductor, and this type of insulation is still used for MV and HV cables. As the electrical loading 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, depending on the electrical stress, with consequent deterioration of the insulation. To overcome this problem at HV, the oil-filled cable, originally designed by Emanueli in 1926, has insulating oil fed into the centre of each conductor under pressure from oil tanks along the cable route, to fill any voids that occur.

In order to prevent water being absorbed by the insulating paper tapes the conductor/insulation assembly is covered by a metal sheath, usually lead (or lead alloy) or aluminium. Steel tape or wire armouring is applied over the lead sheath to protect it from mechanical damage, and layers of fibrous material impregnated with bitumen cover the whole assembly to prevent corrosion of the armouring or metallic sheath. Common practice is not to use armouring with aluminium-sheathed cables, but the sheath is protected against corrosion by a covering of high-quality plastic.

Originally the conducting cores of a cable were made of standard copper wire since this could be readily formed, and because copper has excellent electrical conductivity. The late 1950s saw a considerable increase in the price of copper and attention 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. Using aluminium conductor and sheathing results in a cable that has a smaller diameter and less weight than an equivalently rated cable with copper conductors, lead sheath and steel armouring.

Along with changes in conductor material some changes in insulation have also taken place. Thermoplastic insulants, in particular polyvinyl chloride (PVC), came into use in the 1950s. However, PVC is liable to softening at high temperature, and creates 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 only used in low-voltage cables. Polyethylene (PE) is suitable for all medium voltage levels and is solely used for insulation purposes as cross-linked polyethylene (XLPE) which allows a longer short-time heat duration under fault conditions, and a higher working temperature under normal conditions, compared with thermoplastic PE. The premature deterioration of early polymeric cables has been overcome by advances in cable design and progress in production technology.

The combination of aluminium conductors using mechanical conductor joints and XLPE insulation has been influenced by the difficulties in obtaining suitably trained staff with the skills required to join paper-insulated cables. Coupled with the use of plastic heat-shrink or rubber slip-on terminations, these developments have considerably reduced installation times and costs. XLPE is now available for use at working voltages up to 500 kV, with cross-sectional areas up to 2500 mm^2.

From the foregoing it will be appreciated that the construction of a cable is considerably more expensive than that of an equivalent overhead-line conductor. There is also the cost of installation, with four main methods in use. The most usual method is to lay one or more cables in a trench in the ground and refill the cable trench with a suitable backfill if the original ground is unsuitable. Other methods of installation are the laying of cables in ducts or troughs of various materials, or placing large pipes or ducts underground and pulling the cables into such pipes. The most modern method of laying MV and HV XLPE cables is by directional or guided boring. In good soil conditions some types of LV cables can be directly laid in the ground with the use of special ploughs. On occasions cables may be supported against the sides of buildings.

Table 6.3 lists data for two different cable types and sizes at various operating voltages, including electrical properties at 50 Hz. Different cable formats with differing conductor material and cross-section, and different conductor-conductor and conductor-sheath dimensions, all produce different values for the various cable technical parameters. More precise information can be obtained from cable manufacturers' technical data sheets.

The cable ratings given in Table 6.3 are for continuous loadings, although in practice loadings have a cyclical pattern. Buried cables take some hours to achieve the heat-transfer equilibrium conditions on which continuous ratings are based. Figure 6.8 illustrates the conductor-temperature rise/time curve for a buried cable, based on eqn. 6.2:

$$\theta_t = \theta_f(1 - e^{-\alpha t}) \tag{6.2}$$

where

θ_t = temperature rise at time t from switching on

θ_f = final temperature rise

α = constant, depending on type, size and method of installation of cable

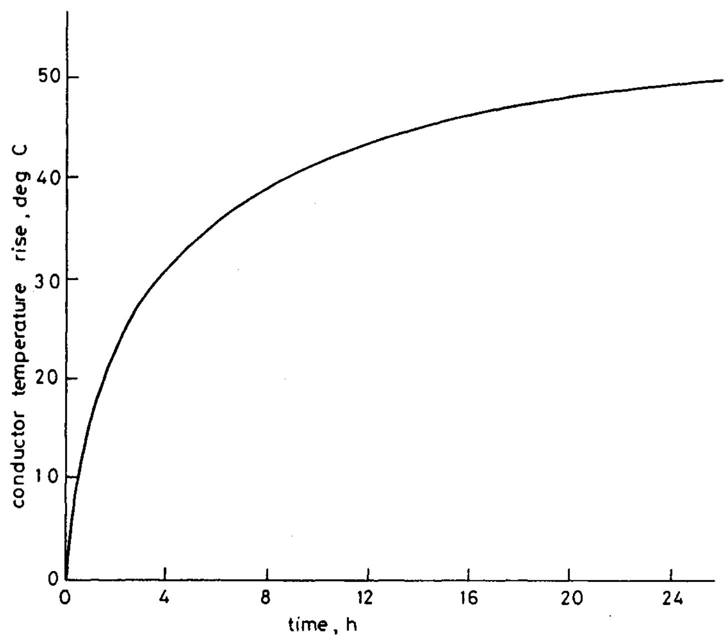


Figure 6.8 Example of variation in cable-conductor temperature rise with time when continuously loaded.

Table 6.3 Typical LV and MV cable parameters (courtesy Nokia Cables)

Rated voltage, kV	0.6/1		12/20	
Conductor	Stranded, compacted sector, shaped A1		Rounded, stranded compacted A1	
Insulation	XLPE		XLPE	
Core sheath	–		semiconductive XLPE	
Concentric neutral or protective conductor	Al		Cu	
Protective covering	PVC		PE	
Nominal cross-sectional area of each core, mm^2	120	185	120	185
Maximum DC resistance of conductor at 20°C, Ω/km Al	0·253	0·164	0·253	0·164
AC resistance of main conductor at 20°C, Ω/km Al	0·256	0·168	0·256	0·169
Inductance, mH/km	0·26	0·26	0·41	0·38
Typical operating capacitance, μF/km 0·26		0·28	0·28	0·23
Typical charging current, A/km	—	—	0·8	0·9
Continuous current-carrying capacity:				
cable in ground at 15°C A at 65°C	255	330	265	330
90°C	295	375	310	390
cable in air at 25°C A at 65°C	—	—	265	345
70°C	220	285	—	—
90°C	280	365	325	425
Maximum permissible short-circuit currents for duration of 1 s, kA	11·4	17·5	11·4	17·5
Net weight, kg/km	2000	3000	3600	4500

Compared with overhead lines the heating and cooling time constants of cables are several times greater for cables than lines with the equivalent conductor cross-section area. Owing to the rather complicated construction of a cable, the simple single-time-constant model used in eqn. 6.2 only provides an approximation of the heat conditions in a modern underground cable.

In practice, for MV and LV networks operating as open loops, the loading on any cable under normal conditions is likely to be less than 50% of its continuous rating. There is thus the possibility of utilising the short-time capability of cables to assist in system operation under emergency or short-term conditions. Different ratings apply for cables installed in ducts or pipes where there is poor heat transfer to the air. For cables installed above ground in air, heat dissipation will be quicker than for buried cables, or cables in ducts.

The heat produced by the passage of current through cable conductors cannot be so easily dissipated as with an overhead-line conductor in air. With cables the insulating materials are often operating close to their maximum permitted temperature. For cables buried in soil, the rating is dependent on the maximum permissible conductor temperature, the ground temperature, the soil thermal resistivity, the depth of the buried cables, the method used to protect the cables in the trench, and the proximity of other cables carrying electrical power. Tables giving factors for deriving cable capability under a given set of conditions are available from manufacturers, cable standards and harmonisation documents, or in handbooks on cables.

Situations can occur where the limiting factor on a particular cable-conductor size is its ability to carry very heavy short-circuit currents due to a close-up fault for up to 1 or 2 s rather than maximum load current for some hours. This problem can occur when an HV/MV infeed substation is introduced at the extremity of an MV network, and for MV and LV cables close to the feeding HV/MV or MV/LV substation. While paper insulation is able to withstand a temperature of 250°C for approximately 5 s, any associated soldered conductor joints limit the maximum conductor temperature to 160°C. The use of compression cable joints raises the permissible conductor temperature to 250°C, as for EPR and XLPE cables.

In the absence of more precise technical information, eqn. 6.3 may be used to assess the maximum acceptable short-circuit current I_{sc} (kA), given the conductor cross-section area S (mm^2) and the duration of the flow of fault current $t(s)$:

$$I_{sc} = KSt^{-1/2} \times 10^{-3} \tag{6.3}$$

The coefficient K depends on the initial temperature assumed, and the maximum temperature allowed for the cable under consideration. For an initial temperature of 65°C, and a final temperature of 250°C for paper and XLPE insulated paper, and 150°C for PVC insulation, the appropriate values of K are given in Table 6.4.

Table 6.4 Values of K for determining conductor short-circuit capability

Conductor material	Insulation		
	PVC	Paper	XLPE
Copper	110	150	150
Aluminium	75	100	100

From eqn. 6.3 and Table 6.4 the maximum short-circuit current-carrying capacity of a cable with a conductor cross-sectional area of 100 mm^2, with protection operating in 0·6 s, is 9·7 kA for an aluminium/PVC combination and 19·4 kA for copper/XLPE.

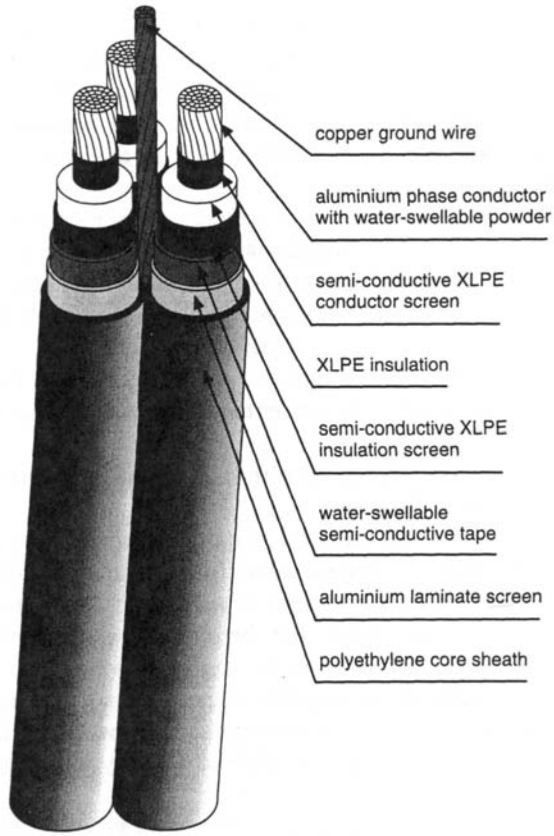


Figure 6.9 Construction of a typical MV underground cable (courtesy Nokia Cables)

6.5 Switchgear

6.5.1 Introduction

In an electricity supply system it is necessary to disconnect equipment from the network quickly if a fault occurs in order to avoid damage to the faulted equipment or other equipment on the network. To permit equipment to be maintained it must be isolated from the live system. For operational requirements it is necessary to group circuits into specific configurations at various substations on the MV and HV networks. On the MV networks it is often necessary to vary the open and closed points to avoid excessive losses, voltage drops or fault levels or to maintain supplies under abnormal conditions. Thus various devices are required to operate an electricity supply network safely and with maximum efficiency.

Switchgear is a general term covering switching devices and assemblies of such devices with associated inter-connections and accessories.
A *circuit breaker* is a switching device, capable of making, carrying and breaking currents under normal circuit conditions; and also making, carrying for a specified time and breaking currents under specified abnormal circuit conditions such as those of a short circuit.
A *switch* is a switching device capable of making, carrying and breaking currents under normal circuit conditions, which may include specified operating overload conditions and also carrying for a specified time currents under specified abnormal circuit conditions such as those of a short circuit. A switch is thus, by definition, not intended to make or break fault current.
A *switch-fuse* is a switch in which one or more poles have a fuse in series in a composite unit, so that high fault currents are cleared by the operation of the fuse.
A *recloser* is a circuit breaker equipped with relays in order to carry out a variable pattern of tripping and closing.
A *disconnector* is defined as a mechanical switching device which provides, in the open position, a specified isolating distance. It should be capable of opening and closing a circuit when negligible current is broken or made. It should be noted that disconnectors are unreliable for breaking capacitative current, with capacitative currents of less than 1 A, causing damage to some types of disconnector. While it should be capable of carrying normal load current, and also carrying for a specified time currents under abnormal conditions such as for a short circuit, a disconnector is not capable of making or breaking short-circuit currents.
A *sectionaliser* is a disconnector equipped with relays so as to operate within the dead time of a recloser.
The interrelation of the operation of reclosers and sectionalisers is described in Section 7.5.

6.5.2 Circuit breakers

A circuit breaker has the capability of breaking fault current up to a specified value and remaking the phase connection when the fault has been cleared, using various input signals which can define the state of the circuit(s) protected by the breaker. It can repeat this operation many times between maintenance periods. In early versions the contacts were opened inside a tank of oil. When the contacts are closed within a small chamber inside the main tank a pressure is generated within the chamber by the gases formed by the arc, and this forces oil across the arc path to cause rapid extinction. In this *bulk-oil-volume circuit-breaker* arrangement the oil is used both for arc extinction and as the main insulation.

Reducing the oil content to that required for arc extinction alone resulted in the *minimum-oil circuit breaker*. Here the arc-control device is enclosed within a small housing containing oil, which is supported by an insulator to provide the necessary insulation clearance between ground and the circuit-breaker phase connections.

The use of magnetic-blowout or *air-blast circuit breakers* is rather limited in distribution systems. Most circuit breakers installed nowadays use a vacuum or sulphur hexaflouride gas (SF_6) as insulation, and combination vacuum/SF_6 breakers are also in service.

In a *vacuum circuit breaker* (VCB) the contacts open and close inside a small vacuum bottle designated as a 'vacuum interrupter'. Within the vacuum there are no ions to conduct an arc, so that contact distance for arc separation is small and there is effectively no deterioration of the contacts. The interrupter can handle high numbers of switching cycles, typically more than 10 000 operations at feeder current rating or up to 100 operations at full fault current, and experience indicates that there should be a service life well in excess of 20 years with no maintenance. Should an interrupter fail in service, replacement of the failed unit will restore the VCB back to full fault duty. The main advantages of vacuum circuit breakers are their faster operating time, lower contact wear and reduced power consumption when operating and, with fewer moving parts, little maintenance requirement. Since there are virtually no fire or explosion risks, VCBs are particularly suited to indoor installations in built-up areas.

By containing the *breaker* contacts within a compartment of *SF_6*, the gas can be forced through a nozzle at high speed into the area of the arc. The gas quickly regains its insulating qualities near current zero, thus completing the current-interrupting process. As an alternative to this puffer technique, the arc plasma can be moved by magnetic forces into a new region of fresh SF_6 gas. The force due to the magnetic field has an intensity related to the fault current. Thus the interrupting characteristic is controlled, within limits, by the level of current being interrupted. The insulating properties of SF_6 can be adversely affected by pollution and humidity, so it is essential that the gas is not contaminated. This requires particular attention to be paid to the cleanliness of maintenance equipment, and special precautions are required by maintenance staff to avoid possible contamination.

In the future, semiconductors or superconducting materials may form the basis of new methods of breaking fault current. High-current thyristors are already available and new materials are being developed which are superconducting without having to be cooled to extreme temperatures. Conduction depends on the surrounding magnetic field. Moving from a high magnetic field to a low magnetic field would cause the superconducting material to change from a non-conducting state to a conducting state, which is the requirement for breaking fault current.

6.5.3 Disconnectors

Disconnectors enable off-load breaks to be made in circuits, for example when isolating sections of overhead line on rural networks. Depending on the physical arrangement, they may also provide a visual indication that an item of equipment, e.g. switch, transformer or line, is disconnected from the system. However, plug-in MV circuit breakers do not require their own individual disconnectors. Disconnectors can be of single- or double-pole operation, operated manually or via a motor drive. Manual operation of disconnectors located on the system is usually by a handle fixed near the base of the structure with a rod drive as shown in Figure 6.10, or by means of a hook stick to reach the

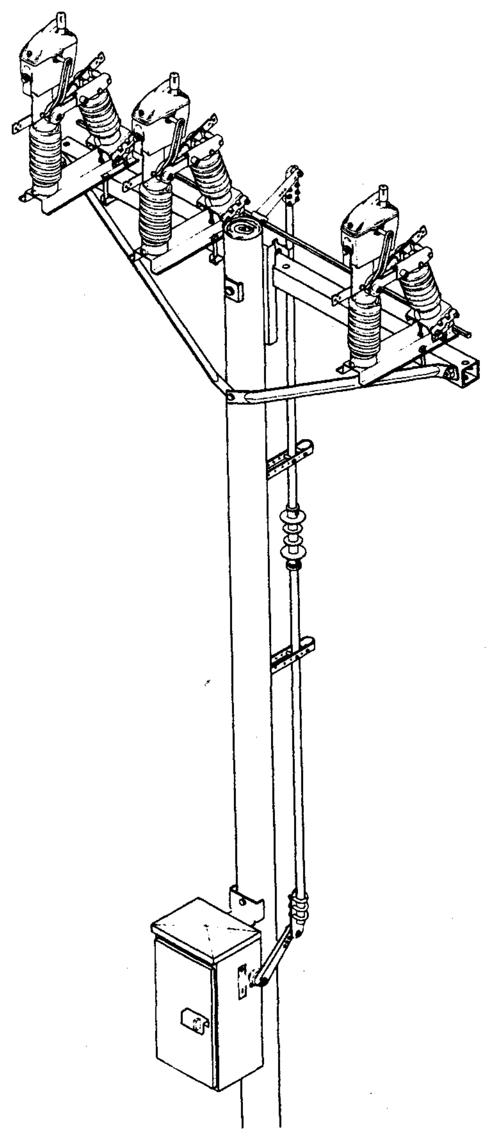


Figure 6.10 Pole-mounted load-breaking disconnector

operating mechanism. Telecontrolled disconnectors have become increasingly popular.

Disconnectors are designed not to be opened when any amount of load current is flowing through them. They are normally capable of closing on to a line where the charging current is small, or to energise a small transformer. Load-breaking disconnectors with special interrupter heads are occasionally used to avoid the cost of a circuit breaker. Where two transformers are banked on the higher-voltage side, the use of load-breaking disconnectors enables a transformer to be off-loaded by opening the lower-voltage circuit breaker, and then de-energised by opening the disconnector. Load-breaking disconnectors are becoming increasingly popular in MV circuits, and, by way of example, the equipment shown in Figure 6.10 is capable of breaking approximately 300 A. In addition pole-mounted SF_6 disconnectors are available for demanding environmental conditions where, for example, ice, vegetation or animals may interfere with the operation of conventional units. The typical breaking capacity of 20 kV SF_6 disconnectors is 630 A, with a making capacity of 40 kA. The use of plug-in-type circuit breakers at MV substations has reduced the number of separate disconnectors required at these locations.

6.6 Replacement of equipment

In many industrialised countries electricity supply systems have been in existence for 50 years or more. The quality of supply now expected by customers has increased considerably, and it is important that ageing equipment should not prejudice the quality of supply being provided, given that operational standards and safety regulations have become more stringent over the years. Failure of equipment due to deterioration can involve loss of supply, and the diversion of a utility's resources to locate, repair and return the equipment to service.

The earlier designs of MV switchgear did not have the facilities now deemed necessary for the safety of the utility personnel, the capability of breaking or making the higher fault currents now met on present-day systems, or the automatic features now required to improve system operational performance. Where double-busbar switchboards had been installed, single-busbar switchboards are becoming more common owing to improved component reliability. The increasing use of automated sectionalisers and reclosers has made it possible to reduce switchgear requirements at major MV switchboards. SF_6 disconnectors are now available which can be installed on cable networks to provide fault isolation facilities associated with autoreclosing facilities similar to those provided on overhead networks.

With MV and HV overhead-line circuits, deterioration of steel-tower metalwork at ground level, and of the conductors due to atmospheric pollution and weather conditions, pose problems in repairing or replacing these items. In many areas it is not possible to build a new overhead line alongside the existing circuit owing to right-of-way problems or the proximity of buildings, and lines which were originally built in fields may now be surrounded by various forms of development. Individual parts of the tower can be replaced as necessary, so that the repaired tower can then withstand the stresses of pulling in new conductors. However, re-conductoring poses further problems in that both the old and the new conductors must be kept clear of roads, railways, buildings etc., and it is very often necessary to erect considerable amounts of scaffolding or use numbers of high-level mobile platforms while re-stringing the conductors under controlled tension.

Wood poles have been used extensively at MV and almost exclusively at LV. Whilst pole lives of 80 years have been claimed, the average life of a wood pole is about 50 years. Failure is usually due to wood rot around the ground-level mark, the degree of rot being influenced by the impregnation process used and local soil conditions. Replacement is relatively easy, with the conductors being supported by temporary poles adjacent to the pole position.

Concrete structures, reinforced with steel rods, are in common use in substations. Damage can result from frost and ice, and ultimately the steel reinforcements can be exposed and suffer corrosion. The application of suitable de-rusting agents to the steel, and repair of the damaged concrete using various epoxy resin mixtures, appears to be an attractive economic solution.

When considering replacement of cables one major factor is the high costs involved. In Great Britain there are many cables 50 years or more old which were originally installed for systems operating at 5 kV, for example, uprated to 6·6 kV working, and then further uprated to 11 kV operation. There are as yet no diagnostic techniques available to predict the likely number of years of useful life remaining in these cables. A sudden increase in fault incidence is often the only indication that a cable has reached the end of its useful service life, as shown in Figure 6.11, which is taken from an actual case in Great Britain. It is generally not possible to excavate a cable and replace it by a new cable in the same trench, because of the unacceptable reduced system security during this replacement period. Where cables have been laid in ducts or pipes it may be possible to extract these and use the vacated duct of pipe for replacement cable.

Replacement of large HV/MV transformers can cost of the order of £3/4 million per unit, when account is also taken of replacing associated HV and MV connections, and relay and control equipment. While research is being carried out to equate transformer dielectric losses with deterioration of insulation, it has as yet not been possible to predict the likely future time of failure. It is unlikely that transformer replacement could be justified purely on any savings in transformer losses or reduced maintenance costs. However, when transformers of any size are replaced owing to excessive deterioration, these benefits should naturally be taken into account.

With the replacement of any equipment, the opportunity should be taken to consider whether it is economic to make provision for the possibility of uprating the network voltage level in the foreseeable future. For example, in Great Britain replacement of switchgear and cables on existing 6·6 kV networks is by 11 kV

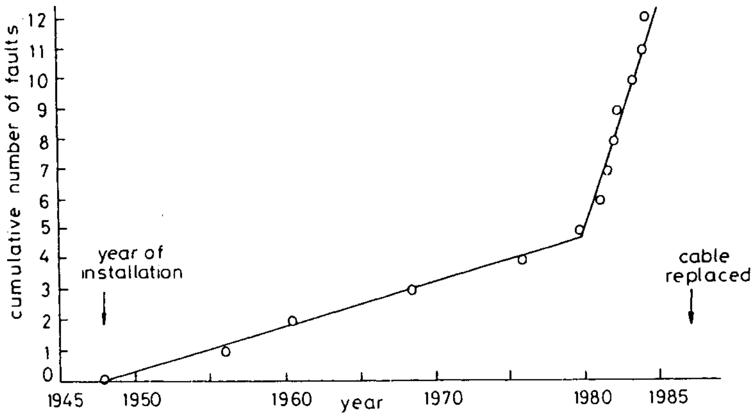


Figure 6.11 Incidence of faults on MV cable leading to replacement

equipment, even if the particular network is not scheduled to be uprated to 11 kV for some years. Double-ratio 11 kV/6·6 kV/LV distribution transformers can be installed in anticipation of a move to the higher voltage. Similarly, when replacing single-phase LV and MV overhead lines it would be prudent to allow for future conversion to 3-phase circuits and the possibility of uprating to a higher voltage level in the future.

Equipment replacement offers the planning and design engineer an opportunity to provide facilities for the long-term development of any system, and this aspect must always be considered rather than concentrating on a like-for-like replacement. Often it is possible to achieve a simplification of the system which improves system reliability and reduces investment expenditure. Examples of this type of development are the replacement of the double MV system, e.g. 33/11 kV in the UK, with a single voltage level, thus saving the costs of MV/MV substations by the adoption of simple satellite substations – small HV/MV or MV/LV transforming points near the load centres.

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Chapter 7

System protection

7.1 General

A properly co-ordinated protection system is vital to ensure that an electricity distribution network can operate within preset requirements for safety for individual items of equipment, staff and public, and the network overall. Automatic operation is necessary to isolate faults on the networks in a minimum time in order to minimise damage. In addition, minimising the costs of non-distributed energy is receiving increasing attention.

The various items of switchgear and automatic disconnectors referred to in the previous chapter require sensing devices to activate them. These must determine whether some abnormal situation has arisen on the network which requires disconnection of any circuit, and are generally referred to as protective devices.

When providing protective devices on any supply network the following basic principles must apply. Disconnection of equipment must be restricted to the minimum amount necessary to isolate the fault from the system. The protection must be sensitive enough to operate when a fault occurs under minimum fault conditions, yet be stable enough not to operate when its associated equipment is carrying the maximum rated current, which may be a short-time value. It must also be fast to operate in order to clear the fault from the system quickly to minimise damage to system components, and be reliable in operation. Back-up protection to cover the possible failure of the main protection is provided on most circuits in order to improve the reliability of the protection system.

Electromechanical relays may still be found in some of the older electricity supply systems, although in recent years there has been a move to replace these with modern relays. Solid-state relays started to come into use in the 1970s and microprocessor-controlled relays were installed from the early 1980s and are replacing the older types of relays. In the following sections only the fundamental principles of various types of protection will be considered.

7.2 Overcurrent protection

7.2.1 Fuses

A fuse acts as both a protective and a disconnecting device, and fuses were the earliest such devices used on electrical systems. It basically consists of a metallic element which melts and becomes discontinuous at a relatively high current, thus preventing the further passage of current. It must, however, permit the maximum load current to flow continuously without operating or deteriorating. While fuses are relatively small and cheap, they suffer from the disadvantage that, once they have melted and operated owing to transient faults, they require replacing before the protected circuit can carry load again.

Operation time due to fault current can be of the order of one half-cycle. The fault current is thus cut off by the operation of the fuse before the current can reach the maximum prospective value. Dependent on the fault current, the operating time can, however, take some seconds to clear the fault. By suitable design and the use of various metallic elements and filler materials, different time/current characteristics can be achieved to aid discrimination with other fuses or protective devices. A fuse rating should be selected basically to provide fault protection, rather than overload protection.

Given the wide variety of fuse characteristics available, the appropriate manufacturer's information should be used to determine correct discrimination between fuses in series, but the following example highlights the main factors.

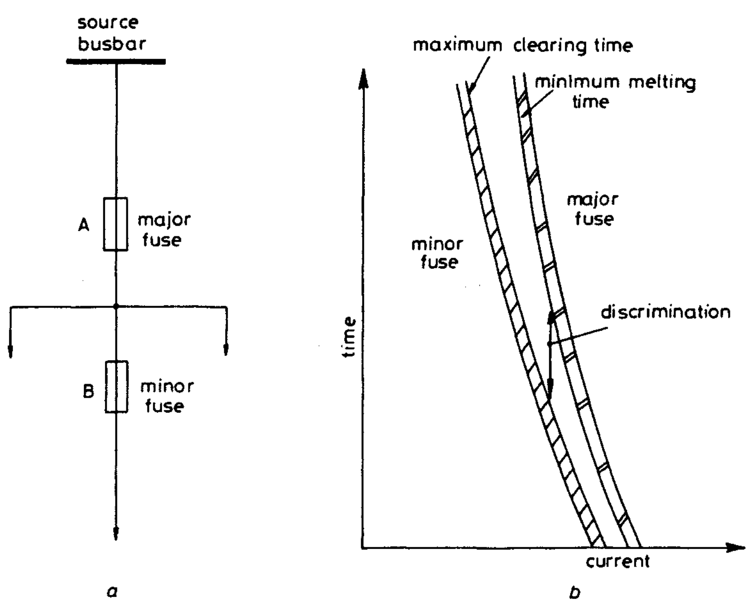

Figure 7.1 Co-ordination of fuses

The simplest situation is with two fuses in series, as shown in Figure 7.1*a*. The fuse nearest the source infeed, fuse A, is usually designated the *major* fuse, with fuse B known as the *minor* fuse. Typical operating curves are shown diagrammatically in Figure 7.1*b*, which indicates the required discriminating interval between the minimum melting time of the major fuse A and the maximum clearance time of fuse B. As an approximate guide successive fuses should be rated at 1·6 to 2 times the rating of their minor fuses to achieve acceptable discrimination. Fuses are in common use on LV systems and are sometimes found on MV underground networks. This practice is based on

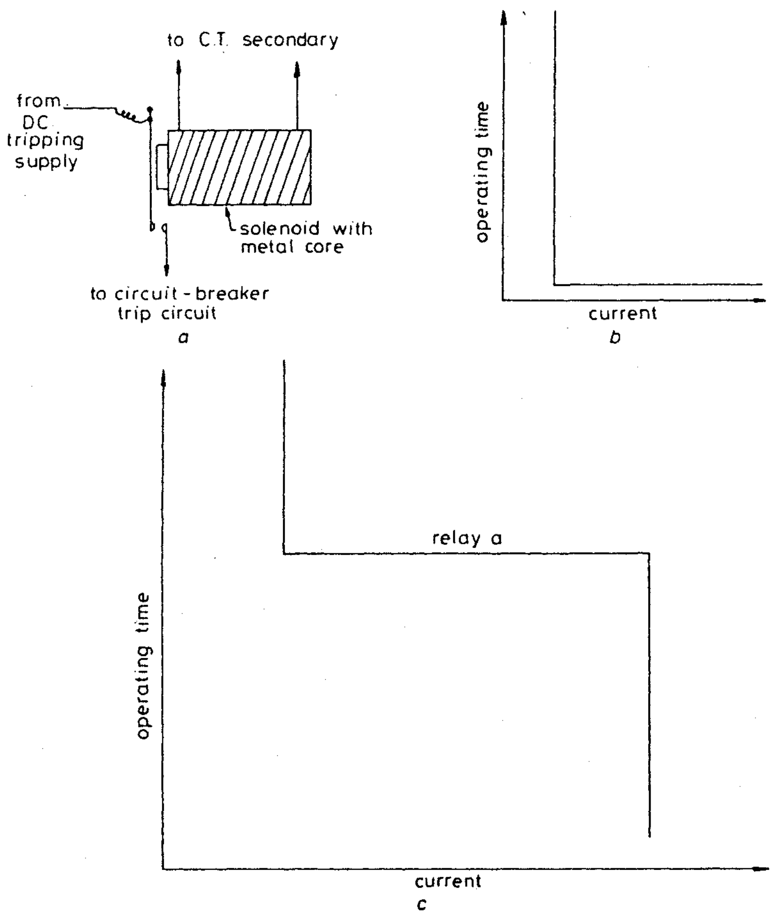

Figure 7.2 Definite-time-delay overcurrent relays

a Relay
b Time/current curve of instantaneous relay
c Co-ordination of definite-time-delay relays equipped with instantaneous tripping at high currents

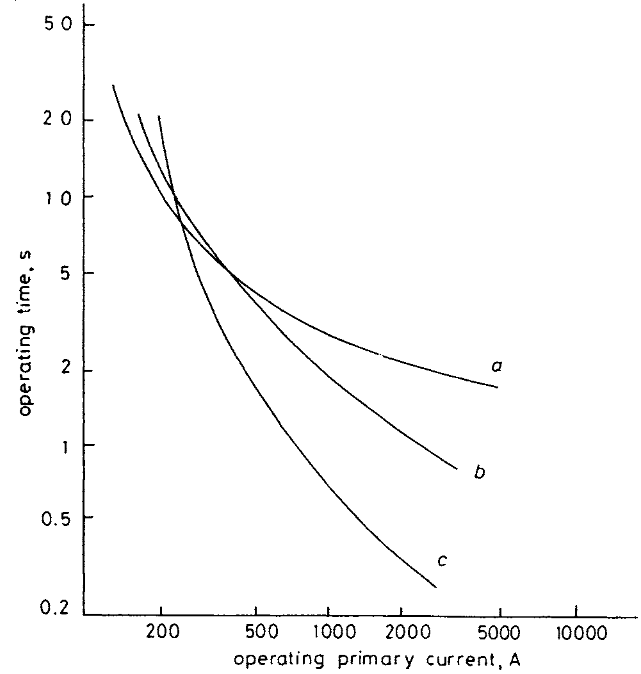

Figure 7.3 Inverse-time-delay overcurrent-relay characteristics

economic considerations. A more sophisticated relay protection system can be justified in MV systems since it reduces outage costs.

7.2.2 Overcurrent relays

The basic method of providing overcurrent relay protection on a circuit is to install current transformers (CTs) on the circuit, which then feed current into the overcurrent relay proportional to the circuit current. When the current exceeds a preset value the relay will operate at a time determined by the characteristics of the relay to initiate tripping of the associated circuit breaker.

One of the earliest forms of overcurrent relay was an instantaneous electromechanical version with a solenoid which, when sufficient current was passed through the coil from the current transformer, would magnetically attract a metal armature to operate the tripping circuit, as indicated in Figure 7.2*a*. This would have a time/current characteristic as in Figure 7.2*b*. The addition of a timing device results in a definite time-delay overcurrent relay. The time delay can be adjusted, but is independent of the value of the overcurrent required to operate the relay. By varying the time delay of successive relays in series, discrimination between the relays can be achieved. As shown in Figure 7.2*c*, these relays can be equipped with an additional element which provides

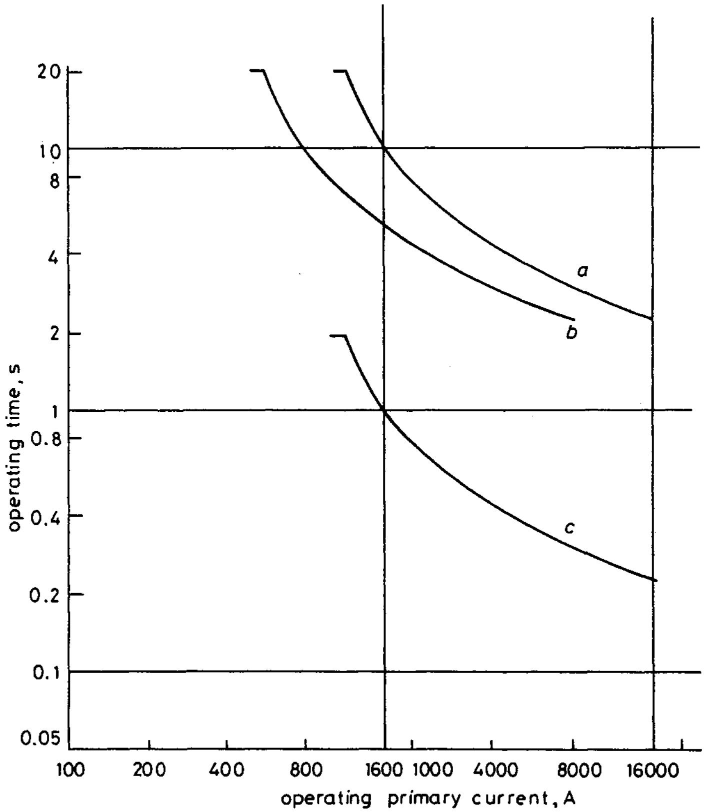

Figure 7.4 Varying relay operating time by using different current and time settings

a 100% current = 800 A; 1.0 time multiplier
b 50% current = 400 A; 1.0 time multiplier
c 100% current = 800 A; 0.1 time multiplier

virtually instantaneous operation at a given high value of current, as indicated by the vertical line on the right-hand side of the relay characteristic. This arrangement has been used extensively in Europe, since it provides a simple solution to the problem of protection selectivity.

In the UK and USA the induction-disc relay, which has a construction similar to that of a conventional energy-consumption meter, has been used extensively. Various time/current characteristics can be achieved as shown in Figure 7.3. These relays are also designated inverse time-delay overcurrent relays, since they operate after a time delay which is inversely dependent on the value of the overcurrent. It should be noted that the time delay approaches a definite minimum value for higher values of overcurrent.

It is essential that there is adequate discrimination between relay/protection stages in series. Faults in different sections of a network will result in fault

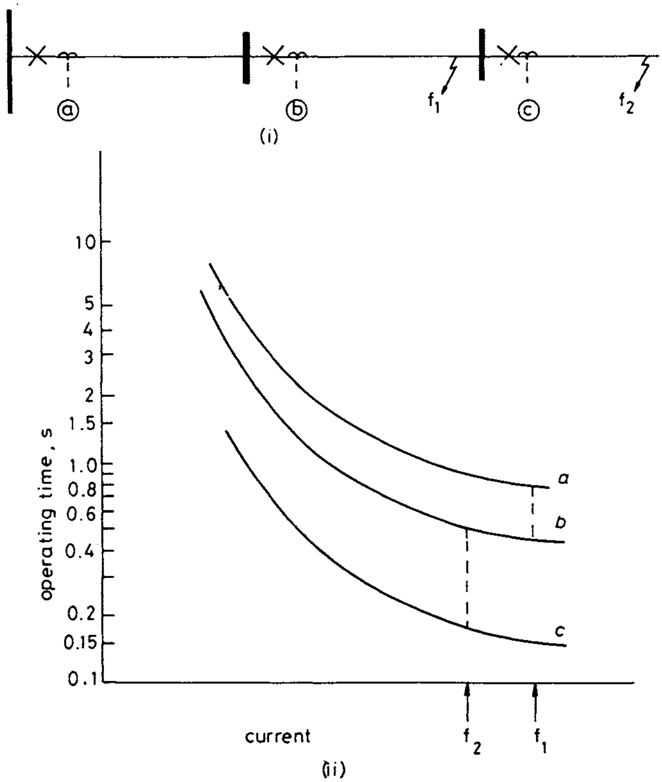

Figure 7.5 Discrimination with inverse-time-delay overcurrent relays

currents of different magnitudes owing to the different impedances between the power source and the fault position. If suitable relay current/time settings are selected only those circuit breakers nearest the fault will trip, leaving the other breakers to supply the healthy sections of the network. It is common practice to arrange for about 0·4–0·5s operating time between relays in series, to allow for tolerances in relay and circuit-breaker operation. With electronic relays, where the time accuracy is better, 0·3 s discrimination is possible.

For the inverse time-delay overcurrent relay the speed of operation may be altered by adjusting the sensitivity of the relay, or the time required for the relay contacts to close to trip the circuit breaker. Consider the time/current characteristic of such a relay, with a nominal operating current of 800 A primary current, and a 1·0 time multiplier, as shown in Figure 7.4*a*. Then, by way of example, for a fault current of 1600 A it will be seen that the relay would operate in 10 s. Altering the current sensitivity to 400 A, i.e. one-half of the previous setting, would result in the relay characteristic being moved to the left as shown by the curve *b* and the relay will operate in the same time as at setting *a* with one-half the current, i.e. 10 s at 800 A. In addition, by adjustment of the

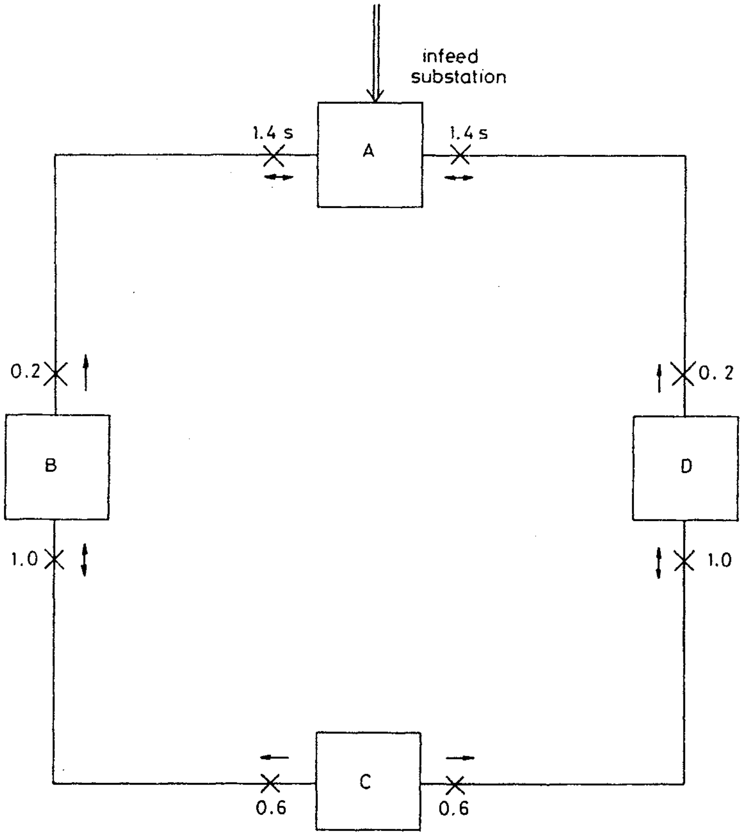

Figure 7.6 Directional overcurrent protection

↔ = non-directional
→ = directional

time setting the operating time for a given fault current can be varied. Curve *c* represents a time setting one-tenth of the original setting *a*, and the operating time at this setting for 1600 A is 1 s compared with the 10 s operating time if the relay had been set to curve *a*.

The ability to change the time and current settings of a relay makes it possible to obtain suitable operating times whatever the fault current may be, in order to obtain discrimination with other relays in series along a feeder. It should be noted that the operating times in this example merely illustrate the variety of operating times that can be achieved by adjusting the time and current settings of an inverse time-delay overcurrent relay, and do not represent actual protection setting times, typically up to around 1 s, which are covered next.

Consider the arrangement in Figure 7.5(i) with relay *b* providing backup to relay *c*, and relay *a* providing backup to relay *b*. Discrimination is achieved by suitable choice of the relay current and time settings as shown schematically in

Figure 7.5(ii) such that at fault current f_2 there is 0·3 s discrimination between relays *b* and *c*, and similarly between relays *a* and *b* at fault current f_1. The fault clearance times should be such that thermal stresses on lines are kept within acceptable limits.

In a closed ring system, relays with an added directional facility are required in order that discrimination is obtained in each direction around the ring. Such a situation is shown schematically in Figure 7.6 where infeed substation A supplies substations B, C and D. The arrows indicate the direction of current flow for which the relays operate, with typical tripping times also shown.

7.3 Earth-fault protection

The majority of system faults occur between one phase and earth, and in overhead lines such faults can involve high fault impedances, resulting in relatively low fault currents. However, any fault condition must be cleared rapidly from the system to avoid damage to equipment and people, and in the interests of safety. The most suitable method of earth-fault protection depends on the particular method of neutral earthing in use, and the required sensitivity and selectivity to ensure correct discrimination.

For systems which are earthed direct, or via an untuned impedance, the usual practice is to connect the secondary windings of the current transformer to one earth-fault relay as shown in Figure 7.7*a*, or to combine the overcurrent and earth-fault elements as in Figure 7.7*b*. In MV overhead systems high-resistance faults may occur, e.g. due to a fallen conductor. The corresponding low-level earth-fault current may not be detected by the zero-sequence relay arrangements shown in Figures 7.7*a* and *b*. This could be because of a lack of sensitivity due to the relay or current-transformer characteristics, plus the need to set the relay at a sufficiently high-current value in order to avoid undue tripping; e.g. due to a momentary imbalance of capacitive current when an earth fault occurs on another feeder.

In unearthed systems, or those earthed through arc-suppression coils, with earth faults the resultant fault currents are very low and can be much lower than the normal load currents. Thus conventional earth-fault relays will not operate even in such cases.

For a network with an unearthed neutral, or one earthed via an arc-suppression coil, an earth fault produces asymmetry in both system voltages and currents, not only from the faulted feeder but across the total network fed from one transformer, or the whole substation if the transformers are in parallel on the MV side. Thus, at an HV/MV substation, the protection on individual MV feeders has to be directionally sensitive in order to operate only for faults on the feeder. The earth-fault current may be detected by current transformers summating the currents in each phase, as shown in Figure 7.7*a*. The voltage asymmetry is usually detected by using an open delta winding in the secondary of the voltage transformer, as shown in Figure 7.8.

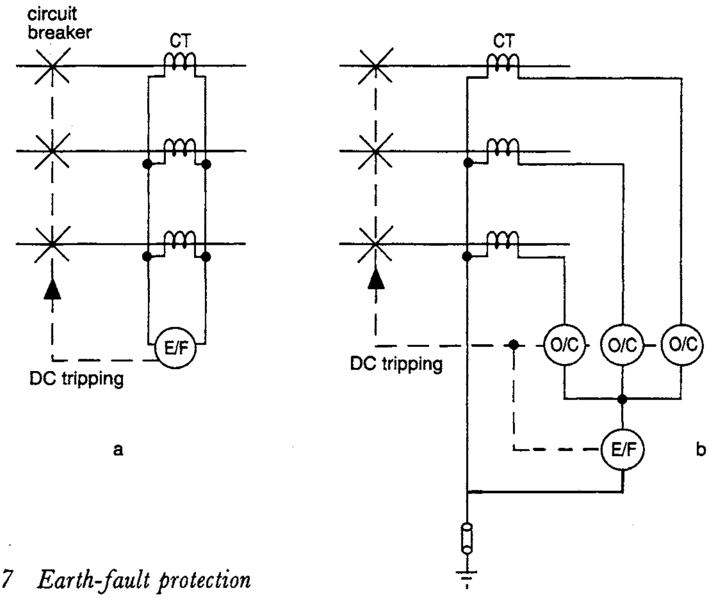

Figure 7.7 Earth-fault protection

E/F = earth-fault relay; O/C = overcurrent relay

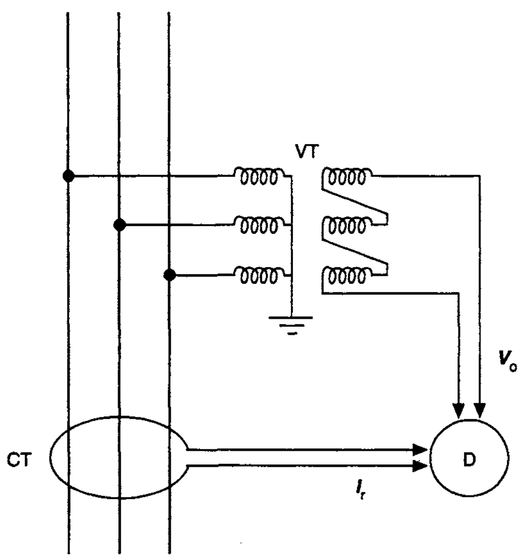

Figure 7.8 Directional earth-fault protection: CT and VT arrangements

D = directional element of earth-fault relay
Relay angle setting = 0° for system earthed via arc-suppression coil, 90° for unearthed system (see Figure 7.9)

With current and voltage supplied to the earth-fault relay the basic criteria for its operation are that both the asymmetric current $\boldsymbol{I}_r$ and the asymmetric voltage between neutral and earth, $\boldsymbol{V}_0$ have to exceed preset values. In addition, operation will only occur within a specific range of the phase angle between $\boldsymbol{I}_r$ and $\boldsymbol{V}_0$ as indicated diagrammatically in Figure 7.9. As discussed in Section 3.7, the fault current $\boldsymbol{I}_f$ and the neutral point voltage $\boldsymbol{V}_0$ both depend on the total phase–earth capacitance. The asymmetry current $\boldsymbol{I}_r$ detected by the relay is a proportion of the fault current $\boldsymbol{I}_f$, and is influenced by the phase–earth capacitance of the network, which will alter as the network configuration is changed.

Microprocessor-based relays can be used to apply more complex criteria, with the additional facility that any settings can be adjusted via remote-control systems. These features have extended the use of unearthed, and arc-suppression-coil-earthed, systems. On the other hand, trends to simpler and more reliable supply arrangements lead to a preference for earthed systems, where, for example, simple current sensors can replace current transformers, and where distributed automation is easier to arrange.

7.4 Unit and distance protection

7.4.1 Unit protection

The simpler protection facilities described in the previous sections can provide suitable discrimination for radial and small mesh networks. They do, however, have limitations in ensuring satisfactory discrimination under all the fault-level and network conditions likely to be met in interconnected HV systems, and in some exceptional combinations of circumstances. Consequently protection schemes have been devised where the protection coverage is limited to only one item of equipment.

If a fault occurs within the protected zone, relay operation should take place, whereas fault current feeding through the protected zone to a fault elsewhere on the system should not operate the protection. This form of protection is designated unit protection, since each protection arrangement protects only one unit of the system; e.g. a line or cable, a transformer, or a generator.

Unit protection schemes are based on the fact that, with a healthy circuit, the currents entering and leaving the circuit are equal. A schematic diagram of one type of this protection is given in Figure 7.10*a* for one phase only. Current transformers at each end of the circuit are interlinked by pilot wires as shown. The example covers the voltage-balance arrangement where the CT secondaries are connected in opposition. Current only flows through the pilot wires, and therefore through the relays, when there is a difference in the induced voltages v_1 and v_2. This will occur when there is a difference in the primary currents at each end of the circuit, as indicated in Figure 7.10*b*, showing a fault within the protected zone. Pilot problems limit the maximum line length which can be protected by such schemes to about 40 km, and these schemes tend to be associated with the higher-medium-voltage and high-voltage systems.

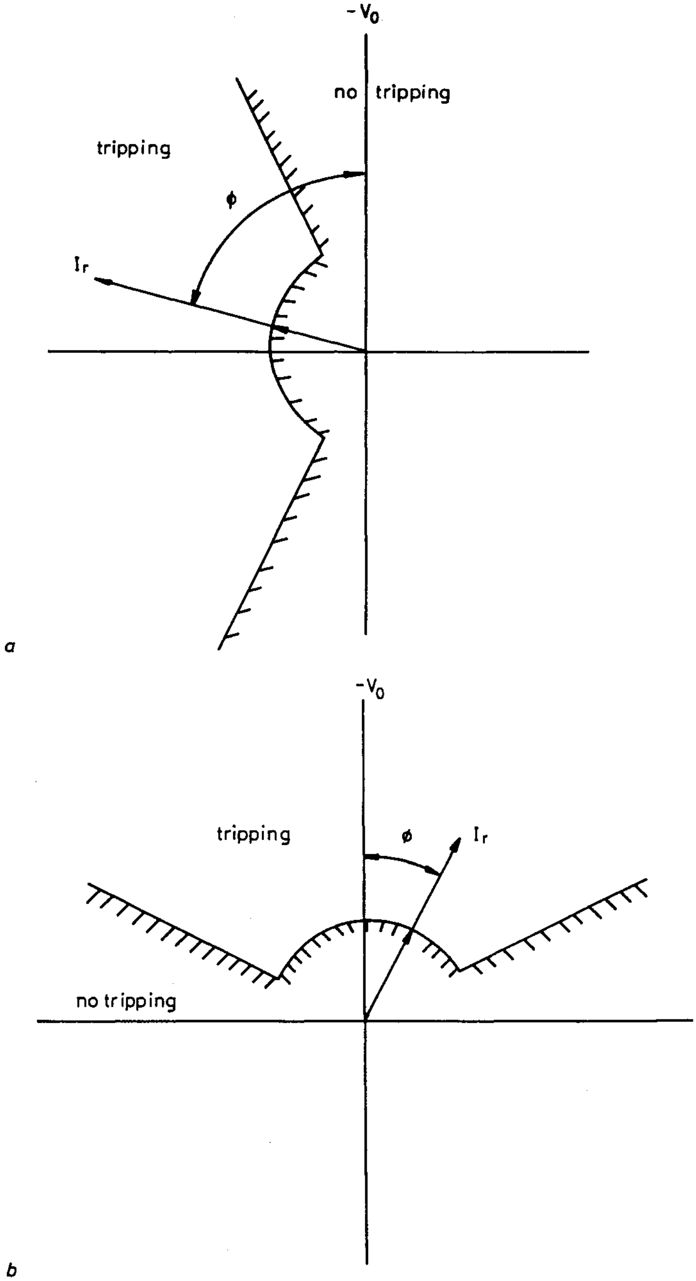

Figure 7.9 Tripping criteria for a directional earth-fault relay

V_0 = neutral-point voltage; I_r = relay current
a Unearthed system
b System earthed via arc-suppression coil

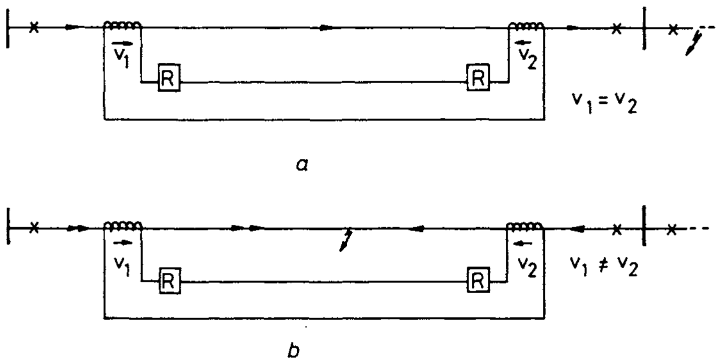

Figure 7.10 Example of unit-protection operation

a Through fault
b Internal fault, fed from two ends

Similar unit protection is used to protect transformers. The turns ratios of the current transformers have to be adjusted to take account of the main transformer voltage ratio, which can vary if the transformer has on-load tap-change facilities. In addition, the primary- and secondary-winding CT connections must take account of the main transformer winding arrangement, e.g. star/delta or delta/star.

7.4.2 Distance protection

The previously mentioned limitations of over-current protection, the possibility of damage to pilot-wire cables, plus possible instability on unit protection schemes with heavy through-fault currents, resulted in distance protection being developed for use mainly on HV systems. In these schemes the circuit voltage and currents are used to detect the fault, on the basis that the distance to the fault is proportional to the impedance or reactance to the fault.

Various time/distance characteristics are available for impedance protection, but stepped or sloping characteristics are most commonly used. In Figure 7.11 A, B, C and D represent the location of substations linked by feeders AB, BC and CD with a fault on feeder CD at F. Considering the stepped characteristics used in Figure 7.11, it will be noticed that a fault in the first zone covered by the protection at A, marked A1, would result in the fastest operating time of the relays at A. This zone extends for about 80% of feeder AB to avoid possible discrimination with relay B. If this 'fast zone' were extended close to substation B, variations in equipment tolerances and system arrangement could result in rapid operation of the protection at A for a fault on feeder BC close to substation B. For example, if the system is earthed at more than one point, the impedance measured by the relay system will be too low, whereas if fault arc resistance is present the fault will appear further away.

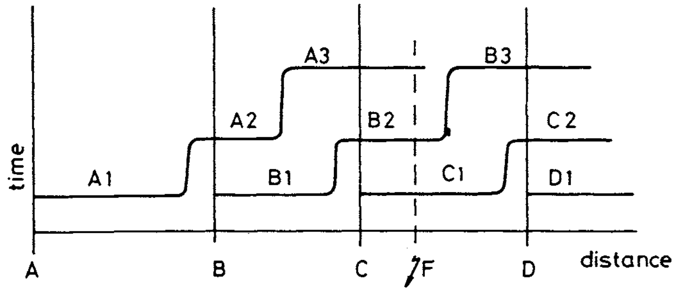

Figure 7.11 Discrimination of distance protection

For a fault at F on feeder CD the fault current flowing down the circuit will initiate the distance protection relays at A, B and C. If the fault is correctly cleared by relay C flow of fault current ceases through A and B and these relays reset, leaving circuits AB and BC in service. The degree of backup by successive stages of the upstream relays is indicated by the vertical time scale between C1 and B2, and between B2 and A3.

7.5 Autoreclosing arrangements

For economic reasons rural electricity supplies are invariably provided via radial overhead-line networks. Since about 80–90% of line faults are self clearing or transient in nature, it has become common practice on MV systems to reclose the source breaker once, or possibly twice, to check whether the feeder is then clear of faults. The minimum time off supply is determined by the need to clear arc ionisation; the maximum time is influenced by the effect on loss of supply to customers. The number and length of the reclosing shots, when fault current is flowing, will also have a bearing on the I^2t heating effect on lines and cables, and substation equipment.

The automatic recloser was developed by arranging for the source circuit breaker to carry out a variable sequence of tripping and closing by suitable relaying. The tripping can either be instantaneous, clearing the fault in about 0.2–0.5 s, or be delayed with clearance times of tens of seconds. Up to four combinations of instantaneous and delayed tripping are usually available, but generally system arrangements are such that only two auto-reclosing operations are necessary. Where it is not desirable to install auto-reclosing on the source breaker, either because it is not suitable for this duty or because the first section of the feeder is underground cable, a high-speed pole-mounted auto-recloser can be installed at the beginning of the overhead network.

One further item of equipment needs to be considered in the protection co-ordination chain – the automatic sectionaliser. A typical example is shown in Figure 7.12*a*. Automatic sectionalisers S are provided on a number of spur

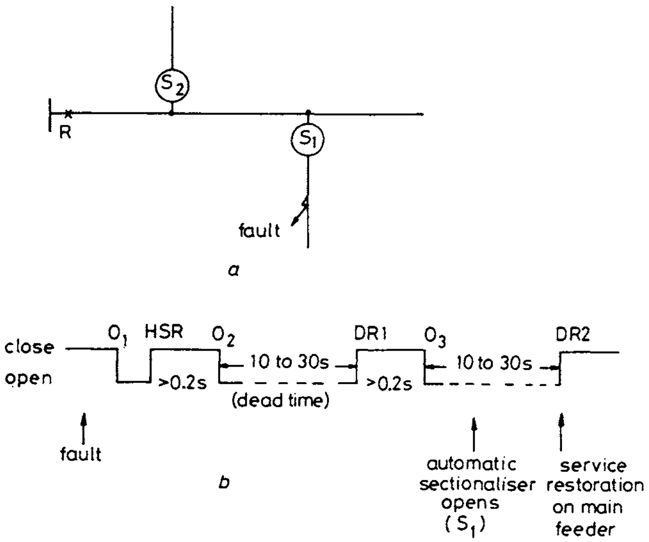

Figure 7.12 *Use of autoreclosers and sectionalisers*

a R: autoreclosing circuit breaker with multishot reclosing
S_1, S_2: pole-mounted automatic sectionalisers

b O_1, O_2, O_3: circuit breaker opens (three trips)
HSR: high-speed automatic reclosing
DR1, DR2: delayed automatic reclosing

feeders in order to isolate any faulted branch during the dead time (open period) of the delayed automatic recloser at the HV/MV substation R. A sectionaliser is not capable of breaking fault current, but may be closed on to a fault. It therefore requires a device to count the number of passages of the fault current on the feeder as the recloser goes through its preset sequence of opening and closing operations. After registering a preset number of fault-current pulses the sectionaliser opens within the dead time of the recloser, to isolate the faulted section of the line without breaking fault current. This sequence is shown diagrammatically in Figure 7.12*b*, covering the case of a fault on a spur feeder connected to the main feeder by an automatic sectionaliser. For a transient fault, when the recloser restores supplies, the sectionaliser sensing devices note that only load current is flowing and return the sectionaliser to its normal state.

For these sectionaliser operations the isolated spur is not automatically identified at the control centre, and this may therefore result in an extended outage time. However, the use of fault-passage indicators can assist in locating the faulty section. Furthermore, telecontrolled switches can avoid such situations. Such an arrangement is also relevant where sectionalisers revert from telecontolled to automatic operation during periods when a telecontrol centre is unmanned.

7.6 Overvoltage protection

As well as preventing damage to equipment due to fault current, it is also necessary to ensure that excessive voltages do not cause damage or lead to unnecessary outages. The optimum methods of protection against overvoltages, and how widely such protection should be applied, depend on system-operation practice and local weather conditions, e.g. lightning strikes. The theoretical aspects of overvoltages are discussed in Section 3.8. Some of the protection aspects will be considered in this section.

The high voltages which are induced on an overhead line from direct lightning strikes, or from strikes to nearby ground, are propagated as surges along the line and can cause damage to substation equipment unless suitable protection devices are installed. In order to prevent steep surges from entering an HV/MV substation, the HV lines are equipped with earth wires. Earth wires on MV lines close to the substations also assist. If the MV-line crossarms are earthed, this limits the overvoltage level which can be formed on the line. Often larger substations are themselves equipped with earth wires or masts to protect the substation from direct lightning strikes.

The insulation strength, or insulation level, of various items of equipment has to be greater than the magnitude of these transient overvoltages. Various overvoltage protection devices can be fitted on the network to reduce the overvoltages to an acceptable level. With the transient overvoltages limited to a given 'protection level' by such devices, the insulation level of the system must exceed the 'protection level' by a safety margin of around 20–25%.

Resonance-induced overvoltages can be prevented by avoiding exceptional operational arrangements; e.g. transformers connected to a system by their higher-, or lower-voltage windings only. A broken conductor can lead to resonance overvoltages. Since the operation of a phase fuse creates a similar situation, omitting fuses on MV systems has the advantage of limiting such overvoltages. The jump resonance of voltage transformers can be dampened to a tolerable level by adding a resistor to the secondary winding, or open tertiary delta, of the voltage transformer (VT). There is no effective protection against sustained overvoltage, so that it is vital to design any system so that excessive overvoltages of this type cannot be produced.

The simplest form of overvoltage protection is the so-called air gap with one metallic rod connected to a phase conductor and a second rod connected to earth. The gaps are frequently connected across an insulator, as, for example, on the higher-voltage side of a transformer. The setting of the air gap is made such that flashover occurs at 70% or less of the rated impulse-withstand voltage. Any such flashover then becomes an earth fault on the system and is usually cleared by an auto-recloser operation. Air gaps are inexpensive, but do not fully protect against very steep-fronted surges induced by direct or indirect lightning strikes.

This limitation has led to the use of lightning arresters, which have the further advantage that their use avoids the follow-on power current experienced with air gaps. A conventional arrester consists of a bushing with a number of air gaps and non-linear resistors in series between the phase and earth connections. The resistance of the resistor decreases very rapidly as the current through it increases, so that, when the gaps break down on overvoltage, the resistors ensure that the voltage on the conductor is limited to a safe value. Once the surge has been discharged, the voltage across the arrester starts to drop and the current falls. The resistance of the resistor then increases and the follow-through power current is sufficiently reduced to be broken by the air gaps at the next voltage zero. Operation is fast and the unit is then once again available for overvoltage protection duty. The voltage and current characteristics of lightning arrester operation are shown in Figure 7.13, where the sharp fall in current following breakdown of the gap can be seen.

The arresters with series air gaps have two shortcomings. The voltage stress on the protected equipment rises to a very high value before sparkover occurs, and the sparkover then causes a sudden drop in voltage, as seen in Figure 7.13. To minimise sudden changes in voltage stresses, a gapless type has been developed, based on the characteristics of non-linear resistors, and is in common use. The modern metal-oxide arrester, without any gaps, leads to a smoother and more effective method of protection.

Lightning arresters are most effective when located as close as possible to the equipment they are protecting – no more than 10 m away. Longer distances lead to higher voltages being imposed on the equipment. They are primarily used at

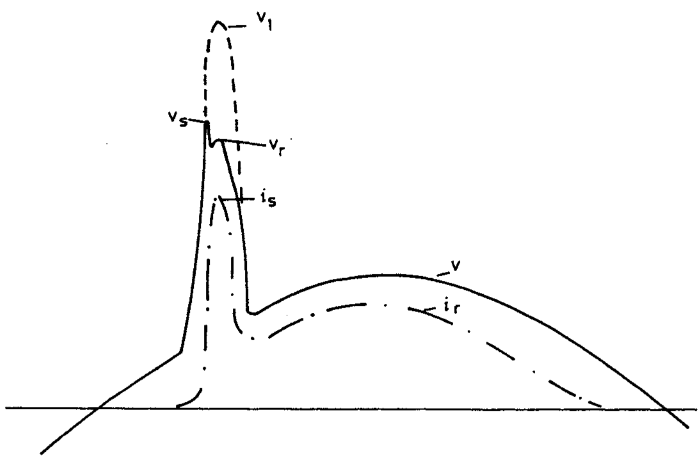

Figure 7.13 Voltage/current characteristic of a lightning arrester

v = normal phase-earth voltage waveform
v_1 = voltage surge if no lightning arrester used
v_s = lightning-arrester breakdown voltage
v_r = residual voltage
i_s = peak current
i_r = follow-through current

both sides of HV/MV substations and on cable/overhead-line junctions. Overhead-line/cable surge impedances are approximately in the ratio 10:1.

In some areas where the keraunic level is high, as in central USA for example, each MV/LV distribution transformer may be fitted with a lightning arrester. While this may not save the transformers close to a lightning strike on the MV circuit, the arresters prevent damage to many units from overvoltages on the network caused by direct or indirect strikes. In countries with lower keraunic levels it is often economic to protect the larger distribution transformers connected to overhead lines with arresters, while protecting the smaller units with air gaps.

7.7 Automation of network operation

The main purpose of automation is to obtain better system performance and to improve the reliability of supplies to customers, by faster clearance of faults and restoration of supplies.

There are many levels of automation. Two simple examples of automatic devices are fuses and air gaps which operate when specified current and voltage levels are exceeded. Protection relays and lightning arresters are more advanced versions of these devices. Various decentralised automatic arrangements have been in service on distribution systems for some decades. One of the earliest was the use of automatic tap changers and voltage regulators for voltage-drop compensation. With conventional distribution network arrangements any faulted MV feeder was identified solely from the operation of the protection relays, and accurate location of the fault was not easy. The introduction of devices on the networks which indicate the passage of fault current, known as fault indicators, has assisted considerably in fault location and isolation of the faulted section.

The use of microprocessor-based relays, which can measure a number of input signals to derive the required operating sequence for the specific fault condition, as well as having in-built self-checking facilities, has resulted in sophisticated protection and fault-clearing schemes being developed. Increasing use of microprocessor logic-controlled sectionalisers is removing the dependence on utility control staff intervention, leading to more rapid isolation of faults and restoration of supplies. Telecontrolled disconnectors, distributed around the MV network, are a further extension of automating system operation to reduce down time for fault clearance or network maintenance, or optimising network flows to reduce system losses, for example. Using suitable computer hardware and programs, network configurations can be automatically re-arranged on the occurrence of faults to minimise the consequences of further system outages.

The advent of telecommunication channels to individual substations made it possible to provide more instruction codes to more equipment, and to receive information back on the state of the equipment. Thus, a single relatively low-powered transmitter operating at a frequency of a few hundred megahertz can provide communication channels between local control centres and individual substations, and also between a central control point and several local control centres. With two-way links each substation is equipped with its own receiver plus a small power transmitter to send back data to the control centre.

With the two-way facility available, system control and data-acquisition (SCADA) systems can be set up, where not only can instructions be transmitted to specific items of equipment at every telecontrol substation but also many and varied types of data can be transmitted from each substation to the control centre. Circuit-overload and fault data, including equipment and protection faults, are instantly transmitted to the control centre, triggering an alarm to alert the control engineer to a fault on the electrical network or one of the auxiliary support systems. The necessary action can then be taken to isolate faulty equipment and restore the network to a satisfactory configuration. Computer-based SCADA systems make it possible to pre-program various system-control operations to minimise down time in the even of a fault, or to optimise network security and/or system losses while at the same time capturing real-time system data for interrogation and storage. Apart from sending back real-time information on the state of each network, such systems can collect energy and demand data from points on each network. Linked to a computer, such information can be processed to provide useful data for statistical analysis, as discussed in Chapter 11.

7.8 Distribution management systems

Arising from the developments referred to earlier, one of the most interesting areas has been the development of *distribution management systems* (DMS) utilising the traditional SCADA system, real-time fault-current information from relays, and the *network information system* to provide support tools for control centre operators in order to minimise the total operational costs (power losses and outage costs) subject to certain technical constraints being kept within acceptable values.

Figure 7.14 shows a model for defining the various states of a distribution network. The normal state can be divided into two parts. The unacceptable section excludes those disturbed states detected and alarmed by SCADA functions but includes those constraint violations which must be detected by network analysis, while the acceptable state is divided into optimal and non-optimal states. Figure 7.14 also shows the close relationship between planning and operation. The functions in the normal state are generally planning tasks while those outside it relate more to operational problems.

In the disturbed state the automation system detects an abnormal network event due to a fault, or some system limitation being exceeded, and sends an alarm. The loss of a feeder would be signalled as a faulted state but a feeder which has been faulted or switched open for maintenance purposes, and is now

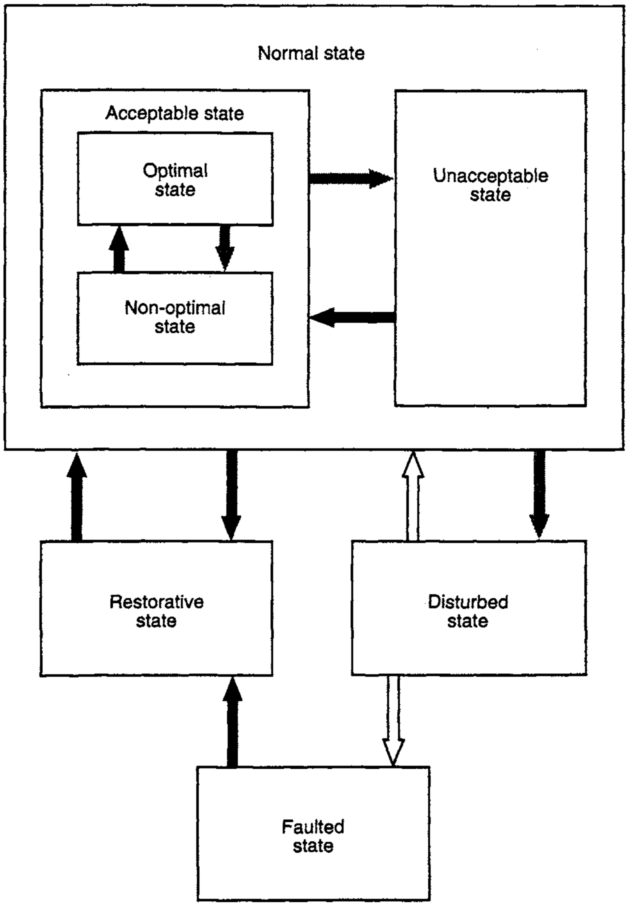

Figure 7.14 Operating states and state transitions of a distribution network

being returned back to service, would be considered as being in the restorative state.

Transitions between the states can be caused by several factors. From the control centre operator's point of view the causes could be external, as shown by the grey arrow in Figure 7.14, and automatic operation (white arrow), or some action by the operator (black arrow). An external factor can be a fault or a change of load which causes state changes independent of the operator. A protective relay operation resulting in a reclosure would be counted as an automatic operation. The other transitions are usually made by the control centre operator. Some of these, such as automatic fault isolation and restoration, may also be automatic depending on the system. The warning and alarm limit values can be set by the user, and the operator is responsible for resolving whether the state of the network is acceptable or not.

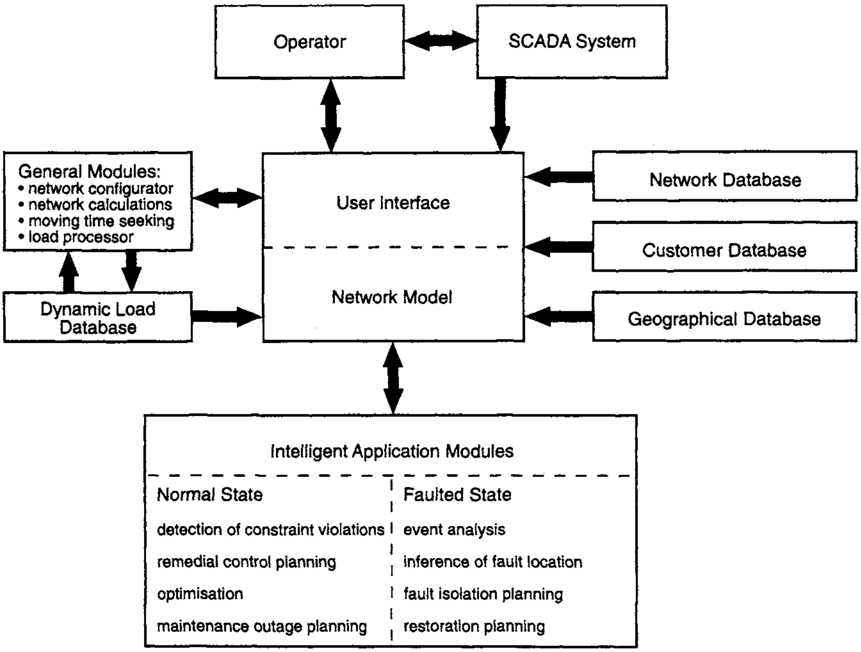

Figure 7.15 The structure of the support system for distribution network management

Based on the foregoing, several tasks can be determined which cannot be solved by a conventional SCADA system. Within the normal state, system analysis is needed to estimate the state of feeders and can be used to detect an unacceptable state. A supporting planning tool is needed for remedial control, optimisation of the network configuration and planning maintenance outages and, in the case of a fault situation, for event analysis and fault location as well as for fault isolation and restoration operations. Such an intelligent support system can be developed to support the operator in monitoring the distribution network. The structure of such a system is shown in Figure 7.15. An integration of several data systems is needed. This system maintains the real-time state of the monitored network in the network model ready for the execution of advanced applications.

The detection of constraint violations is based on real-time load-flow and fault current calculations. The voltages at load points and feeder current-carrying capacities for backup conditions are checked and a warning or alarm is given depending on the violation. The co-ordination of protective devices is checked by comparing the calculated fault currents and relay settings and a warning or alarm is given if the protection is now incorrectly co-ordinated.

Planning of the remedial controls needed to remove the constraint violations is supported by an interactive process activated by the detection of constraint violations. The support system advises alternative controls and proposes the best option using heuristics. The user can choose one option and the system analyses the effect of the control and displays the results. The heuristic optimisation is based on real-time and forecast network calculations and can be interactive or independent.

The interactive planning of a maintenance outage begins when the user lists the circuits or busbars to be de-energised. The system analyses the target state and proposes the best alternative based on heuristics, but here also the user can choose another one. The selected switching sequence is then carried out on the network model and network calculations are executed using the estimated loading on the network for specified periods. If there are any problems, the system presents the next options and proposes the best one but ultimately the operator is responsible for opening or closing remote controlled disconnectors or advising staff to operate the manual disconnectors.

When a distribution system transfers from the normal state, the SCADA system obtains information from the process. In the case of a permanent fault, the primary system transfers to the faulted state and some operations such as event analysis, fault location, fault isolation and restoration are needed. The objective regarding operations in the faulted state is to minimise the outage costs of customers. In this analysis the faulted feeder, the type of fault, and the fault current measured by the fault indicators are determined. The analysis can also produce an assumption of the cause of the fault.

The fault location module uses the results of event analysis, network data and the heuristic knowledge of operators to suggest possible fault locations. First the measured short-circuit current is compared with the short-circuit calculations, and the data on the operations of fault detectors are used. The possible locations are classified using terrain and weather data, and heuristic rules. In the module fuzzy reasoning is used to model any inexact knowledge.

Confirmation of the fault location is obtained by interactive experimental switching measures to isolate the faulted line sections. The system gives relevant information on the outage areas and back-up connections and proposes the best option, minimising the outage costs, but again the user can choose any other one. The impact of the chosen operations on the network is analysed and the constraints are checked. The interactive process continues until a successful arrangement is obtained. In both the fault isolation and restoration procedure operations are carried out in two phases, with remote controlled operations being performed before manual operations. In addition the road network in the area is taken into account for examining various routes to each manually controlled disconnector and using the fastest one in order to assess the optimal restoration time.

The use of the intelligent application functions of the support system increases the ability to minimise the total costs subject to technical constraints. The use of the functions in the faulted state reduces the outage costs while the optimisation function reduces losses. Also constraint violations are efficiently detected with this system.

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Chapter 8

HV networks and substations

8.1 General

High-voltage systems provide a link between major transmission and medium-voltage distribution systems. In addition, medium-sized power stations are connected into these HV networks. Many HV systems now operating primarily as distribution networks have earlier been used for transmission purposes until superseded by higher-voltage systems. High-voltage switching stations provide suitable node points for adjusting network configurations for system-operation purposes, and often are focal points for HV/MV transformation supplying the MV systems. Standardised layouts have tended to be adopted. These include single- and multi-busbar arrangements, often involving large open-air layouts or low-volume metal-clad switchgear in purpose-designed buildings. The trend is for enclosed construction requiring less space, often utilising simpler busbar layouts than the more conventional open-air arrangements.

HV/MV substations have an important role in the security and quality of supplies to the distribution system. This influences the type and size of each substation layout. In addition, various auxiliary systems – protection, local substation control (such as the tripping and closing of circuit breakers and disconnectors), remote control and voltage-control facilities – are necessary to maintain a good system performance, and prevent damage to equipment; and these are discussed in Section 8.4.

8.2 HV networks

In HV system design two basic network formats are used. In the so-called radial system the minor substations are each supplied via individual circuits from the major EHV/HV substation, without interconnection between the minor substations, as illustrated diagrammatically in Figure 8.1*a*. In a mesh system the security of supplies to the individual minor substations is provided by the circuits forming a simple ring from the EHV/HV substation as illustrated in Figure 8.1*b*. Increased security can be provided by the addition of further interconnecting circuits as shown in Figure 8.1*c*.

The main role of the HV networks is to provide supplies to HV/MV substations. Depending on the load density and geography, supplies may be provided by single- or double-circuit transformer feeders or by substations looped into the HV circuits, often in an interconnected system. Examples of these three arrangements are shown at A, B and C in Figure 8.2. On occasion it may be necessary to loop the HV circuit into a substation, away from its original route, as shown at substation D. Tapped substations are connected to the main circuit by a branch or spur line, as at E and F. In practice, circuit arrangements can vary considerably depending upon the importance of the HV/MV substation and the philosophy adopted by the supply organisation.

Simple, standardised and economical HV/MV substations have been developed specially for rural areas. Figure 8.3*a* shows the layout of a typical single 110/20 kV transformer arrangement. Figure 8.3*b* shows the arrangement schematically. There is no 110 kV busbar at the substation. In front of the transformer at the end of the incoming feeder there is only a disconnecting

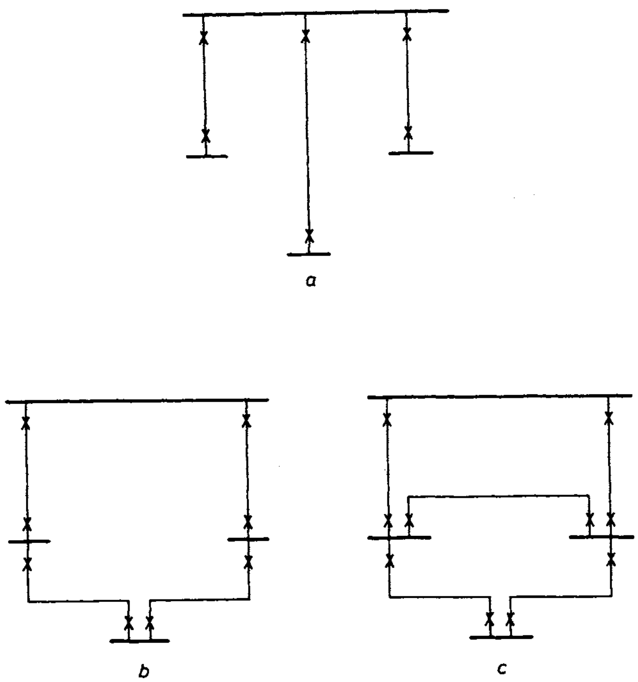

Figure 8.1 Radial and interconnected networks

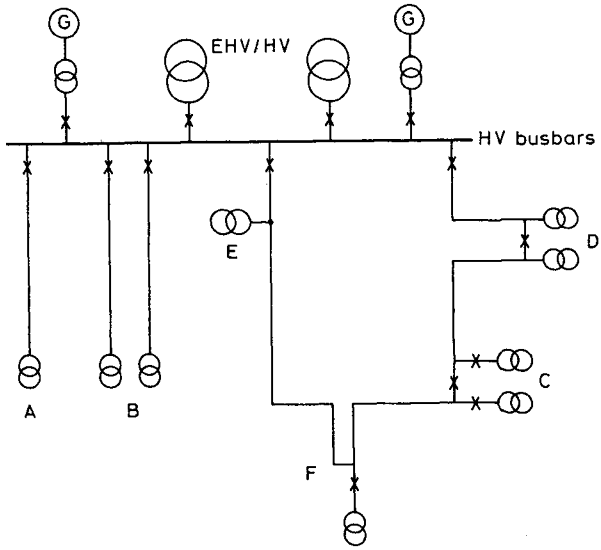

Figure 8.2 Alternative feeding arrangements to HV/MV substations

X circuit breaker
transformer

switch and a circuit breaker with current transformers. A bypass facility has been provided to permit servicing of the 110 kV circuit breaker without disconnecting the transformer. When the circuit breaker is bypassed a fault-making switch is used for back-up protection in case a fault occurs while the circuit breaker is being serviced.

HV circuits are usually provided on overhead lines except in urban areas or where permission for overhead lines cannot be obtained; e.g. in some areas of outstanding natural beauty or where the number of overhead lines around an EHV/HV substation is considered excessive. Various types of overhead-line construction have been referred to in Section 6.3. The construction adopted in a particular locality will depend to a considerable extent on the materials available locally, the above-mentioned amenity requirements, and the local ground and weather conditions. For long overhead lines the three phases of an HV line may be transposed at regular intervals in order to achieve symmetrical phase impedances.

In city areas with high load densities the optimal size of HV/MV substations is higher than in rural areas. If the HV/MV voltage ratio is not too high then MV circuits may provide a useful means of providing back-up capacity to the HV supply. In many countries the division of responsibility is often at some point on the HV system, which may cause organisational problems when considering the overall simultaneous planning requirements for the HV and MV systems.

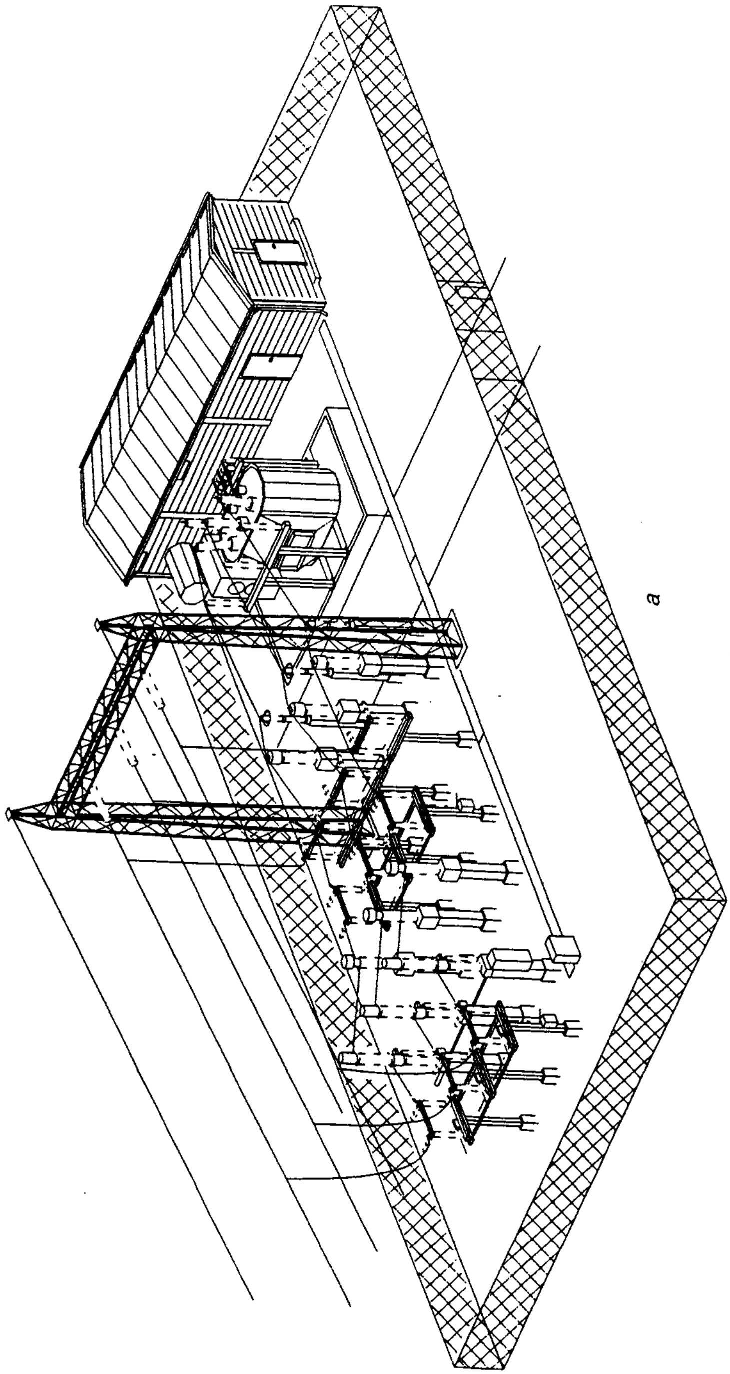

Figure 8.3a *Layout of a simple one-transformer HV/MV substation (Courtesy ABB Finland)*

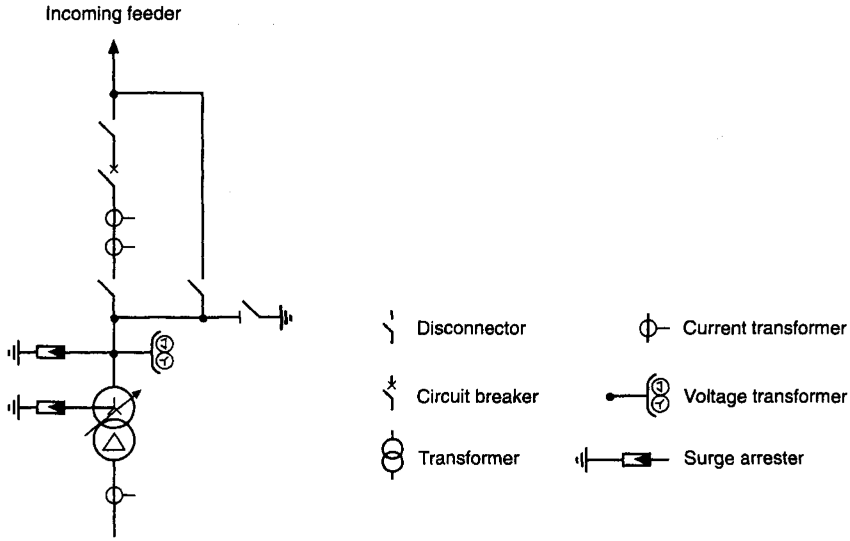

Figure 8.3b Simple one-transformer HV/MV substation (Courtesy Strömberg Co.)

8.3 Substation arrangements

8.3.1 Site location

The importance of HV/MV substations to the quality and security of supply has already been mentioned. It follows that the siting and timing of these substations is one of the most essential aspects of power-system planning, especially when the overall cost of such a project is taken into account. It is therefore vital that all the options being considered must be capable of coping with the long-term provision of electricity supplies in the area; i.e. upwards of 25 years in the future. This involves consideration of the initial and ultimate requirements for HV feeders, HV/MV transformers and substation switchgear arrangements, as well as adequate provision for the associated MV equipment. All the options considered must be assessed from both technical and economic viewpoints.

The precise location of a new HV/MV substation is influenced by many factors. It should always be placed as near as possible to the centre of gravity of the load, or the expected centre of a high-load-density area. Attempting to supply too many load centres from one substation often turns out to be false economy. Solving such problems involves long-term studies, and sensitivity analysis applied to load growths and equipment costs.

The difficulty of obtaining land at the exact required location can make it impossible to achieve the optimum site technically and economically, and this is another aspect to be included in any sensitivity analysis of the economics of supplying the area. With a limited number of sites of the right size to choose from, the choice must take account of the total cost of developing the site; i.e. the cost of bringing in new circuits plus the civil work and building costs, including earthing costs. Poor site conditions, resulting in increased civil-engineering costs, may be offset by reduced line costs, but it is the total construction cost for each site, including the line work, that is important in the overall economic assessment.

If the site is some distance from the existing HV network, considerable costs can be involved in extending circuits to the new substation. Equally, the cost of extending numbers of MV circuits will exclude certain potential sites. The optimum location, economically, is thus determined by the number of HV and MV circuits involved, and is influenced by being a rural or urban situation, since this then affects the relative overhead/underground costs, as discussed in Section 6.3.

Having established the technical and economic consequences of factors such as those mentioned above, it is then possible to set out 'balance sheets' for the various sites being considered, having particular regard to the forecast long-term future of the substation, in order to determine the optimal site. An example of optimising substation location is described in Section 14.5.2.

8.3.2 Design philosophy

Substations are convenient points for the control and protection of the transmission and distribution networks. In their design a number of interrelated problems have to be solved before a layout can be achieved which is both technically sound and economically attractive. Wherever possible, at the high-voltage level it is common practice to install equipment outdoors provided that there are no major environmental or weather constraints.

The substation equipment includes circuit breakers to interrupt fault current, disconnectors to isolate circuits for maintenance, plus busbars and other connections to interconnect the circuits, as well as supporting structures, insulators and various auxiliary systems, and generally power transformers also. All these items have to be co-ordinated to provide a suitable and satisfactory substation arrangement. It must also be remembered that every item of equipment added to a substation arrangement can itself introduce further possibilities of failure which must be considered against the overall substation operational performance.

A large number of different electrical arrangements are available to provide maximum facilities at minimum cost. In all cases consideration must be given to such factors as whether the substation can be easily extended in the future. The substation should be capable of easy maintenance without danger to staff or any interruption of supplies, and there should be alternative facilities available in the case of an outage, whether caused by a fault or required for maintenance purposes.

8.3.3 Mesh-type substations

The earlier UK HV systems utilised mesh substations to minimise the amount of switchgear required at any one site. In Figure 8.4*a* a 3-switch open-mesh

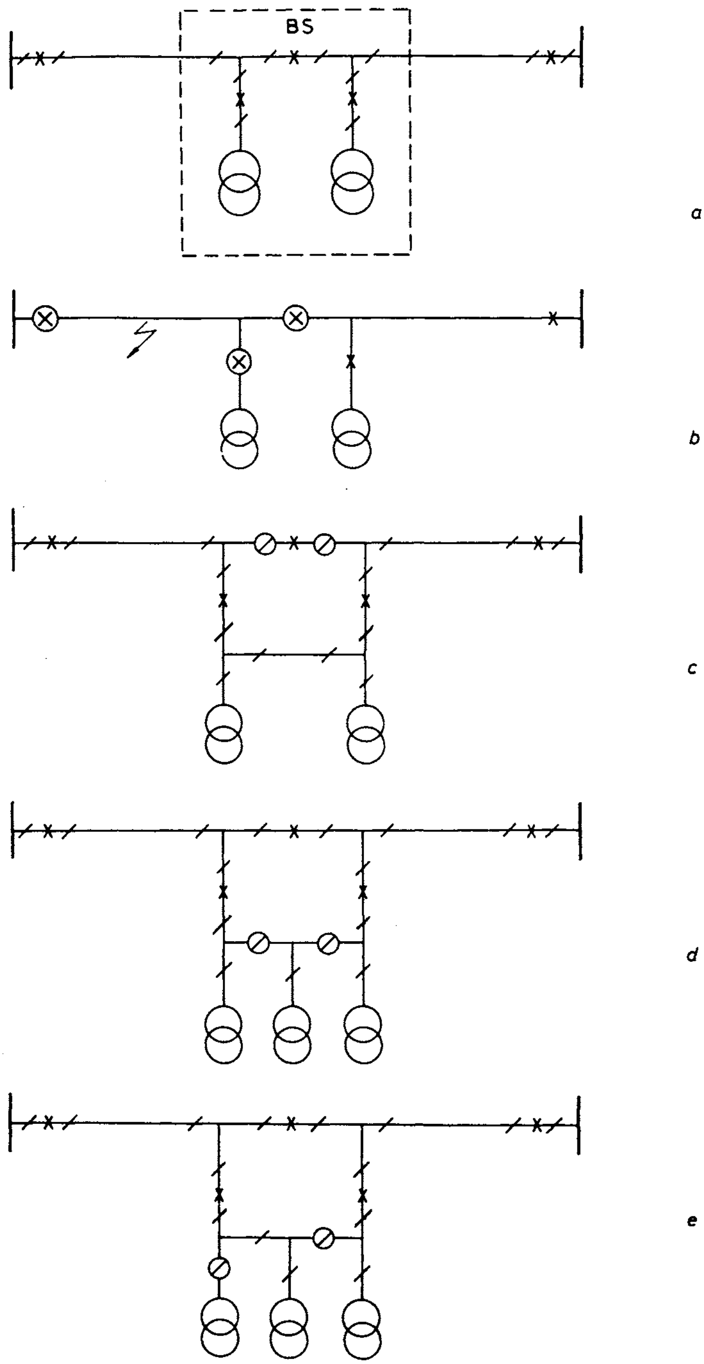

Figure 8.4 HV-mesh substation arrangements

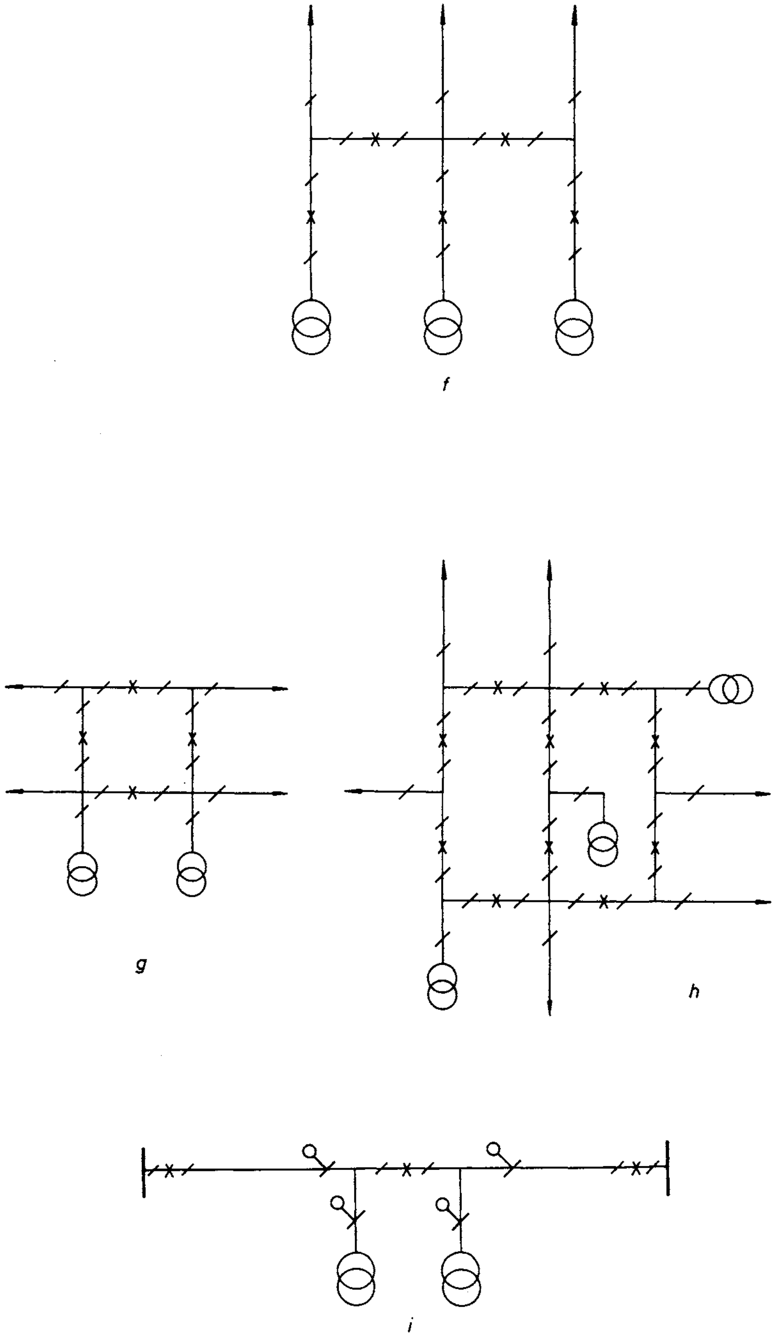

Figure 8.4 (continued)

substation is shown located on a feeder between two HV substations. The dashed lines indicate the equipment within the mesh substation, while only the relevant section of the substations at each end of the feeder has been shown. This 3-switch open-mesh arrangement was normally used to control two circuits and two local HV/MV transformers. With this arrangement a fault on a transformer can be cleared by tripping the transformer HV circuit breaker, leaving the HV circuit arrangements unaffected. A circuit fault is cleared by tripping open the bus-section circuit breaker BS and the associated transformer HV circuit breaker, as well a the far-end circuit breaker as shown in Figure 8.4*b*. Continuity of supplies at the substation is retained by the remaining circuit and transformer.

With this arrangement, maintenance of the bus-section circuit breaker would involve interrupting the HV through circuit. A bypass arrangement is therefore sometimes installed to alleviate this situation. By closing the bypass disconnectors and isolating the HV bus-section circuit breaker, as shown in Figure 8.4*c*, continuity of the through circuit is retained during the maintenance outage of the bus-section circuit breaker. Where an additional HV/MV transformer is required to provide security of supplies on loss of one of the loaded transformers, but cannot be permanently switched through to the MV switchboard owing to the resultant excessive fault levels on the MV switchgear, a third transformer can be connected to the bypass busbar but isolated from the HV mesh as shown in Figure 8.4*d*. On the outage of one of the transformers, owing to fault or maintenance, the standby transformer can be put into service by re-arranging the isolation facilities as shown in Figure 8.4*e*.

An extension of the 3-switch arrangement already discussed is the open-mesh arrangement shown in Figure 8.4*f*, where provision is made to control three circuits, plus three local transformers each having individual HV circuit breakers, so that any fault on a transformer does not break the continuity of the HV network connections. Figure 8.4*g* illustrates the 4-switch closed-mesh arrangement, capable of controlling four circuits plus four local transformers or transformer feeders. As Figure 8.4*h* shows, these mesh arrangements can get quite complex, and one major problem with mesh-substation arrangements is the difficulty in extending the substation if provision was not included in the original layout.

The advent of HV automatic motorised disconnectors has made it possible to reduce switchgear at mesh substations, with arrangements such as that shown in Figure 8.4*i*. For a fault on a circuit or transformer, the far-end circuit breaker and the substation bus-section circuit breaker open to isolate the fault. Under 'dead' conditions the appropriate disconnector is automatically opened to isolate the faulty equipment from the rest of the system and the circuit breaker(s) reclosed to restore the unfaulted circuit or transformer back to service.

8.3.4 Single- and double-busbar arrangements

The single-busbar arrangement shown in Figure 8.5*a* is the simplest configuration to provide a convenient method of operation. Here a number of incoming

MV feeders are bussed together with local HV/MV transformers. With this arrangement a circuit or transformer has to be taken out of service to enable maintenance of the associated circuit breaker to be carried out. In addition, any extension of the busbar would require a complete shutdown of the substation. Furthermore a busbar fault would cause all circuit breakers to trip, isolating the switchboard. By adding a bus-section circuit breaker as in Figure 8.5*b*, a busbar fault or work on the switchboard to extend a busbar only leads to the loss of one-half of the circuits connected to the substation. Grouping incoming and outgoing circuits evenly across the two sections of busbar, and ensuring that where feeders go to the same load point they are connected to separate sections of the busbar, further improves security. Further improvements can be achieved by wrapping around the ends of the single busbar to obtain the ring busbar shown in Figure 8.5*c*. Here additional busbar disconnectors have been provided to ensure adequate electrical clearance when maintaining the busbar disconnectors, and then only one circuit has to be taken out of service during maintenance.

By providing an auxiliary transfer busbar and a bus-coupler circuit breaker BC to the original single-busbar layout, as in Figure 8.5*d*, a circuit can be selected to the auxiliary busbar by suitable use of the busbar-selector disconnectors, e.g. circuit 1. The circuit is then protected by the bus-coupler circuit breaker BC. Circuit breaker CB can then be isolated as shown for routine

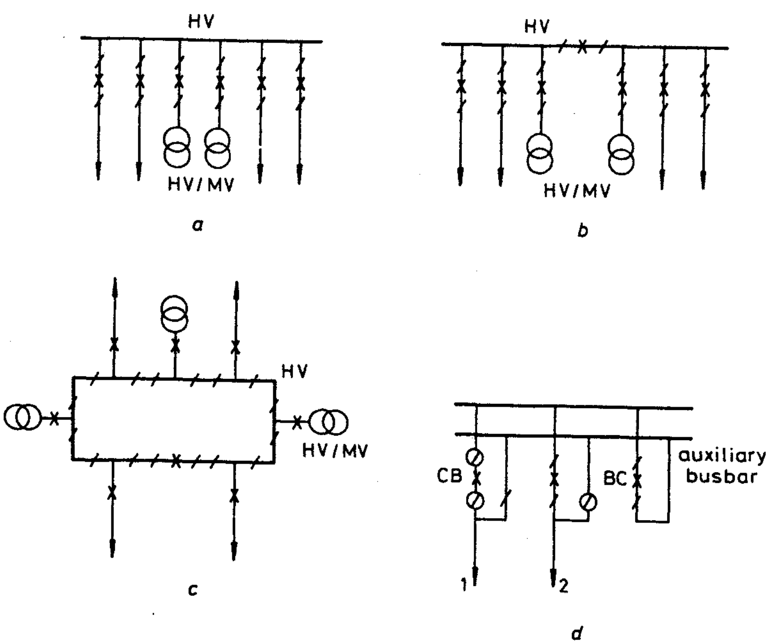

Figure 8.5 Single-busbar arrangements

maintenance or repair, or examination after fault clearance with the circuit still in operation.

The use of two busbars with isolating facilities, such that each circuit can be selected to either busbar, is shown in Figure 8.6*a*. It is then possible to arrange the various circuits into different configurations on the two busbars, as required for operational reasons. It is also possible to select all circuits to one busbar, releasing the other busbar for maintenance such as insulator cleaning.

The addition of a bus-coupler circuit breaker, as shown on the right-hand side of Figure 8.6*b*, enables on-load transfer of a circuit from one busbar to the other to be carried out. The installation of a bus-section circuit breaker in one of the busbars provides improved circuit marshalling facilities, and permits segregation of circuits to minimise the effect of busbar faults.

For reasons of space, 'wrap round' arrangements are often adopted with the reserve busbar encircling a central main busbar. Complex configurations are possible. By way of example, Figure 8.6*c* shows 12 circuits connected to an arrangement with a total of six sections of busbar. Only busbar disconnectors are included for clarity. It will be noted that busbar sections A1 and A3 are connected together, with sections A2, B2 and B3 separately joined, while section B1 is isolated from all other sections. Thus circuits 1, 3 and 8 are grouped together, circuits 7, 2, 9, 5, 12, 11 and 10 are grouped together separately, with only circuits 4 and 6 on the isolated busbar B1.

The above example is typical of the variations that can be achieved in system configurations using double-busbar layouts, and which make it possible to cater for a wide variety of system operational requirements. It is often usual to connect two circuits from one area to different sections of busbar, in order to avoid 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. Sections of the network can be isolated from the rest of the system; e.g. industrial plant causing fault-level or nuisance load problems. Generators can be selected to particular circuits to force power into a given area. This facility to rearrange circuit configurations also assists in carrying out maintenance work on busbars without interruption of supplies.

The introduction of compact metal-clad SF_6 switchgear has made it possible to install large HV substations in urban areas either within buildings or underground to avoid environmental problems. The reduction in space occupied by 145 kV gas-insulated switchgear (GIS), compared with that for a conventional open-terminal arrangement, is shown in Figure 8.7. The respective bay widths are 1·4 m and 10·5 m. A cross-section of a phase-integrated 145 kV GIS bay is shown in Figure 8.8. Typically this would be 3·3 m high, with a bay width of 1·4 m and depth of 6 m.

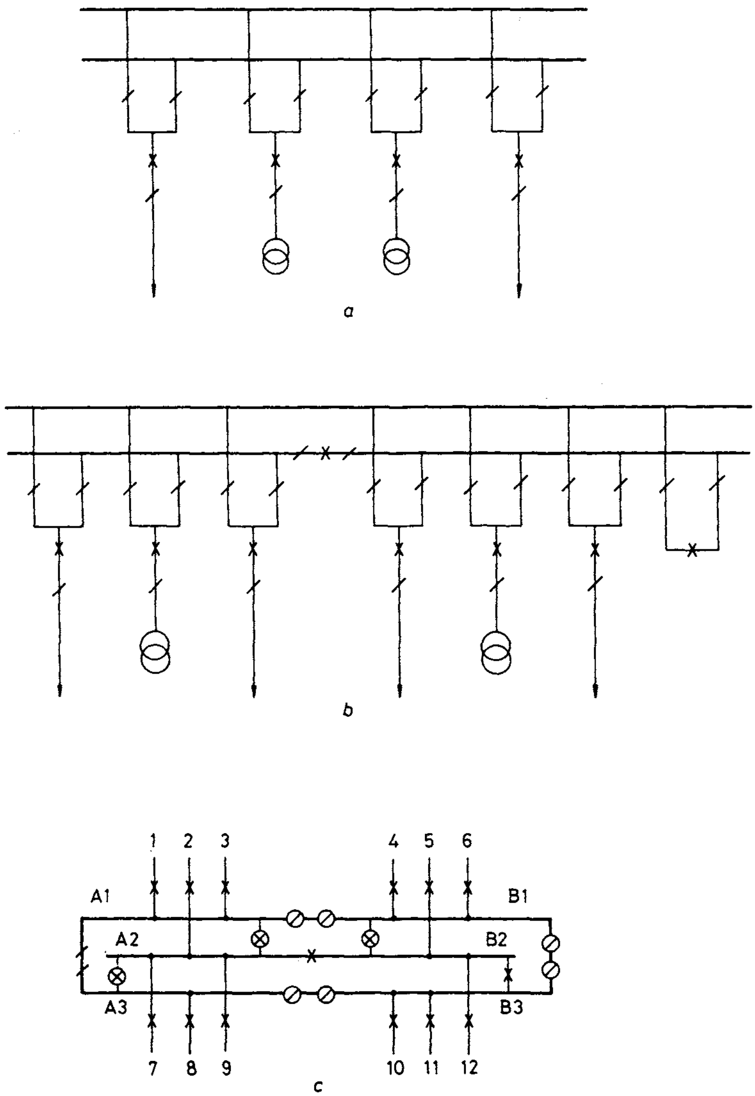

Figure 8.6 Double-busbar arrangements

X circuit breaker (closed)
⊗ circuit breaker (open)
/ disconnector (closed)
⊘ disconnector (open)
automatic motorised disconnector
HV/MV transformer

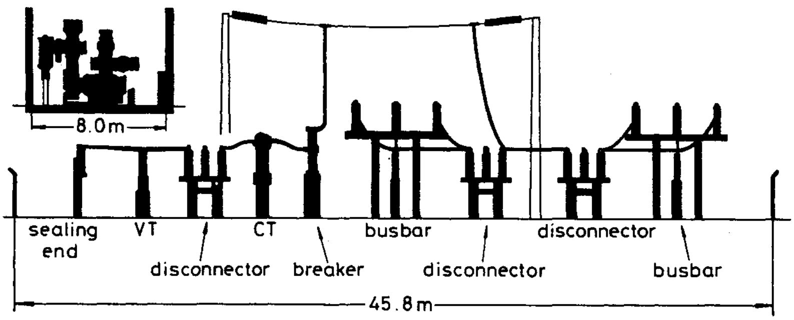

Figure 8.7 Comparison of space occupied by GIS switchgear and a conventional open-terminal arrangement (reproduced from Power Engng.J., July 1987)

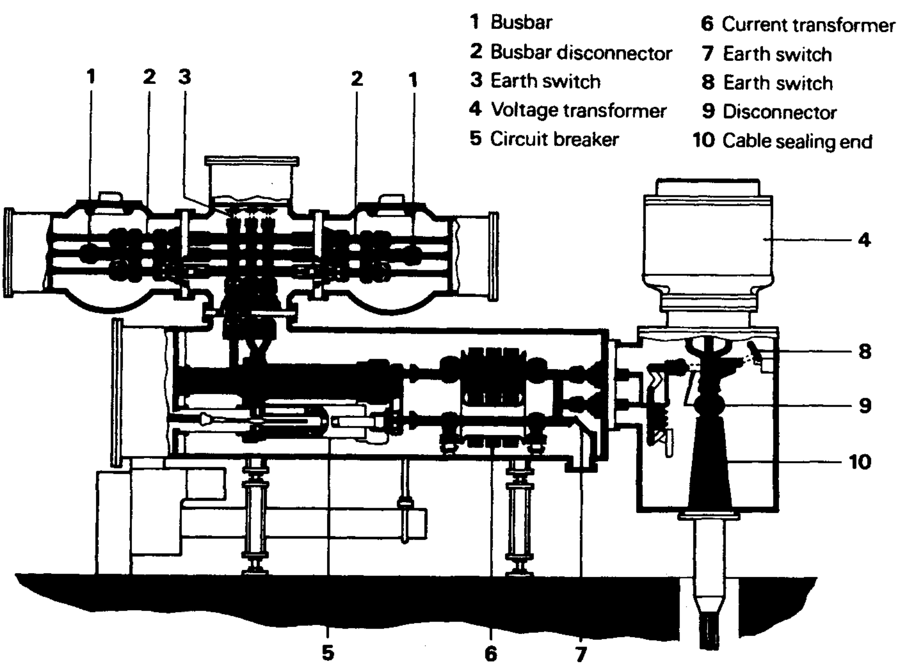

Figure 8.8 Cross-section of a phase-integrated 145 kV GIS bay

8.3.5 MV busbar arrangements

The optimum arrangement for the MV side depends on the size and the role of the substation. For rural single HV/MV transformer substations the single-busbar system is also most appropriate at MV. There are the same constraints mentioned in the previous section on maintenance and lack of flexibility in grouping circuits. As mentioned in Section 8.3.4, adding an auxiliary transfer busbar, as shown in Figure 8.5*d*, enables feeders to be grouped together on to either of the busbars, and linked via the busbar coupling circuit breaker. This arrangement increases flexibility of system operation considerably, and was popular in some of the older substation layouts.

With the so-called duplex system, a movable wheeled truck is used to transfer the circuit breaker off load to either of the two busbars, as indicated in Figure 8.9, thus avoiding the need for circuit-selector disconnectors. The SF_6 3-phase sealed-for-life chamber results in a compact unit which is frequently used on MV networks. The duplex arrangement again provides the facility of arranging the incoming HV/MV transformer circuit(s) and outgoing MV feeders to suit operational requirements and improve system security. Owing to the considerable reduction in maintenance requirements when using SF_6 or vacuum circuit breakers, single busbar systems are being used more, especially in rural areas.

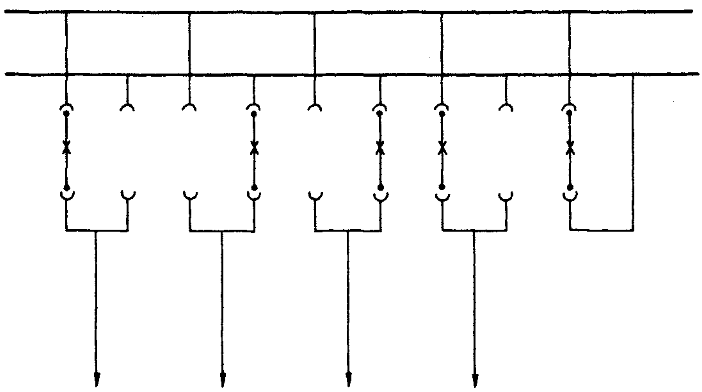

Figure 8.9 Duplex arrangement

8.4 Auxiliary systems

8.4.1 General

Various auxiliary systems are necessary for the correct operation of HV substations, which contain costly equipment vital to the security of the supply system. The HV/MV transformers require special protection arrangements, and there is a need for continually monitoring and updating of the status of not only the switchgear but also their support systems. The low-voltage-control supplies for these systems must be monitored, as well as telecommunication circuits. The major aspects of equipment and protection have been covered in Chapters 6 and 7, but, because of its specific importance in relation to HV substations, the protection of large transformers is included in Section 8.4.2. For more detailed information on particular aspects of HV substation equipment not covered here, the reader is referred to the Bibliographies associated with Chapters 6 and 8.

8.4.2 Transformer protection

Reference was made to transformer unit protection in general terms in Section 7.4.1. Figure 8.10 refers to a differential protection scheme across a star–delta transformer. To compensate for the primary phase change it will be noted that the protection current transformers are delta-connected on the primary side, and star-connected on the secondary side. To avoid the possibility of relay operation owing to transformer magnetising current inrush on switching in the transformer, restraining coils sensitive to the third-harmonic components of current are generally included. The current transformers are often located in the main-transformer primary and secondary bushings to provide overall protection. More modern relaying systems include the facility to programme the protection system to compensate for the various transformer winding arrangements whilst retaining the same CT configurations on both windings.

Whilst differential protection can detect severe internal faults, on occasion a fault between a few turns of a winding can occur. Eventually these faults cause the transformer insulation to decompose and release gas. Appreciable quantities of gas may be produced before the fault is detected by the differential protection

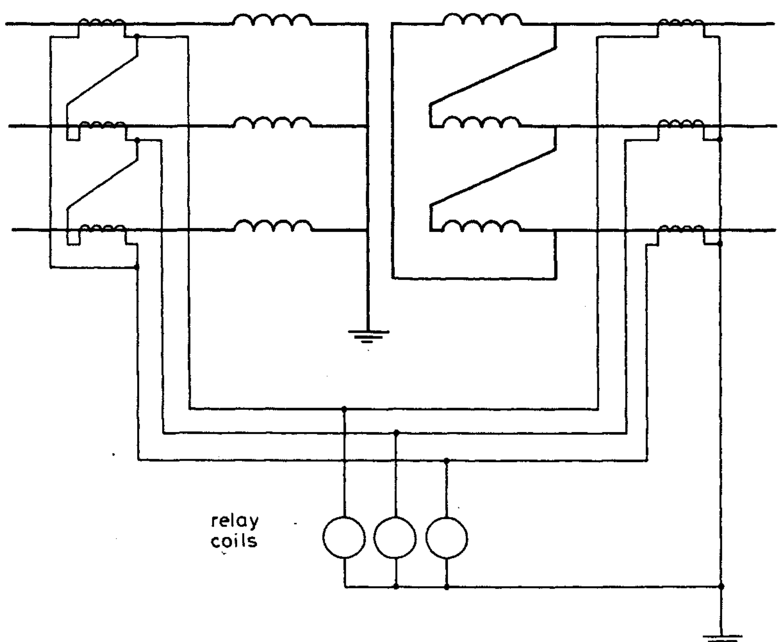

Figure 8.10 Transformer differential protection

relays. A Buchholz relay connected in the oil pipework between the top of the tank and the oil conservator traps any gas. Eventually sufficient gas accumulates in the Buchholz relay chamber so that the level of oil falls, causing a float alarm relay to operate. A heavy fault which causes a surge of oil or gas to flow through the Buchholz relay operates a trip relay to open both the HV and MV circuit breakers.

As mentioned in Chapter 6, large transformers have a thermal time constant of some hours, so that short-time overloads should not trip out a transformer.

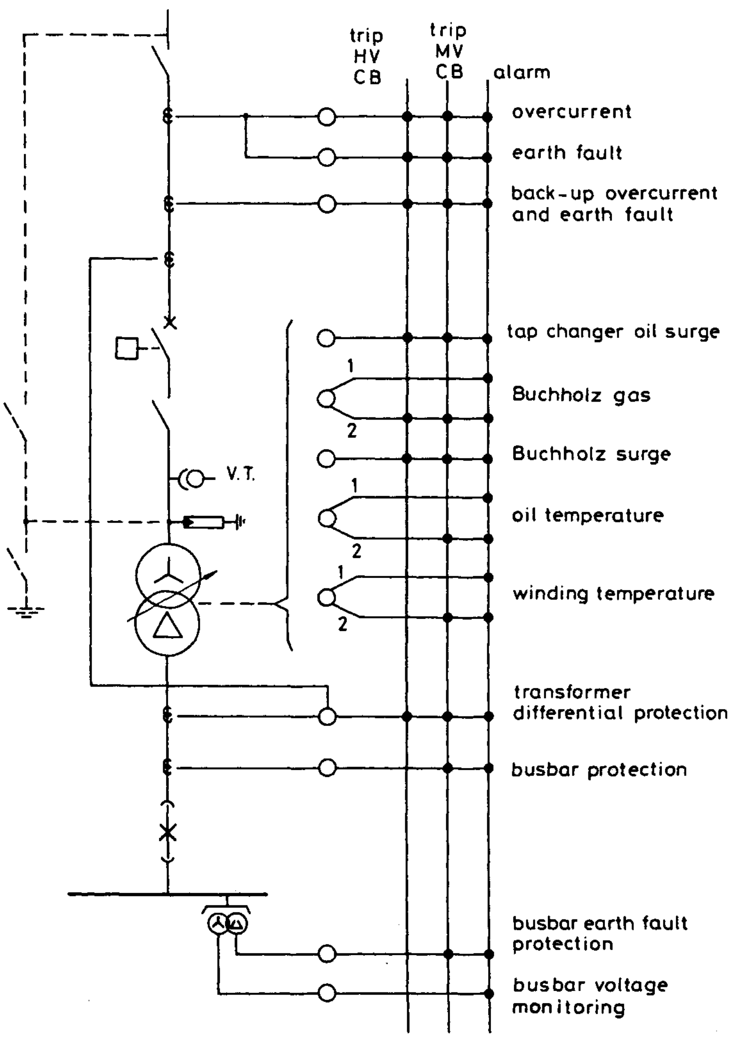

Figure 8.11 HV/MV transformer protection facilities (Courtesy ABB Finland)

However, a relatively slow cumulative effect of excessive load may slowly overheat the windings and insulation. Therefore a suitably dimensioned resistance element, which closely models the response of the transformer winding which has a time constant of between 5 and 10 min, is supplied with current proportional to the load current from a separate CT. Thus the temperature-sensing element is influenced by both the oil and load temperatures. Normal practice is for this relay to set off an alarm at a temperature where load can be reduced without damaging the transformer, say 85°C. Should the temperature rise higher, say to 100°C, the lower-voltage circuit breaker is tripped open to remove the heat-producing load.

The tap changer is also vulnerable to faults. However, being located within the transformer differential-protection zone, any electrical fault is detected by this protection. Figure 8.11 shows schematically the protection facilities usually installed to cover various transformer faults.

8.4.3 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, 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 summed. A busbar fault would result in an imbalance in the summed 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 circuit breakers 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 energised circuits be connected to earth.

8.4.4 Auxiliary supplies

Low-voltage power is required at substations to supply various auxiliary services. Low-voltage AC is used for the lighting, heating, cooling and ventilation of buildings, together with supplies to auxiliary equipment such as transformer cooler fans and pumps, and tap changer motors, and the charging or DC batteries. Usually the LV AC supplies are obtained from MV/LV auxiliary transformers associated with the HV/MV transformers, with alternative supplies available from the utility's LV network adjacent to the substation, wherever possible. Typically the AC system is 400/230 V of 50–200 kVA capacity, depending on the size of the substation and the amount of equipment.

DC low-voltage supplies are required to provide power for the operating mechanisms of circuit breakers, for operating alarm, protection and control systems, and for emergency back-up lighting. Typical DC voltage levels used at substations are 48, 110 and 220 V. The battery and the associated charger capacities are determined from the average load in association with the peak demand. Duplicate DC systems are sometimes installed at the larger substations to ensure high reliability.

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Chapter 9

Medium-voltage networks

9.1 General

In the early days of the commercial use of electricity, power was produced by small generators close to the customers of municipal or industrial electricity producers. As systems expanded it was necessary to distribute electrical energy over distances of some tens of kilometres with circuits operating in the 5–20 kV range. When HV systems were introduced to deal with the longer distances and increased power requirements, the earlier systems changed in nature to become intermediate MV systems mainly to be used for distribution. The use of a single higher-voltage system (40–250 kV) to supply local LV networks directly would lead to unacceptably high costs and amenity problems. Thus another voltage level, or levels, is used to interlink the HV and LV systems. Material and construction costs of 10–20 kV overhead lines are only slightly higher than those for a 400 V line of the same length, but are approximately one-tenth the costs of a 100 kV line. It is this large cost differential which economically justifies the inclusion of an MV network between the EHV/HV and LV systems, even when account is taken of the costs of HV/MV substations.

The medium-voltage system also provides a convenient voltage for connecting substantial industrial loads, or the larger buildings and office blocks. In some cases large motors and generators can be connected to a utility's MV supply system. In industrial complexes customers often provide their own MV distribution system together with the necessary MV/LV substations.

The requirement that the MV system should be as close as possible to each individual load point, in order to provide voltage within required limits, can lead to long line lengths. In rural areas the total line length of 20 kV networks can be greater than that of the associated LV system. Once constructed, in general only occasional reinforcement of an MV network is necessary, mainly by short spurs to new distribution substations, or uprating various circuits. It is essential, however, that those schemes dealing with main feeders are compatible with the utility's overall development plan.

9.2 Choice of network voltage

The operating voltage of an MV system has the major effect on the characteristics, and therefore the design, of such a system. The voltage selected determines the maximum length of individual feeders and their loading, and the number of feeders and the number of distribution substations supplied from each feeder. It thus also influences the number of customers affected by any one outage, system losses, operational procedures and maintenance practices; these last three items themselves affecting annual revenue costs.

When considering the electrification of a country or an isolated area such as a large island, the medium voltage to be used within the proposed electricity network is a major factor to be taken into account at an early stage in the planning of the new network. It is also necessary to consider an appropriate higher voltage when an existing network voltage becomes inadequate to cope with high load density, such as occurs in developing city areas. When selecting the operating voltage of an MV system it is also important to consider the availability of circuit routes and substation sites, and their cost. In many cases, owing to the historic development of the networks, there may be only one or two choices which are economic because of existing standard voltages, e.g. 10 or 20 kV, 11 or 33 kV, 12·5 or 34·5 kV. Usually the higher voltage will be preferred if there is a choice, and new standard voltages may need to be adopted utilising higher voltage levels than already exist.

It is necessary to consider the combined technological and financial effects of utilising all the possible voltage levels available before determining the optimum voltage for the area under consideration. Higher voltages lead to higher insulation costs, but also usually result in lower conductor and system-loss costs. Substation costs will increase, but the number of substations required to supply the MV network will be less. In addition, a higher voltage level leads to a lower percentage voltage drop per unit length for a given loading, and thus longer feeder lengths are possible without using booster transformers or capacitors.

Historically, higher voltage levels have been preferred in rural areas, since the additional costs of towers or poles and increased insulation have not been significant compared with the improvement in electrical capability. In densely populated urban areas the power demand of individual office blocks may exceed 10 MW, and space is limited for suitable infeed points even when modern compact substations are used. In such areas the adoption of a higher voltage may thus be economic, even though substation and cable costs will be higher. Thus, whilst in rural areas the feeding distance is the main criterion in deciding to move to a higher voltage, in urban/city locations the cost of substation equipment, limited cable routes and the overall cost of losses are usually the main factors.

Table 9.1 gives approximate percentage values for the maximum overhead-line feeder length for a given load, and the power losses and construction costs for different voltage levels compared with an 11 kV feeder, based on the same conductor cross-sectional area.

Table 9.1 Relative characteristics of medium-voltage overhead lines.

Voltage, kV	Feeder length, %	Power losses per km, %	Capital cost per km, %
6·6	41	278	93
11	100	100	100
20	331	30	112
33	900	11	131

Table 9.1 shows the advantage of obtaining a considerably increased capability for a small increase in capital costs which are themselves offset by reduced power losses. By taking into account the various cost components and the voltage-drop constraint, comparisons can be made of the cost of providing a feeder plus associated distribution transformers and the relevant portion of the main infeed substation costs for various feeder operating voltages.

Figures 9.1 and 9.2 are based on studies carried out to assess the optimum medium-voltage level in a number of countries where the existing small networks needed to be extensively developed. In deriving these diagrams, in addition to the costs of the MV lines, the costs of the associated HV/MV and MV/LV substations have been included. Figure 9.1 indicates that, based on a 20 km line, 33 kV is cheaper than 20 kV for line loadings above 100 kW/km. Figure 9.2 shows that the profitability of a single MV level 33 kV system, compared with an 11 kV system, is sensitive to the load density, the average length of feeders and the estimated annual load growth. For example, at an estimated annual load growth of 15%, 20 km feeders at 33 kV would be economic for load densities above 30 kW/km, while at a 3% per annum growth the limit would be 90 kW/km. The former limit would, however, lead to excessive voltage drops as indicated by the broken lines which show the effect of a 10% voltage drop so that only about 10 kW/km could thus be accepted for an 11 kV line.

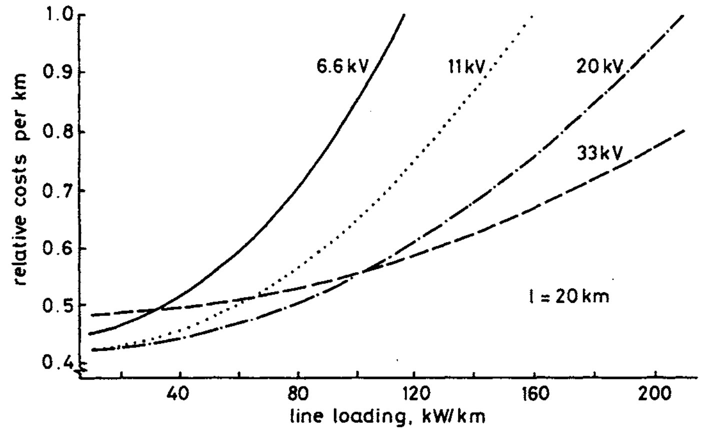

Figure 9.1 Relative costs for 20 km overhead lines

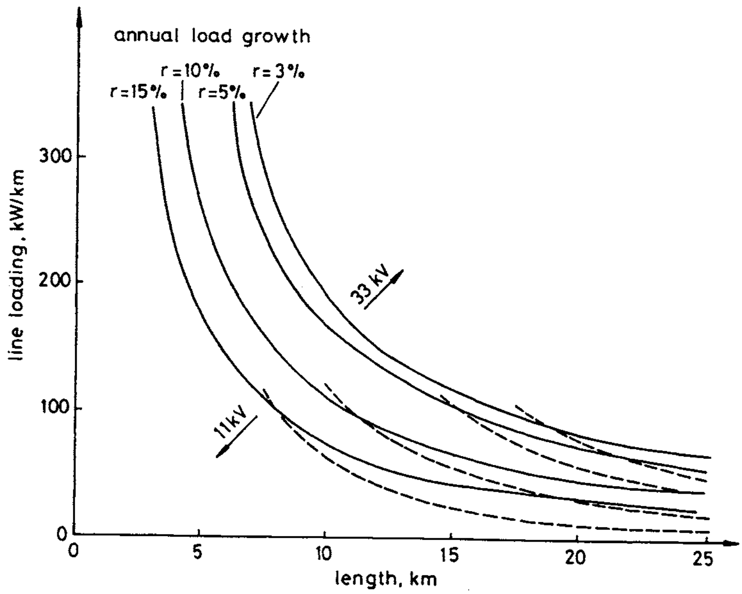

Figure 9.2 Feasibility studies for 11 kV and 33 kV feeders
11 kV 95mm^2 Al; 33 kV 35mm^2
-- limit based on voltage drop
— limit based on economic considerations

The decision of the voltage level to be selected must be based on long-term studies. When considering the electrification of developing countries, it is necessary to consider the potential loads in areas which will not be covered in the initial stages of the electrification programme, so that the long-term requirements of each area are properly catered for. In existing networks it is generally not possible to economically justify a voltage uprating in the short term (5–10 years) because of the high investment required initially to set up the higher-voltage network, especially in built-up areas. It is seldom reasonable for an individual utility to select a voltage level which is not being used by other companies in the same country, or to consider the use of non-standard voltages. The use of a common voltage level should lead to savings in component prices owing to the large volumes being produced, plus increased competition between manufacturers.

9.3 System modelling

In addition to the correct choice of the voltage level for an MV system, other technical policies have to be agreed. Examples of these include the use of underground cables or overhead lines, neutral earthing practice and protection arrangements, and the eventual future use of any existing single-phase spurs. Any policies on the valuation of losses or non-distributed energy, or variations in local economic conditions or safety regulations, have an effect on planning philosophies, and many of these decisions are interrelated. In many utilities most of these policies will probably be already fixed, especially in industrialised countries with a long-standing electricity supply.

Considering the fixed design policies, it is possible to construct simplified techno-econometric models for the MV system. These models can include simplified mathematical descriptions of such items as:

- Area load models
- Network configurations
- Any technical constraints
- Cost models for components, and for supply interruptions

Typical results of this type of study would include the following items, as functions of various parameters such as load density:

- Optimum sequence of voltages
- Optimum density of HV/MV substations
- Optimum sizes of transformers
- Optimum standard sizes of cables and lines

It is also often possible to obtain the sensitivities of such items to variations in economic parameters and technical constraints.

Although the mathematical equations used in such studies are generally as simple as possible the results are often complex, owing to the large number of factors involved, so that the results are usually presented graphically. However, it is sometimes possible to develop very approximate formulas. For example, the following formulas may be used for an urban area for estimating the optimum density and sizes of substations:

$$S_s \simeq k_1 \sigma^{1/3} \quad \text{and} \quad L/S_F \simeq k_2 \sigma^{-1/2}$$

where S_s = optimum ratings of HV/MV substations, MVA

k_1, k_2 = coefficients depending on local cost relations and MV arrangements ($k_1 \simeq 50$, $k_2 \simeq 3$)

σ = area load density, MVA/km^2

L = optimum length of MV feeders, km

S_F = feeder load, MVA

Instead of using simple network configurations and very approximate load models, the system model can be based on typical existing systems. Also, in such a case simple cost functions can be used for substations and circuits, but average circuit lengths and the location of concentrated loads would be obtained from actual systems, preferably by using information collected from network-monitoring computer programs and regression analysis.

Results from these model-based studies can be used to determine the most appropriate electricity-supply arrangements for a developing country. These studies are also useful when considering various long-term scenarios for a particular area. The model can provide an indication of the required number of substations, and the total costs associated with different development projects.

Alternative methods are also available to provide such information. These are based on case-oriented computer-aided simulations, as discussed in Chapter 14. For most MV planning tasks, CAD systems provide more reliable results than those obtained from the above-mentioned approximate formulas or system modelling techniques.

9.4 Principles for determining circuit dimensions

Determining the dimensions of the conductor cross-sectional area for a new spur or a section to be replaced is a commonplace task. In this section some fairly simple rules are introduced. A more difficult but important task is the consideration of a single circuit section as a link in the whole network; e.g. the influence it has on the voltage drop and other characteristics of the entire route, under both normal and back-up conditions.

In determining the dimensions of a new section it is necessary to meet the requirements of the overall general plan for the network. For example, the future provision of a new primary substation will limit the use of the smaller sizes of cables or lines around the proposed location owing to the increase in fault level when the substation is connected into the network. This is one of a number of constraints which has to be considered. The most economic size of conductor must be chosen from those sizes which are acceptable from all points of view. In an overhead line, if the conductor has been dimensioned on an economic basis, there will usually be a large margin between the full-load rating and the thermal limit. However, extremes of ambient temperature need to be carefully considered.

The *voltage drop* is an important constraint in designing MV overhead networks. There is no agreed exact value of the voltage drops that can be accepted, either in the overall distribution system or allocated to the individual voltage levels. Often a specific voltage drop, say 5%, is permitted for the whole MV network. Thus, depending on the estimated load growth and required life of the system, the maximum voltage drop for present loading conditions will be somewhat lower. A detailed consideration of network voltage theory and practice will be found in Chapter 13.

The voltage drop V_d can be calculated using the following formula from Section 3.4:

$$V_d \simeq \sqrt{3}I_pR + I_qX) \simeq \frac{P}{V}(R + X\tan\phi) \tag{9.1}$$

where V_d = voltage drop (phase–phase)
I_p = resistive current component
I_q = reactive current component
R = resistance
X = reactance
P = real power (3-phase)
V = phase–phase voltage
ϕ = angle between phase voltage and current

The first term I_p is the most important, except in the case of overhead lines with large conductors carrying highly reactive loads. It is also necessary to consider the distribution of load along the line. For example, an even load distribution along a line will produce one-half of the voltage drop as compared with the case where the same total load is located at the end of the line.

The voltage drop may be the critical factor in dictating conductor dimensions. If the conductors are selected purely on the basis of economics, the voltage drop per unit length will be almost constant throughout the network. In circuits where conductors larger than the economic size have been selected for fault-level or mechanical reasons, the voltage drop per unit length will be smaller.

Also the requirement that the conductors must be adequate to cope with *fault currents* may entail cross-sections being used that are larger than needed on a purely economic basis. Particularly in underground cable networks, the smallest cable cross-sections may have to be avoided because a new HV/MV substation or a transformer replacement in the future could lead to expensive cable replacements. When using underground cables, the *thermal limit* may be the critical factor for conductor dimensioning. It should be noted that, under emergency conditions, high loads may occur for a short time on back-up circuits.

Thus the critical factor for overhead-line or underground-cable conductor dimensioning can vary from case to case. However, an experienced design engineer does not necessarily have to check all the possible constraints and *economic factors*.

Two examples have been selected to indicate procedures for determining optimum circuit dimensions on an economic basis. The basic underlying theory can be found in Chapters 3 and 5.

9.4.1 Example: Choice of conductor size for a new line on an economic basis

Here the aim is to select the conductor size which leads to minimum total cost. Thus, when comparing two options, the larger size is selected if its losses during the review period are low enough to offset the increased construction costs.

The present-worth values of energy losses over a given time can be determined as shown in Section 5.2. In this example a constant annual load growth of $r\%$ per annum is assumed.

$$C = C_1\gamma_1 \frac{\gamma_1^t - 1}{\gamma_1 - 1} = \beta C_1 \tag{9.2}$$

where C = present worth of losses

C_1 = annual cost of losses in year 1

$\gamma_1 = (1 + r/100)^2/(1 + p/100)$

$\beta = \gamma_1 \times (\gamma_1^t - 1)/(\gamma_1 - 1)$

p = interest rate

t = review period, years

$$C_1 = \frac{S_1^2}{V^2} RLc_l \tag{9.3}$$

where S_1 = peak power at year 1

R = resistance of conductor, Ω/km

L = length of line, km

c_l = equivalent price for power losses, including allowance for energy losses, £/W per annum

V = phase–phase voltage

If the optional conductors are a and b, with b the larger, then b will be the economic choice if the savings in losses are larger than the extra investment costs, i.e. if

$$C_a - C_b > (c_{Ib} - c_{Ia})L \tag{9.4}$$

where C_a = present worth of losses for conductor a

C_b = present worth of losses for conductor b

c_{Ia} = investment cost for conductor a, £/km

c_{Ib} = investment cost for conductor b, £/km

L = length of line, km

From eqns. 9.3 and 9.4, the limit S_1 for the first-year load can be obtained. If this is exceeded by the first-year demand, the larger conductor b will prove to be more economical.

Thus

$$S_1 > V\sqrt{\frac{c_{Ib} - c_{Ia}}{\beta c_l(R_a - R_b)}} \tag{9.5}$$

The investment costs for conductors shown in Table 9.2 includes material and installation costs of poles and conductors. Using the values shown in Table 9.2, an interest rate of 8% per annum, a network operating voltage of 20·5 kV, with the overall cost of losses as £70/kW per annum, and taking a review period of 20 years, a dimensioning guide (Figure 9.3) can be constructed. This can be used to choose conductor sizes when designing a new 20 kV overhead line.

It will be noted that, in Table 9.2 and Figure 9.3, the type and size of the conductor is represented by a code. ACSR 54/9 represents a conductor with 54 mm^2 of aluminium conductor wire strands plus 9 mm^2 of steel core reinforcement, while AAC 132 refers to a conductor with 132 mm^2 of aluminium conductor wire strands.

Table 9.2 Conductor data

Conductor	Thermal limit MVA	R, Ω/km	Investment costs, £/km
ACSR 34/6	7·4	0·848	7870
ACSR 54/9	9·9	0·536	9200
AAC 132	17·5	0·219	11470

By way of example, if the first year demand S_1 is 1.6 MVA and the estimated annual load growth is 4%, the AAC 132 conductor is the most economic, but if the load growth is only 2% per annum ACSR 54/9 should be selected. Comparing Figure 9.3 with Table 9.2 shows the considerable difference between the thermal limit and the economic loads. Similar studies and dimensioning rules can also be carried out for underground or overhead cables, LV lines and different types and sizes of transformers.

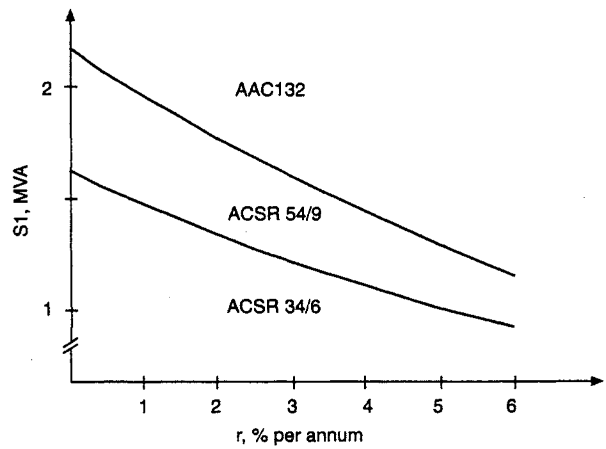

Figure 9.3 Dimensioning guide for conductors for new 20 kV line

S_1 = first-year demand
r = annual load growth, %

9.4.2 Example: Choice of conductor size to replace an existing conductor

In this example it is required to determine the optimum demand for conductor replacement. One justification for replacing a conductor by a larger-size one is to reduce the cost of the losses by more than the investment costs of the conductor replacement. Figure 9.4 illustrates annual savings in losses if a conductor is replaced by a larger one. The larger the line loading the greater will be the savings in losses, since they are proportional to current squared. The annuity of the investment is also shown in the Figure. The optimum demand for conductor replacement is when the annual savings in losses are equal to the annuity of the investment, i.e. when

$$\frac{S^2}{V^2}\Delta R L c_l = \varepsilon c_I L \tag{9.6}$$

where c_I = investment cost of replacing conductor a by conductor b, £/km

ε = annuity factor = $(p/100)/[1 - \{1/(1+p/100)^t\}]$

$\Delta R = R_a - R_b$

R_a = resistance of conductor a, Ω/km

R_b = resistance of conductor b, Ω/km

From eqn. 9.6 the optimum demand for conductor replacement is given by

$$S = V\sqrt{\frac{\varepsilon c_I}{c_l \Delta R}} \tag{9.7}$$

The optimal load for the conductor replacements, given in Table 9.3, can be determined, when using the data from the example in Section 9.4.2 and the investment costs for conductor replacement given in Table 9.3. The investment costs for conductor replacement include material and installation costs of a new conductor and costs of pulling down an old conductor. The residual value of an old conductor has been also taken into account when defining the investment costs for conductor replacement. The resistance of ACSR 21/4 is 1·360 Ω/km.

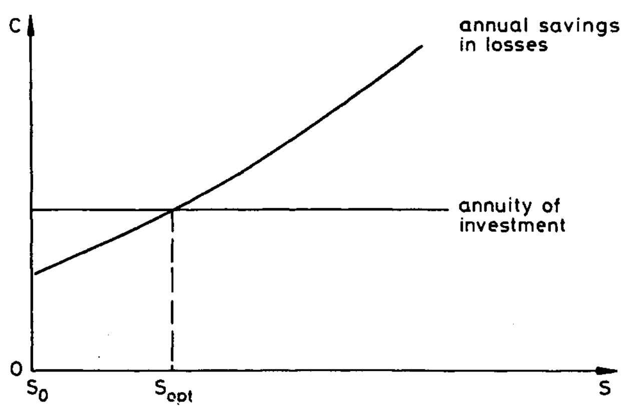

Figure 9.4 Annual costs which have to be compared for line reconductoring studies

Table 9.3 shows, for example, that, if the load exceeds 1·8 MVA, replacement of ACSR 21/4 conductor could be either by ACSR 54/9 or by AAC 132 conductor. Both alternatives are economically equal. In this example, for ACSR 34/6 conductor, the most suitable replacement at all loads above 2·4 MVA is AAC 132. If the reason for replacement is not purely economic, say because the existing conductor size is inadequate for the prevailing fault current, it is possible that the smaller replacement conductor may be more economic.

Table 9.3 Optimum load levels for replacement of 20 kV overhead-line conductors

Conductor change		Investment costs, £/km	Load level MVA
Existing	New		
ACSR 21/4	ACSR 54/9	4140	1·8
ACSR 21/4	AAC 132	5870	1·8
ACSR 34/6	ACSR 54/9	4060	2·8
ACSR 34/6	AAC 132	5790	2·4
ACSR 54/9	AAC 132	5650	3·3

9.5 Operational aspects

9.5.1 Network arrangements

When planning the arrangement of each MV system, the general targets for satisfactory system performance at minimum cost, given in Chapter 2, should be kept in mind. Details of the various calculations are given in Chapters 4 and 5 as well as in Sections 9.3 and 14.6; so the requirements for optimum conditions will be discussed qualitatively rather than quantitatively here.

The majority of the outage time that customers experience is due to faults occurring on the MV system. Various sectionalising and load-transfer facilities are used to limit the effects of MV faults. Operating arrangements for overhead-line and underground-cable networks differ considerably. The economic and thermal limits of individual cables used in city centres are close, and this has an influence on the size of cables used for back-up purposes. However, in other urban areas, the relationship is greatly influenced by the cost of laying cables, the load density and the rate of return adopted for the economic appraisal. Overhead systems are more prone to transient faults, which has led to the development of rapid autoreclosing schemes for these systems.

Almost without exception MV networks are operated radially, although an interconnected method of operation could lead to lower voltage drops and losses. However, in radial networks the protection arrangements are simpler, voltage control is easier and fault levels are lower, and if construction costs alone were considered, the preferred network arrangement would be radial.

Overhead networks

The most common network configuration is the partially looped network with interconnections to other networks fed by neighbouring primary substations. Under normal conditions, by opening switches or disconnectors at the appropriate points, the network can be operated as a radial arrangement with a high degree of reliability. The effect of a fault on a looped circuit or interconnector can then be limited to customers on the section of the network which is taken out of service by opening disconnectors or switches to clear the fault.

Figure 9.5 shows schematically typical arrangements for a rural overhead radial feeder, with some of the manually operated disconnectors omitted for simplicity. It will be noted that each main trunk feeder has a number of lateral spurs. Except in the more remote areas supplied by such a system, there would usually be the facility of interconnection to other MV feeders, supplied either from the same, or adjacent, HV/MV substations, as indicated in Figure 9.5.

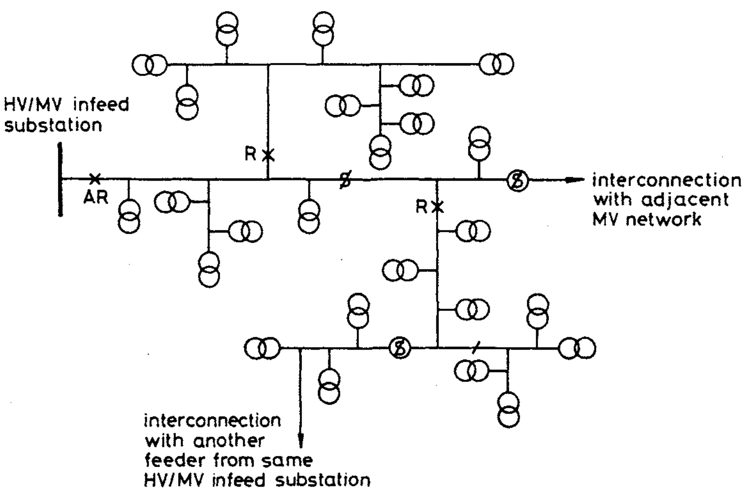

Figure 9.5 Schematic of typical MV overhead radial feeder

X circuit breaker
AR autoreclosing facilities fitted
R pole-mounted autorecloser
/ disconnector, normally closed
⊘ disconnector, normally open
S̸ automatic sectionaliser
pole-mounted transformer

Because of the long distances involved in sparsely loaded localities, the cost of interconnection tends to be high, and thus radial spurs are in common use in rural networks. The use of autoreclosing circuit breakers and sectionalisers has been covered in detail in Section 7.5. These have improved fault outage times. In addition, the use of remotely controlled disconnectors is spreading in many countries, particularly in those rural areas where the average fault location and disconnection times may be of the same order, or longer, than the repair times.

The addition of fault-passage indicators linked to a central processor can lead to improved network security. The lock-out of the source circuit breaker, or a pole-mounted recloser on the main feeder, would initiate interrogation of the fault-passage indicators downstream of the locked-out unit to determine where the fault has occurred. The automated disconnectors on either side of the fault would be instructed to open to isolate the faulty section, and supplies to the healthy sections would be restored by instructing both the locked-out device and the normally open point to close.

To offset voltage drop on long feeders, booster transformers and capacitors are used in some countries. Whilst their flexibility is useful to enable major network reinforcements to be deferred, they are not necessarily economic on a permanent basis. In MV systems where the voltage level is relatively high compared with the average load level, satisfactory voltage conditions can usually be maintained without the need for boosters etc.

When considering how to increase the capacity of a circuit to cope with back-up conditions, it is often more appropriate to consider some smaller investments rather than the larger expenditure on new substations or on replacing conductors since these back-up conditions are only likely to be in operation for a short time and therefore the additional cost of losses is not important. In Figure 9.6 the investment costs of increasing the capacity of a medium-voltage rural network by various methods are presented as a function of the length of the 20 kV feeder. Thus, for example, for feeders 20 to 30 km long, the most expensive way of increasing the capacity would be to construct a new line, whereas the cheapest arrangement would be to use the existing feeder and add compensation at the end of the feeder. It should, however, be noted that in this assessment the costs of losses were not taken into account. In practice the best way to determine the most economic method of increasing feeder capacity in any network can only be achieved by comparing the total costs of the various options.

Most MV networks comprise a 3-phase arrangement with 3-phase spurs or lateral feeders tapped off the main feeders as shown in Figure 9.7*a*. In other countries, notably the USA and Great Britain, single-phase MV supplies are taken from the 3-phase system. Typical British arrangements are shown in Figure 9.7*b*, where a 3-phase spur may itself supply 3-phase distribution transformers or smaller-rated single-phase transformers connected across two phases of the 3-phase MV spur. Single-phase spurs can be tapped off the main MV feeder to supply a number of small single-phase distribution transformers. Equally, single-phase transformers may be tapped direct off the main feeder.

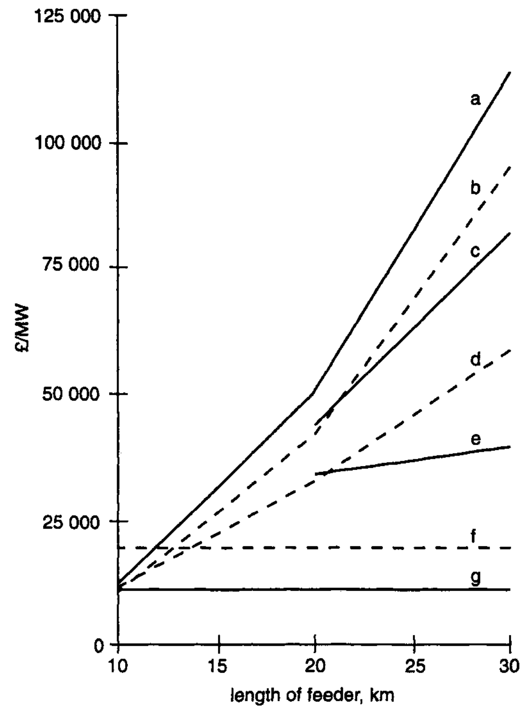

Figure 9.6 Investment costs for different network improvements – an example

a New AAC132
b Reinforce from ACSR54/9 to AAC132
c New AAC132 plus voltage regulator
d New AAC132 plus 3·6 MVAr compensation
e Existing AAC132 plus voltage regulator
f Existing ACSR 54/9 plus 1·2 MVAr compensation
g Existing AAC132 plus 3·5 MVAr compensation

It should be noted that UK practice is to connect the MV winding of single-phase MV/LV transformers across two phases of the MV supply, whereas US practice is to connect the MV windings between phase and neutral. The latter requires a neutral conductor which is not provided in MV systems in most other countries.

The arrangements shown in Figure 9.7 are more usual in rural areas, but are not unknown in some parts of underground networks. The main problem, especially with long lengths of single-phase overhead spurs, is that the connection of a number of single-phase spurs can lead to unbalanced loading on the three phases of the main MV feeders. It is then necessary to re-arrange the phase–phase connection of the spurs to achieve an acceptably balanced 3-phase loading on the system.

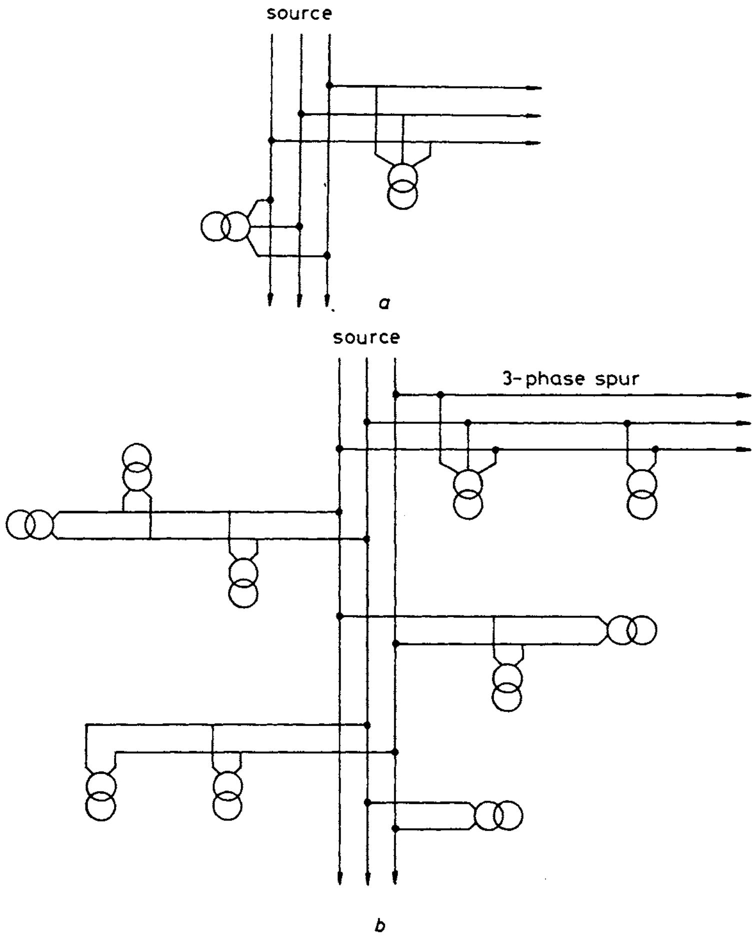

Figure 9.7 MV 3-phase and single-phase systems

Single-phase systems may provide a cheaper method of supplying rural areas with a low load density. Where it is likely that the network loads may increase significantly in the future, the overhead line should be constructed so that conversion to a 3-wire 3-phase system can be achieved at minimum additional cost when network loadings or voltage-drop considerations justify the uprating. It should be noted that, with the heavy demands now taken by many LV domestic customers, a single-phase LV supply is often inadequate, so that a 3-phase LV supply may be necessary. However, with a single-phase MV supply it is not possible to provide this 3-phase LV supply from a single-phase MV system without the expense of uprating the MV and MV/LV supplies to the customer from single-phase to 3-phase.

Underground networks

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 the pavements because of the number of other services (gas, water, sewers, telephone, low-voltage cables etc.) already installed there, and/or the narrow width of the pavements.

In the open-loop configuration shown in Figure 9.8*a*, the various MV/LV distribution substations which are supplying individual customers or general distribution load have some form of disconnecting device on the incoming and outgoing feeder and on the transformer itself. For example, substations C and D are shown equipped with ring-main units, described in Section 10.2. At a suitable point on the network the loop is opened by a sectionalising device S, which may be a circuit breaker, switch, fuse or link. The system then effectively operates as two radial feeders.

On the occurrence of a fault, e.g. at F, the source circuit breaker A would open to remove the fault from the system and supplies would be lost to all customers between A and S. In the example shown, when the faulty section has been located, it can be isolated from the system by manually opening the isolating devices *c* and *d*. Closing S would restore supplies back up to D. Reclosure of A restores supplies between A and C, so that, under the arrangement shown, supplies would eventually be restored to all customers leaving the faulted section of cable isolated for repair work.

Developments in 3-phase SF_6 load-break switches, which can be accommodated in small underground chambers, permit auto-sectionalising to be used. In Figure 9.8*b*, the distribution substations contain a feeder sectionalising unit (FSU). With the introduction of microprocessor-controlled switch actuator units and remote fault-section indication (RFSI) equipment, both the in-line disconnector and the transformer disconnector can be automatically controlled by various signalling arrangements, in a manner similar to that already in use for automatic sectionalisers on overhead systems.

On the occurrence of a fault, the source breaker (1) would open. With the section of the MV feeder now de-energised, the RFSI (2), having registered the passage of fault current, would cause the in-line disconnector in the FSU on the upstream side of the fault at substation B (3) to open. The transformer disconnector at substation B would then be transferred from the downstream MV feeder to the upstream feeder (4), and the source circuit breaker can then be closed to restore supplies to the substations A and B. At substation C the transformer disconnector (5) would also be transferred to the downstream MV feeder. The MV in-line feeder isolator downstream of the fault (6) would then be opened under de-energised conditions to isolate the fault. With no voltage being registered on the MV section between the isolated faulted section and the open point (7), the open point would be closed to restore supplies to substation C from the adjacent feeder.

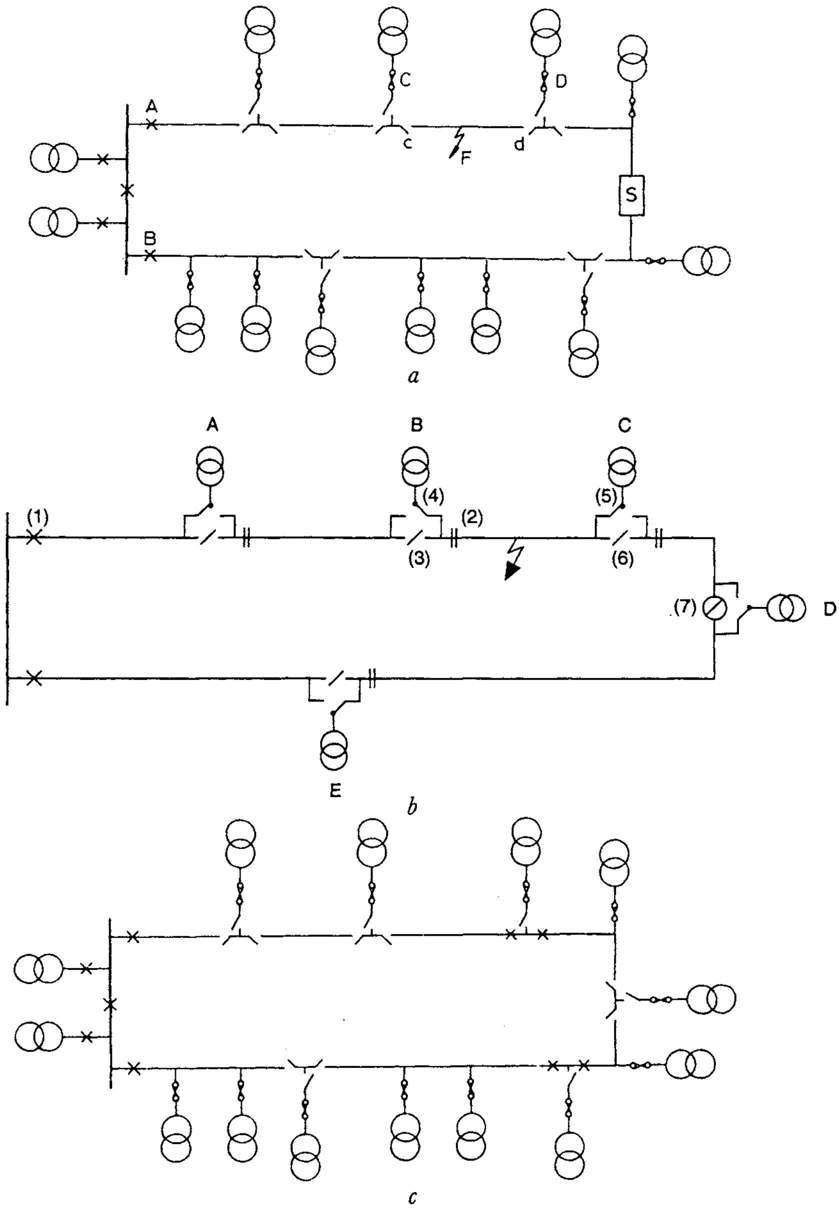

Figure 9.8 MV underground loop arrangements

X circuit breaker
—⁄— load-breaking switch
⚮ fuse
ↀ customer or distribution transformer
S isolation point
—/— disconnector
—⫲— fault current detector

By introducing circuit breakers into a loop network, the totally closed-loop arrangement shown in Figure 9.8*c* is obtained. The ratio of MV/LV distribution substations with circuit breakers, to those without circuit breakers, will generally be a utility policy decision. The inclusion of circuit breakers reduces the downtime of the non-faulted section of the network for any fault on the loop, with sections of the feeder being automatically isolated by opening the circuit breakers on either side of the fault. Such arrangements also aid fault location, and reduce the amount of manual switching required to transfer load off the faulted MV section.

9.5.2 Load-transfer schemes

Where an individual HV/MV transformer supplies an isolated section of MV busbar, a fault on the transformer, or on an HV circuit solely supplying that transformer, can lead to a large number of customers being off supply for a long period of time. To reduce the effects of such faults, a number of arrangements have been devised to transfer the supply from the faulted transformer circuit to the remaining transformer unit(s) and/or alternative infeed circuits. These alternative feeding arrangements are normally capable of meeting the total demand, although on occasions there may be some limitation in the back-up supply, generally due to larger voltage drops than normal being experienced.

By way of example, consider the arrangement shown in Figure 9.9*a*, where the two HV/MV transformers are operated independently on the MV side, e.g. to avoid excessively high MV fault levels. On the loss of transformer T1 or T2, the MV bus-section circuit breaker 3 is automatically closed, either via auxiliary contacts on circuit breakers 1 or 2 as appropriate, or from loss of voltage signal from a VT on the MV side of T1 or T2. Closure of circuit breaker 3 restores supplies.

As discussed in Section 12.2.3, arc-furnace and similar interference loads often need to be segregated from the normal distribution loads to avoid affecting the quality of supply to the normal distribution customers. It is then sometimes necessary to provide duplicate transformers for both the distribution load and for the interference load to ensure independent security of supplies to both loads; i.e. a total of four transformers. However, consideration may be given to the arrangement of Figure 9.9*b*, where the distribution and interference loads are supplied by three transformers. Under normal operating arrangements two transformers would be switched to supply the largest load, say the distribution load, in order to minimise series losses. This is achieved by operating with circuit breaker 3b open.

Should transformer T2 be faulted, for example, circuit breaker 2 would trip open and this action would cause circuit breaker 3a to open and 3b to be closed, restoring supplies within a few seconds. This arrangement requires only three transformers, instead of the four-transformer arrangement referred to in the previous paragraph. Since the loads are carried by only three transformers in this arrangement, the total series losses will be greater than with the

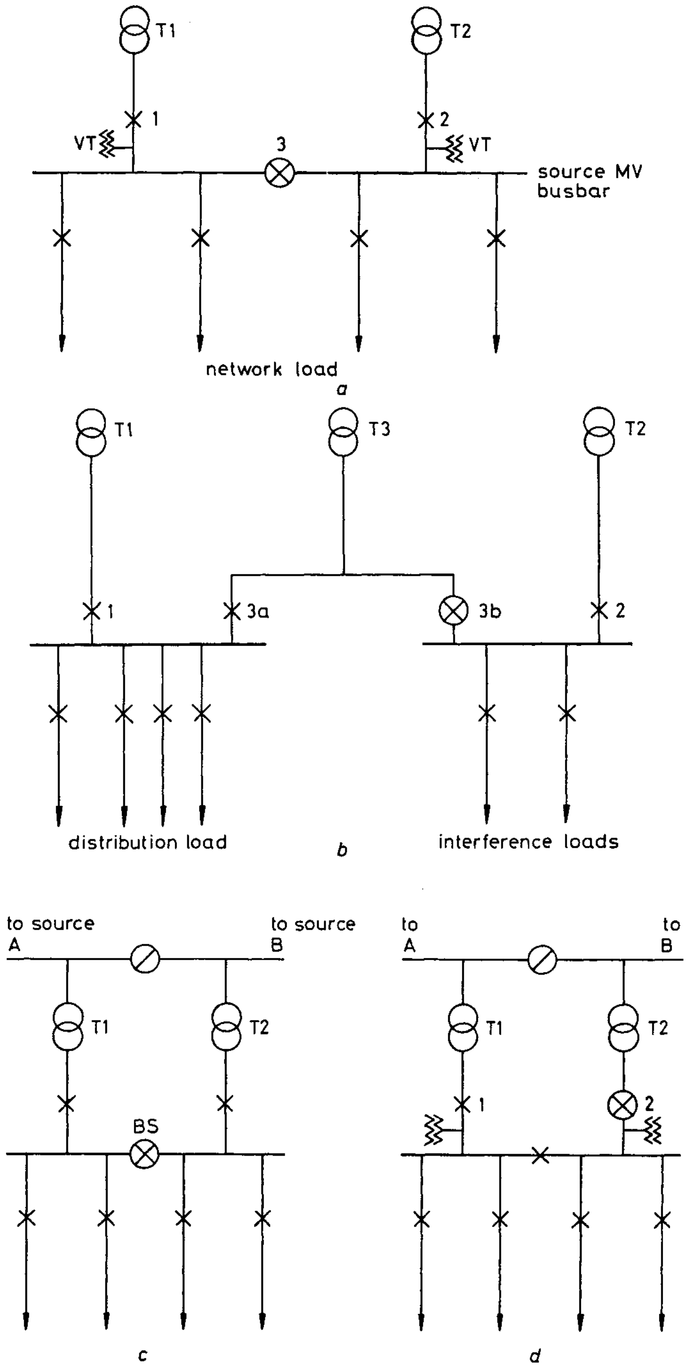

Figure 9.9 MV load-transfer schemes

four-transformer arrangement, although the shunt losses will be lower. Additionally the arrangement shown in Figure 9.9*b* will require additional intertripping and relaying equipment.

Reference has already been made to the need to have open points on networks for operational reasons. The location of such open points must include practical matters such as convenience of location and the isolation of sections that are difficult to patrol. It is often convenient for such open points to be provided at a circuit breaker or disconnector at a substation, in order to permit telecontrol operation if required.

Figure 9.9*c* shows an arrangement where the open point is at a substation where the incoming and outgoing supply feeders are from different networks. Opening the bus-section circuit breaker BS will prevent any reverse current flows and also simplify protection arrangements. Should either infeed and/or transformer be out of service, the bus-section circuit breaker can be closed, automatically if required, to restore supplies to the network load. If it is proposed to supply the total load from one infeed point, the arrangement shown in Figure 9.9*d* may be used. Under normal conditions the total load is supplied from one transformer, in this case T1. Should the incoming supply fail, loss of voltage on the VT associated with circuit breaker 1 would initiate closure of circuit breaker 2 to restore supplies.

9.5.3 Optimum location of protective equipment and switching devices

Protective equipment and switching devices are located in a network to protect equipment and to isolate equipment failures and faults, or to isolate equipment to be maintained. Some of the basic equipment used and discussed in this section are as follows

- breakers (and relays)
- manual, telecontrolled or automatic disconnecting switches
- autoreclosers
- fuses

The optimum use of protective equipment and switching devices is achieved when protection co-ordination is adequate and the overall costs are minimised. Thus the protection co-ordination can be handled as a technical constraint which is based upon fault characteristics and the load flow. The types of equipment used can have a direct effect on the frequency and duration of outages experienced by customers. Thus these two aspects are interrelated and composite results are obtained; e.g. by first evaluating each characteristic separately and then combining the results.

When assessing network alternatives with different amounts and types of equipment, the associated costs, including the assigned values of the energy not supplied, should be evaluated. The calculation and comparison of the costs and benefits of the reliability achieved can only be accomplished through the use of adequate quantitative reliability analysis, as discussed in Chapter 4. The optimum types and locations of equipment can be considered either by carrying out individual cost/benefit analysis or by using optimisation methods.

In an individual analysis, costs of outages on the network are first evaluated before any new equipment is added, and the studies are then repeated with any proposed equipment installed at various alternative locations. These alternatives are then assessed by comparing the differences in overall costs. This method is adequate if not too much new equipment is to be added. Such a situation often arises when existing networks are being considered. The various types of new equipment to be used, and their locations, can be selected heuristically by the engineer, or they can be based on the results of a reliability analysis. These cost/benefit analyses can be carried out either manually (see example in Chapter 4), or more effectively by using an adequate reliability calculation program as described in Section 14.5.2.

When new networks are being designed, or large amounts of new equipment are being added, it is often beneficial to use methods whereby the amount and locations for the new equipment can be evaluated more simply. It is then possible to use approximate methods based on making some simplifications about the networks. Approximations that can be made for mathematical modelling and optimising are, for example, that the demand, and the failure rate per unit of line length, are constant. When the amount of equipment required has been approximately calculated, the planning engineer can place the individual items at suitable locations on the network. He can then refine the study by justifying the cost/benefit of each item, and optimising its location as illustrated in the following example.

(i) Optimum location of a disconnector

The optimum location of a pole-mounted disconnector is determined by comparing its benefit, in terms of the reduction of outage costs, at various possible locations. The basis of the method is that the new equipment protects customers upstream of its location, i.e. nearer the source, from faults downstream. The location is thus determined by the product of the transformer kVA capacity upstream, and the length of line (km) downstream.

Without a switch in the feeder circuit, a fault anywhere on the feeder will cause an interruption of supply to all customers supplied from that feeder equal to the repair time. After addition of a disconnector, then any faults downstream of its location will result in loss of supply to the customers upstream only for the length of time taken to reclose the disconnector (switching time). If we assume that:

- Risk of failure is proportional to length of line
- Costs of outages are proportional to energy not supplied
- Growth of load is equal at every load point
- Average values are used

the savings in the total costs can be expressed as:

$$C_i = KP_i f_l l_i t c_n - C_a \tag{9.8}$$

where C_i = savings in total costs if a new disconnector is at location i

K = coefficient by which the first-year outage costs are to be multiplied in order to obtain discounted costs over the whole review period

P_i = demand upstream of i

f_l = failure rate per line length

l_i = line length downstream of i

t = the difference between the repair time and the switching time

c_n = outage-cost parameter of energy not supplied

C_a = costs of a disconnector (including maintenance) over the whole review period

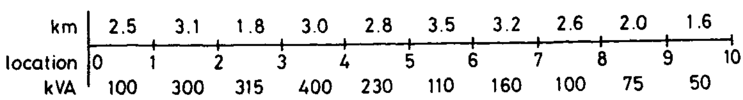

Figure 9.10 Example of determining the optimum location of a disconnector

As an example consider the line shown schematically in Figure 9.10. The possible positions for a disconnector are at locations 1–9. The total nameplate ratings of the distribution transformers and the line lengths for each section are also shown in the figure. The data to be used for solving eqn. 9.8 for this example are:

$K = 10$
average demands = 0.25 times the nameplate ratings
$f_l = 0.125$ faults/km per annum
$t = 2h$
$c_n = £0.5$/kWh
$C_a = £3750$.

The values for C_i for the different locations are given in Table 9.4. It will be seen that the best site for a disconnector is at location 4 with total savings of £1720. However, it will often be necessary to check if the addition of two or more disconnectors, instead of only one, would give still better savings. In this example, the optimum arrangement is for the one disconnector only.

This type of study is sensitive to the values applied to the parameters of eqn. 9.8, as shown in Figure 9.11, where the value c_n of energy not supplied has been varied. For a value twice that used in the above calculations for Table 9.4, it seems likely that more disconnectors could be justified, whereas at half the value there is no justification for placing a disconnector at any of the specified locations.

Table 9.4 Determination of optimum location on a disconnector

Location	Upstream, kVA	Downstream length, km	kVA km	C_i, £
1	100	23·6	2360	−3010
2	400	20·5	8200	−1190
3	715	18·7	13370	430
4	1115	15·7	17505	1720
5	1345	12·9	17350	1670
6	1455	9·4	13677	520
7	1615	6·2	10013	−620
8	1715	3·6	6174	−1820
9	1790	1·6	2864	−2850

The optimum location of other equipment, e.g. telecontrolled disconnectors, and circuit breakers, can be calculated in a similar way to those used in the above two examples. In each case it is necessary to take account of the appropriate annual costs, the duration of outages and outage rates, and possibly also system losses, in order to derive the total costs.

In addition to the location and type of new equipment to be installed, the timing of such work should also be optimised. If it can be assumed that the savings achieved with new equipment will not decrease in the future, the optimum installation time is when the annual savings are equal to, or greater than, the annual costs of the new equipment.

9.5.4 *Network reinforcements*

MV network reinforcement is motivated by three different factors. The necessity to replace equipment reaching its technical or economical life has been discussed in Chapter 6. Reinforcement due to changes in load level has been referred to earlier in this chapter. In this section the need to reinforce because of a revision of the MV system will be considered.

A voltage-system revision usually involves simplification of the existing system or the introduction of a new higher-voltage level. These are easier to carry out on overhead systems, but in any case the necessary work can take many years and requires large capital investments. Figure 9.12 gives an example of the time required for such an operation, covering a situation where a 110/30/10 kV system was replaced by a 110/20 kV system. The revision proved highly successful, giving payback times as short as five years in many rural areas.

Where large-scale equipment changes or extensions are necessary it is often economically viable to uprate, e.g. 6·6 kV networks to 11 kV operation, owing to the saving in system losses even before the additional capability at the higher voltage is required. By good planning it is often possible to install switchgear, cables and dual-ratio distribution transformers on the system some years before the voltage uprating is to take place, in order to ease both the financial and

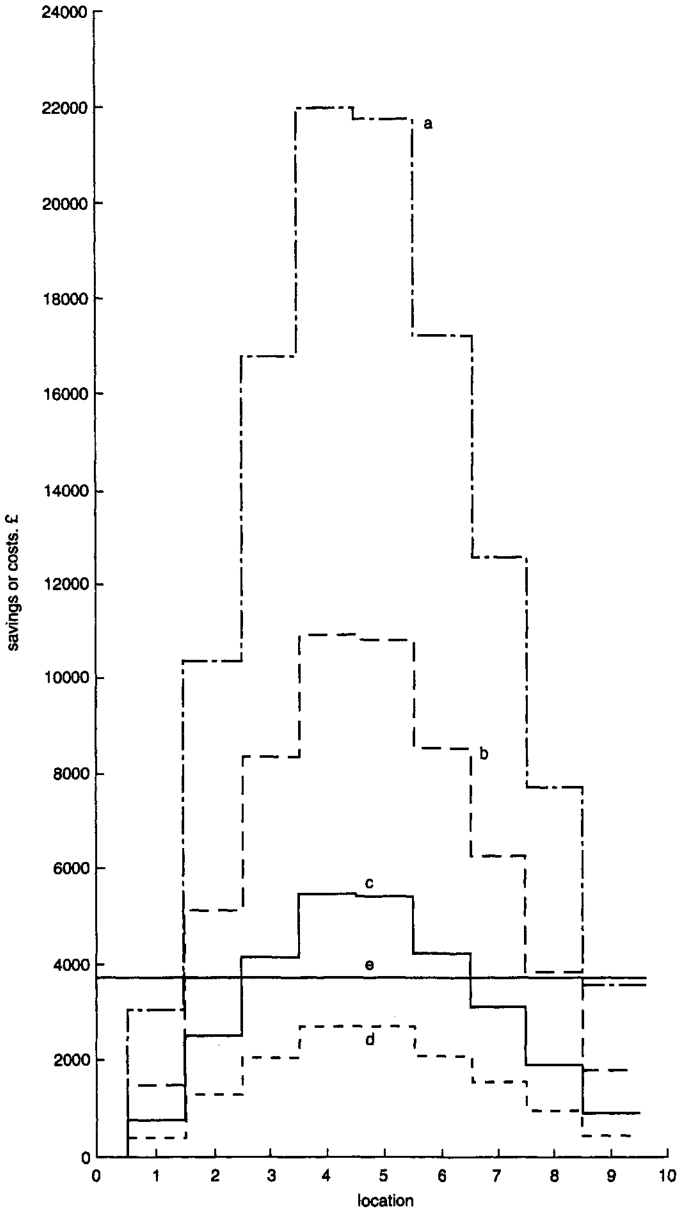

Figure 9.11 *Savings, or costs, gained by installation of a disconnector*
Location nodes refer to Figure 9.10
Savings in costs of outages if
a c_n = £2/kWh
b c_n = £1/kWh
c c_n = £0·5/kWh
d c_n = £0·25/kWh
e Costs of a disconnector

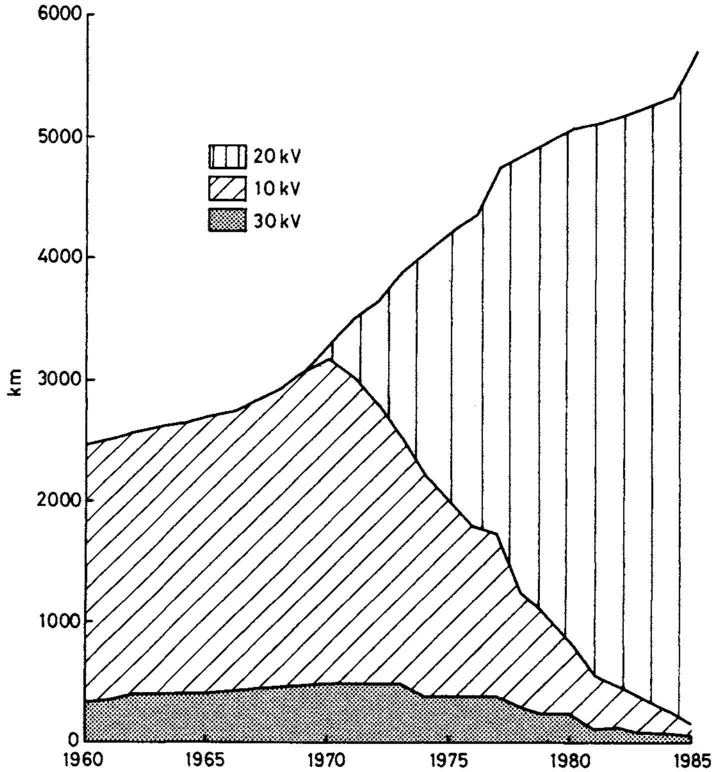

Figure 9.12 Total line lengths during voltage restructuring on an MV system (Courtesy Lounais-Suomen Sähkö Oy, Finland)

resource problems of such changeovers. In looped networks the voltage-replacement programme can be carried out transformer by transformer.

Planning and design engineers should recognise that equipment replacement offers them the opportunity of restructuring networks so as to be suitable for the long-term development of the system. This must be considered whenever such an opportunity occurs rather than concentrating on a like-for-like replacement, or minimising the degree of replacement on a short-time economic basis without proper regard for the future.

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Chapter 10

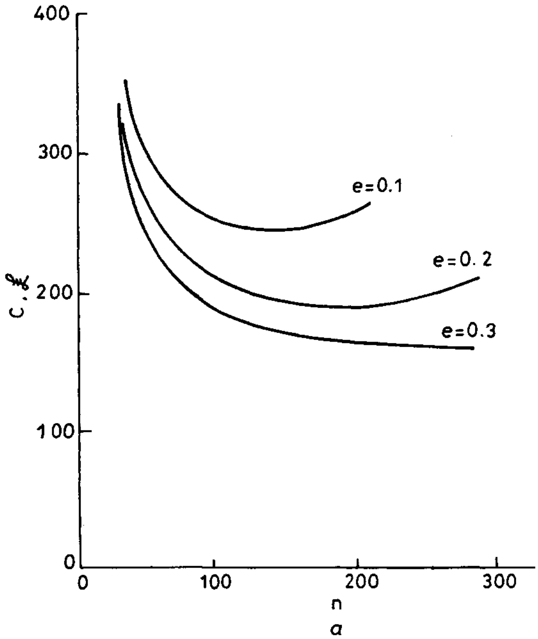
Distribution substations and LV networks

10.1 General

Comparison of low-voltage networks and distribution systems operating at higher voltage levels reveals a considerable number of similarities. Both are usually operated radially, and thus each network has only one infeed point. In the MV system the construction of a new 110/20 kV infeed substation can involve investment of the order of several million pounds and require extensive design work. However, such schemes are not so numerous as the provision of new 20/0·4 kV distribution substations, each costing only about £3000–£30 000, and the associated changes in operating arrangements of the low-voltage system. These latter schemes are carried out almost daily, depending on the size of the utility and the distribution network conditions. Although individual LV construction schemes are small, the large number of such jobs carried out each year tends to absorb a major part of a utility's capital and design resources. This leads to the need for good design practice involving an efficient organisation to oversee the large number of LV schemes, with standardised approaches to LV network design.

When planning for the electricity supply to a new area or the reinforcement of an existing network, it is necessary to consider the requirements for MV/LV distribution substations and LV circuits at the same time. For each scheme there are optimum locations and sizes for each substation, as well as the configuration and dimensioning of the associated LV systems. This topic is covered in more detail in Chapter 14, where computer-based design methods are discussed.

Figure 10.1 indicates how the costs of providing electricity supply are influenced by the number of customers fed from an individual distribution substation, the density of housing in the area being supplied, and the main construction policy which has been adopted, i.e. underground or overhead. The options most often used in system reinforcements are to replace existing



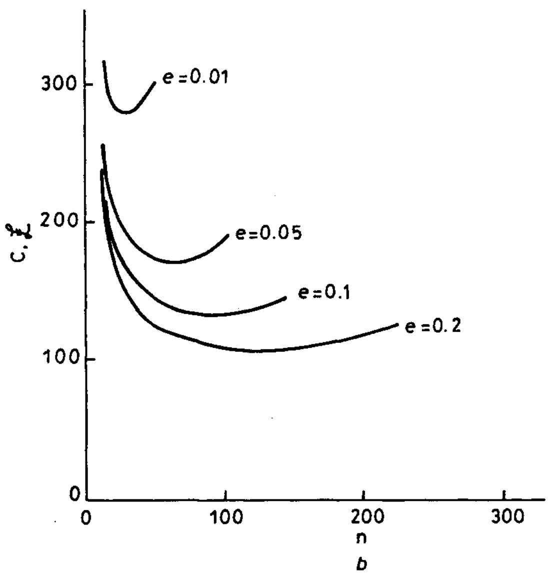


Figure 10.1 *Cost per consumer (C) of electricity distribution networks as a function of the number of consumers (n) fed by the transformer; service cables not included*

e: house area/plot area
a Underground cable network
b Overhead line network

overhead-line conductors by conductors of larger cross-sectional area and/or to add new MV/LV distribution substations. Here also it is necessary to combine studies to cover the effect of new substations and LV network changes.

In the United States general practice is to minimise the LV circuits, overhead or underground, by using more, and smaller, MV/LV transformers which may serve only a few customers. This arrangement is mainly due to the lower standard voltage used there.

If the ratio of the nominal voltages of two networks is 50:1, then, with the same conductor size, the higher-voltage network is capable of transferring 50 times as much power as the lower-voltage network for the same voltage drop. If the same percentage voltage drop is required, which approximates to present practice, then, at the higher voltage, a load 2500 times larger can be transferred over the same distance compared with the lower-voltage network. Alternatively, a load 50 times as great could be transferred over a distance 50 times as long. These conditions exist in 20/0·4 kV MV/LV systems. The normal power levels in LV circuits are therefore much lower than those associated with MV circuits. Consequently it is less economic to improve the security of low-voltage lines compared with that of medium-voltage lines of equivalent conductor size.

Low-voltage lines are more susceptible to lightning overvoltage than MV systems owing to their lower insulation level. Lightning strikes close to LV lines may induce overvoltages causing damage. The practice of keeping LV lines short, the present trend of placing systems underground, and the increasing use of aerial bunched conductors have proved successful in reducing these overvoltage problems.

The R/X ratio for LV lines and cables is usually high. Thus reactive loads do not often cause voltage-drop problems (see eqn. 3.24), but the high R/X ratio considerably effects the power losses (see eqn. 3.5).

Of necessity LV networks, services and appliances are often located in proximity to human beings and animals. The average person is not aware of the potential danger from the misuse of electrical appliances, or from the consequences of faults on their equipment or the installations at work, home or places of entertainment. The voltage levels used in Europe can lead to electric shock under adverse situations, so that strict Government and utility regulations are necessary to cover the safety aspects of wiring installations, protective devices within a customer's premises, and the individual electrical appliances. The degree of control imposed by such regulations has an influence on acceptable design arrangement and their costs.

There are large variations in load density between different areas. In the centre of large cities the average load density can exceed 100 MW/km^2 while in rural areas the maximum density may only be some tens of kilowatts per square kilometre, and less in remote areas. This leads to considerable differences in the optimum network arrangements. In rural areas small transformers, sometimes below 10 kVA rating and supported on poles, feed a few customers via overhead lines with the average load per line being sometimes only a few kilowatts. In city centres, substations at basement or street level inside commercial blocks, with a number of transformers in the 1 MVA range, feed many customers via strong underground cable networks.

10.2 Cable-connected substations

In urban areas where the load density is high the optimum distribution-transformer size tends to be between 0·5 and 2·0 MVA. Depending on the location, the MV/LV substation can be of a kiosk type or contained within a commercial building or a multi-storey housing block, often having to meet strict environmental and amenity requirements. In such areas it is usual for the MV and LV systems to be underground and, owing to the relatively high powers delivered through the MV/LV substations, reliability is particularly important. To ensure maximum continuity of supplies, looped MV networks as illustrated diagrammatically in Figure 10.2 are used.

Various switching and isolating arrangements are now in operation on underground urban MV systems. A diagram of a totally enclosed 'ring-main unit' is shown in Figure 10.3. The incoming MV feeders are provided with load-breaking disconnectors, with the transformer connected to the ring system through a loadbreak switch in series with a current-limiting fuse. The switch-fuse arrangement protects against a transformer fault and can disconnect a faulted

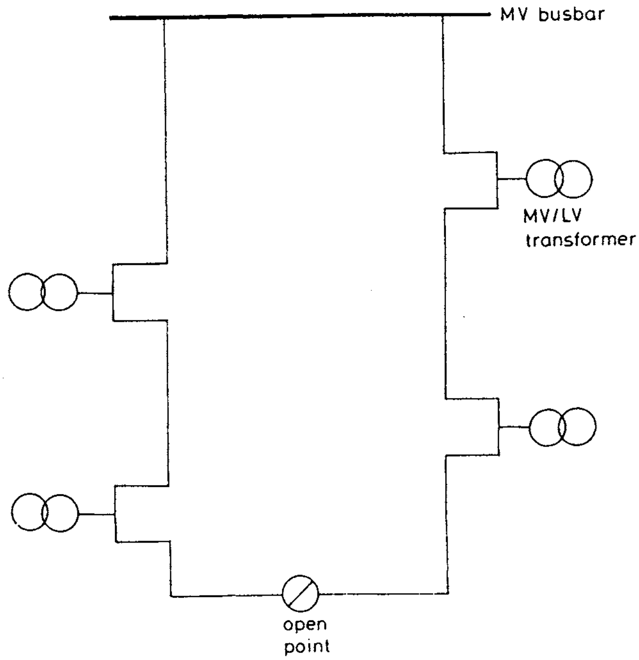


Figure 10.2 Looped MV network arrangements

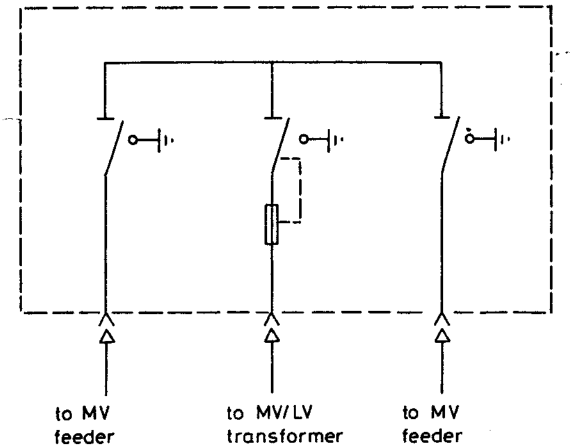


Figure 10.3 Ring-main unit

transformer without breaking the MV ring-main cable interconnection. In more modern arrangements the switching devices and busbars are contained within a sealed enclosure containing SF_6 at low pressure. Connection of the MV ring cables and the MV/LV transformer is achieved by plug-in-type connectors into sockets on the outer side of the enclosure.

A more detailed consideration of the connections to a single-transformer MV/LV urban substation is given in Figure 10.4. The MV switches A in the three left-hand cubicles must be capable of breaking a current higher than that determined by the thermal capability of its associated MV cable, or of the distribution transformer. Transformer overload protection can be provided by a thermistor which is connected to trip the switch fuse B if the temperature inside the transformer becomes too high. The transformer LV switch C should be capable of breaking the transformer no-load load current, with the individual LV switch fuses providing protection against overloads and faults on the LV

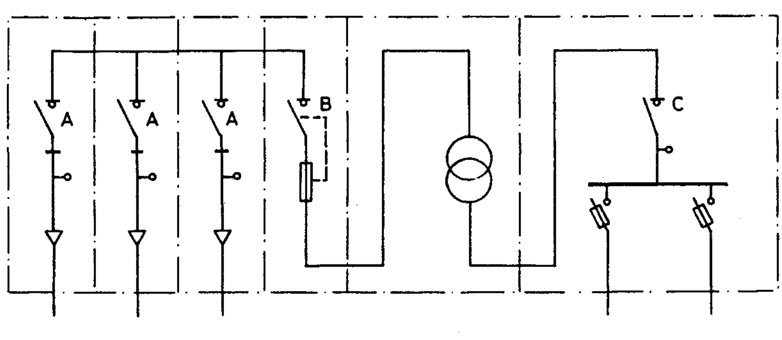


Figure 10.4 Schematic of an urban single-transformer MV/LV substation

system. A thermal maximum-demand indicator enables the transformer peak loading to be determined, although more and more sophisticated load-data-collection instrumentation, associated with developments in telecontrol data-collection schemes, is being used. Such an urban substation, including the incoming MV feeders, the MV/LV transformer and the LV distribution board, can all be located within purpose-designed housing, factory assembled for ease of installation at the required site. A typical prefabricated pad-mounted arrangement is shown in Figure 10.5

Cable-connected substations are usually but not necessarily mounted on concrete pads. In the USA transformer units semi-buried or completely buried in specially designed underground chambers, often in extremely compact arrangements, are popular. Some utilities place substations below ground in basements, or on the ground floor of large public or private buildings. It is then necessary to ensure that adequate space is available to install and maintain the utility's equipment, that fire and safety regulations are strictly obeyed, that the substation is always accessible to utility staff, and that such amenity aspects as ventilation, noise problems and the magnetic field are adequately covered. Figure 10.6 shows a typical service arrangement for a large building, with individual MV feeders to supply the customer's own MV/LV substations.

Should any of these substations become fully equipped with the maximum size of transformer possible, and further load growth occurs within the feeding area,

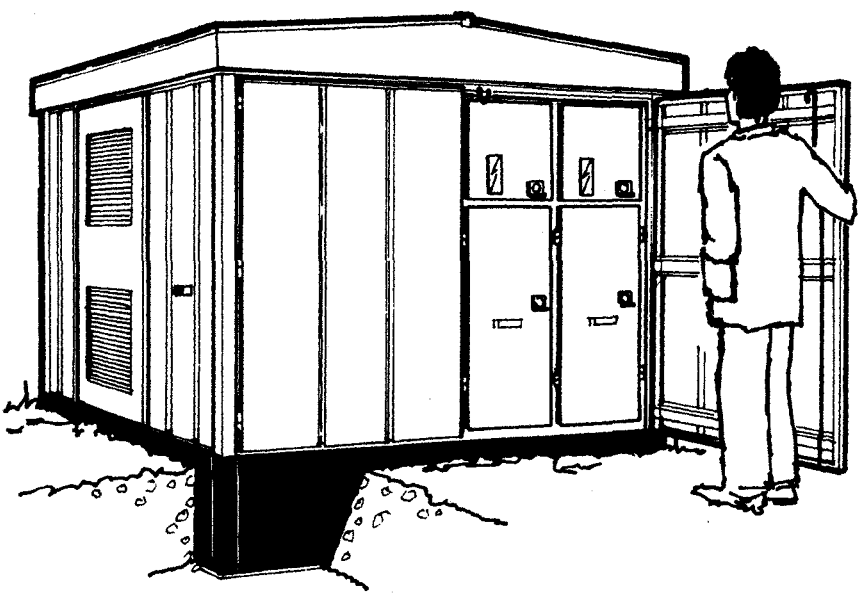


Figure 10.5 Typical prefabricated pad-mounted MV/LV substation

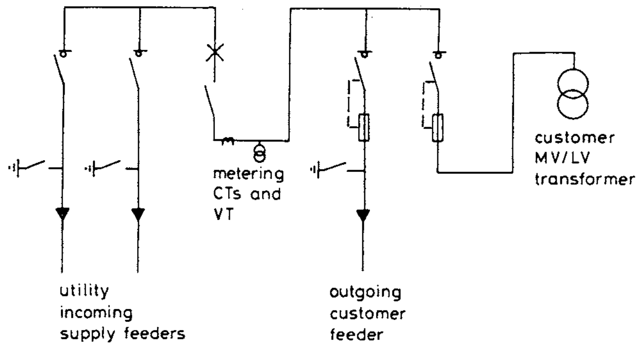


Figure 10.6 Typical service arrangement for a large building

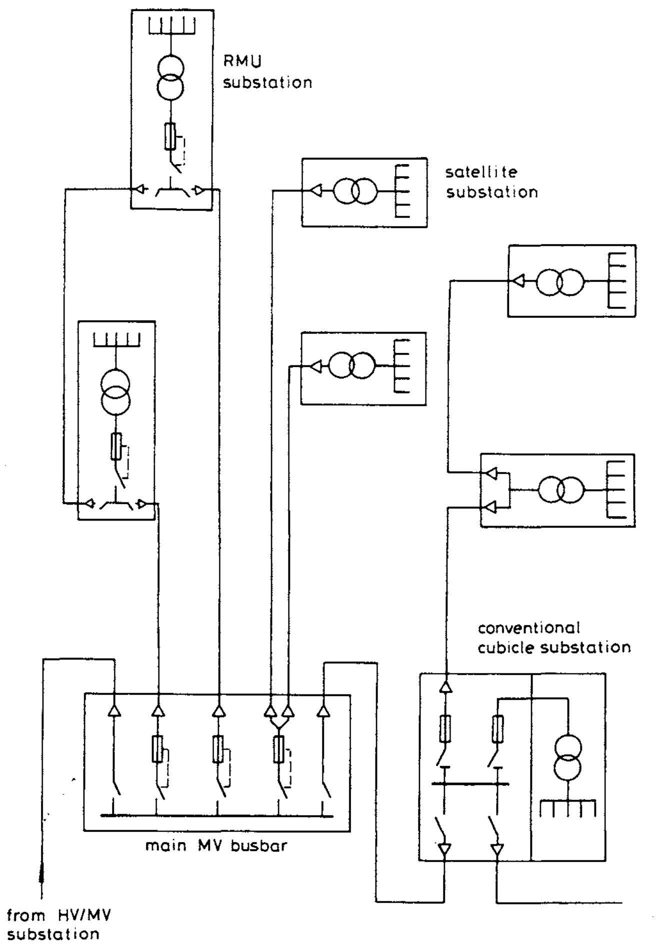


Figure 10.7 Urban MV/LV substation arrangements

considerable difficulties may be faced. The use of 'satellite' substations, each containing a single 100–300 kVA transformer, can be one solution. Cabled direct to the main MV infeed substation or into a convenient MV cable, as illustrated in Figure 10.7, the satellite substation requires no MV switchgear, being protected either at the main infeed substation or at some intermediate conventional MV substation; and it thus lends itself to a simple compact arrangement. Owing to their smaller size, suitable sites can be found more easily, and the use of satellite substations is becoming increasingly popular. A further advantage is that, being located near the load centres, this arrangement results in reduced LV circuit lengths.

10.3 Pole-mounted substations

In rural areas where the load density is low and overhead lines are used, pole-mounted substations are a natural choice. For MV/LV transformers below 100 kVA it is possible to bolt the transformer onto a single pole or place it on a metal frame attached to the pole. For larger-sized units a platform supported by two poles is used to hold the transformer up. Typical arrangements are shown in Figure 10.8, with some details omitted for clarity.

The use of individual MV fuses is not recommended since they frequently operate under storm or transient fault conditions. One 3-phase disconnector can cover a group of small pole-mounted substations connected to a section of the MV network, as discussed in Chapter 9. Larger transformers are equipped with individual disconnectors, as shown in Figure 10.8*b*. On the low-voltage side each feeder is usually equipped with its own protective fuses, although the use of miniature circuit breakers in place of fuses is increasing.

For overvoltage protection spark gaps are in common use on the MV side. A prerequisite for this arrangement is that the transformer-winding construction is not over-sensitive to the rapid collapse of surge voltages. Depending on local price levels and reliability appraisals and the average level of lightning strikes in the area, it may be economic to protect the larger rated transformers, say over 160 kVA, by lightning arresters. Further details of overvoltage protection are included in Section 7.6.

Pole-mounted substations also provide an economic arrangement in areas where MV overhead lines and LV underground cables are used.

10.4 LV network arrangements

Network practices vary as much as substation arrangements, depending very much on the district concerned. In urban areas with high housing density it is usually only possible to use underground cables for the LV system. In such situations LV cables from neighbouring distribution substations can terminate very close to one another, thus permitting interconnection of the LV network, at

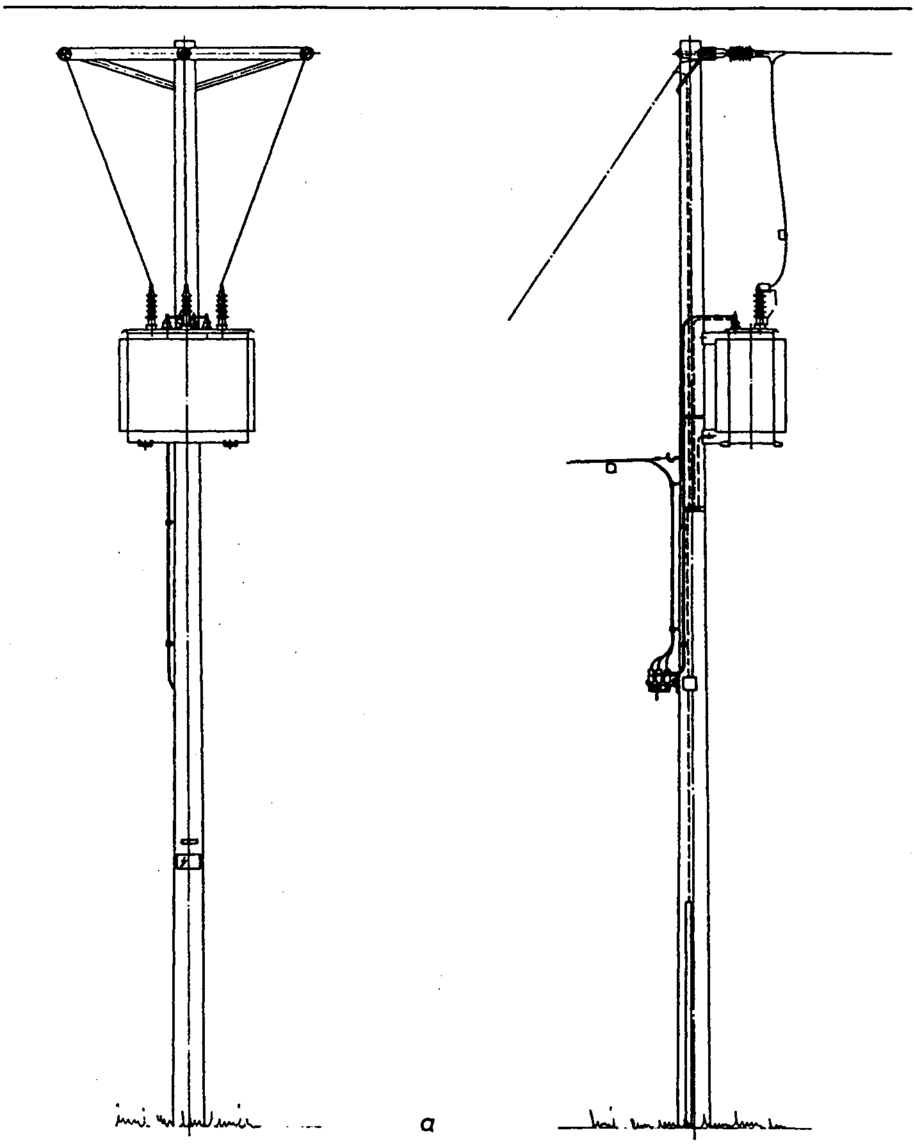


Figure 10.8 *Various methods of supporting transformers on poles (Courtesy Association of Finnish Electric Utilities)*

a Single pole

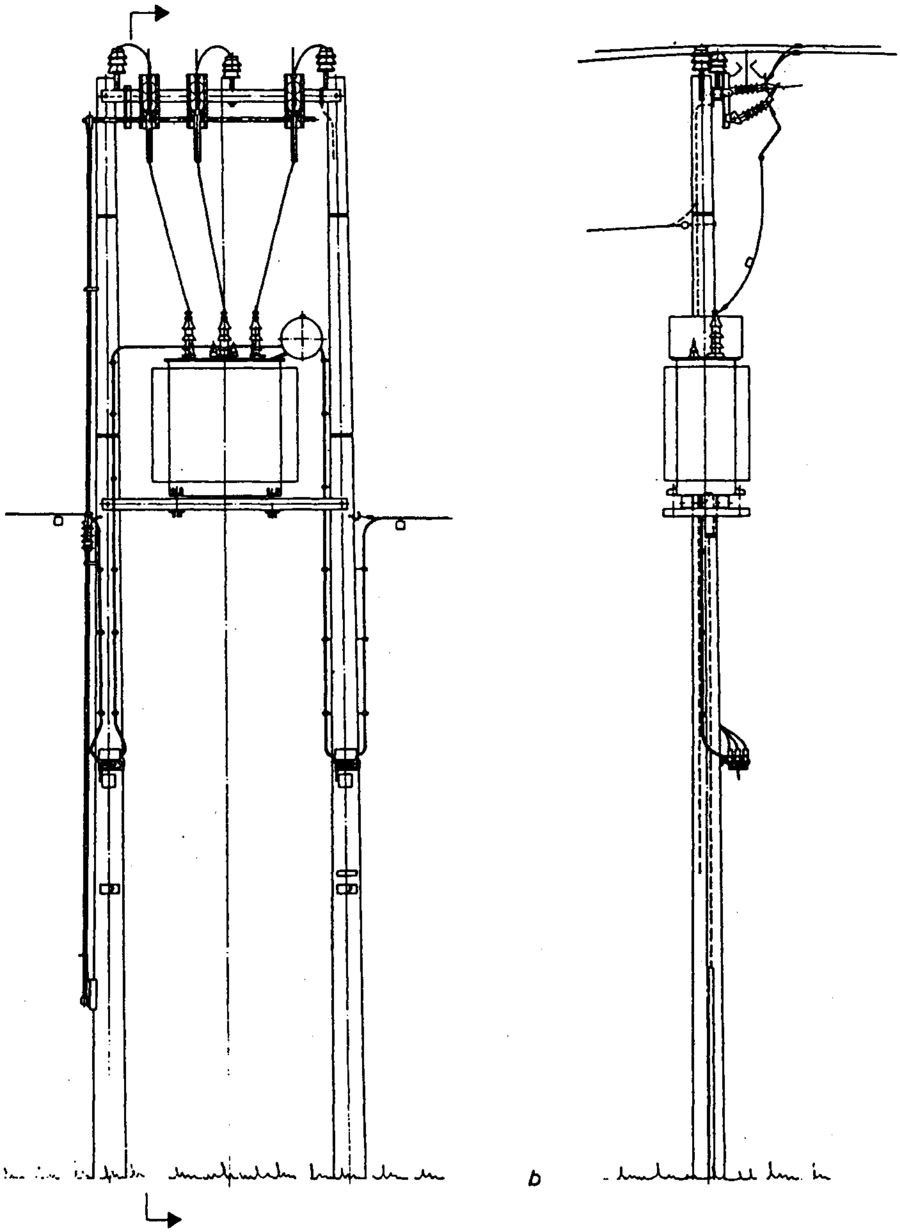


Figure 10.8 (continued)
b Twin poles

low cost. In the 1930s such systems were often operated as mesh networks in cities, but present practice is for radial operation to predominate, with open link points on the LV systems. Where load factors are low, it is then also possible to utilise the spare capacity available at low-load periods to facilitate outages, e.g. for maintenance. High-capacity interconnectors between substations can provide back-up feeders for some or all of the customers supplied from a particular distribution substation. While the costs of providing these interconnectors may be high, such arrangements are often justified on the basis of the requirement in certain areas for a high level of reliability linked with demands for above-average quality of supply. Under some fault conditions it may be necessary to provide emergency interconnector cables, which in some rural situations may even be temporarily laid above ground, to ensure that back-up supplies are available.

Rural situations often involve long distribution networks separated by areas with little or no habitation. Here the average distance between homesteads can be some kilometres. In these areas it is probable that only a single domestic or agricultural customer is supplied from each distribution substation. In rural areas it is therefore seldom worthwhile adopting looped LV systems or providing LV interconnection between substations. However, even in these areas there may be customers with special requirements or for whom the normal level of reliability is not adequate. For example radio transmitters are often located in remote areas, or in difficult terrain such as the top of a mountain, in order to maximise the transmission range. Near-perfect reliability is effectively required, necessitating two infeeds, preferably from two independent MV sources. A fault on the normal supply must be quickly and automatically isolated, and supplies transferred to the standby supply. Depending on the nature of the transmitter load, it may be desirable for it to be provided with an independent main feeder, but other customers would be connected to the standby supply. The use of diesel generators to provide back-up supplies under fault or maintenance conditions may prove to be more economical than network reinforcement, and should be considered when only single MV supplies are available or the distances involved make interconnection uneconomic.

The mechanisation of farming and forestry has led to the increasing use of motors in remote areas, which can also cause problems particularly when starting up, resulting in excessive voltage drops. The network designer thus has to tackle the problems of meeting these special requirements while recognising that neighbouring customers are also entitled to a supply of reasonable reliability and quality, having due regard to the economics of each case.

In many countries there is a two-way movement of population. Agricultural mechanisation leads to a population movement from rural to urban areas, whereas more and more people are moving away from large towns and cities to the so-called 'dormitory' villages. Often government policy leads to the establishment of New Towns in previously rural areas, to limit urban sprawl, and utilities are faced with rapid load growth in rural areas with little MV or LV capacity.

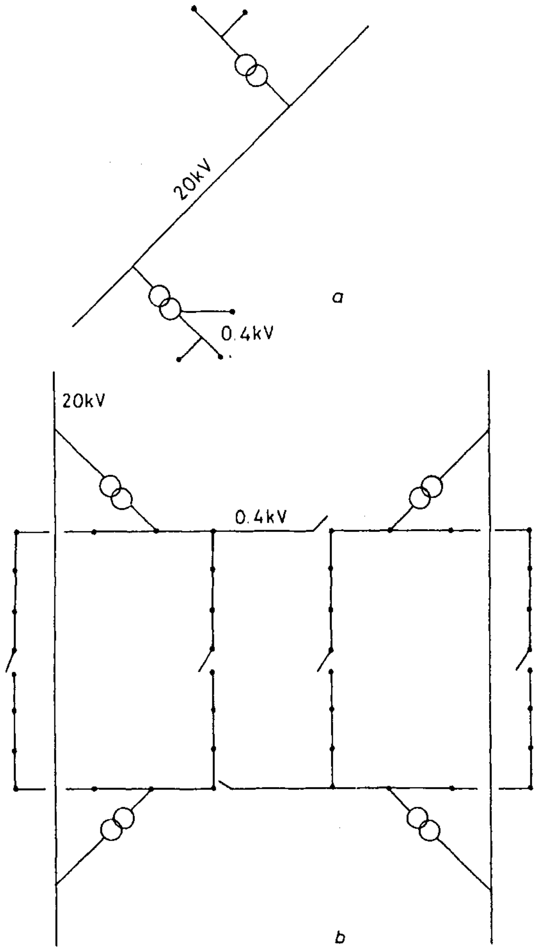


Figure 10.9 *Typical LV systems*

a Rural
b Urban
● = customer or cable box

The majority of designs for LV networks arise from the need to connect new customers; e.g. the provision of new supplies for a new housing, or industrial, estate. However, there will also be the need to reinforce existing systems owing to growth in load of existing customers, plus the requirement to replace out-dated and obsolescent equipment. Such studies often involve a review of a large part of an entire low-voltage network, and in so doing it is then necessary to consider the appropriate conductor size for a number of circuits. Only by comparing different network configurations with individual circuit dimensions can an optimum overall solution be obtained.

The basic target of dimensioning studies is to find the conductor size which minimises the total discounted costs of investments, losses, maintenance and operation over the life of the scheme, and also fulfils the necessary technical and safety constraints. The methods for determining the dimensions of MV lines given in Section 9.4 are basically valid also for LV line design. However, in this latter case the aspects which need to be emphasised, including safety regulations, are somewhat different.

In overhead-line circuits the most important constraints are voltage drop and adequate fault current to operate the protection. With short cables, thermal limits may lead to the rejection of otherwise acceptable alternatives, or at least reduce the availability of some cables for back-up supplies. The most appropriate ranges for two sizes of LV overhead cables are shown in Figure 10.10.

The vertical lines showing the limits of acceptable line length are derived from the need for adequate fault current compared with the feeder fuse rating. The curved lines are calculated from the maximum voltage drop. The continuous horizontal lines are based on the thermal limits, with the broken lines showing the economic effect of applying an interest rate of 5 or 10%. This type of diagram is only valid for a particular combination of assumed costs, load growth and specified safety regulations.

In practice, the load is not usually concentrated at the end of the feeder as was assumed in deriving Figure 10.10. The optimum cross-section therefore varies along the line, depending on the load level. This then results in a constant voltage drop per unit length of line. However, there is often only a small cost difference, for the same voltage drop, between networks with optimum conductor cross-section tapering and those using just one correctly chosen

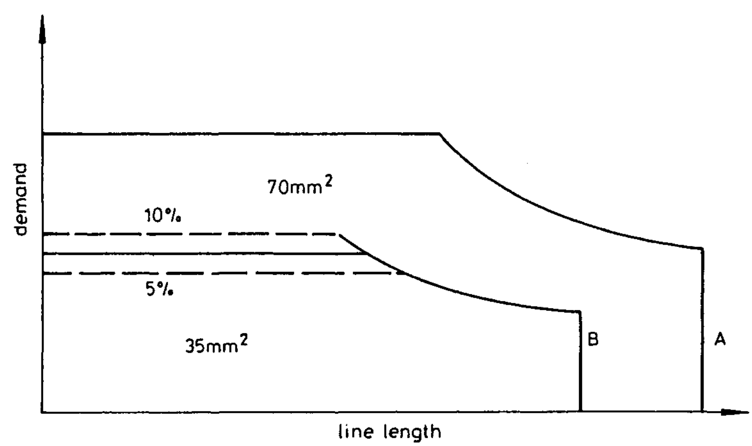


Figure 10.10 Range of applications for various LV overhead cables, and their constraints

A 125 A feeder fuse rating
B 80 A feeder fuse rating

standard-size cross-section conductor. Thus a maximum of two different conductor sizes in each LV network, correctly determined, will provide an economic arrangement in most cases.

10.5 Service connections

The method by which low-voltage customers are connected to the LV network depends mainly on the type of network (overhead or underground), the load density and local utility regulations. For example, the requirements for fault and overcurrent protection and the use of live-line working vary considerably in different countries.

In remote rural areas the low-voltage-supply conductors may be terminated on the walls of houses directly from the low-voltage overhead line. In other rural areas and small villages the service connection to a customer is usually provided by a spur which may have a lower cross-sectional area than the main line. Overload protection of the customer's installation can be provided by the main fuses at the customer's intake point. If local safety regulations also require protection for faults on the service, then fuses on the LV feeder at the distribution substation may not be sensitive enough, so that additional fuses may be required at the junctions of the overhead feeder and the services.

A service connection arrangement linking several customers is also accepted practice in some countries. In those countries where bare overhead conductors are still used, the service connection is often insulated. In more modern housing areas, where the buildings are close together and often of single-storey construction, the services are often underground although the LV mains are overhead. It is useful if the service joints to the feeders are so arranged that they can be connected and disconnected while the network is 'live', i.e. with voltage still applied. This enables the connection of a new house to be carried out without any outage of supply to the other customers connected to that feeder.

In housing estates there are many methods of connecting detached or terraced houses to the underground cable network, and some of these are shown in Figure 10.11.

In arrangement (i) the disconnection boxes not only provide facilities to connect up the services but also make it possible to provide fuses on each outgoing cable. Arrangements (ii) and (iii) are cheaper owing to the linking connections, but do not permit such individual good protection facilities as arrangement (i). Arrangement (iv) is for individual large or remote customers. Arrangement (v) represents the situation with fixed underground joints, which are much cheaper than cable disconnection boxes or cabinets although the selective protection facility discussed earlier is not possible.

Arrangements (vi) and (vii) are variations on arrangement (v). In particular, arrangement (vii) has proved to be cost effective in countries where each customer in a terraced house has his or her own service and this simple arrangement meets the local safety regulations.

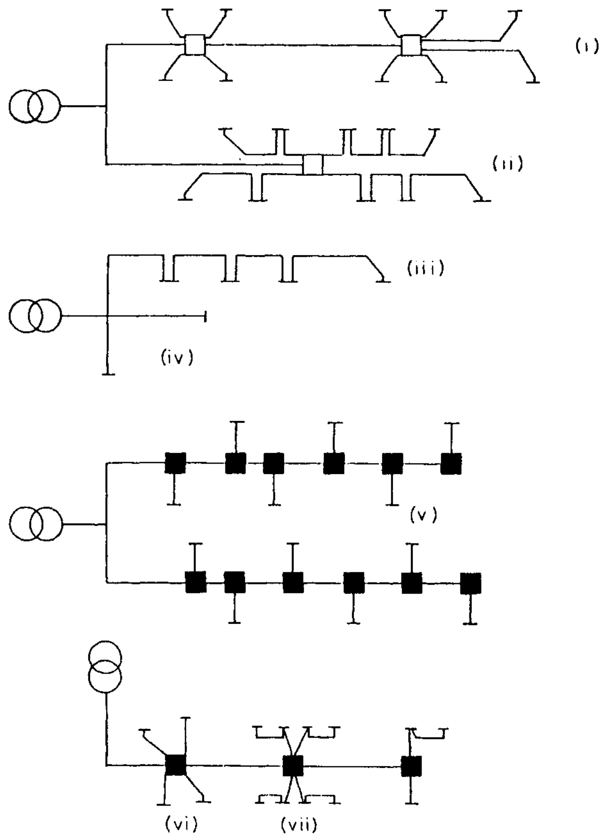


Figure 10.11 *Some service cable arrangements*

□ disconnection box
— customer
■ underground fixed joint

Determining the correct practices for service connections within a utility should be an optimisation process. Depending on the distribution network conditions, the practices adopted by one utility are not necessarily the most economic, or environmentally acceptable, under different circumstances. However, when general practices have been determined it is then possible to set out guidelines which can be easily applied by the design staff.

As an example of developing such guidelines consider the system shown in Figure 10.12, which is the same as arrangement (i) of Figure 10.11. The more customers connected to a disconnection box the longer and more expensive the services will become, but the cost of boxes per customer will decrease. The number of relevant factors involved makes it difficult to decide on the type and average distance between disconnection boxes for a particular new housing area,

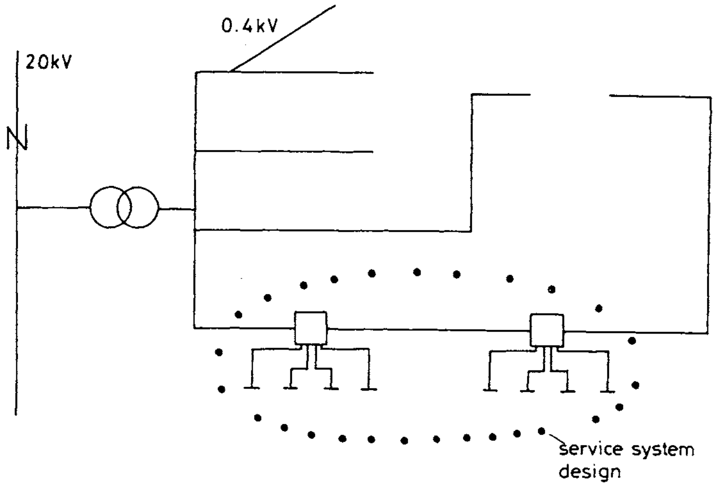


Figure 10.12 Part of the distribution network considered in the service-system optimisation

□ disconnection box
— customer

even if the general practice for feeder arrangements has been fixed. The voltage drop and costs of materials, excavation, joints and losses must all be considered when determining the size of the service cables.

An example of design guides obtained by computer program is given in Figure 10.13. The program utilises data files including plot-area and location information, the necessary calculation parameters, service-cable information

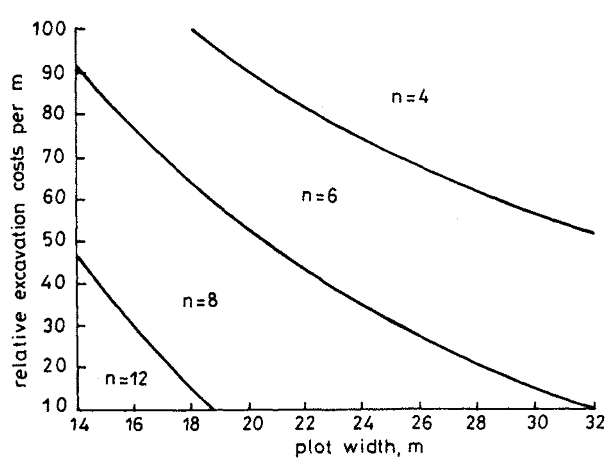


Figure 10.13 Example of cost diagrams for service design

n = optimum number of customers per disconnection box and cost per unit length, and the cable-route information; and produces the most economical feeder arrangements for all specified conditions. The costs of different arrangements can be compared and the results plotted on diagrams such as Figure 10.13, from which the optimum number of customers per disconnection box, e.g. 4, 6, 8 or 12, can be found for any combination of the width of the plots along the road, and the relative excavation costs.

Such a program would be an efficient means of generating recommendations for service practices. When used by utilities themselves, the program could incorporate local per-unit costs so that the results would be more relevant to that particular utility.

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Chapter 11

Load data

11.1 Demands for design

Most network reinforcements and extensions, and therefore the associated design work, are required because of additional or new electrical-power requirements in a particular area. The present and estimated future demand levels influence not only the sizes of individual lines and cables and other equipment, but also the optimum system configuration as a whole, e.g. substation density. Of all the parameters affecting the network design and timing of major reinforcements, the forecast load is the most sensitive. It is therefore essential that special emphasis should be placed on developing effective and reliable routines to cover this aspect of the planning function.

Unless there is positive evidence to the contrary, plans to meet future demands are generally based on the assumption that load patterns will not change significantly. Economically, any system reinforcement should be planned on the basis that further reinforcement will not be required for a given number of years. However, the actual load growth and method of operating the system, having regard to equipment short-time overload capabilities, will determine the actual date of reinforcement.

In determining the losses for a particular section of the network, the most critical time periods are during the peak demand for the utility as a whole. At these times the losses incurred will have to be purchased at peak-energy high-price levels, and will themselves increase the peak demand charges. Usually the nearer the location of the section under consideration is to individual customers, the greater will be the diversity between the peak demand on that section and the total system peak demand. When studying voltage drops and voltage variations, the simultaneous loading of all items of plant from the voltage-controlled busbar to the furthest load point need to be considered.

The loads on distribution circuits are the instantaneous summation of the individual demands of many customers, and of the losses on each section behind the section under consideration. Since the pattern of electrical demand of each customer cannot be determined precisely, it is usually necessary to calculate system loadings on a statistical basis, whether considering existing loads or forecast values.

11.2 Load-monitoring measurements

Load data are collected from an existing network for circuit monitoring, for tariff purposes, and for various research and supply quality-control studies. For simplicity the tariffs of most customers do not require demand or load curve measurements, so that these must be obtained separately for the above-mentioned studies. It is therefore essential to build in a system to transmit all the relevant measurement data to the utility's load file.

Telecontrolled substations offer an ideal arrangement for collecting transformer and feeder load data. However, if the interval between load sampling is too short, this can lead to large amounts of data being transmitted which cannot always be processed or utilised sensibly, unless steps are taken to select only essential data. Large distribution substations are often equipped with a maximum-current meter, maximum-demand (kVA) indicator, or a kWh meter. With advances in distribution-system automation these measuring devices are being connected into supply-network data-collection schemes, which sometimes include data transmission to and from the substation. Occasionally load and voltage measurement surveys are carried out in specific LV networks in order to check the quality of supply.

The short-term aim of the above measurements is to ensure that the existing distribution system is operating satisfactorily, in order to determine where rearrangement of the feeder configuration could improve the overall system performance, and also to locate any areas where improved system performance is likely to be required in the next few years. In addition to the above, it is essential to collect load-curve information since this can be used when developing the load forecasts necessary for both the long-term, and the more detailed short-term, system-design work.

As discussed in Section 11.3, the instantaneous customer and system loads are often considered to have Gaussian distributions. In order to develop the relevant mean values and standard deviations of load curves for customers belonging to difference classes, large numbers of recorded consumption values are required. There must be at least 100 metered customers for each customer class with consumption records taken over the last three years; or a smaller number for a longer time period.

When setting up a measurement project to obtain the above data, alternative means of obtaining the load data must be carefully assessed. In addition, it is useful to obtain background information on each series of tests and for each metering point, e.g. customer class and data on ambient temperatures throughout the test, so that these factors can be taken into account when finally analysing the studies. Within the relatively small area covered by an LV network, knowledge of the maximum demand at each substation and the unit consumption can provide sufficiently accurate data for statistical analysis to produce worthwhile load forecasts, even if data on individual LV circuits are not available.

11.3 Load analysis and synthesis

Where full loading information is not available from metering equipment on the system, techniques of load analysis and synthesis may be used, but they should, where possible, be checked against measured information. The power demand of any one customer has a daily pattern which is influenced considerably by the day of the week concerned and also the time of year. Daily and seasonal load curves can be constructed for various customer groups if satisfactory metered data are available. The distribution of the load for a particular hour of the day can be approximated by a Gaussian distribution curve, which is characterised by its mean value and standard deviation.

Load curves can then be used to simulate the load of one customer belonging to a particular customer group by scaling the annual units of that customer to the average units of the group. A load curve for a group of customers can be constructed by summing the individual customer load curves statistically. If required, load curves can also be constructed using abnormal values for some of the parameters involved, e.g. by drastically changing the input value of the ambient temperature to simulate extreme winter or summer conditions.

There are considerable variations in the load curves and the standard deviations for different types of customers. Figure 11.1 gives examples of the variations in mean demand over 26 two-week periods for a customer with electric space heating, a domestic customer without electric space heating, and an agricultural customer.

Distribution utilities often categorise customers into different classifications for billing purposes, statistical analysis etc. In assessing whether such a classification is valid for generating load curves, the following points should be borne in mind:

- The main features of the consumption pattern of individual customers within a given customer class must be very similar, otherwise the standard deviations will become excessive.
- The number of classes should not be too high, usually below 15, in order to keep the costs of data collection and manipulation within reasonable limits.
- The customer data system should be related to the classification codes of the utility's customer information system. This will lead to increased use of automatic methods of utilising load information for distribution system studies.

Some examples of customer classification are given in Table 11.1. Other examples might include commercial- and industrial-customer consumption information, with perhaps the industrial figure split into groups having 1-, 2- or 3-shift working each day, and street lighting.

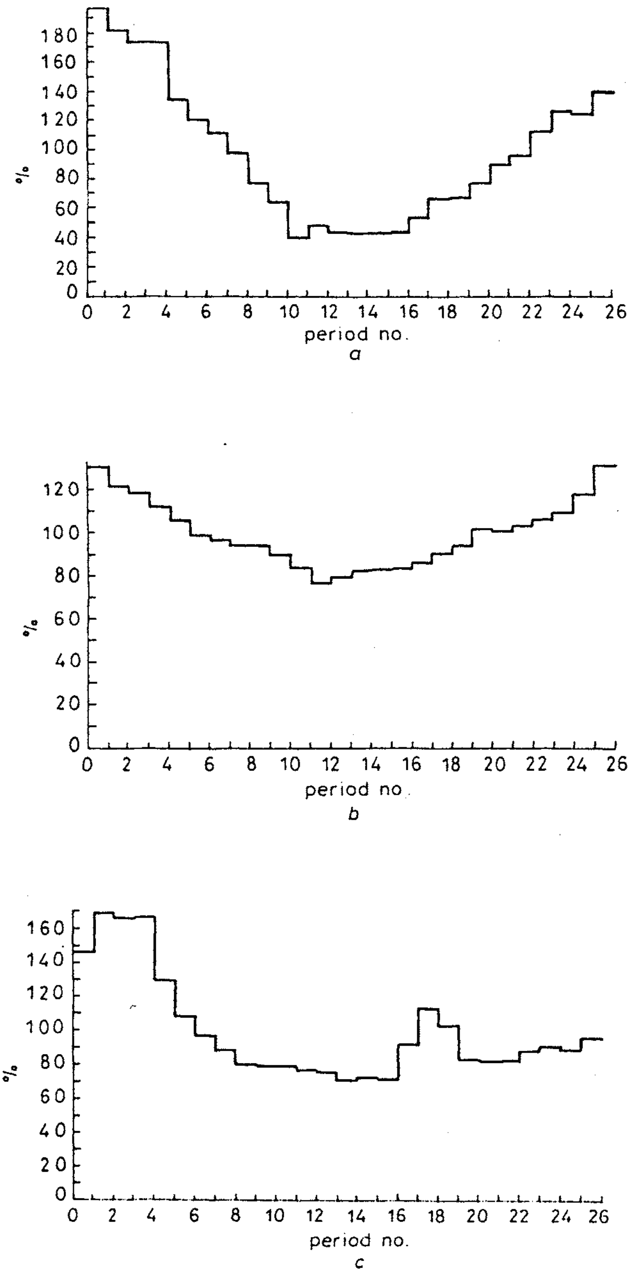

Figure 11.1 *Examples of mean demands for different types of customer*

100% $\simeq$ annual mean
a Electric space heating
b Domestic
c Agriculture

Usually the actual load curves at a customer's service infeed point, or at various points on a network, are not known. The energy supplied to each customer can, however, be obtained from the billing files for existing conditions, and estimates made for future conditions. If practically all the customers in the area under study belong to one particular customer group, then approximate peak demands can be estimated by more conventional methods such as the use of load factors, or the use of Velander's formula for this particular group as given by

$$P = k_1 W + k_2 \sqrt{W} \tag{11.1}$$

where P is the peak demand of the group, W is the annual unit consumption and k_1 and k_2 are constants.

Table 11.1 Examples of Velander coefficients

Customer group	k_1	k_2
Domestic	0·29	2·5
Electric space heating	0·22	0·9
Commercial (shops)	0·25	1·9

Typical values for the constants in eqn. 11.1 for some customer groups are given in Table 11.1. With W given in MWh, P is obtained in kW.

For areas containing a number of customer groups, a statistical method should preferably be used to sum the load curves for the different customer groups.

For each time period the demand of each customer is represented by a mean value and a standard deviation. The summed mean value of the demand over any one hour is the sum of the mean values of the individual component loads. The standard deviation of the summed load depends on the correlation between the component loads. If there is no correlation between them, the total standard deviation is given by

$$\delta_t = \sqrt{\sum \delta_i^2} \tag{11.2}$$

The percentage deviation is obtained by dividing δ_t by the sum of the mean values of the loads. Thus, in this case, the percentage deviation decreases as the number of customers increases. If there is a positive correlation between customer demands, the total deviation decreases more slowly.

In Figure 11.2 the lower curve 1 represents the mean values for a terraced house with four domestic customers (total sum is 20 MWh/year) in kilowatts over a 24 h period. The upper curve 2 will be exceeded with a small 1% excess probability.

In Gaussian distribution the following relationship exists between the values of mean probability and a given excess probability level:

$$P_p = P_m + k_p\delta \tag{11.3}$$

where P_p = power having an excess probability of $p\%$

P_m = mean power

k_p = coefficient related to $p(k_1 \simeq 2.3;\ k_5 \simeq 1.6;\ k_{10} \simeq 1.3)$

δ = standard deviation

The standard deviation is different for the different hours and combinations of customer groups.

The manner in which different loads can be summed is illustrated by using the simple example shown in Figure 11.3. The total demand at node 2 is the sum of the loads at nodes 3 and 4, the latter being a domestic customer with the load curve given in Figure 11.2.

The load curves for nodes 2, 3 and 4 in Figure 11.3 are shown in Figure 11.4 as 1% excess probability values. It should be noted that curve 2 is not the arithmetic sum of curves 3 and 4 since these must be combined in accordance with statistical rules. The power values with excess probability around 10% are relevant for voltage-drop calculations, while smaller probabilities are used when considering overload conditions where equipment may be damaged. The mean values (50% excess probability) are used when calculating losses.

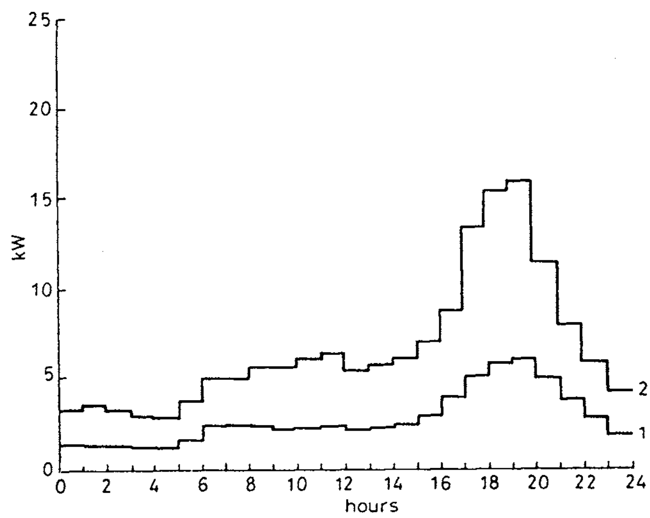

Figure 11.2 Load curves for domestic customers

1: mean estimate (50% excess probability)
2: high estimate (1% excess probability)

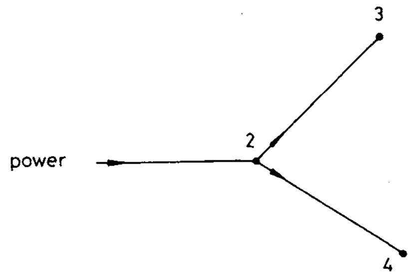

Figure 11.3 Simple network example

Node 3: electric space heating; 30 MWh/year
Node 4: domestic; 20 MWh/year

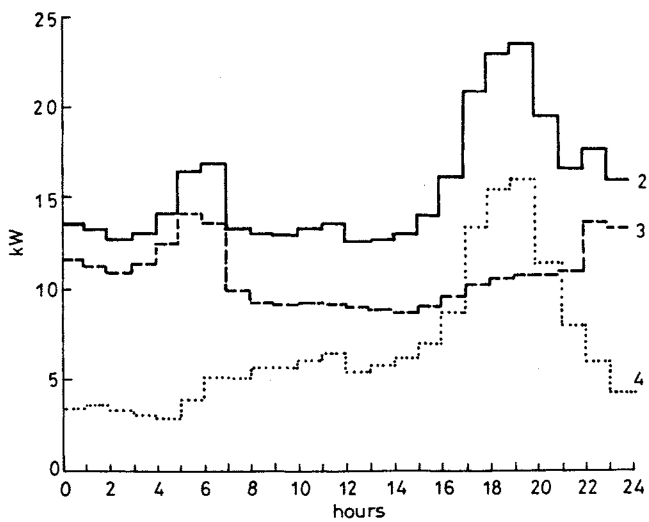

Figure 11.4 Load curves with 1% excess probability

11.4 Load forecasting

Load estimates are one of the most vital data requirements in network design. There are three basic statistical methods of producing forecasts of future electric-power demands, and in practice some combination of all three methods can be used, and all have their own special area of application.

In *extrapolation methods* the estimate of future demand in total is extended forward in time from historic data for the area under consideration. The method is feasible for a short period ahead, say one to three years, but the longer-term

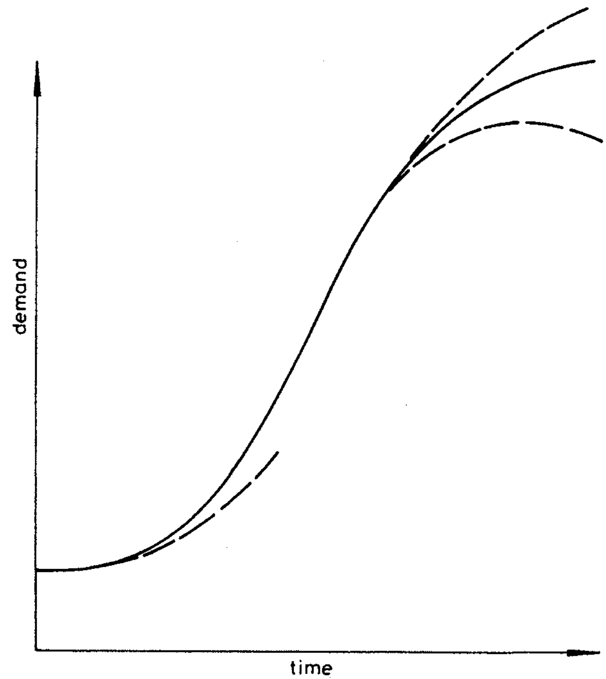

Figure 11.5 Typical load-growth curve with extrapolated forecasts at varying times

trend usually follows an S curve as shown in Figure 11.5. In the earlier years of an electricity-supply system, there may be a high annual rate of growth in demand, but as individual customers' dwellings become saturated with electrical equipment the rate of increase will drop as indicated by the full line in Figure 11.5. Economic factors within the area concerned and in the country overall, as well as in the influence of relative costs of alternative energy sources, also have an influence on the growth rates.

Considerable errors can occur in the forecast since this method takes no account of the stage of development of the area under review.

Simulation methods are based on using specific annual consumption figures, obtained from surveys of individual consumption classes and the number of customers in each consumption class. The present situation can be printed out from the utility billing files. The future development of each consumption class can be estimated from national information and then modified for local use, e.g. by information from municipal or parish authorities on expected future industrial and housing developments. Simulation forecasts are especially relevant for areas where large developments are expected or when the forecast period is longer than five years or so.

Econometric modelling is based on obtaining suitable correlation between power consumption and various economic parameters such as gross national product, index of industrial production and rate of inflation. The effect of the price of electricity is also relevant. Large-scale econometric models are not appropriate for the small areas usually associated with individual distribution-system studies.

Load forecasts at individual HV/MV substation level can often be based on both of the first two methods mentioned above. The existing and predicted future population being supplied, and likely future housing and industrial developments, can be assessed from discussions with the appropriate local area-planning authority, using the billing file to provide information on existing and past consumptions as a starting point for such load forecasts.

If the expected development of each customer group, and any increase in the assumed consumption within that group, are taken account of a forecast can then be made of the predicted future consumption of the group.

Table 11.2 is based on a survey carried out in Finland. The first line, number of houses, is the sum of the family houses, with and without electric space heating, and farms. Considering the first customer group covering houses with

Table 11.2 An example of forecasting area consumption

Year	0	10	20
Population	11 700	11 900	12 200
Number of houses	4550	4940	5450
% with electric space heating	14	21	32
Number with electrically space-heated houses	637	1037	1744
Heating consumption, MWh/house per year	17·1	17·6	18·1
Consumption, MWh/year	10 900	18 300	31 600
Number of family houses	4135	4540	5080
Domestic consumption, MWh/house per year	4·2	4·7	5·2
Consumption, MWh/year	17 400	21 300	26 400
Number of summer cottages	1030	1240	1600
Number electrified	490	650	930
Specific consumption, MWh/cottage per year	1·5	2·5	3·0
Consumption, MWh/year	740	1630	2790
Number of electrically space-heated summer cottages	200	330	560
Heating consumption, MWh/cottage per year	4·2	4·6	5·0
Consumption, MWh/year	840	1500	2800
Number of farms	415	400	370
Specific consumption, MWh/farm per year	5·6	6·7	8·0
Consumption, MWh/year	2300	2700	3000
Number of industrial workers	1350	1400	1475
Specific consumption, MWh/worker per year	6·1	7·0	8·2
Consumption, MWh/year	8200	9800	12100
Number of public and services workers	2650	2740	2800
Specific consumption, MWh/worker per year	5·4	5·9	6·8
Consumption, MWh/year	14 300	16 200	19 000
Total consumption, MWh/year	54 700	71 500	97 700

electric space heating, then, by using the forecast number of houses, the percentage of these houses expected to have electric space heating, and the predicted increase in consumption per house each year, the total consumption for this customer group can be forecast as rising from 10900 MWh in year 0, which is the last year for which statistics are available, to 31600 MWh by year 20. Similar calculations are used to derive the forecast consumption by cottages and farms. Energy sales to industrial customers have been based on forecast electrical consumption per worker in specific industrial groups linked to the predicted number of workers in each group in the years under consideration. The total forecast consumption for the area can then be obtained by summing the individual group forecasts as shown.

The total area consumption is obtained by summing the individual customer-class consumptions, as shown in Table 11.2. Such calculations can be carried out by suitable computer programs and the results used directly in network-design programs. The energy forecasts obtained can be converted to demand forecasts by applying the Velander formula of eqn. 11.1 for each customer group, and taking into account the differences in time for the peak demands for each group.

Load forecasts at distribution substation level (MV/LV) can be based on the above-mentioned MV studies, in many cases extracting information on computer file relating to customer loads, network system data, and known developments if these are part of the computer filing system. It is also possible that customer-appliance information for specific substation feeding areas may reveal parts of the area where more rapid load growth may occur, compared with the average situation. An example of this is electric space heating in rural areas. Since this can be a popular heating alternative, those areas with a lower percentage of customers with electric space heating have potential for rapid load growth, which should be kept in mind when developing the associated electrical systems.

Load forecasts for low-voltage networks in urban areas can be generated in the same way as those for distribution substations described in the previous paragraph. In rural areas the use of average values of load growth is not recommended. Here the main part of load growth comes from individual new customers, or by a transfer to electric space heating, which can have a large effect on one or two local circuits but not affect the distribution network outside the area local to such a load increase. Therefore, to apply the principle of estimated average load growth could lead to too high loading estimates for most lines, and much too low estimates where new customers are likely to be connected, or where existing heating is changed to electric. Unlike individual LV circuits the MV feeders supply hundreds, and often thousands, of customers. Thus the average load-growth forecasts for the area being supplied are appropriate when carrying out MV network design.

It is essential that load forecasts can be relatively easily adjusted when any new background information becomes available. It is therefore worthwhile that there should be close liaison between those responsible for the data banks covering load forecasting, customer information and network data. The crossindexing of all the interrelated data is vital for optimising the load-forecasting process, which is an essential stage in the network planning process. This means, for example, that similar location codes and customer classifications are used in all these systems and that good communications exist with community planning staff.

11.5 Short-term load forecasts

While the type of long-term forecast introduced in the previous Section is relevant for network planning purposes, short-term forecasts are needed for the operation of distribution systems, with typical lead times ranging from one hour to one week.

New automation facilities such as remote controlled disconnectors and microprocessor-based relays, together with low-priced computer technology, have made it possible to develop systems that support distribution network operation in a more sophisticated manner, as discussed in Section 7.7. These distribution management systems (DMS) include real-time network analysis and support the operator in operation planning. DMS usually necessitates the integration of a utility's computer systems. The supervisory control and data acquisition system (SCADA) provides real-time data from primary substations and various devices in the network. On their own, the data obtained from the SCADA are usually not adequate for real-time monitoring of the state of the distribution network as a whole, since detailed information from lines and network components, and the load distribution along MV feeders and loads on various spurs, are not known. However, the data on network components which are required are available in a network information system (AM/FM-system), which will be introduced in Chapter 14.

The advanced functions of distribution network operation, for example restoration and power-loss reduction by feeder reconfiguration, require load forecasts in order to achieve accurate results. For these functions the forecast results must be flexible enough to be used in any simulated network configuration, so that the target of the short-term load forecasting method for distribution network operation is to forecast the loads of the distribution substations (20/0·4 kV). The load forecasting method is based on combining available remote load measurements with the load models of customer groups introduced in Section 11.3. The present load on each distribution substation is calculated based on load models of various customer groups, and on the prevailing weather information. These load models include hourly demands and temperature dependencies for, say, 50 customer groups. The modelled loads of distribution substations together with the voltage measured at the feeding-point busbar are used in the load-flow calculation of the medium-voltage network to arrive at the first estimate of the state of the network.

The principles of state estimation are then applied, with redundant and doubtful measurements being used in a statistical process utilising, for example, the weighted least-squares index to achieve the most probable values for the chosen state variables. In the distribution network case, these state variables can be the loads of distribution substations, while other variables such as the voltages at network nodes can be calculated according to the state variables.

Very often there are no redundant measurements of feeder loads. However, the modelled loads of distribution substations based on billing and load-curve information can be used as pseudo-measurements. Some redundancy is achieved since the load-flow results – the sum of substation loads plus losses – can be compared in state estimation with the medium-voltage feeder load measurements and the busbar voltage values which, at least, are generally available at the primary substation. In this case weighted least-squares estimation can be used to estimate the distribution substation loads more accurately. The standard deviation of the load measurement and the standard deviations of the modelled loads are used to weight the estimation, as in eqn. 11.4. In the case of a radial feeder the total load of the feeder is the sum of all the load points if losses are neglected, and the following equation for the substation load is obtained:

$$S_i^* = S_{mod,i} + \frac{\sigma_i}{\sigma_{mea} + \sum \sigma_i}(S_{mea} - S_{mod}) \tag{11.4}$$

where S_i^*,$S_{mod,i}$, S_{mea} and S_{mod} are the estimated load for substation i, the modelled load for substation i, the measured load of the feeder and the modelled load of the feeder respectively, while σ_{mea} and σ_i are the standard deviation of the measured load and the modelled load for substation i. If several measurement points are available along a feeder, these can be used to define new sections for estimation and be treated separately for additional accuracy.

State estimation results are used to create dynamic load models for distribution substations, which in turn can be used to determine the final load forecast when the temperature forecast is available. A dynamic load model for a distribution substation can include loads for the next week, i.e. for the next 168 hours, and is formed from the load calculated by the static load models of different customer groups. This load is adjusted by the average ratio of the estimated and modelled loads calculated in the state estimation of the previous same weekday, for example Friday, and the loads for the same hour of that day. In addition, the forecasts for the next three hours are updated hourly since the present hourly load measurements provide valuable information on the loads likely to occur in the next few hours.

The load presented in the monthly normal temperature, and the temperature dependency of the load of each substation calculated separately, are stored in a database. In this way the load forecast can be calculated using the latest temperature forecast, or a worst case analysis can easily be performed by setting a very low (or high) value for the temperature. When the DMS is connected in real-time to the SCADA, state estimation is performed at least once an hour and the dynamic load models of substations are updated. Hourly forecasts for the same hour one week later are continuously updated, and a rolling one-week load forecast is thus constantly available.

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Chapter 12

Special loads

12.1 General

Customers expect an electricity supply of good quality. Consequently it is necessary to give special consideration to loads which may produce various irregularities on the supply voltage, resulting in interference with the correct operation of customer appliances or utility equipment. Typical of such loads are steel-making arc furnaces, welding equipment, induction furnaces, rolling mills and colliery winders, and railway traction, where rapid variations in load currents may result in fluctuations in the voltage at customers' intake points. While the larger industrial loads will often require individual attention, there are also items of equipment, mainly in use in domestic and commercial premises, which, while individually not causing problems, can collectively affect the quality of supply owing to the large number of items involved. In addition some installations, such as computers and process-control equipment, are themselves susceptible to the quality of the supply voltages.

The overall effect of these 'disturbance loads' on individual supply voltages will depend on such factors as the magnitude, phase angle and rate of change of the currents taken by the load, and whether the load changes occur at regular or random intervals of time. The frequency of such load changes and whether they occur at time of peak demand, or at off-peak periods such as during the night, have a bearing on their interference with the operation of other equipment.

12.2 Electric-arc furnaces

12.2.1 Load characteristics

A particular feature of the operation of electric arc-furnaces is the frequent recurrence of short circuits between the electrodes and the scrap-metal charge.

Often when the molten scrap metal drops away from an electrode the arc will extinguish and no current will flow. During the melt-down period there will thus be random current changes with two or three phases short-circuited, or one phase on open circuit. The swings from short circuit to open circuit produce violent current fluctuations, often several times larger than the furnace nameplate rating, whether this be some kilowatts or tens of megawatts. These result in large voltage variations being impressed on the incoming supply voltage, usually LV for the low ratings and MV for the MW range of furnace ratings. Since the fluctuating load current to the furnace passes through the supply network, a corresponding fluctuation is impressed at the busbar linking other customers on the same network, which is often referred to as the *point of common coupling* (PCC), as indicated in Figure 12.1.

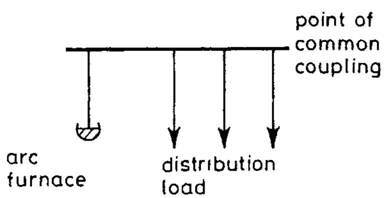

Figure 12.1 Point of common coupling

12.2.2 Voltage fluctuations and lamp flicker

The fluctuation of the supply voltage which occurs during the melt down of the scrap metal can cause flicker in incandescent lamps, to which the human eye is very sensitive. Tests have been carried out in a number of countries to assess what amount of voltage variation can be tolerated by customers in order that the electricity supplier can limit the voltage fluctuations to a level where unacceptable flicker is avoided. The sensitivity of the human eye to lamp flicker, relative to changes in the supply voltage, is illustrated in Figure 12.2.

As a result of the movement of the arc between the electrodes, the furnace current rapidly fluctuates at varying frequencies from below 0.1 Hz to in excess of 10 Hz. This causes an irregular fluctuation of the supply voltage. A section of this fluctuation is shown in Figure 12.3*a*, where the supply voltage waveform, having an instantaneous value v, may be considered as a carrier wave being modulated by the random voltage fluctuations caused by the arc furnace. This modulation voltage may then be considered as being independent of the normal supply waveform but having an instantaneous value v_f around its own notional zero line, as shown in Figure 12.3*b*.

It is necessary to derive a single parameter of this fluctuating voltage, so that this can be measured and used to define the severity of flicker to human subjects. Tests have shown that the RMS value of the voltage fluctuation V_f is a

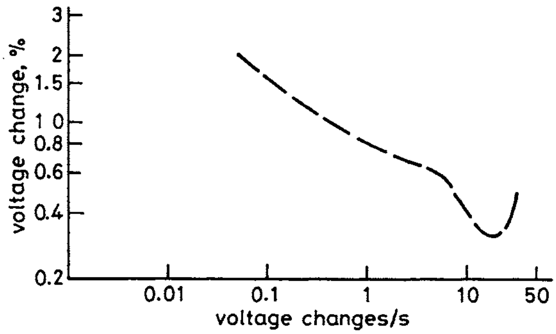

Figure 12.2 Maximum value of voltage change to avoid flicker annoyance

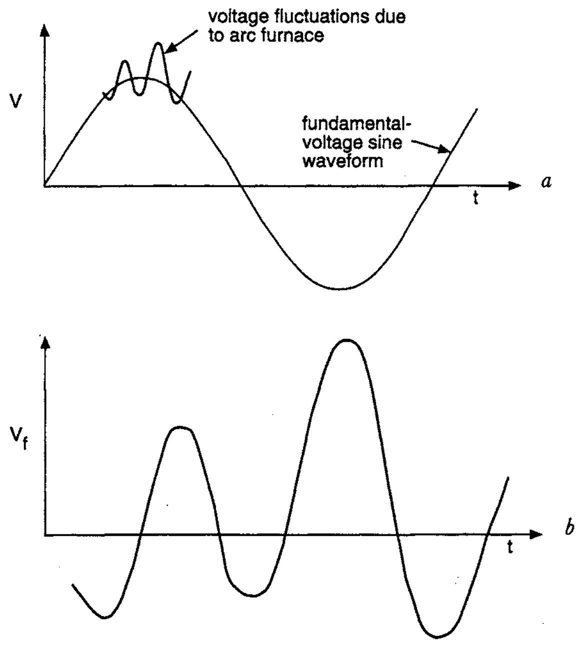

Figure 12.3 Voltage fluctuation

a Voltage fluctuation impressed on fundamental voltage waveform
b Fluctuation voltage around fundamental voltage

satisfactory measurement for arc-furnace voltage flicker, and this value can therefore be used as a measure of flicker severity to the human eye. In practice, V_f is quoted as a percentage of the RMS value of the supply voltage, typical values being some tenths of 1%.

The short-circuit voltage depression V_t is the percentage change of voltage at the point of common coupling when the furnace electrodes are taken from open circuit to short circuit by dipping them into the molten metal. V_t can be calculated to within reasonable accuracy from

$$V_t = \frac{S_f}{S_{pcc}} \times 100\% \tag{12.1}$$

where S_f is the apparent short-circuit power of the arc-furnace as seen at the point of common coupling and S_{pcc} is the fault level at the point of common coupling. In order to arrive at a suitable value of S_{pcc} it is appropriate to carry out calculations based on system operating conditions when the infeeds to a short circuit are low, e.g. due to reduced generation at time of light load, or because of the loss of an EHV/HV transformer feeding into the system.

For a group of arc furnaces, either at the same installation or in the same locality, or of sufficient power to transmit flicker via the EHV networks to the point of common coupling under consideration, it is necessary to derive the equivalent short-circuit furnace MVA to the point of common coupling. For a number of furnaces having apparent short-circuit powers S_{f1}, S_{f2}, S_{f3} etc, this equivalent short-circuit power S_{eq} is calculated as the nth root of the sum of the nth power of the short-circuit powers of each arc-furnace at the point of common coupling; i.e.

$$S_{eq} = \sqrt[n]{(S_{f1}^n + S_{f2}^n + S_{f3}^n + \ldots S_{fi}^n)} \tag{12.2}$$

and the combined flicker V_{FG} at a given point of common coupling can be assessed from

$$V_{FG} \simeq \sqrt[m]{\sum V_{fg}^m} \tag{12.3}$$

where the flicker contribution V_{fg} from any installation under review, plus those from existing installations, is defined as a percentage value of the supply voltage at the point of common coupling. m can be between 2 and 4 depending on the operating mode of each furnace affecting the installation being assessed.

Alternative methods of defining the severity of voltage fluctuations are given in Section 12.7.2.

12.2.3 Methods for reducing voltage fluctuation

Where excessive voltage fluctuations are caused by arc-furnace installations so that supplies to other customers are seriously affected, or calculations indicate that a proposed arc-furnace installation will result in excessive voltage fluctuations, a number of options are available to reduce arc interference. These may involve re-arranging the system configuration to minimise the effect of the arc furnace on other customers, or adding some compensation devices to counteract the arc-furnace reactive-power swings.

Re-arrangement of supply connections

If excessive voltage fluctuations are impressed on the system and are adversely affecting the customers, it will be necessary to transfer the point of common coupling, PCC1 in Figure 12.4*a*, to a higher voltage level. This can be achieved by providing a transformer solely for the arc-furnace load as in Figure 12.4*b*, where the point of common coupling between the arc furnace load and the distribution load is now at PCC2. If security of supply is required for both the arc-furnace and distribution loads, against loss of a transformer, then a standby transformer can be provided as in Figure 12.4*c*. Operationally it would be preferable for this transformer to supply one of the loads as in Figure 12.4*d*. Should a fault occur on transformer 3 for example, circuit breaker 3T would trip, circuit breaker BS2 would be closed and then circuit breaker BS1 opened to restore supplies to the distribution load whilst maintaining supplies to the arc-furnace load.

Capacitor compensation

An arc-furnace load is reactive since current flow commences when the voltage between the electrode and the metal is high enough to cause arcing; i.e. current lags voltage. Various forms of capacitor-compensation arrangements are available to reduce voltage fluctuations.

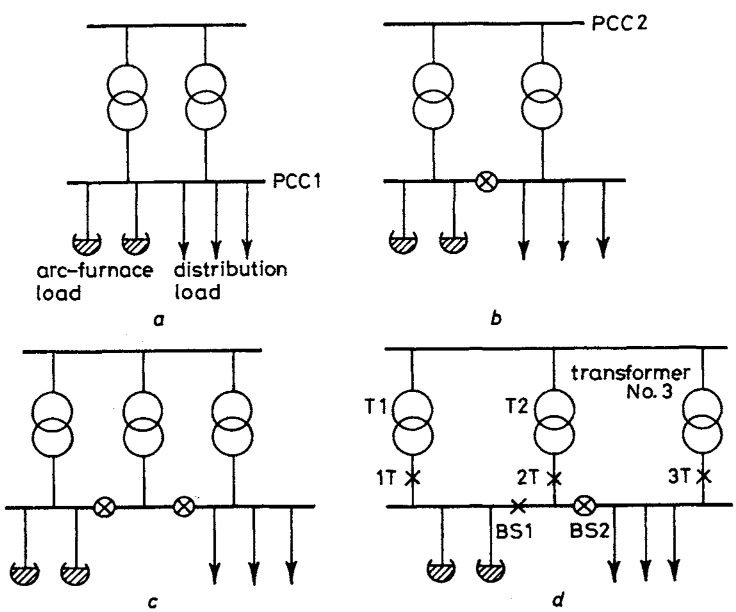

Figure 12.4 Segregation of arc-furnace load

A fixed shunt capacitor is the cheapest and most frequently used method of compensation for loads with a poor power factor. A major problem is in providing the optimum capacitance as the load varies over the melting cycle. Consequently installations are often designed so that, during the melt down, some uncompensated reactive power is taken from the supply system. If the capacitor overcompensates and feeds back reactive power into the supply system this may cause overvoltage problems on the system. It should be noted that fixed capacitors alone do not reduce reactive-power swings or network voltage fluctuations caused by an arc-furnace. Therefore it is impossible to compensate fully for flicker with fixed capacitors.

Using thyristors it is possible to switch capacitors in and out extremely fast and reduce the voltage fluctuations considerably. By installing fixed capacitor banks to the arc-furnace busbar, 1 and 2 in Figure 12.5, then, provided they do not cause voltage problems on the system, it may be possible to reduce the value of the switched capacitors 3 and 4.

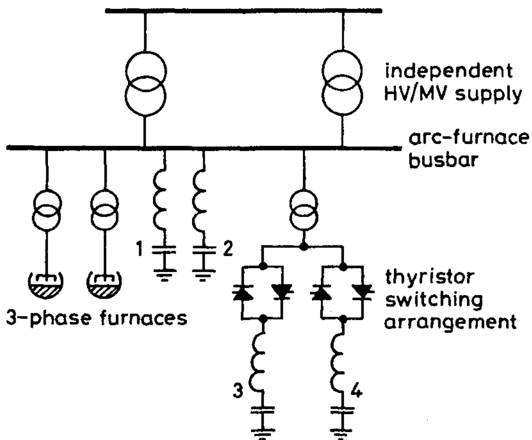

Figure 12.5 Thyristor-switched capacitor compensation

12.2.4 Loading cycles and transformer losses

Figure 12.6 is a record over 24 h of the average demand every 7½ min at a multiple-arc-furnace steelworks supplied via HV/MV transformers. Swings of 60 MVA can be noted, with 40 MVA swings common. Continuously recording ammeters showed even larger current swings. Over a period of time these large current swings resulted in a I^2t heating effect considerably higher than that calculated on average half hourly readings of demand.

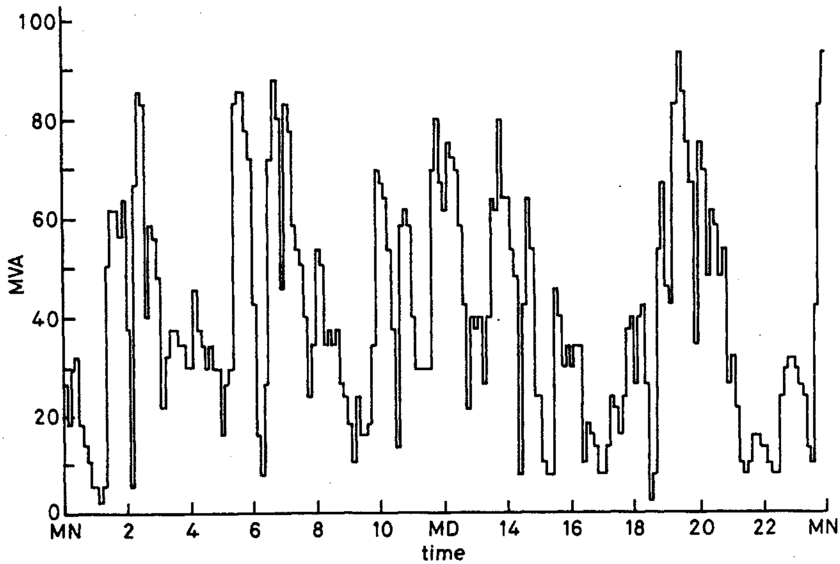

Figure 12.6 Multiple-arc furnace load cycle (Courtesy Midlands Electricity plc)

Consider the four sets of load currents varying in time around a 1.0 p.u. level, as shown in Figure 12.7a: (i) the I^2t effect for a load current of 1.0 p.u. for 1.0 p.u. time is $(1{\cdot}0)^2 \times 1 = 1{\cdot}0$; in (ii) the current variation is $\pm 0{\cdot}2$ p.u., also over 1·0 p.u. time, and the I^2t effect for this case is then $\frac{1}{2}(1{\cdot}2)^2 + \frac{1}{2}(0{\cdot}8)^2 = 1{\cdot}04$ p.u. Thus although the average current in this case is still 1.0 p.u., the heating effect has increased by 4%.

Similarly for two equal current swings up to 1·4 p.u. and two down to 0·6 p.u., shown in Figure 12.7a (iii), averaging 1.0 p.u. over a 1·0 p.u. time, the net heating effect is $2(1{\cdot}4)^2/4 + 2(0{\cdot}6)^2/4 = 1{\cdot}16$. For four swings up to 1·8 p.u. and four swings down to 0·2 p.u., as in Figure 12.7a (iv), the average current is still 1.0 p.u. but the heating effect is $4(1{\cdot}8)^2/8 + 4(0{\cdot}2)^2/8 = 1{\cdot}64$, and this trend is shown in Figure 12.7b.

Thus for the widely varying short-time current swings experienced with arc-furnace loads, the actual cumulative I^2t effect is considerably greater than would be expected from the average half-hourly demand values. The cyclic rating of the supply transformer, as discussed in Section 6.2, is therefore inappropriate. Depending on the actual load cycle it may be necessary to install a transformer with a nominal rating at least equal to the predicted maximum half-hourly average demand or up to 20% higher. In addition, the transformer manufacturer should be informed of the nature of the load being supplied through the transformer, as special bracing of the core and windings may be necessary owing to the electromagnetic stresses induced by the heavy currents during the melt-down period of arc-furnace operation.

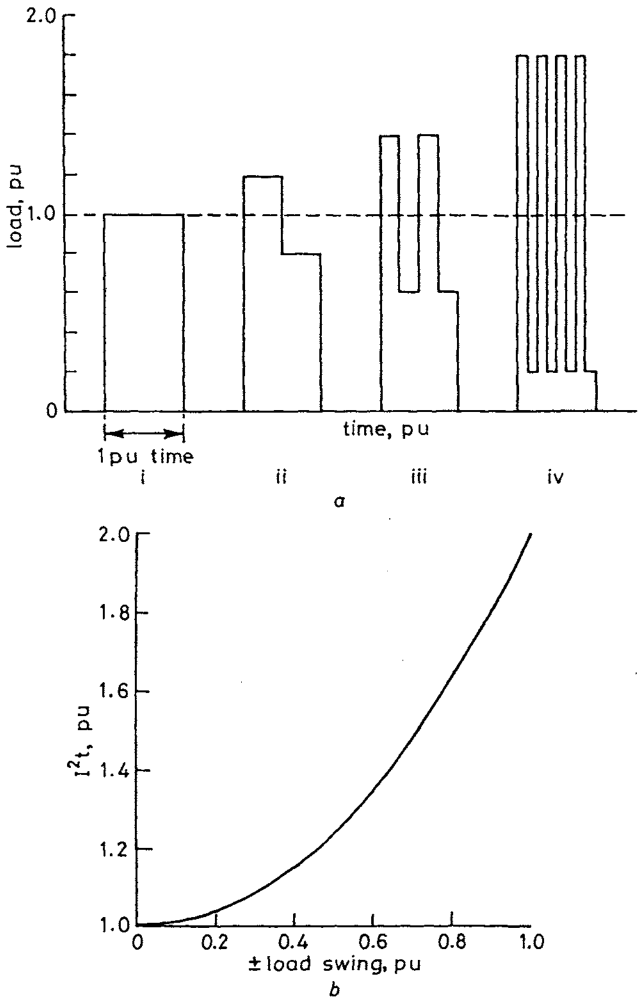

Figure 12.7 Effect of current swings on I^2t

a Varying load patterns for I^2t calculations
b Variation in I^2t effect with load swings

12.3 Convertors

In this Section the harmonic currents and voltages caused by rectifiers and inverters are discussed. Rectifiers convert from AC to DC and inverters from DC to AC. The use of heavy-current rectifiers and inverters has contributed significantly to the development of variable-speed DC and AC motor drives, which have many applications in industry and rail traction. However, these installations can be sources of harmonic distortion affecting other customers.

An ideal diode allows current to flow in one direction only, the current being determined by the supply voltage and the load impedance. With reversal of the input voltage the diode acts as an infinite impedance and no reverse current flows. Considering the arrangement shown in Figure 12.8*a*, with a diode connected into each of the three phases of an AC supply, reference to the voltage waveforms in Figure 12.8*b* shows that at any point in time one or two diodes will have a positive AC voltage applied to them. Conduction will take place through the diode subjected to the higher voltage.

As the voltage in one phase falls and that in another rises a point will be reached when the voltage across two units will be equal, as at ab_1, bc_1 and ca_1. Conduction will then pass from the unit receiving the falling voltage to the unit

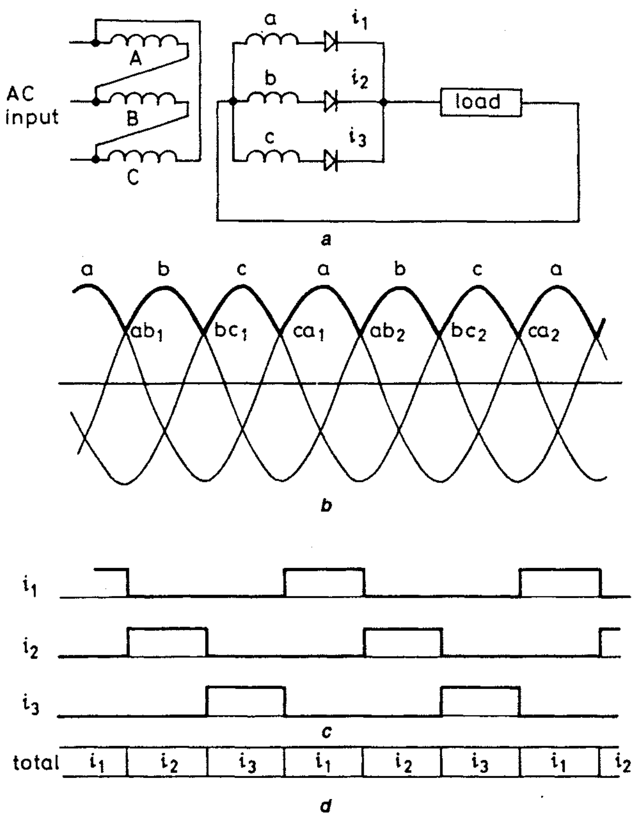

Figure 12.8 3-phase rectification

a Schematic of connections
b Input voltage/current waveforms
c Ideal input-current waveforms
d Ideal output-current waveforms

receiving a rising higher voltage. This transfer of conduction is called commutation. Individual outputs occur during time $ab_1 - bc_1$, $ab_2 - bc_2$ etc. in one phase, and similarly in the other two phases but displaced by 120° and 240°. As shown in Figure 12.8*d* this results in a continuous DC output under this theoretically ideal situation, where the load has been assumed to be purely inductive and, seen from the AC input of the convertor, each phase is loaded by currents which have a rectangular shape. Since these pulses are no longer pure sine waveforms, harmonics appear. For a particular harmonic current flowing through the supply network, a voltage drop will be produced in the system series impedances, and thus a harmonic voltage is produced. The summation of these individual harmonic voltage drops gives the total harmonic voltage distortion.

The harmonic currents also cause increased losses, thus decreasing the loading throughput capacity of a network. They may also cause errors in energy meters and system protection. Serious problems can occur if the frequency of one harmonic coincides with the resonant frequency of the network, resulting in overvoltages. In addition, harmonics can result in increased vibration in transformers and motors.

The arrangement shown in Figure 12.8*a* is the simplest of 3-phase rectifiers, and is known as a 3-pulse rectifier because there are three individual pulses of current (i_1, i_2 and i_3) in the DC output for each complete cycle of AC input. An improvement on this arrangement is to provide two diodes in each phase, as shown in Figure 12.9*a*, so that full-wave rectification takes place. An analysis of the individual currents will show that six pulses of direct current are produced during each complete cycle of AC input, and this arrangement is known as a 6-pulse rectifier.

From the point of view of suppression of harmonics, the 6-pulse bridge is the best that can be obtained with one 3-phase AC input. To obtain further improvement more phases are required, and a special transformer must be used. For example, a transformer with two secondary windings, one connected in star and the other in delta, will provide six phases spaced 60° apart. With each secondary winding connected to a pair of rectifiers, as shown in Figure 12.9b, the DC output now has 12 pulses for each cycle of AC input. Similarly 24 pulses, and even higher numbers, can be achieved. The reasons for going to these higher pulse numbers will be appreciated when consideration is given to the harmonics generated by the various arrangements.

The harmonics generated by an ideal rectifier are given by

$$\mathcal{N} = kp \pm 1 \tag{12.4}$$

where p = pulse number
k = any integer from 1 to infinity
$\mathcal{N}$ = harmonic number

Thus the simple 3-pulse rectifier produces all harmonics, except the triplens where the harmonic is a multiple of 3. With a 6-pulse arrangement, the even

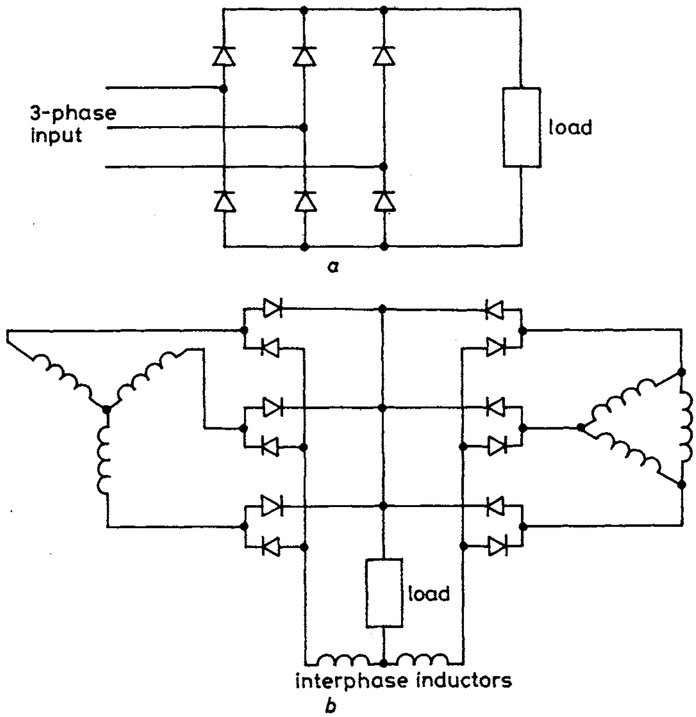

Figure 12.9 *6- and 12-pulse rectification*

a 6-pulse rectifier
b 12-pulse rectifier

harmonics are also eliminated, leaving 5th, 7th, 11th, 13th, 17th, 19th, 23rd, 25th etc. harmonics. A 12-pulse arrangement has only the 11th, 13th, 23rd, 25th, 35th, 37th etc. harmonics, and as the pulse number increases the number of lower harmonics decreases. It is usually found that, in industrial equipment, rectifiers are 6-pulse as standard and that manufacturers change to 12-pulse at higher loads, above about 1 MVA. If a controlled DC voltage is required thyristors are used instead of diodes.

If the individual pulses of current were rectangular in shape, the Fourier analysis of a square wave could be used to obtain the magnitudes of the harmonic currents in the input waveform. This gives

$$\frac{I_N}{I_f} = \frac{1}{N} \tag{12.5}$$

where I_N and I_f are the harmonic- and fundamental-frequency currents, respectively. This is, however, an approximation as the pulses are in practice distorted for various reasons.

Thus the magnitude of any harmonic current is inversely proportional to the harmonic number, so that, as the pulse number increases, the harmonic currents have a smaller magnitude. The reduction of the harmonic distortion of the voltage waveform is important both from a technical and an economic basis. Some harmonics can be eliminated by increasing the pulse number of the rectifier, as mentioned previously. However, rectifiers generate sub-harmonics owing to deviations in the thyristor delay angles which also cause asymmetry between the phases.

The spread of the harmonics from the rectifiers to the supply network can be reduced by using filters. For filtering the lower harmonics the arrangements in Figure 12.10*a* can be used, presenting a low impedance to a particular frequency as shown in Figure 12.10*b*. In theory a filter is required for each unwanted harmonic, but in practice filters adjusted for two frequencies are adequate. For example, with 6-pulse rectification, filters absorbing the 5th and 7th harmonics are usually an economic solution. For the higher harmonics the circuit shown in Figure 12.10*c* is used.

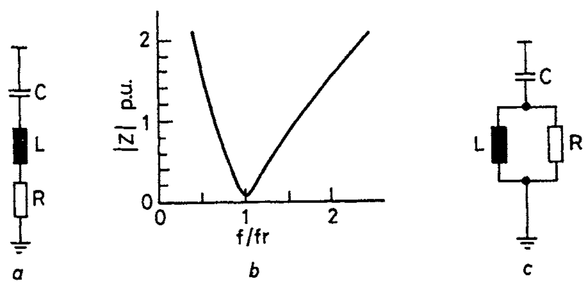

Figure 12.10 Filters to absorb unwanted harmonics

a Filter arrangement for lower harmonics
b Impedance/frequency characteristics for arrangement a
c Filter arrangement for higher harmonics

Variable-speed control for DC motors can be obtained by producing a variable DC voltage output with the arrangement shown schematically in Figure 12.11*a*. An AC motor drive can be supplied from a variable-frequency output with variable voltage using the rectifier/inverter arrangement shown in Figure 12.11*b*. The components of the DC link shown in the diagram have a distorting effect on the current pulses as seen by the feeding LV network.

For the system design engineer such controllers can be the source of considerable harmonic problems on a network, particularly where large industrial motor installations are connected to the supply systems. These aspects must be considered in conjunction with any problems of motor starting etc., as discussed in the following section.

12.4 Motors

There are three main problems which can arise from the connection of motors to electrical supply systems. The first is whether, under depressed voltage conditions at starting, the motor will successfully run up to speed. For larger motors the customers will need details of the system characteristics to check this. The second results from the effect on other customers of this voltage depression when starting the motor from standstill. The third arises from the currents which motors feed back into the network when the supply voltage is suddenly reduced because of faults on the network.

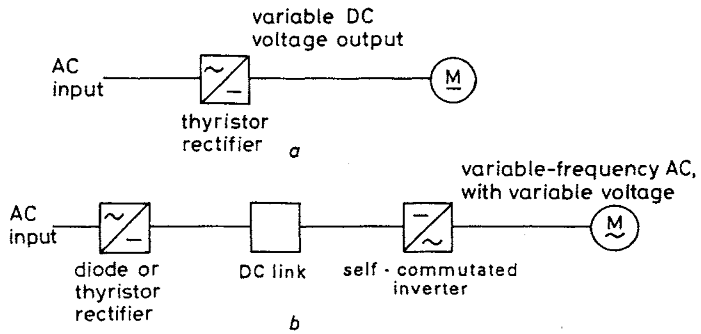

Figure 12.11 Speed control of motors

12.4.1 Starting currents

Switching any load which has a demand greater than about 0·25% of the network short-circuit fault current can cause disturbance to other connected loads. The degree of interference will depend not only on the magnitude of the current taken but also on its phase angle relative to the system voltage, and on whether the current change is gradual or sudden, and on how frequently the change occurs. In addition, variations which occur frequently tend to be more disturbing to other customers.

Direct on-line starting of a motor at standstill is a particular case of this, when the current will be several times the full-load motor current and at a relatively low power factor, typically 0·3 or less. The initial current is limited only by the system impedance and the internal impedance of the motor. As the motor runs up to speed the current will be reduced because of the back EMF generated by the motor, and its power factor will increase.

The initial current of a squirrel-cage induction motor, if started direct on line, will typically be 5–8 times full-load current, although special double-cage motor designs can reduce the current to 3·5–5 times full load. Star–delta starting conditions can be used to limit the initial current to within the range 2·5–3·5 times, while an auto-transformer start could further limit this to within 1·5–3·5 times full-load current. Thyristor-controlled soft-start devices are also popular. With these arrangements the starting current is automatically kept virtually constant. More expensive wound-rotor machines employing resistance starting can reduce the initial current to 1·5–2·5 times full-load current. Although some stepped starting methods, such as star–delta, may have higher current changes at changeover, this will be at a much higher power factor and the resulting voltage depression will usually be less than the voltage depression at switch-on.

12.4.2 Voltage variations

The percentage voltage variation caused by motor starting can be calculated from

$$V\% \simeq \{\sqrt{3}I/V\} \times (R\cos\phi + X\sin\phi) \times 100\% \qquad (12.6)$$

where I = motor starting current
R and X = resistive and reactive components of system impedance
$\cos\phi$ = power factor of motor starting current
V = system phase–phase voltage

Care must be taken to use appropriate values for R and X in calculating the voltage variation for single-phase motors, allowing for feed and return paths.

UK experience indicates that typical limits to avoid unacceptable interference to other customers' equipment would be 1% of phase voltage at the point of common coupling for sudden voltage changes caused by frequent starting, and up to 3% where voltage changes are gradual over 2 s or more. The limit for sudden changes may be increased to, say, 3% if starting is less frequent than every 2 h, and up to 6% if starting is only once or twice a year. If several motors, which cause voltage depressions close to the limit of acceptability, are connected to the same point of common coupling, the combined effect should be considered, and where they involve frequent starting the limit may have to be reduced in accordance with Figure 12.2.

12.4.3 Short-circuit contribution

The contribution to short-circuit levels by motors can be considerable in the first half-cycle, and may still be appreciable at time of circuit-breaker contact separation with fast clearance times. The contribution from synchronous motors to the short-circuit current is more significant because the decay time of these machines is longer. The value can be calculated in the same way as for synchronous generators, as discussed in Chapter 3.

The contribution which induction motors can make has not always been appreciated, particularly in respect of the capability of switchgear when closing onto a fault. In general, a supply utility will not have specific information about the number, sizes or characteristics of the many small motors installed in customers' premises. These motors can therefore only be dealt with in groups, or in terms of the proportion of motor load to total load on the network. The initial contribution to short-circuit current from these small motors can be up to seven times their full load rating, and in total will depend on the proportion of connected motor load to total load. Typically figures are 1 MVA of fault infeed per MVA of aggregate non-industrial load, and up to 2.6 MVA per MVA of aggregate industrial load. The time constant of decay for small induction motors is about 30 ms.

When considering induction motors, the initial AC and DC components of fault current will have waveforms similar to those shown in Figure 12.12a, with the AC component remaining steady and the DC component decaying exponentially with time. The instantaneous value of current at time t after fault initiation i is given by

$$\begin{aligned} i = {} & \sqrt{2}\, I_{rms} \sin(\omega t + \theta_1 - \theta_2) \\ & - \sqrt{2}\, I_{rms} \sin(\theta_1 - \theta_2) \exp\{(-R/X)\omega t\} \end{aligned} \tag{12.7}$$

where I_{rms} = root-mean-square value of the AC component fault current

θ_1 = closing angle which defines the point on the source sinusoidal voltage when the fault occurs

θ_2 = system impedance angle, = $\tan^{-1} X/R$

ω = angular frequency, rad/s

From eqn. 12.7, the peak value of the AC component is $\sqrt{2}$ times the RMS value of the AC component. If the closing angle is such that $\theta_1 - \theta_2 = n\pi/2$ radians, where n is an odd integer, e.g. 1, 3, 5 etc., the DC component will have a maximum value at $t = 0$, immediately the fault occurs, of $\sqrt{2}\, I_{rms}$ also. The combined AC and DC component will then total twice $\sqrt{2}\, I_{rms}$, the so-called 'doubling effect'.

In Figure 12.12a the current waveforms have been drawn for an R/X ratio of 0·1, and a closing angle θ_1 of 0°. The ratio of the maximum peak current to the RMS value of the AC component, the peak current factor, depends on the instant of the fault and the rate of decay of the DC component. The maximum peak current occurs when the closing angle θ_1 is zero, irrespective of the R/X ratio of the system. Figure 12.12b gives the peak current factors for a range of R/X ratios.

For the larger induction motors, say those with a rated output exceeding 1% of the short-circuit fault level of the network under consideration, AC and DC components can be individually calculated using the locked-rotor reactance. In assessing the breaking duty of switchgear, allowance should be made for the

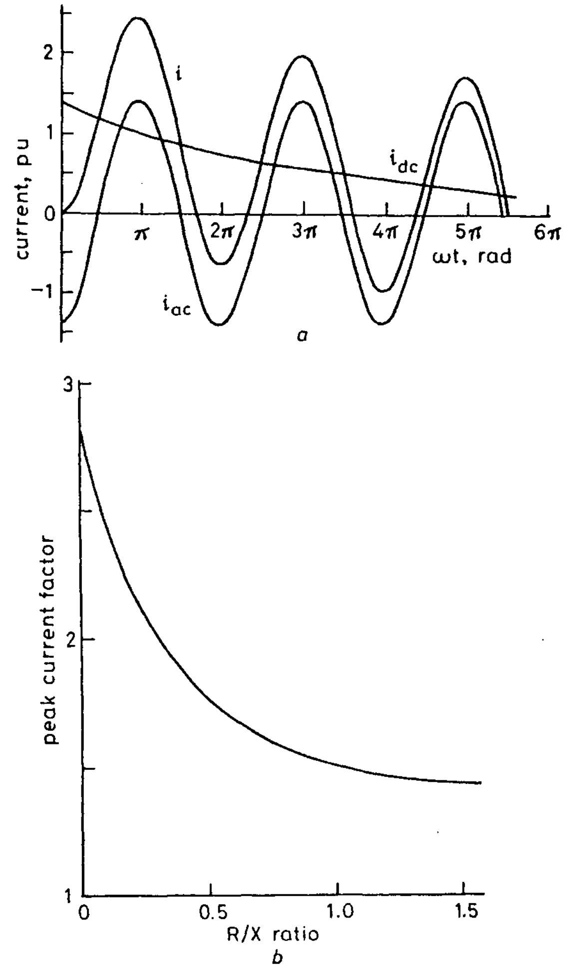

Figure 12.12 *Asymmetrical fault-current waveforms, and variation of peak current with R/X ratio*

a Plot of total (asymmetrical) current for a 0° closing angle, $R/X = 0.1$. Total current consists of a DC component i_{dc} and an AC component i_{ac}
b Variation of peak current with R/X ratio

reduction in peak current with time, as both AC and DC components decay much more rapidly with induction motors than with synchronous machines. In practice, the contribution from most induction motors, unlike synchronous machines, may be disregarded after 100 ms. This is because those motors which have not tripped due to under-voltage will either have reverted to motoring at reduced supply voltage or will be providing infeeds out of phase with the infeeds from the rest of the system.

12.4.4 Example of effect of motor loads on system

Figure 12.13 represents an EHV/HV substation supporting a local HV system supplying 60 MVA of industrial load and 65 MVA of non-industrial load. The local HV/MV substation supplies industrial loads totalling 10.7 MVA, a non-industrial load of 9·6 MVA plus two 2·5 MVA induction motors. Each motor has a starting current of 3·2 times full-load current at 0·3 power factor. The HV and MV voltage levels are 132 kV and 11 kV, respectively. The impedance from source to the 132 kV busbar is $0{\cdot}19 + j9{\cdot}67\ \Omega$ at 132 kV. The impedance between the 132 and 11 kV busbars is $0{\cdot}024 + j0{\cdot}608\ \Omega$, referred to 11 kV.

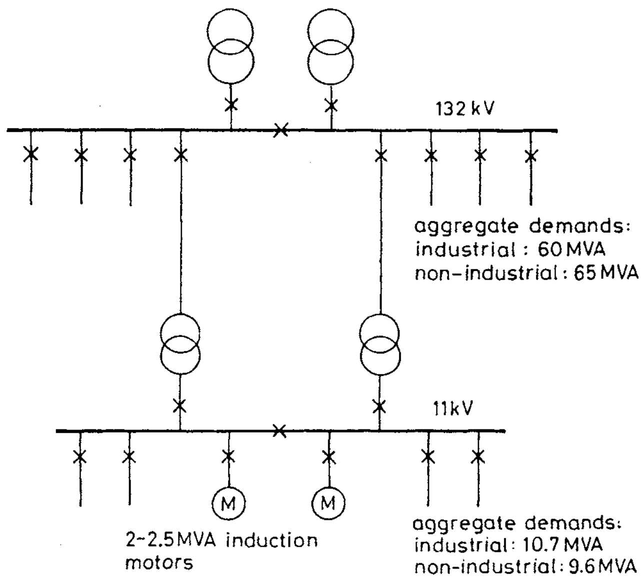

Figure 12.13 Example network for motor-infeed calculation

Calculation of voltage depression on starting a 2·5 MVA motor

(i) *At 11 kV busbar:* First the source impedance must be referred to 11 kV; i.e. this is then $(11/132)^2 \times (0{\cdot}19 + j9{\cdot}67) = (0{\cdot}00132 + j0{\cdot}0672)\ \Omega$ at 11 kV. The total impedance from source to the 11 kV busbars is thus $(0{\cdot}00132 + j0{\cdot}0672) + (0{\cdot}024 + j0{\cdot}608) = (0{\cdot}253 + j0{\cdot}675)\ \Omega$. From eqn. 12.7 the percentage voltage depression at the 11 kV busbars on starting one 2·5 MVA motor is

$$\frac{3{\cdot}2 \times 2{\cdot}5 \times 10^6}{\sqrt{3} \times 11\,000} \times \frac{\sqrt{3}}{11\,000}\{(0{\cdot}253 \times 0{\cdot}3) + (0{\cdot}675 \times 0{\cdot}954)\} \times 100\%$$
$$= 4{\cdot}31\%$$

(ii) *At 132 kV busbar:* The impedance from source is $0{\cdot}19 + j9{\cdot}67\ \Omega$ at 132 kV, giving a voltage depression on starting of

$$\frac{3{\cdot}2 \times 2{\cdot}5 \times 10^6}{\sqrt{3} \times 132\,000} \times \frac{\sqrt{3}}{132\,000}\{(0{\cdot}19 \times 0{\cdot}3) + (9{\cdot}67 \times 0{\cdot}954)\} \times 100\%$$
$$= 0{\cdot}43\%$$

Calculation of short-circuit contributions

(i) *At 132 kV busbar:* The impedance from source to the 132 kV busbars is $\sqrt{\{(0{\cdot}19)^2 + (9{\cdot}67)^2\}} = 9{\cdot}672\ \Omega$. The system R/X ratio is 0·19/9·67, say 0·02, which, from Figure 12.12b, results in a peak current factor of 2·75. Thus the peak asymmetrical current at the 132 kV busbars due to source infeeds is

$$2{\cdot}75 \times \frac{132}{\sqrt{3} \times 9{\cdot}67} = 21{\cdot}67 \text{ kA}$$

At the 11 kV busbars the general industrial load will provide a contribution of $2{\cdot}6 \times 10{\cdot}7 = 27{\cdot}8$ MVA, using the multiplying factor quoted in the second paragraph of Section 12.4.3. In addition, assuming a motor EMF of 90% supply voltage and a starting current of 3·2 times full-load current, the two 2·5 MVA motors will provide an infeed of $2 \times 3{\cdot}2 \times 2{\cdot}5 \times 0{\cdot}9 = 14{\cdot}4$ MVA. The non-industrial load will provide a contribution of $1 \times 9{\cdot}6 = 9{\cdot}6$ MVA. The three infeeds thus total 51·8 MVA, equivalent to a 336·2 Ω reactance at 132 kV and 2·34 Ω at 11 kV. Neglecting resistance, the impedance between the 11 kV and 132 kV busbars is 87·6 Ω at 132 kV.

Assuming an R/X ratio of 0·35, from Figure 12.12b the peak current factor is 1·94, so that the resultant infeed from the 11 kV busbars to the 132 kV busbars is

$$1{\cdot}94 \times \frac{132}{\sqrt{3}(336{\cdot}2 + 87{\cdot}6)} = 0{\cdot}35 \text{ kA}$$

There will also be an infeed from the other industrial loads connected to the 132 kV busbars of $2{\cdot}6 \times 60 = 156$ MVA, plus $1 \times 65 = 65$ MVA from the non-industrial loads, making a total contribution of 221 MVA, equivalent to a reactance of 78·8 Ω at 132 kV and 0·548 Ω at 11 kV. Owing to the higher R/X ratio and the rapid decay of the DC component, the infeed due to this equivalent reactance is unlikely to exceed, say,

$$1{\cdot}85 \times \frac{132}{\sqrt{3} \times 78{\cdot}8} = 1{\cdot}79 \text{ kA}$$

Thus the total infeed to the 132 kV busbars is $21{\cdot}67 + 0{\cdot}35 + 1{\cdot}79 = 23{\cdot}81$ kA.

(ii) *At 11 kV busbar:* The infeed from the industrial load and the motors is

$$1{\cdot}94 \times \frac{11}{\sqrt{3} \times 2{\cdot}34} = 5{\cdot}27 \text{ kA}$$

The infeed from the 132 kV busbar is the combined infeeds from the source and the industrial motors, represented by 0·067 Ω and 0·548 Ω impedance, respectively; i.e. equivalent to (0·067 × 0·548)/(0·067 + 0·548) = 0·060 Ω impedance. Taking the impedance between the busbars at 0·608 Ω at 11 kV the infeed from the 132 kV busbars is then

$$2{\cdot}75 \frac{11}{\sqrt{3} \times (0{\cdot}608 + 0{\cdot}060)} = 26{\cdot}2 \text{ kA}$$

giving a total infeed to the 11 kV busbars of 5·27 + 26·20 = 31·47 kA.

As mentioned earlier, when considering the breaking duty on switchgear, the smaller motors will produce negligible contribution after 100 ms and the contribution from the two larger motors in this example would be considerably reduced.

12.5 Railway traction

It has been forecast that, by the end of the 20th century, some 40% of the world railway traffic routes will be electrified and carrying 75% of the total rail traffic. While some railway traction operates on DC using 3-phase trackside rectifiers, mainly in urban or suburban areas, the majority of traction supplies are now being provided at single-phase AC, typically 25 kV 50 Hz.

Particularly when starting heavy train loads, large currents are drawn from the infeed supply points. Figure 12.14 shows a typical recording of a main-line station where the starting of peak-hour inter-city trains, and of local smaller units, can be distinguished.

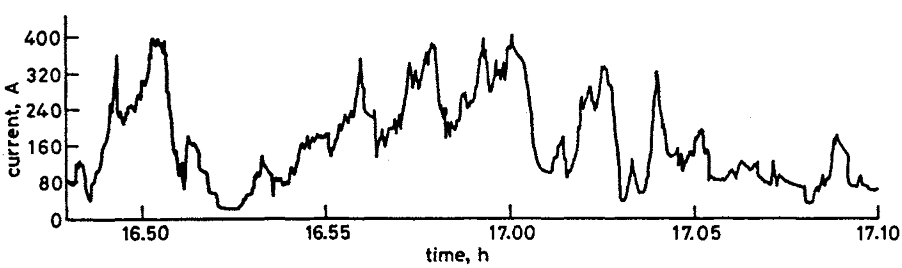

Figure 12.14 Current recording at traction-supply point (Courtesy Midlands Electricity plc)

There has been an almost total use of diode rectifiers or thyristor converters on traction power units in order to use DC motors. As discussed in Section 12.3, diodes and thyristor arrangements introduce harmonic distortion into the supply network. Provision of single-phase supplies from two or three phases of the supply system results in voltage unbalance, and these two factors can lead to excessive propagation of negative-phase-sequence currents. Although it is possible to connect traction supplies to systems operating at MV or HV, the need to limit disturbances to other customers generally requires that the point of common coupling must be at the supply authority's HV distribution level.

To avoid load unbalance on the HV system it is usual to connect each substation across a different pair of phases on the HV side, as shown in Figure 12.15. Under normal conditions the HV/25 kV transformers feed the 25 kV overhead feeders in opposite directions as far as an intermediate switching station halfway between the substations. The arrangements are such that, for the total loss of any one HV/25 kV substation, due either to some local fault or a fault on the HV system, then trackside supplies are available from the substations on either side of the faulted substation. The average distance between substations is approximately 35 km on single-track lines and about 50 km on double-track lines.

From the load-current waveform it is possible to determine the magnitude of the individual harmonic currents and derive the total harmonic distortion at the point of common coupling. Experience suggests that the RMS value of the HV supply-voltage distortion can be around 2–2½% without causing undue interference to other loads. It should also be borne in mind that in taking traction supplies from only two phases of the HV supply the triple harmonics do not cancel out as with balanced 3-phase loads.

In areas with poor earthing conditions, the rail 25 kV overhead system is usually provided with booster transformers at approximately 3 km spacings in order to reduce induced voltages and noise interference in telecommunication

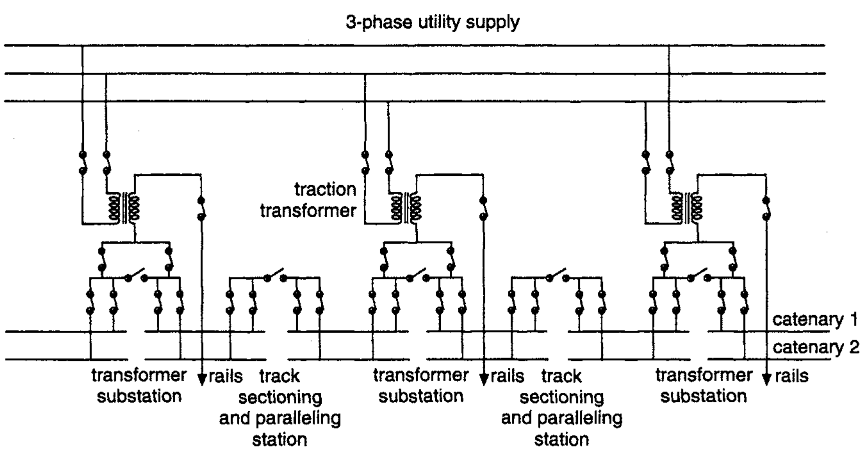

Figure 12.15 Centre-fed AC railway traction feeding system with catenary-fault isolation arrangements

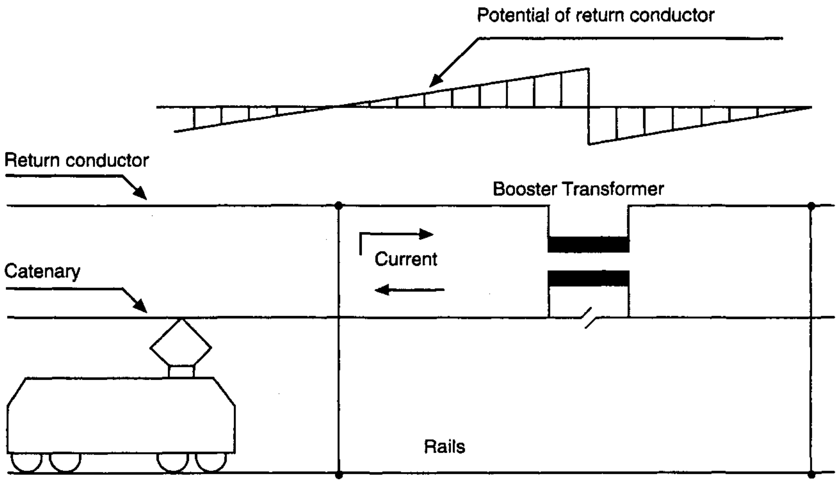

Figure 12.16 Principle of booster transformer

lines as well as the rail potential. These booster transformers are effectively current transformers with a 1:1 ratio and induce a voltage opposite to the voltage drop of the return rail conductor, offsetting the effect of the conductor reactance and forcing the load current to flow along the return conductor; see Figure 12.16.

With varying loadings on individual traction supply points the net unbalanced loading can result in excessive negative-phase-sequence currents circulating in the HV system. Consideration may then have to be given to phase balancing. Figure 12.17 shows typical connections for balancing a single-phase line–line load on a 3-phase system. It should be noted that the inductive arm of the balancer is connected between the phase not used for the railway load and the leading phase of the load, and that in practice it may be uneconomic to provide complete balancing.

12.6 Other loads

12.6.1 Welding equipment

Welding equipment usually draws a fluctuating current from the supply system, and therefore produces voltage fluctuations. Whilst these fluctuations are less erratic than those from arc furnaces, the limit of acceptability is the same, i.e. as shown in Figure 12.2. Consider a single-phase welder connected across two phases of a 3-phase system. A single-phase load on a 3-phase system involves a

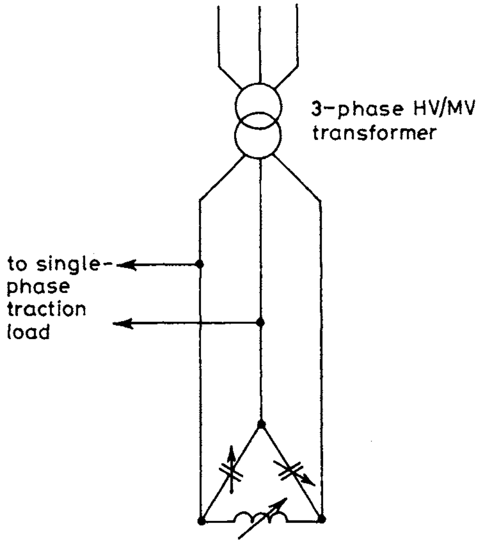

Figure 12.17 Phase-balancing arrangements

30° phase shift, and two of the phase–neutral voltages will experience voltage drops. The worst voltage drop is given by

$$\Delta V = I\{R_s \cos(\phi - 30°) + X_s \sin(\phi - 30°)\} \qquad (12.8)$$

where R_s and X_s are the resistance and reactance at the welder supply terminals, respectively.

For a 400 V 3-phase system, and taking an average power factor for welding equipment of $\cos\phi = 0.3$, the approximation given by eqn. 12.9 can be used to determine the numerical value of the percentage voltage drop at the point of connection of the welder to the system, using the numeric values of the various quantities shown.

$$\Delta V\% \simeq (0.81R_s + 0.73X_s) \times S_w \qquad (12.9)$$

where $\Delta V\%$ = percentage voltage drop caused by the welder, relative to the nominal 3-phase supply voltage

R_s = resistance at welder supply terminals, Ω/phase

X_s = reactance at welder supply terminals, Ω/phase

S_w = apparent 'step kVA' of the welder, which can usually be taken as twice the nameplate rating

12.6.2 Induction-heating equipment

Induction-heating equipment basically falls into two categories, depending on the frequency of the power used for the heating effect. The induction-coil system is a single-phase device and, if the coil works at normal supply frequency, it is usually directly connected to the supply. This then presents an unbalanced load to the 3-phase system and the voltage-unbalance problems discussed in Section 13.8 have to be considered. The coarse control associated with this system also results in voltage fluctuations occurring. Alternatively, and more commonly, the induction coil operates at a higher frequency, which is obtained from a 3-phase rectifier/inverter arrangement, and the harmonic aspects referred to in Section 12.3 should be considered.

12.6.3 Miscellaneous loads

In general, the loads discussed in the previous Sections are those associated with industrial installations, many taking a high power demand. In contrast, there are items of customer equipment which, although individually acceptable on the supply system, can collectively affect the quality of supply locally. For example, if high-power electric showers are connected to single-phase domestic supplies, this may result in excessive local LV-system voltage drop if a number are operated at the same time.

Numbers of thyristor dimmer switches can introduce harmonics into the low-voltage network. The introduction of television sets with half-wave-thyristor/half-wave-diode rectification created more problems in Great Britain than in USA or the European continent, since the rectangular 3-pin plugs used in Great Britain resulted in all TV sets being connected in the same polarity. If suitable standards for such equipment are agreed with manufacturers, potential problems caused by the large number of equipment connected can be avoided.

The majority of this chapter has concentrated on assessing the effect that various types of load have on the quality of the supply voltage provided to other customers. Sensitive equipment such as computers, and electronically controlled devices such as microprocessor installations, are particularly susceptible to variation in voltage, and from voltage spikes with a duration time of some tens of microseconds.

Given that a utility and those customers with fluctuating loads, or motor loads, are operating within agreed constraints to avoid undue interference with other customers, experience has shown that malfunction of electronic equipment is generally due to voltage spikes which originate within that customer's premises, e.g. by the switching of fluorescent lamps and the operation of water- and space-heating thermostats. The time period and frequency are usually such that any spikes etc. are attenuated by the supply MV/LV distribution transformer, or by a short length of LV circuit, and are not propagated into other customers' premises. In most cases electronically controlled devices can usually be protected from any adverse effects of fluctuations of the supply voltage at little cost, and usually suitable filters and voltage stabilisers are installed to cope with these problems. It may, however, be necessary for the customer to provide a back-up uninterruptible supply to avoid malfunction of sensitive equipment.

12.7 Electromagnetic compatibility

12.7.1 International regulations

Electromagnetic compatibility (EMC) can be defined as the ability of an equipment or system to operate satisfactorily in its electromagnetic environment without introducing electromagnetic disturbances intolerable to anything in that environment. The problems described in Section 12.6.3 are examples of poor electromagnetic compatibility between equipment. To achieve electromagnetic compatibility, the emission and immunity levels of equipment in an environment must be properly co-ordinated. The emission levels specify the maximum level of electromagnetic disturbance an equipment or system is allowed to produce, while the immunity levels specify the level of electromagnetic disturbance an equipment or system must tolerate for maintaining a predefined operational performance. When dealing with equipment connected to a public electricity supply system the characteristics of the voltage at the user supply terminals also become an issue of interest.

From the equipment point of view the fundamental problem of EMC co-ordination is to select the equipment immunity levels to match the disturbance levels expected in the operating environment. This environment is determined by the characteristics of the user plant (internal electric installation and loads) and by the voltage characteristics available at the supply terminals. The voltage characteristics at the supply terminals are primarily determined by the other users connected to the network, and the structure and dimensioning of the network. In addition to user equipment, disturbances may also be caused by unpredictable factors including exceptional weather conditions (lightning, rain, snow, ice etc.), environmental conditions (natural and man-made pollution) and third-party actions (intentional or accidental damage to the supply installations, strikes, acts of the public authorities).

Compatibility levels are given for the guidance of International Electrotechnical Commission (IEC) product committees specifying the immunity levels of equipment to public power system disturbances and of experts and power supply authorities setting limits for disturbance emission in power systems so that some co-ordination can be achieved (Figure 12.18). The compatibility levels are specified in IEC and Comité Européen de Normalisation Electrotechnique (CENELEC) standardisation documents for three reference environments – special supply systems, public supply systems and industrial internal supply systems – and are statistical levels which are usually defined so that they can be exceeded with a 5% probability in time and location. Planning levels are used for planning purposes in evaluating the impact of all disturbing customers or equipment on the system.

The EMC co-ordination problem is rather complicated because it involves several parties including end users of electricity, equipment and system manufacturers, designers of plants and installations, electricity distributors and public authorities (Figure 12.19). Specifying the characteristics of the voltage at

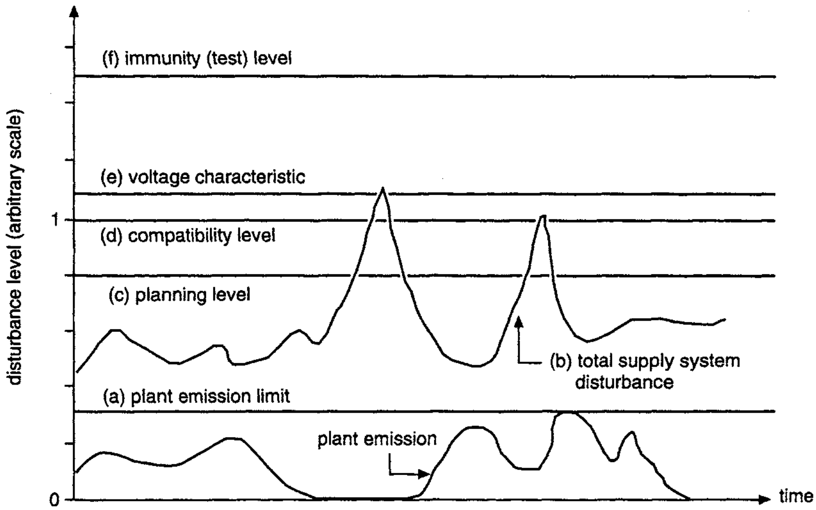

Figure 12.18 Deterministic representation of the co-ordination of conducted disturbances (Courtesy UNIPEDE NORMCOMP 89)

a Defined by standards or electricity supplier (maximum or 95% value)
b For a network location with a medium-high disturbance
c Defined by electricity supplier (time static, 95% value)
d Defined by standards (time and location statistic, 95% value)
e Defined by standards (time statistic, 95% value)
f Defined by standards or agreed between user and manufacturer

the user supply terminals is part of the problem. Relatively loose requirements for the voltage quality would result in high immunity levels for the equipment, which would ultimately make them very expensive. On the other hand, strict requirements would increase the utilities' investment costs, which would also affect the price of electricity.

The international standardisation work relating to electromagnetic compatibility and quality of electricity supply is carried out by the IEC. In European countries the standardisation work related to these issues is done at CENELEC. The general guidelines and requirements for legislation are established in directives issued by the Commission of the European Communities while the technical details (specific limits, test procedures, etc.) are presented in harmonised standards (ENs – European standards). Usually these harmonised standards are adopted directly in all the member countries of the European Communities as national standards. Two directives in particular have an important impact on the standardisation work related to the quality of electricity supply and EMC: the Product Liability Directive (85/374/EEC) and the EMC Directive (89/336/EEC). To clarify the application of the Product Liability Directive to electricity as a product CENELEC prepared the European standard EN 50160 'Voltage characteristics of electricity supplied by public distribution systems' published in January 1995. The standard specifies the

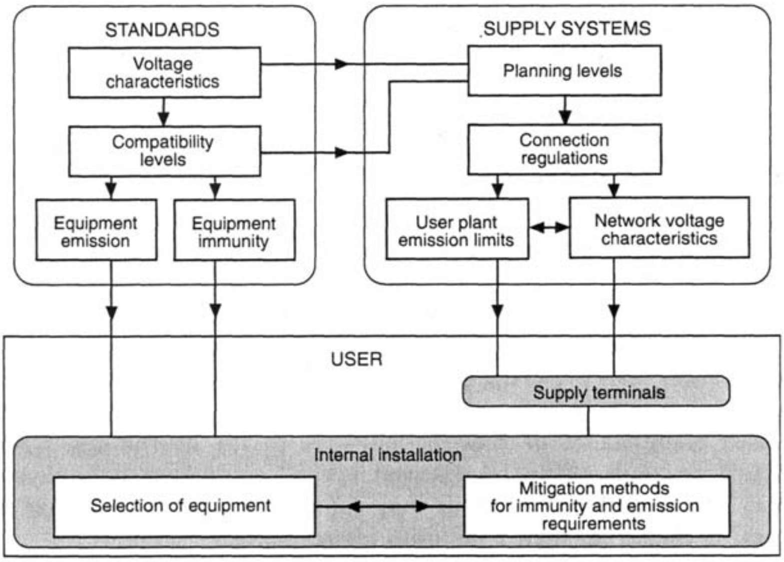

Figure 12.19 *Relation between standardisation, management of voltage characteristics, user equipment and installation options (Courtesy UNIPEDE NORMCOMP 89)*

characteristics of the voltage in public low-voltage and medium-voltage electricity distribution systems. The requirements related to the safety of electrical equipment are defined in the Low-Voltage Directive and associated harmonised standards, which apply to equipment with nominal voltages of 50 to 1000 V AC and 75 to 1500 V DC. The Low-Voltage Directive is not directly related to the EMC Directive, but is practical to test the conformity of the product with both directives at the same time.

12.7.2 Voltage characteristics

Rapid voltage changes can be divided between single rapid voltage changes, for example those caused by switching on a motor, which are described as a rapid depression of the RMS value of the supplied voltage, and the voltage fluctuation described as a series of consecutive voltage changes, caused for example by electric arc furnaces or welding equipment.

Rapid voltage changes can be evaluated by measuring the change in voltage RMS value compared with the nominal voltage, or by measuring and calculating the flicker severity. Short-term severity P_{st} is measured with a specified equipment over a period of ten minutes and long-term severity P_{lt} is calculated from a sequence of $12 P_{st}$ values over a two-hour interval, according to the expression

$$P_{lt} = \sqrt[3]{\sum_{i=1}^{12} \frac{P_{sti}^3}{12}} \tag{12.10}$$

According to EN 50160, for example, the voltage fluctuation should be less than or equal to $P_{lt} = 1$ for 95% of the time.

Supply-voltage dips are sudden reductions of the RMS voltage value to a magnitude between 90% and 1% of the nominal value followed by a voltage recovery, and the duration of a voltage dip is typically between 10 ms and 1 minute. The dips are mostly caused by single-phase or phase–phase faults and their effects depend on their depth and duration. A condition in which the voltage is lower than 1% of the declared voltage at the supply terminals is called supply interruption. Supply interruptions may be pre-arranged (e.g. due to scheduled maintenance or construction work in the distribution system) or accidental (caused mostly by external events, equipment failures or interference). Accidental interruptions may be classified as long (longer than 3 minutes) or short (less than 3 minutes) interruptions.

Temporary (power frequency) overvoltages are oscillatory overvoltages of relatively long duration, which are undamped or weakly damped, and are caused by switching operations or faults – for example, sudden loss of load, single-phase faults, nonlinearities. Transient overvoltages are short in duration (a few milliseconds or less) and usually highly damped and are mostly caused by lightning, switching, or the operation of fuses.

Harmonic voltage may be defined as a sinusoidal voltage with a frequency equal to an integer multiple of the fundamental frequency of the supply voltage. Correspondingly, interharmonic voltage is defined as a sinusoidal voltage with a frequency between the harmonics. Harmonic voltages can be evaluated individually or globally; individually by their relative amplitude u_h related to the fundamental voltage u_1, where h is the order of the harmonic, and globally by the total harmonic distortion factor THD which is calculated as follows:

$$\mathrm{TDH} = \sqrt{\sum_{h=2}^{40} u_h^2} \tag{12.11}$$

The harmonics of the supply voltage are caused mainly by nonlinear loads and supplies. Harmonic currents flowing through the system impedance give rise to harmonic voltages. EN 50160 specifies the limits below which the 10-minute-average values of the harmonic voltages must remain for 95% of the time during each period of one week.

Mains signalling voltages may also degrade the quality of the voltage. The signalling voltages are superimposed on the supply voltage for the purpose of transmission of information in the public distribution system. Three types of signals are commonly used: ripple control signals (110–3000 Hz), power-line-carrier signals (3–148·5 kHz) and mains marking signals (transient signals).

High-frequency (> 150 kHz) electromagnetic interference (EMI) is not included in EN 50160 but is regulated by the EMC standards. High-frequency EMI may be generated in medium-voltage distribution systems by electrical discharges occurring in insulators, disconnectors and other hardware. The highest interference levels are usually generated by gap- or corona-type discharges, and interference may also be generated by solid-state switching elements such as thyristors used in some power system equipment. Thus, some of the equipment used to increase the utilisation of power networks such as static VAR compensators (SVCs) may increase the overall EMI. The characteristics of EMI generated by these power electronic devices are completely different from those of electrical discharges. Rotating machines, saturated magnetic circuits (transformers, coils with magnetic cores), welding equipment etc. are also possible sources of EMI. The EMC Directive and associated standards set the requirements for EMI generated by power system equipment. CENELEC's standardisation programme on electromagnetic compatibility includes product family standards for high- and low-voltage switchgear, remote-control, protection and communication equipment and fuses. Product family standards define the specific limits and test procedures for the electromagnetic interference which equipment is allowed to produce (emission levels), and the interference levels which equipment must tolerate (immunity levels) and yet still maintain a predefined functional level.

12.7.3 Measurement of voltage characteristics

Measurements of voltage characteristics can be divided into three categories according to the purpose of the measurements: permanent monitoring (for example for verifying contractual obligations), temporary surveying (for example to check the performance of the supply system, or to check user complaints) and general investigations. Each category of measurements sets specific requirements for the instruments and the measurement methods. Portable power-quality instruments are most suitable for temporary surveying as they can be optimised for finding and solving intermittent power problems. Network power-quality instruments are used to gather long-term statistical data and to measure the general performance of a distribution system. They are optimised for data accumulation and communication, for example with a host computer.

In low-voltage supply systems the voltage to be measured can usually be connected directly to the instrument and the measurement is technically simple. In medium-voltage systems instrument transformers have to be used and the voltage-quality instrument then performs the measurement of various voltage characteristics by means of an analogue or digital data-acquisition technique. Modern power-quality instruments may be equipped with multiple microprocessors and a communication interface for data transmission to a host computer. They usually utilise digital signal processing (DSP) and may even include some level of expert advice to help the user of the instrument in interpreting the results.

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Chapter 13

Network voltage performance

13.1 General

The quality of electricity 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 unbalance of 3-phase voltages. In addition, other irregularities such as 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 a supply system. Some examples of these are shown in Figure 13.1*b*.

To avoid harmful effects to equipment belonging to the supply authority, or any customer, various forms of legislation and recommendations exist in

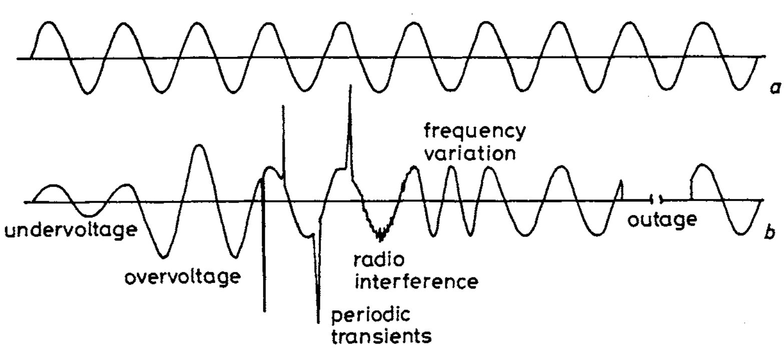


Figure 13.1 *Ideal voltage waveform and voltage variations*[4]

a Ideal voltage waveform
b Variations in voltage waveform

different countries to ensure that the level of the voltage supplied does not go outside prescribed tolerances. The characteristics of the supply voltage specified in voltage-quality standards usually describe its frequency, magnitude, waveform and the symmetry of the three phase voltages. Worldwide there is a relatively wide variation in accepted tolerances related to different voltage characteristics. Standards are constantly being developed in order to respond to technical, economic and political evolution.

Because some incidents affecting the supply voltage are random in time and location, some of the characteristics may be described in the standards with statistical parameters instead of specific limits. An important aspect in applying the standards is to look at where in the supply network, and when, the voltage characteristics are specified. The European standard *EN 50160*, for example, specifies the voltage characteristics at the customer's supply terminals under normal operation conditions. 'Supply terminals' is defined as the point of connection of the customer's installation to the public system.

EN 50160 indicates that, in the member states of the European Communities, the range of variation of the 10 minute RMS values of the supply voltage (phase–neutral or phase–phase) is $V_n \pm 10\%$ for 95% of a week. For 4-wire 3-phase systems $V_n = 230$ V between phase and neutral. Strictly speaking, this means that for more than 8 hours a week there are no limits for the supply voltage value. There has also been some criticism that the voltage tolerance of $V_n \pm 10\%$ is too wide. Until the year 2003, the nominal voltage and the tolerances may differ from the values stated above according to the harmonised document *HD 472 S1*. During this transitional period, the countries having 220/380 V systems should bring the voltage to 230/400 V+6%/−10% and those countries having 240/415 V systems should bring the voltage to 230/400 V+10%/−6%.

The frequency of the supply system depends on the interaction between generators and load and the range of variation is smaller the higher the ratio between generation capacity and load. This means that it is more difficult for small isolated supply systems to maintain an accurate frequency than for systems with synchronous interconnection to adjacent systems. In the European Communities the nominal frequency of the supply voltage is 50 Hz. According to *EN 50160* 'the average value of the fundamental frequency measured over 10 s in distribution systems with synchronous connection to an interconnected system shall be within a range of 50 Hz ±1% during 95% of a week and 50 Hz +4%/−6% during 100% of a week'. Distribution systems with no synchronous connection to an interconnected system have wider tolerances of ±2% and ±15%, respectively. The frequency tolerances of *EN 50160* are also rather wide compared with the present situation in many member states.

In a series of studies on customer voltage variation, one UK electricity utility recorded the maximum and minimum voltages of every customer for each one hour period. From this information the mean values of these maximum and minimum voltages were plotted for all the customers, as shown in Figure 13.2. It can be seen that those customers whose voltage level was high had a small variation in their voltage. On the other hand, those customers who received a lower level of voltage experienced larger variations in the voltage throughout the 24 hour period. Often it is this varying low level of voltage which is a cause of annoyance to customers, even though the actual voltage received may be within the prescribed limits.

Where no customer equipment is directly connected to a network, which generally applies to those operating above 100 kV, there is no need for such a precise voltage level. Consequently the voltage levels are determined from considerations of power flows and system losses. The tapping range on step-down transformers from these networks will have to be sufficient to cope with these variations in voltage level, as well as with the internal voltage drop in the transformer and any compounding required for the secondary medium-voltage network.

All networks experience voltage drops on each circuit proportional to the loading, which is continually varying. Compensating equipment is therefore provided at suitable points on the various networks to offset the resultant variations in voltage. For example, automatic on-load tap changers on EHV/HV and HV/MV transformers maintain the voltage at the HV and MV busbars, respectively, within acceptable operational limits. In some systems MV/LV transformers have tappings which can be selected off load to take account of voltage drops on the MV network, the MV/LV transformers and through the LV network.

Overall the various voltage-control equipments are operated in such a way that the voltage provided to MV and LV customers remains within the required limits, despite varying voltage drops due to changing loads and alterations in network configurations. Although a large variety of methods of compensating for voltage drop are available, such equipment increases the complexity of network operation and maintenance. Where the chosen MV level is high, e.g. 20 or 30 kV, voltage-drop problems are rare and usually the regulation provided by automatic tap changers on the HV/MV transformers is adequate.

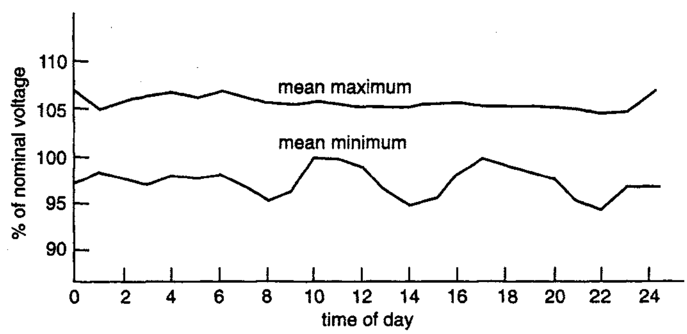


Figure 13.2 Variation of customers' voltage over 24 h period

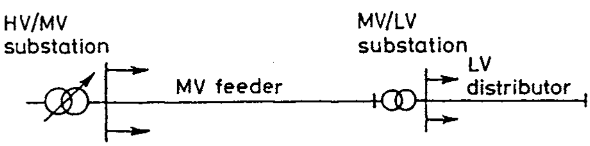
13.2 Voltage regulation

Figure 13.3*a* diagrammatically represents part of a distribution network. For simplicity the voltage variation along one MV feeder only will be considered together with the effect of any distribution-transformer tapping, the distribution-transformer load voltage drop, as well as the voltage drop along the LV distributor and the individual service connection to a customer.

Figure 13.3*b* shows diagrammatically the relative voltage variation along the MV and LV systems when the networks are heavily loaded. The distribution-transformer tap has been set to give voltage boost to offset the MV feeder voltage drop, and to keep the LV voltage within acceptable limits. The manner in which the various voltage-control facilities are adjusted to ensure that customers receive a voltage within specified limits is covered in Section 13.7.

One problem is how the total voltage drop from the HV/MV substation to the furthest LV customer should be divided across the various elements of the system. In principle this can be solved by using cost functions for MV lines (see Figure 14.9), distribution substations and LV lines, and then scanning the network arrangement until the required total voltage drop, e.g. 12%, is achieved and the incremental costs, e.g. £/%, for the MV and LV lines are equal. The solution is dependent on load distributions and MV line lengths and on the unit cost values applied.

An example of such a study is shown in Figure 13.4 which gives the optimum voltage drop for a 20 kV overhead line as function of the feeder length. Distribution conditions, for example rural or urban, will influence the result. The distribution transformer load voltage drop may sometimes be critical and



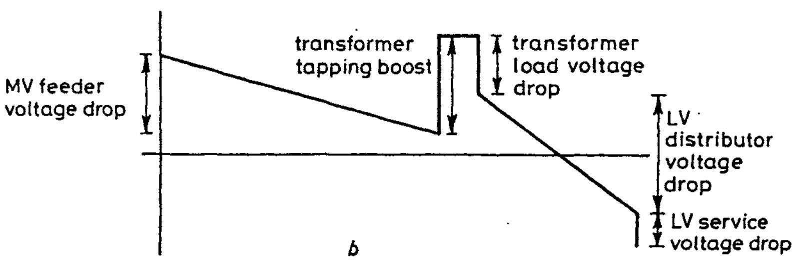


Figure 13.3 Voltage regulation on MV and LV networks

a Simplified distribution network diagram
b MV- and LV-network voltage variation

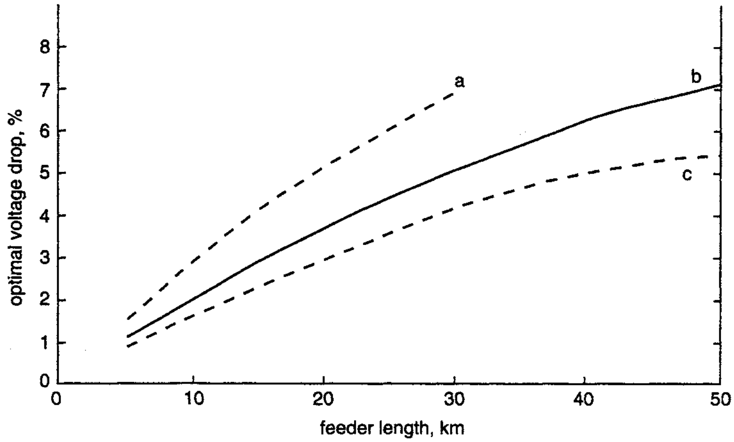


Figure 13.4 *Optimum voltage drop for a 20 kV overhead line as a function of the feeder length*

a Typical urban feeder
b Mixed urban/rural feeder
c Typical rural feeder

justify the selection of a bigger unit size than the load would require, in order to reduce the voltage drop.

13.3 Automatic voltage control

Typically, automatic voltage control is used at the HV/MV substations to maintain MV levels. This can be done by automatic tap changers on the HV/MV transformers. The choice is by economics and the similarity of the characteristics of the MV feeders.

The control of voltage on the secondary side of a transformer can be achieved by altering the transformer winding ratio, usually by altering the relative length of the higher-voltage winding. This variation can be carried out manually or by an automatic relay sensing the secondary busbar voltage, the latter arrangement being usual practice for HV/MV units. This arrangement compensates for variations of the higher voltage level and for voltage variations due to changes of load through the transformers, so that the voltage on the secondary busbar may be maintained constant, subject to the tolerances of the sensing relays.

These tolerances mean that, in practice, the regulated busbar voltage has to fall below the nominal setting of the voltage regulating relay before the relay operates to initiate a tap change to raise the busbar voltage. It is therefore necessary to ensure that, after causing a tap step-up, the voltage regulating relay does not then see the busbar voltage as being too high because of the relay tolerance and then initiate a tap step-down. This could result in a continuous sequence of tapping up and down – the so-called 'hunting effect'. Although the minimum tolerance of electronic voltage-regulating relays can be less than 1%, it is usual practice to utilise a relay tolerance of just under twice the transformer tap step to avoid this hunting effect. Thus in the UK, where the tap step for HV/MV transformers is 1·67%, the tolerance of electronic relays can be of the order of 2%. It is also usual to include a time-delay relay to prevent tap change initiation for short-time voltage variations, and also to avoid excessive wear on the tap changer.

If transformers operate in parallel on the secondary side they should be maintained on a similar tap at any time to minimise the total transformer losses by reducing circulating reactive current. A 'master/follower' arrangement can be used whereby, following a tap change by the 'master' transformer tap changer, auxiliary contacts on the tap changer automatically initiate a similar tap change on the 'follower' transformer(s). A preferred arrangement detects the circulating current, which arises when transformers in parallel are on different taps, to initiate the appropriate tap change in order to ensure that all transformers are maintained on, or near, the same effective tap.

13.4 Line-drop compensation

It can be an advantage to increase the busbar voltage as load increases to offset the increased MV feeder and LV system voltage drops, and conversely to decrease the voltage as the load decreases. For example, in Figure 13.3*b*, at times of low load when the voltage drops in the MV feeder and MV/LV transformers are greatly reduced, the fixed MV/LV transformer tapping boost could cause the LV level to exceed the upper tolerance unless the MV busbar voltage is reduced. This correction of voltage at the MV busbar is achieved automatically,

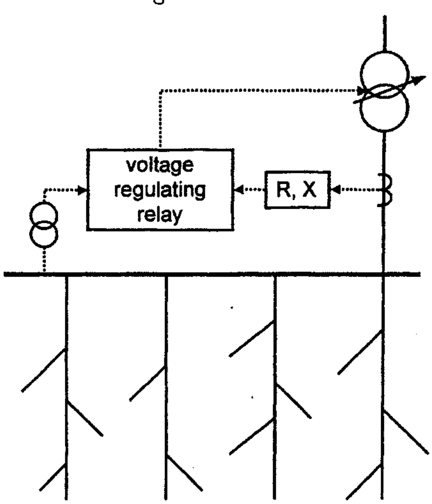


Figure 13.5 Schematic of line-drop compensation

and is often termed line-drop compensation since it compensated for variation in the MV-feeder voltage drop.

Line-drop compensation, also known as voltage compounding, is applied to the voltage-regulating relay controlling the voltage of a source busbar, so that the busbar voltage is varied depending on the load supplied from that busbar. The compensation is achieved by injecting a current proportional to the transformer load current (derived from a CT) through an impedance r_S and x_S adjusted to model the network impedance. The resultant voltage drop is combined with a voltage proportional to the controlled busbar voltage (derived from a VT) to operate a voltage regulating relay. The voltage-regulating relay is maintained in balance by causing the supply-transformer tap changer to operate

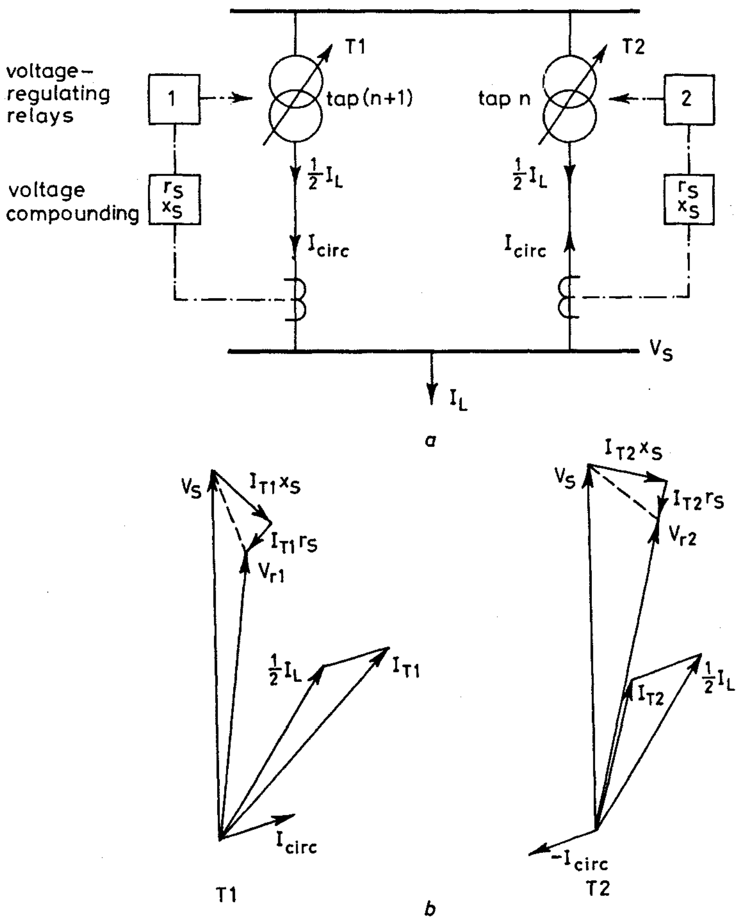


Figure 13.6 Positive-reactance compounding

a Schematic
b Phasor diagrams for T1 and T2

and change the busbar voltage up or down as necessary. The arrangement is shown schematically is Figure 13.5.

Figure 13.6*a* shows two transformers in parallel, each with a voltage-regulating relay, and compounding with a positive-reactance setting of x_S. Owing to equipment tolerance one transformer will tap-up first, say T1. The combination of load current I_L and current circulating between the two transformers I_{circ} causes the regulating relay voltages V_{r1} and V_{r2} to be as shown in Figure 13.6*b*. It will be seen that this arrangement is unstable. T1 regulating-relay voltage V_{r1} is now reduced and tending towards another tap step-up, whereas T2 regulating-relay voltage V_{r2} is increased and tending to tap-down. This process leads to tap divergence.

With the negative-reactance compounding, settings of r_S and $-x_S$ are used. For the same condition as illustrated in Figure 13.6*a*, i.e. with current circulating owing to a difference in tap positions between T1 and T2, the resultant phasor diagrams are as shown in Figure 13.7. T2 regulating-relay voltage V_{r2} is depressed and is thus tending towards a tap change to bring the transformers on to the same tap. However, T1 regulating-relay voltage V_{r1} is increased and therefore has no tendency to tap up again.

Thus stable parallel operation can be achieved by the use of negative-reactance compounding, although changes in load power factor will alter the voltage rise obtained. For lagging power factor an improvement in power factor will cause an increase in voltage V_S at the regulated busbar. In addition to providing stable parallel operation at one substation, negative-reactance compounding schemes permit the parallel operation of transformers at different substations on the lower-voltage networks.

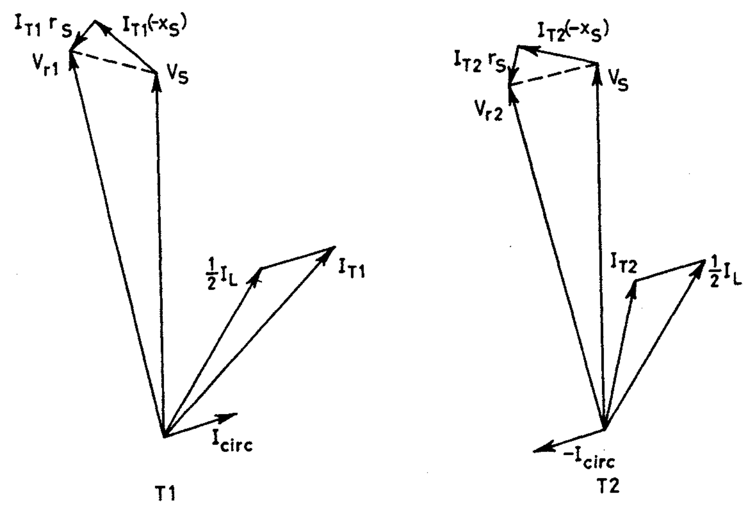


Figure 13.7 Phasor relationships for negative-reactance compounding

While automatic voltage control is applied at most EHV/HV and HV/MV transformer substations, the use of line-drop compensation (voltage compounding) is restricted to some HV/MV substations in certain supply organisations. In some cases facilities exist for adjustment of the line drop compensation setting by remote control.

13.5 Distribution-transformer tap settings

In MV/LV substations the distribution transformer can be provided with tapped MV windings which permit off-load adjustment of the transformer MV/LV ratio. The actual tapping used is determined by the need to maintain the voltage supplied to low-voltage customers within the required tolerances. Typically, the range of tappings is ±5% in 2½% or 5% steps either side of the nominal ratio. The tapping selected depends on the voltage drop along the MV feeder, the voltage drop through the distribution transformer, which is a function of the transformer loading, the maximum low-voltage-distributor voltage drop, and the automatic voltage control and line-drop compensation arrangements on the source HV/MV transformers.

Generally there are zones in a distribution network within which standard distribution transformers can all operate on the same tapping. Calculations to optimise the voltage conditions across the MV and LV networks are generally aimed at identifying and defining the boundaries of these zones. In some boundary areas of the network there may be an overlap of zones with a subsequent choice of tapping. If the loading on a particular distribution transformer does not bear the same relationship to transformer rating as the other transformers in a 'tap zone', or its associated low-voltage-network voltage drop varies considerably from the average value within the zone, it may be necessary to utilise a different tap from that used for the particular tap zone. Usually one tap higher or lower is adequate. There is evidence that, where voltage compounding is in use on the MV busbar of the associated infeed HV/MV transformer substation, most MV and LV networks operate satisfactorily with a range of 5% being used for the distribution-transformer tappings.

The major difficulty in resolving a distribution-network voltage problem is the co-ordination of the various voltage-control facilities, given that much of the information required is not readily available or is of unknown accuracy. However, in practice the tap setting of individual distribution transformers supplied from one HV/MV substation is rarely critical. Experience suggests that typically only 2 or 3% of distribution-transformer tappings may require special investigation, and the incidence of justified customer voltage complaints would indicate that the use of one tapping for a given zone of the network, as discussed earlier, is a sensible engineering approach.

Opinions vary concerning the usefulness of tappings on distribution transformers. If the MV network open points have to be altered owing to network faults, the tappings in use could result in uneven LV-network voltages.

Whilst under adverse conditions these may be outside the prescribed limits, in practice customers are rarely inconvenienced, since, in general, any one distribution-transformer tap setting is not critical to the local LV-network voltage under most system operating conditions. In distribution systems where medium-voltage drops are relatively low, and the voltage elasticity on the LV networks is also small, there may be little benefit in using MV/LV transformers with taps.

13.6 Regulators and capacitors

If reinforcement of a network were required because of excessive voltage drop(s), any such reinforcement could be deferred if the voltage drop could be sufficiently reduced by some means, subject to economic as well as the technical considerations. Various devices can be installed to reduce the voltage drop, or voltage range, experienced at critical points on MV networks. Secondary considerations are that, by maintaining the correct voltage tolerances along the feeder, this could also possibly permit the use of distribution transformers without taps.

One method of maintaining the voltage along the feeder is the use of a voltage regulator. Figure 13.8 provides a single-phase representation of a moving-coil regulator. This type of regulator contains two coils A and B of similar impedance connected in series opposition. Two secondary windings *a* and *b* are associated with the main windings, shunted across the input and mounted on the same magnetic core as the main coils. Another coil m is short-circuited upon itself, and can be moved along the magnetic core by hand or motor, the power requirements for movement of the coil being fairly small. In the example shown, winding *a* has 21 times the number of turns of winding A, and winding b has nine times the number of turns of winding B.

To raise the voltage from 0·9 to 1·0 p.u., coil *m* would be located as shown in Figure 13.8. The impedance of winding *a* would be small owing to the effect of the short-circuited winding *m*, and that of *b* would be relatively large so that effectively the voltage across the regulator appears across winding *b*. With 0·9 p.u. in winding *b* and a 9:1 ratio, the voltage induced in winding B is 0·1 p.u. With zero voltage induced in winding A the output voltage is thus 0·1 p.u.

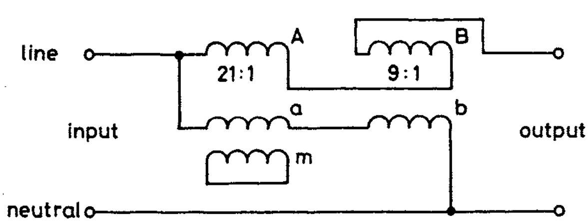


Figure 13.8 Schematic of moving-coil voltage regulator

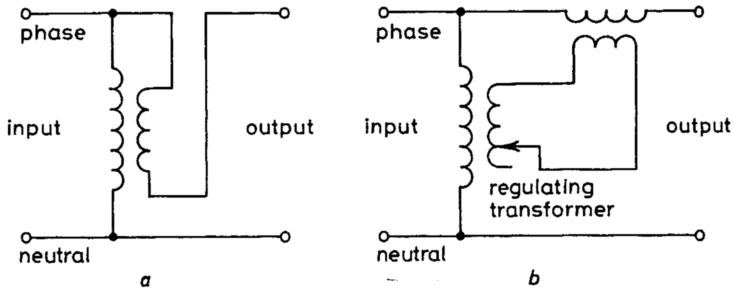


Figure 13.9 Booster transformers

higher than the input voltage, i.e. the voltage on the feeder has been raised from 0·9 p.u. to 1·0 p.u.

In the 'buck' condition, winding *m* would be opposite winding *b*. An input voltage of 1·05 p.u. applied across winding *a* would result in a voltage drop of 0·05 p.u. in winding A owing to the reversal of polarity. The output is thus 1·05 − 0·05 = 1·00 p.u. Variation from full buck to full boost can be obtained smoothly, depending upon the relative position of winding *m*.

An in-line transformer can also compensate for line-voltage drop. A fixed boost can be achieved by the auto-transformer arrangement in Figure 13.9*a*. The addition of a series booster transformer and buck and boost facilities on the regulating transformer results in the arrangement shown in Figure 13.9*b*. Booster-transformer regulators are rated on their nominal voltage and their percentage boost or buck. For example, if a regulator boosts, or bucks, the voltage by 10%, it transforms only 10% of the load so that, if the load to be carried is 5 MVA, the size of regulator required is 500 kVA.

Regulators are also used in many countries on low-voltage networks to maintain a more constant voltage profile across the network, whatever the loading. Additionally regulators may be installed within a customer's electrical installation, and these are often of the saturated-core type.

An alternative method of reducing voltage drop in MV lines is the installation of shunt capacitors. The capacitive current causes the voltage at the point of connection to rise, and overall reduces the voltage drop. Some, or all, of the capacitors may be switched in and out using relays sensing the voltage level to enable the compensation to be matched to the variation in load. Generally, shunt capacitors are preferred since series capacitors have to be protected against the maximum current which could flow through them under fault conditions.

Capacitors have lower power losses than other voltage boosting devices. In addition, they can be switched in at periods of high load to reduce the reactive-power demand, whereas boosters always add to the system reactive-power demand. Capacitors and single-phase regulators can be arranged individually to control the voltage of each phase, unlike 3-phase regulators and HV/MV transformers which can only operate on the average phase voltage and are susceptible to load unbalance.

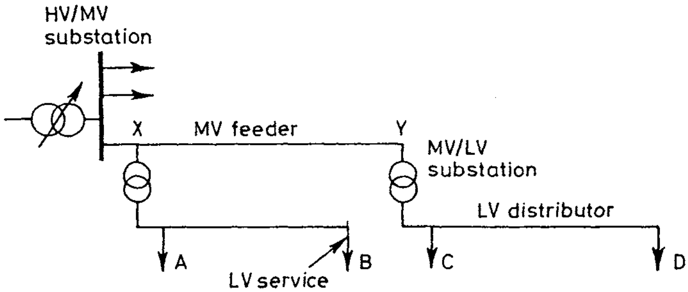


Figure 13.10 Simplified MV/LV networks for voltage regulation: example for calculation

13.7 Integration of voltage-control facilities

From the previous Sections it will be seen that there are a number of voltage-control facilities available to a distribution engineer to derive the most satisfactory voltage profiles across the MV and LV networks. By way of example to assess the interaction of some of these, consider an HV/MV substation with transformer voltage control facilities, supplying an MV network.

Figure 13.10 shows a simplified section of the MV and LV networks. An MV feeder supplies distribution substations at X and Y. These distribution transformers each supply a number of LV distributors, but for clarity only one LV distributor per substation is shown. The customer nearest to substation X is at A, and the one who is electrically the most remote it at B. Similarly for substation Y the near-end and far-end customers are at C and D, respectively.

For the purposes of this example the voltage at the MV infeed busbar is assumed to be kept constant at 103% of nominal voltage at all loads from maximum to minimum. Under maximum load conditions the voltage drop down each MV feeder is taken to be 6%, 2% through each distribution transformer owing to transformer loading, with the LV-network voltage drop 6% and LV-service voltage drop 1·5%.

The MV feeder drop from the source MV busbar to the nearest transformer X is 0·5% under maximum load conditions, and the LV-network voltage drop from each of the two distribution-transformer LV terminals to their nearest customers, at A and C, is also 0·5%. As a start point the taps on the two distribution transformers have been set to provide a 5% boost to the LV secondaries. Minimum loading has been taken as 1/6 of the maximum loading on the MV and LV systems.

It is required to adjust the HV/MV transformer voltage compounding, and the distribution-transformer tap settings, to values such that customers A, B, C and D receive supplies within ±5% of nominal voltage between maximum and minimum load conditions.

Table 13.1 sets out the MV-busbar voltage, and then lists the various voltage drops associated with each customer at time of maximum and minimum load, to derive the customers' voltages under these two load conditions, in percentage values. The customer voltage is thus the summation of the MV-busbar voltage, and the voltage gains and drops through the network, as shown at the bottom line of Table 13.1*a* and *b*.

Given that the maximum variation in voltage permitted is between 95% and 105%, then, from Table 13.1*a*, at maximum load customer D has a supply voltage below tolerance, and from Table 13.1*b* all customers are above voltage limits at time of minimum load. Table 13.2 summarises the situation at maximum and minimum loadings, and then details in the left-hand row the successive actions to bring the customers' voltages within limits.

With an MV-source busbar voltage of 103% at all times, customer voltages vary from 92·5% (D at maximum load) to 107·2% (A at minimum load). By adjusting the voltage compounding on the HV/MV source transformer to 105·5% at time of maximum load and 100·5% at time of minimum load, this variation is reduced to 95·0–106·0%. However, customer A is still outside limits at maximum load (106·0%) and very close to the required value of 105% at minimum load.

Adjusting the tapping on distribution transformer X to reduce the voltage boost from 5% to 2·5%, as shown in lines 5 and 6, results in supplies to all

Table 13.1 Voltage-drop example

(a) Maximum load conditions: percentage voltage values

Customer	A	B	C	D
MV-busbar voltage	103	103	103	103
MV-feeder voltage drop to distribution transformer	−0·5	−0·5	−6	−6
Transformer-ratio change	+5	+5	+5	+5
Transformer-load voltage drop	−2	−2	−2	−2
LV-network voltage drop	−0·5	−6	−0·5	−6
LV-service voltage drop	−1·5	−1·5	−1·5	−1·5
Customer voltage	103·5	98	98	92·5

(b) Minimum load conditions: percentage voltage values

Customer	A	B	C	D
MV-busbar voltage	103	103	103	103
MV-feeder voltage drop to distribution transformer	−0·1	−0·1	−1·0	−1·0
Transformer-ratio change	+5	+5	+5	+5
Transformer-load voltage drop	−0·35	−0·35	−0·35	−0·35
LV-network voltage drop	−0·1	−1	0·1	−1
LV-service voltage drop	−0·25	−0·25	−0·25	−0·25
Customer voltage	107·2	106·3	106·3	105·4

Table 13·2 Action to improve customer voltages

Action	Customer voltage (% of nominal)			
	A	B	C	D
Situation as specified				
1 Maximum load	103·5	98·0	98·0	92·5
2 Minimum load	107·2	106·3	106·3	105·4
Voltage compounding				
3 105·5% at maximum load	106·0	100·5	100·5	95·0
4 100·5% at minimum load	104·7	103·8	103·8	102·9
Tap setting of transformer X changed from 5% to 2·5%				
5 Maximum load	103·5	98·0		
6 Minimum load	102·3	101·3		
Tap setting on transformer Y unchanged				
7 Maximum load			100·5	95·0
8 Minimum load			103·8	102·9

customers being within the required voltage range of 95–105%. The variation in supply voltage of each customer has also been considerably reduced from the initial situation. For customer A the variation has dropped from 3·7% to 1·3%, for customers B and C from 8·1% to 3·3%, and for customer D from 12·9% to 7·9%.

Thus by suitable values of source busbar voltage, voltage compounding on the HV/MV transformer(s) supplying the MV networks, and adjusting distribution-transformer tappings, acceptable voltage levels can be maintained for the LV customers across the range of system loading. Interactive computer programs can be used to improve the performance of these voltage-control facilities, with the engineer having the facility to fix parameters at individual locations to meet specific network requirements.

13.8 Voltage unbalance

Voltage unbalance is usually expressed in terms of a voltage unbalance factor which is defined as the ratio of the negative-phase-sequence voltage component to the positive-phase-sequence voltage component.

Voltage unbalance is caused by unbalanced phase impedances, or unbalanced loads, or a combination of both. Unequal phase impedances arise on horizontal- or vertical-formation lines due to the asymmetrical conductor spacing, so that the centre phase presents approximately 6–7% lower impedance than the outer two phases.

Unbalanced load conditions can arise on MV rural systems where single-phase distribution transformers and spur-line supplies are tapped off the 3-phase network and the loads of these tappings are not balanced across the three phases. The load unbalance on individual LV distributors can be considerable and vary with time of day but, with three or four LV distributors from each MV/LV substation, the overall effect will be less pronounced at the substation. On an MV feeder supplying a number of MV/LV substations, the overall unbalance, due to LV unbalance, will generally not be very significant.

The negative-sequence impedance of a motor is much lower than the positive-sequence impedance. With voltage unbalance any resultant high negative-sequence currents in motors can lead to high temperature rises. Whilst some motors are equipped with protective devices which trip out the motor when temperatures becomes too high, there have been cases of motors overheating which have been attributed to excessive voltage unbalance. In addition, negative-sequence current causes reverse torque which tends to retard the motor. International experience indicates that some voltage unbalance is acceptable provided that this is under 2%, and preferably below 1.5%.

Most voltage-compounding equipment operates from the load current in one phase and the phase voltage in the other two phases. With voltage unbalance the equipment will incorrectly adjust the transformer tap position, assuming that these values represent a balanced system. Similar problems may occur with protection equipment.

Two types of winding connections are used in 3-phase distribution transformers, either the delta/wye (Dy) or Wye/zigzag (Yz) connection. The connection of the distribution transformer must be chosen so that any unbalanced secondary loading causes minimum distortion of the MV-phase voltages.

Any reduction in voltage unbalance will reduce network voltage drop and will also reduce system losses. In general, it is the load unbalance which is the major cause of voltage unbalance. The connection of single-phase loads to 3-phase supplies also results in higher losses.

13.9 Constraints affecting network-voltage performance

Apart from the limitations of the tap steps at the primary substation or on the distribution transformers, and the problems of voltage unbalance, other factors influence the ability to provide optimum voltages to consumers. Two main problems are the variation in loadings across the distribution network and the arrangements necessary to cover outage conditions. Loading patterns on the various distribution transformers will be different, so that the voltage drop on individual feeders will be different and vary with each other with time. The degree of line-drop compensation that can be applied may be limited. For example, if the amount of compensation is related to the general loading on the HV/MV substation, the compensation could be incorrect for any feeder supplying loads which have significantly different daily load curves.

Under fault or maintenance conditions on an MV feeder it is necessary to supply the MV/LV distribution transformers on the remaining healthy section of the MV feeder. Figure 13.11*a* shows normal operating conditions on a typical distribution network. For a fault or maintenance outage between points d and e on the lower MV feeder, this section of feeder would be isolated by opening the disconnectors at points d and e as in Figure 13.11b. Closing up at the normally open point at c restores supplies to the distribution transformers between c and e. Under this situation the healthy MV feeder a–b providing the back-up supply will be more heavily loaded, with a consequent increase in the MV feeder voltage drop. The distribution transformers along its length will thus be subjected to a reduced voltage with a consequent lowering of the voltage of the association LV networks.

In this situation, those distribution transformers receiving standby supply, e.g. those between points c and e, will similarly receive a lower voltage on the MV side. The resultant effect on the LV networks supplied from these latter transformers will be furthered worsened by the fact that, in many cases, the power flow down the remaining section of the faulted MV feeder will now be in the opposite direction to normal flows. If the distribution transformers have preset tappings, this reversal of power flow could, in certain adverse conditions, result in the voltage received by some customers being outside normal tolerances. In urban situations the low-voltage supplies from the distribution transformers on the disconnected section of MV feeder will generally be redistributed and supplied from other transformers outside the disconnected section of the MV feeder, as indicated in Figure 13.11*b*.

If the fault is such that a number of distribution transformers have to be switched to an adjacent MV substation, as in Figure 13.11*c*, the loading on that substation will be increased. The degree of additional loading will depend on the number and the loading of the distribution transformers transferred to the second MV substation. With line-drop compensation in operation at the second substation, the MV busbar voltage will be raised. There may thus be a need to limit the range of line-drop compensation (LDC) to avoid unacceptable voltages under such outages.

13.10 Customer-voltage fluctuations

There are a number of factors which cause irregularities and fluctuations in the voltage supplies to 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. These may be sufficiently attenuated so as not to cause annoyance to adjacent customers, although they may affect or even disrupt other equipment within the customers' premises.

Irregularities in the supply voltage can cause various problems depending on the nature of the disturbance. The quality of the voltage depends not only on the degree to which these irregularities are propagated throughout the various networks, but also on the sensitivity of electrical appliances to such irregularities. It is therefore necessary to consider the effects of a sudden step change in voltage,

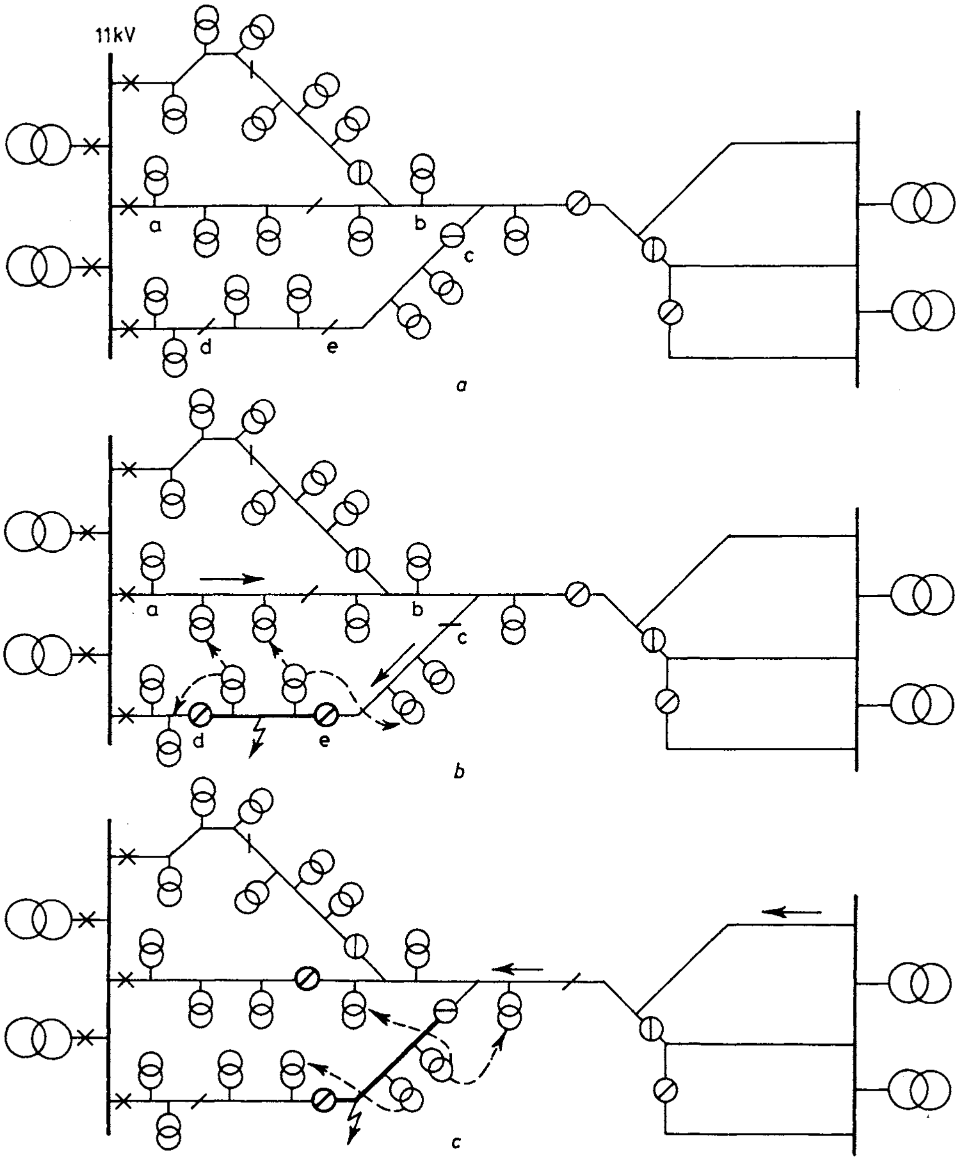


Figure 13.11 Distribution feeding arrangements under normal and fault conditions

a Typical distribution network – normal conditions
b Revised feeding arrangements on loss of section of MV feeder
c Alternative supply from adjacent MV substation under abnormal conditions

/ disconnector closed
Ø disconnector open
distribution transformer
⟶ abnormal flow on MV feeder
- - -→ LV load transfer (when available)
—— feeder section lost

e.g. a rapid fluctuation in voltage which may cause flicker, plus voltage dips and slow changes in voltage. The problems of lamp flicker due to rapid voltage fluctuations have been discussed in Section 12.2.2. The more general aspects of those loads where special consideration is necessary to avoid imposing unacceptable interference variations to the supply voltage are covered in Chapter 12.

Since the supply authority has no prior knowledge of the number or the characteristics of the various appliances connected to a given distribution network, it is not possible to predict the combined effect of any particular type of voltage variation. It is therefore necessary to ensure, when planning and designing networks, that an adequate margin of safety is provided to ensure that unacceptable voltage irregularities will not be present on distribution networks. If the question of safety is involved, an even greater margin should be allowed.

One further voltage variation is the deliberate reduction in the supply voltage by a supply authority in order to reduce the load on the system. This is normally only carried out when, owing to abnormal circumstances, there is insufficient generation capability. Such voltage reductions are usually carried out in a number of stages by remote operation of HV/MV transformer tap changers, which are then locked in at the appropriate tap position.

13.11 Harmonics

In general, the existing harmonic content in any given network is not known, and special measurements are necessary in order to assess the total effect of connecting any harmonic-producing load. In a balanced 3-phase systems the triplen harmonics (3rd, 6th, 9th etc.) have the same instantaneous magnitude in each phase. They can therefore be considered as being equivalent to zero-sequence values. When triplens appear in low-voltage systems they can cause problems by overloading the neutral conductor when the 3-phase components add arithmetically. These currents also occur in the MV winding of distribution transformers but, if this is a delta connection, the currents will merely circulate and not be transferred to the MV system.

The 4th, 7th, 10th, 13th etc. $(3n+1)$ harmonics have the same phase sequence as the fundamental (positive sequence), while the 2nd, 5th, 8th, 11th etc. $(3n-1)$ harmonics have the reverse phase sequence and are therefore of negative sequence.

Zero- and negative-sequence harmonic voltage distortions may be considered in just the same way as the negative-sequence voltage derived from voltage unbalance. As described in Section 13.8 the negative- and zero-sequence impedances of rotating plant are low, resulting in increased losses and overheating. As the negative-sequence components act in opposition to the positive components this results in reduced torque in rotating plant. Transformers may also suffer from increased iron and copper losses plus increased noise levels. Because the admittance of shunt capacitors increases with

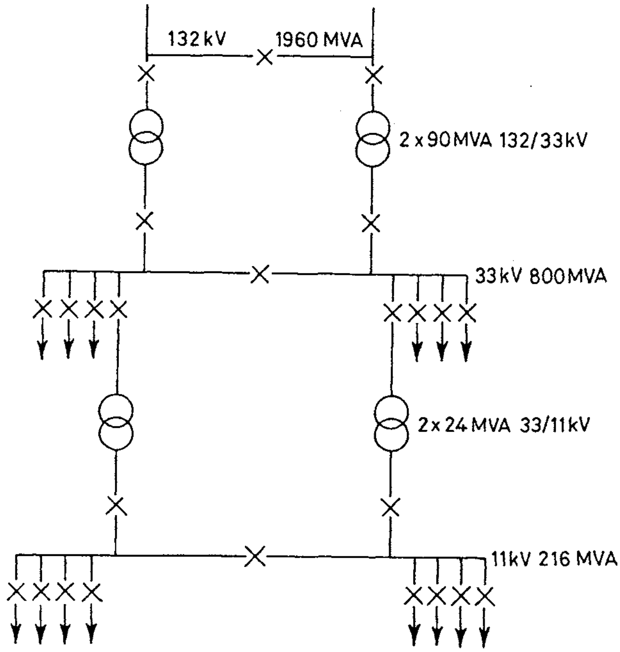


Figure 13.12 Network for impedance/frequency study

increased system frequency, they may become overloaded. It is also possible to obtain a resonance condition in capacitor banks, and if the resonant frequency is close to a harmonic present in the system, large over-voltages are possible.

Figure 13.13 gives the impedance/frequency characteristic for the 11 kV busbar of the network shown in Figure 13.12, measured over the frequency range 50–1000 Hz. The characteristic has the typical 'hill and valley' curve, the

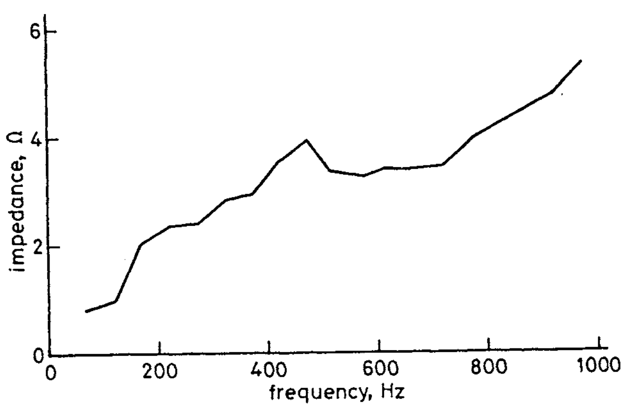


Figure 13.13 Impedance/frequency characteristic for 11 kV busbar in Figure 13.12

peaks being due to parallel resonance occurring within the system and the troughs being caused by series resonance.

In order to reduce harmonics, harmonic filters can be connected into the appropriate MV or LV circuit. Where there are several harmonic-generating loads, each fed by a distribution transformer, it is often more economical to eliminate the harmonics by installing filters at the MV busbar, rather than to have separate filters on the LV side of each transformer. Harmonic-filter arrangements, and their impedance/frequency characteristics, are shown in Figure 12.11.

Reference should be made to Section 12.7.2 regarding the calculation of total harmonic distortion (THD).

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Chapter 14

Computer-based planning

14.1 General

In distribution-network design a large amount of data is required, e.g. information on the present networks, design objectives, cost parameters and possible ways of reinforcement. Complicated calculations are necessary in some cases to optimise network configurations. The use of computers makes it possible to carry out sophisticated network-design calculations. The main aim of using computers here is to improve the quality of routine design.

Common tasks for computer-aided network design are obtaining quantitative information on the status of networks or determining the most suitable future network configuration and the optimum circuit ratings. Computer programs can also act as an efficient tool for long-term planning and the study of more complex aspects such as network reliability.

In practical network design the computer serves as a tool for the designer. Referring to Figure 14.1, many policy decisions such as voltage steps, unit sizes etc. must be fixed beforehand. Also clearly defined data on the existing network configuration and its components, and on feasible solutions, are necessary. The central block, 'modelling of system structure at planning horizon' includes the computer hardware and software, plus the designer's actions. The example in Section 14.6 will illustrate further the planning procedure.

It is usual for computers also to be used for the basic investigations shown in the right-hand column of Figure 14.1, but these are carried out separately from the modelling studies. The network-design programs are preferably integrated with other functions of a utility. It is thus desirable to create a common data bank to cover a large proportion of the information requirements of a utility, and to ensure that it is available to all sections of the utility.

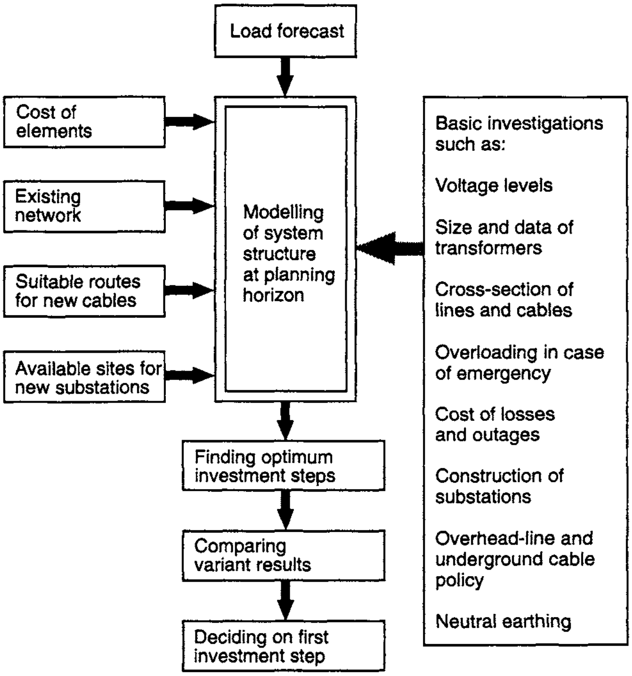

Figure 14.1 Planning procedure (courtesy Dr. W. Kaufmann, TWS, Stuttgart)

14.2 Network information system

14.2.1 General

A large number of commercial applications is now available which can be used for storing network information and carrying out technical calculations. In addition, different utilities may also have their own specifications. In this chapter some general features of these network information systems will be introduced and some special features for two different commercial applications will be discussed.

The network information system is a planning and documentation system for electricity distribution networks typically containing systematically stored technical, economic and location data about existing and planned networks. Its primary purpose is to support the management of distribution systems including the planning, design, construction, operation and maintenance functions. It thus supports a utility's day-to-day operational, and medium- and long-term decision-making processes.

Every distribution network company has some sort of a network information system, even if only a manual type. For different utilities the optimum system is obviously different. It depends for example on the following features of the utility:

- number of customers and area of distribution
- housing density of the distribution area
- history and architecture of computing
- policies of the software houses
- management and organisation.

Owing to the rapid technical development and decreasing prices of computer hardware, new computer applications are being developed and installed at an increasing rate in many fields of business and engineering, and this is especially true for power distribution companies. Power distribution is changing from a monopolistic utility industry to a more competitive business and individual companies compete with each other in the price and quality of supply and service. Distribution companies are being urged to cut their costs and offer special tariffs and new information services. For practical reasons, the network activity (transfer of electricity) still remains monopolistic and regulated but costs must, however, be reduced and the relevant backup information be made available to the government officer 'regulator'. All of these business activities can be effectively supported by an advanced network information system.

14.2.2 Development phases

Alphanumeric systems

By the early 1960s computer-aided record keeping and reporting applications were being used in some power-distribution utilities. The next step was to collect data about the circuits and loads and thus make it possible to calculate radial load flows and fault currents. At first these were separate technical applications but very soon they were combined with the record-keeping systems to develop the first network information systems utilising a common database. Usually these were run in a batch processing mode in the utilities' mainframe computers or in commercial data-processing centres, typically once or twice a year. In some countries like Finland the load information was mainly based on the billing information files, while elsewhere, for example in UK, it was based on measured data.

For technical calculations line node and node pair files need to be established. These define the configuration of the network and include technical information for the various network components. Typically, the outputs of these systems consist of long lists of plant data and calculation results because map information has not been included. Most applications now used in utilities are still alphanumeric and, although the more recent ones are interactive, the lack of graphics limits their flexibility. This type of network information system is often called a facilities management (FM) system.

Automated mapping systems

Computer-aided design (CAD) systems also spread rapidly in the 1970s to urban electricity utilities. In spite of the work 'design' in the title, CAD systems are mainly oriented towards drawing. They provide a flexible tool for producing and handling accurate geographic maps for underground cables. Location information of network components can often be transferred from portable measuring equipment in the field (tachymeter) to the system. This can then be completed from the terminal to include information about the excavation, cable and additional map symbols — see Figure 14.2.

National or municipal ordnance survey authorities often produce various maps in digital form with equivalent CAD systems, and so background maps are quite easily available. With CAD systems views with different scales which are independent of the traditional map sheets can be obtained. Conventionally these systems are separate from network calculation applications. CAD systems which are used for producing digitised maps are often called automated mapping (AM) systems.

Graphic network information system

A disadvantage of FM systems is the poor clarity of the result and the limited possibilities for interactive design. AM systems require an additional and partly parallel database for line and plant information. Thus a strong demand was introduced for integrating FM and AM systems or for developing new network information systems with such features.

Typically, such a system has an interface showing the geographic background and network maps. The display often also includes several windows where alphanumeric information on different objects is displayed. Graphic and alphanumeric data can be updated at the same time and the attributes of different objects can be found by pointing to the object on the screen with the cursor. In addition, these objects may be linked to scanned images such as photographs or drawings. The characteristic of the objects may be different in different views having, for example, a different scale. Numerical results can also be displayed linked to the network map, and different colours in line sections or nodes can be used to indicate, e.g. levels of fault currents or voltage drops.

These systems are often called AM/FM systems or AM/FM–GIS systems (geographic information system).

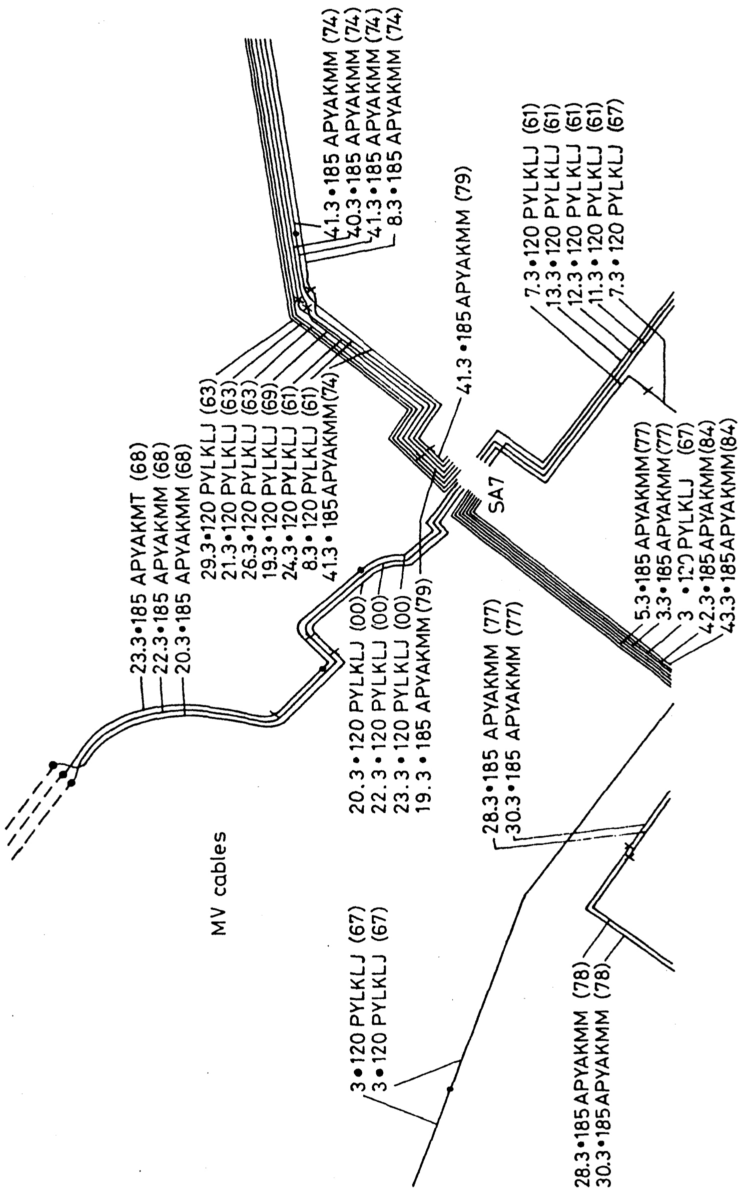

Figure 14.2 Network map plotted by computer (courtesy Helsinki Energy Board)

14.2.3 Information system components

There are many differences in the large number of commercial network information systems which are now available. All of them, however, can be illustrated by Figure 14.3 showing the general principle of database-oriented systems.

A database system consists of a database, a database management system (DBMS) and application programs, and the system also includes the necessary hardware such as the computers, display and printer units plus networks and system software such as the operating system and drivers.

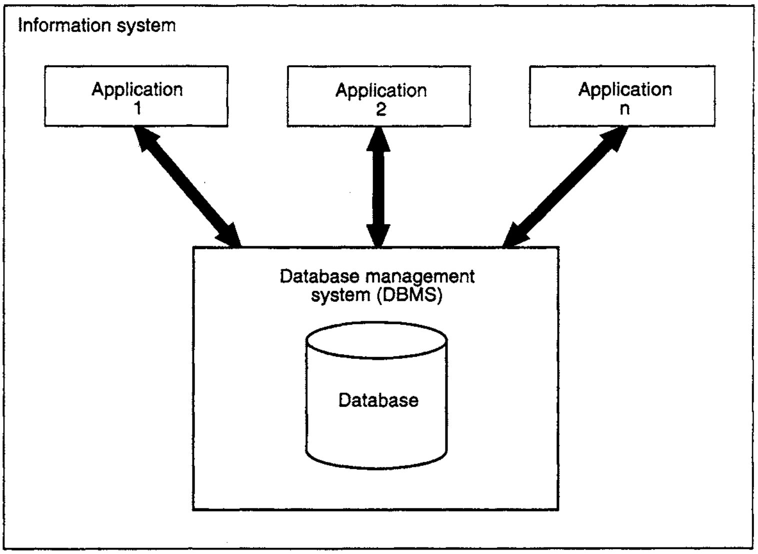

Figure 14.3 Components of an information system

Database

For a utility the database is the most valuable part of the system, since it is the core of the stored and linked data. Physically the database consists of files usually stored on the hard disk. When the system is established or revised the data needed by the user and applications are modelled in a systematic manner, usually referred to as the creation of data models.

Data are stored or updated in the database only once and the same data are available for various applications and users. This is a very valuable feature because it prevents the existence of different parallel updated data. As shown in Figure 14.3, the stored data and application programs are separate from each other. A common supervision mechanism (DBMS) is applied for searching and updating of data.

Database management system

The database software is a general program which is used for managing and handling the data stored on disk. At present the most important class of database software is a relational database. These databases consist of tables and each object in a data model, for example a distribution substation or circuit breaker, can form a table. Links between tables are formed during enquiries. In this way each piece of information is stored in one location only and any set of related data can easily be retrieved simultaneously. The user can make enquiries to the database flexibly by using the Structured Query Language SQL.

Relational databases are flexible as regards revision and developments to the network information system, and are also well standardised which supports data exchange and linking between systems.

Application programs

When using a database system it is possible to apply the same interface program for many applications. This makes the development of applications more efficient. For the user it is convenient when all applications have similar interfaces. When application programs are separate from the data, new applications can be added without necessarily affecting the configuration of the database.

14.2.4 Network databases

Network information systems are often large and complicated and, unlike other data systems in a utility, their essential features are their capability for planning and handling graphic information.

Contents of database

For a utility most of the overall costs related to its network information system are concerned with the establishment and upkeep of its data. The main groups of data are network and plant data, data for day-to-day operation, work information and customer data. They include, for example, data related to the following items:

- construction, location and maintenance of LV, MV and street-lighting networks
- topology and connections between networks and substations
- faults and measurements
- consumptions and loads including load curves for customer groups
- customers and delivery points
- jobs in progress, labour costs and work results
- switching programmes, switching-state changes and measured data.

Links to other data systems

The more usual data systems interfaced to the network information system are shown in Figure 14.4. Each system has its basic data and is responsible for updating its own, and if other systems use the same data it is transferred as copies. The most important data transferred from other systems to the network information system are:

- customer information system: delivery point, customer and consumption
- SCADA: state changes of switches and measurements
- material information system: equipment and standard materials
- economy- and cost-information system: job and cost
- national and municipal geographical information systems: background map with attributes

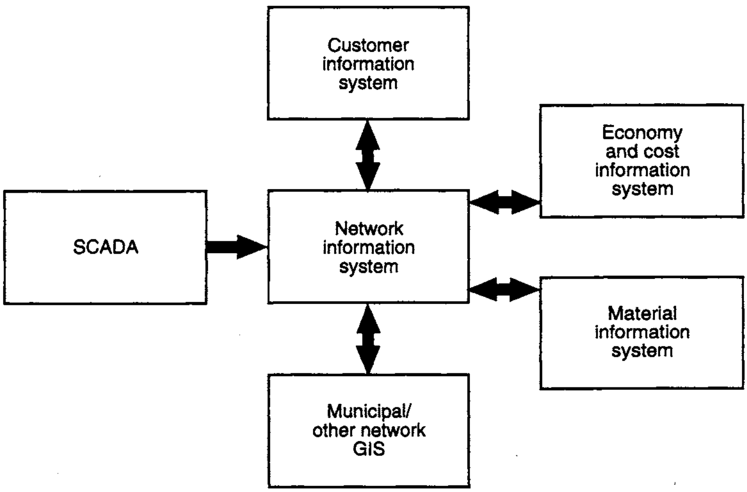

Figure 14.4 Interfaced data systems

Network modelling

Application programs, especially those for technical functions, need network graphics for the user interface, with both maps and diagrams. Different available views may be:

- an accurate 1:250 to 1:1000 location map
- a semi-schematic 1:1000 to 1:10 000 MV and LV network map
- a general 1:10 000 to 1:50 000 MV network map
- a schematic map for operational purposes of the MV network

The above-mentioned semi-schematic map has the accuracy of a few metres as regards the location of equipment. It also shows the configuration and switching state of the network and therefore is often the optimal choice for the interface in planning and maintenance activities. The general MV network map is suitable for the interface in technical calculations and in the management of the switching status, especially outside city areas. Alternatively, the schematic version can be used for the latter purpose.

One way of modelling the network for planning and design purposes is introduced here.

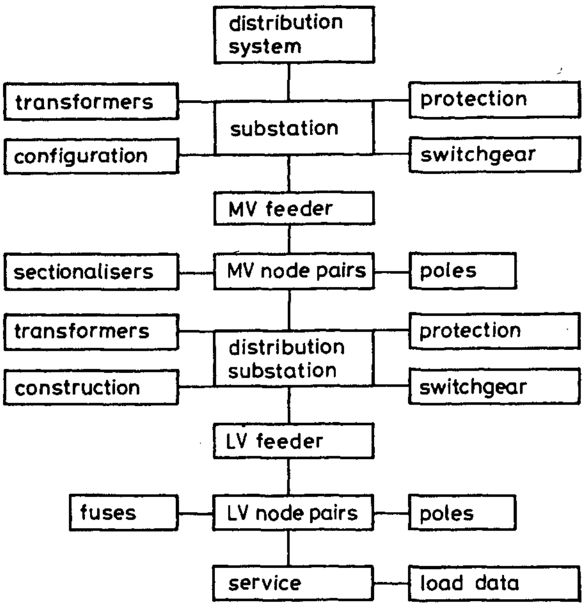

Figure 14.5 Linking of data in a network information system

Network data

The network database includes the following information for each line section of MV and LV networks:

- near and far end codes
- conductor type
- length
- construction data
- pole data
- maintenance and inspection data
- geographic location data

Substation data

- identification symbol (name) of the substation
- serial numbers of the transformers

- busbar configuration
- data on auxiliary systems (telecontrol, protection, compensation etc.)
- construction data
- inspection data
- supporting data for plotting the main diagrams of the substation

Transformer data

For each HV/MV and MV/LV transformer the following data are included in the database:

- location in the network
- manufacturer's serial number and year
- maintenance year
- exact technical specifications (power ratings, impedances, dimensions etc.)

Switchgear data

The node codes in the above network and substation data provide a link to any switchgear records. Here the following data are specified for each device (disconnecter, recloser etc.):

- location in the network
- identification symbol for the device (name)
- type code
- voltage and current ratings
- breaking and making current ratings
- relay settings plus VT and CT ratios
- manufacturing year
- maintenance year
- statistical values (number of operations etc.)
- status of the equipment (closed/open)

Other data

The technical values of conductors, data on all earthing arrangements, on LV cable boxes, and economic data for network design are also stored in the database.

Load data

The loads of the existing customers required for network calculations are transferred from the customer database to the network database. Normally the transferred data include the code for each customer, the annual units and the codes for customer group and tariff. The codes used in the customer database for each customer must be compatible with the network node codes, so that it is possible to connect the loads to the right network nodes.

14.2.5 Database management

Separate databases

AM/FM systems usually have two separate databases: a graphic database and an alphanumeric database. These are linked with each other. When graphic and attribute data of objects are revised the changes are made to both databases (Figure 14.6). Graphic information can be represented either in vector or raster mode (bit map). In the vector mode, for example, a line section can be presented when the co-ordinates of the ends of the section and the line type are known. In the raster mode a figure consists of pixels and their value gives the colour of that area element. Vector data are usually formed by digitising network maps with digitising tables, while raster data are produced with scanners which form a digitised file. In practice after automated scanning some manual adjustments are necessary.

As mentioned earlier, relational databases are popular for storing alphanumeric data. Several suppliers of CAD programs offer interface programs to most commercial relational databases like Oracle and Ingres.

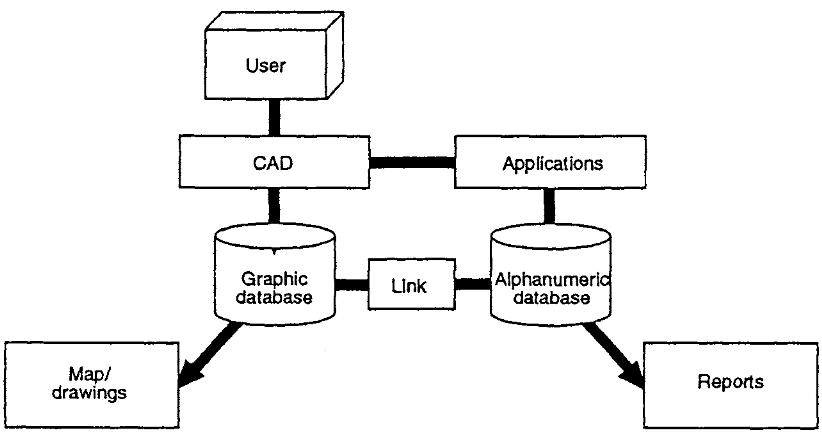

Figure 14.6 Separate databases for graphic and alphanumeric data

A common database

In many of the recently developed network information systems the concept of one common database is applied. Only one relational database is used both for graphic and alphanumerical data. Figure 14.7 shows the main basis of such a system. The database does not usually include, for example, the 1:2000 network map pictures as these are formed outside the database whenever required.

From the utility's point of view a system with a common relational database is useful. Most utilities have the knowledge for operating and connecting new interfaces to a relational database and are thus also able to manage and develop

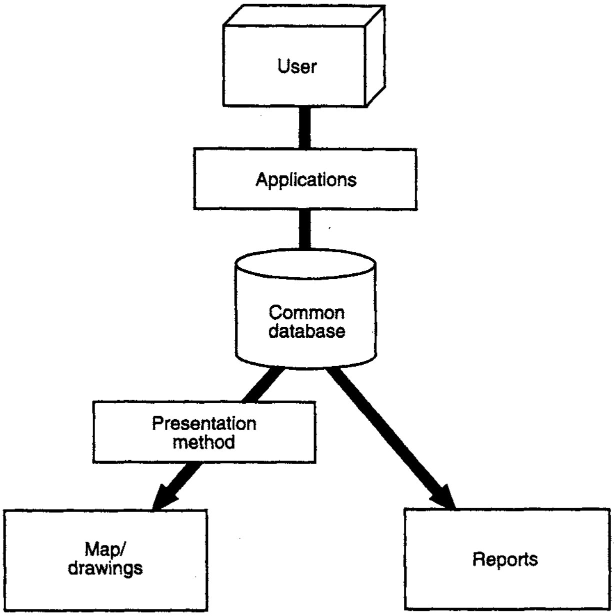

Figure 14.7 A common general database for graphic and alphanumeric data

the above system. The long response time faced earlier with relational databases has disappeared since the performance of computers and the management of the virtual memory have improved. When a large number of application programs have been implemented, even for a smaller utility the database may include hundreds of tables. The size of background map files outside the database may be up to several gigabytes.

14.2.6 Application programs

A modern network information system can include a large variety of application programs which support the management and development of the electricity distribution system and utilise the same database and a graphic interface.

General applications

- maintenance and management of alphanumeric and graphic data
- printing and plotting of maps, schemes, drawings, pictures etc. related to existing or planned networks
- summaries and reports of equipment, annual performances of employees, etc.

General planning

- management of area load forecasts
- generation of horizon-year target networks

- production of annual investment plans
- management of the capacity of the network and setting the development targets
- calculation of various parameters and summaries for the long-term development of the distribution system (e.g. degrees of utilisation of transmission capacities, losses, safety regulations, reliability).

Planning and design

- MV and LV planning (e.g. technical and economical comparison of alternative developments)
- production of documents for network tasks (e.g. basic work data, maps, estimated costs, construction, equipment)
- management of contracts (e.g. land use for lines and substations)
- management of construction standards.

Construction

- opening and co-ordination of tasks
- resource planning and management
- monitoring and reporting.

Maintenance

- management of inspection data
- analysis of maintenance and equipment data
- management of historical maintenance data
- management of the inspection and maintenance work programme.

Operation of the MV network

- operation planning (technical and economical)
- monitoring electricity delivered
- monitoring the switching state
- switching planning
- management of faults (e.g. supporting the identification of the fault location, restoration, collecting statistical data)
- trouble call activities.

An AM/FM-GIS system offers an effective and rapidly developing environment which can be used on more and more new applications and which effectively supports other graphic-related functions of the utility. In particular, the versatile capability for utilising geographic, network-map and substation-scheme information offers many possibilities for design, operation and customer services.

14.3 Network calculations

In an FM system used in the monitoring, design and planning of distribution networks, various results describing either the present or future state of the system are calculated. These results include, for example, power flows, power and energy losses, voltages in the network, fault currents and reliability indices.

In order to calculate these parameters the following network information system programs are used:

- load flow
- fault currents
- reliability

These modules are implemented in the application programs discussed in Section 14.2.6.

When the load flow of a radial distribution network is calculated the Newton–Raphson and fast-decoupled load flow methods, which are used for interconnected transmission systems, are not appropriate. Instead, algorithms developed specifically for solving radial distribution networks can be used involving only algebraic expressions so that the computation time is reduced. In addition, less computer memory is required.

The algorithms applied in radial load-flow calculations are based on equations for the voltage drop in a feeder section. If we consider the feeder shown in Figure 14.8 and use real and reactive power demands instead of currents and angles, the approximate voltage drop equation given in Section 3.4 can be written as

$$V(i) - V(i+1) = \frac{P_t(i+1)R(i) + Q_t(i+1)X(i)}{V(i+1)} \tag{14.1}$$

where $P_t(i+1)$ = total real power demand and losses fed through the node $(i+1)$

$Q_t(i+1)$ = total reactive power demand and losses fed through the node $(i+1)$.

It should be noted that the voltages in the equation above are line–line voltages and that the demands fed through the node $(i+1)$ include the loads of the node $(i+1)$ as well.

From the previous equation the voltage of the receiving end of the feeder $V(i+1)$ can be solved and we obtain the equation

$$V(i+1) = \frac{V(i)}{2} + \sqrt{\frac{V(i)^2}{4} - \{P_t(i+1)R(i) + Q_t(i+1)X(i)\}} \tag{14.2}$$

When the voltage at the substation (the source node) is known, the voltage at the first node of the feeder can be calculated. After this the voltage at the second

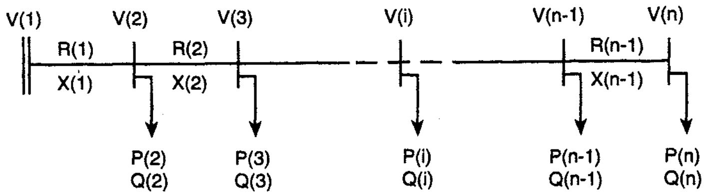

Figure 14.8 Simple radial feeder illustrating the load-flow algorithm

node of the feeder can be calculated, and this calculation is repeated until the end of the feeder is reached. Another part of the algorithm involves the summation of the power demands of each demand node of the feeder and the power losses of each feeder section. For each iteration-corrected values of losses and voltages are applied. Usually the algorithm takes only three to five iterations to reach a satisfactory convergence.

The electrical behaviour of the network is simulated with the aid of a load-flow study, usually for the peak-power-demand situation. The power demands at each demand node of the feeder are needed as input data. Usually only the energy consumption is available for most of the customers, and some method for energy-to-power transformation is needed. Conventionally the Velander formula is applied but the use of time-dependent load models, defined separately as load curves for each customer group, is increasing. When load curves are used the load-flow studies are not limited to peak-load conditions and the contribution of each customer group to the total load can be obtained and entered into the calculations, (see also Section 11.3).

The output from the load flow program consists of:

- real and reactive power flows in each feeder section
- real and reactive power losses in each feeder section (kW/km and kVAr/km)
- load current in each feeder section
- voltage at each node of the feeder.

In addition the sum of the power losses in the whole feeder is provided.

Analysis of fault currents enables the operation of various protection systems to be assessed. Usually the 3-phase, phase–phase, and phase–earth fault currents are calculated. The maximum 3-phase fault current is important for checking the capability of cables, overhead lines and other network components to withstand the fault current. The minimum fault current is needed when checking the sensitivity of the protection. When earth-fault currents in isolated or Petersen-coil earthed systems are calculated the earth capacitance of each feeder connected to the same busbar of the substation must be considered (see Section 3.7.3).

Reliability studies are usually carried out for the MV networks since the main proportion of the outages experienced by a customer is due to the faults in the MV network. They also produce various reliability indexes, such as interruptions/customer/year. For planning purposes it is convenient to measure the reliability of the network with monetary values. The outage costs are thus calculated applying the value of non-delivered energy. Its value is based on customers' opinion of the inconvenience caused by the interruptions. Polling studies have been made about the value of non-delivered energy in various countries (see Section 4.2).

In the network monitoring function of the network information system the load flow and fault currents are calculated for the whole network of the utility. This is usually carried out once or twice a year. The results of monitoring calculations are given as summary sheets indicating, for example, electrically weak segments of the network. Based on these results, further studies are initiated in order to find out suitable ways to reinforce the network.

In the expansion planning of distribution networks the network-calculation modules have two functions:

- to provide the data needed for the calculation of the costs (e.g. power losses for the costs of losses); and
- to provide the data needed for checking that all the technical constraints have been achieved.

In an interactive planning procedure a possible future network is first designed so that the technical constraints are met. After that, the costs are calculated with the plan with the lowest costs being the preferred option. Sophisticated mathematical methods for network planning are discussed in Section 14.4.

The calculation modules can also assist in various operational tasks. If the network information system has a connection to the SCADA system, for example, on-line load-flow studies can be carried out. In an on-line study the current state of the system is simulated so that the calculations made with the aid of load curves are corrected using available measurements. The results can be used, for example, in estimating the effects of switching actions. The calculations needed for these tasks are only possible with the aid of load curves defined for the whole year.

Another important benefit of the connection between the network information and SCADA systems is the real-time information received about the states of switches so that the calculations can always be made using the actual switching configuration.

14.4 Mathematical methods for network planning

In addition to programs for network calculations, a modern network information system often includes modules for distribution network planning. For this purpose interactive design programs may be used, where the main tasks of the program are the calculation of the costs and checking the technical constraints. The design of different possible plans and the comparison of costs is made by the planner. However, in order to reduce the time required for planning and producing economically better plans, efficient optimisation models are needed.

During the last three decades several distribution planning models have been proposed. Very few of them have been successfully applied to practical planning tasks which illustrates well the complexity of the planning and design tasks faced in utilities.

The network planning task can be formulated as an optimisation problem where the object is to minimise the costs while taking into account the technical constraints. The objective function contains not only the investment costs, but usually also

- costs of losses
- costs of outages, and
- operational and maintenance costs.

A part of the constraints is always related to the structure of the network, e.g.

- all loads should be connected, and
- the network should be radial.

The constraints are also used for verifying that the solution satisfies

- safety regulations
- thermal capacities of the network components
- voltage drop limits, and
- operational requirements for the protection.

The planning model can be divided into four categories:

- static load/subsystem
- static load/total system
- dynamic load/subsystem
- dynamic load/total system.

In the static-load models (single-stage planning) the growth of loads is not taken into account, while in the dynamic-load models the loads are time varying and the planning process is viewed in several stages. In subsystem models only a portion of the distribution system is considered (usually either feeders or substations). The total-system approach considers the whole system, i.e. both the substations and the feeders. An exact mathematical model of the planning problem would lead to an extremely complicated model and therefore several approximations are usually made. The most common approximation relates to the cost function describing the total costs of a component as a function of the power flow. The exact form of the cost function is nonlinear, but it can be approximated by a straight line, the tangent approximation in Figure 14.9. This permits the use of efficient linear programming or mixed integer programming methods.

When a linear programming method is applied the fixed costs cannot be taken into account. Therefore the linear underestimate of Figure 14.9 must be used. In

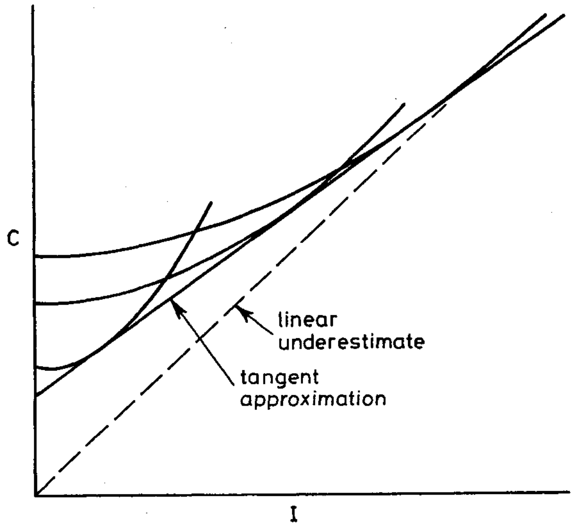

Figure 14.9 Linear approximations for the cost function

the mixed-integer-programming approaches the fixed costs can be included by applying 0–1 decision variables, which indicate the addition of a new substation or new feeder section.

Graph theory has proven to be very useful for the modelling of network planning problems. The distribution network is modelled as a flow network, where the directed arcs represent the power flow in feeder sections and the nodes are either source (substation) or load nodes (see Figure 14.10). The distribution-

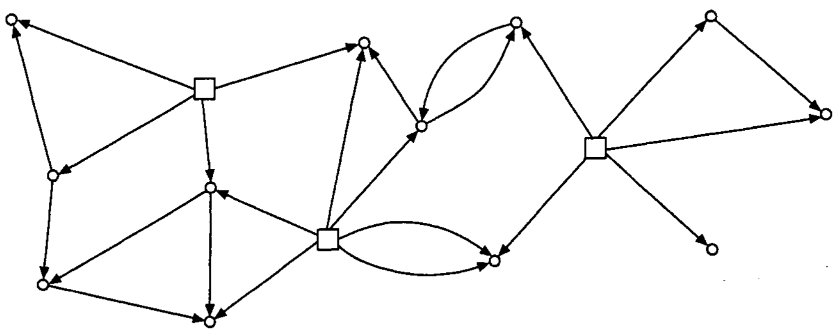

Figure 14.10 Network modelling

□ substation node
o load node
↘ arc (power flow)

network planning problem can now be formulated as a minimum-cost flow problem.

For each arc in the network model a cost coefficient is defined, which indicates the unit costs due to the power flow through the arc, and a linear cost model is applied. If two or more arcs are connected in parallel and in the same direction, a piecewise linear approximation is achieved. Two parallel arcs with opposite directions indicate that two alternative directions are allowed for the power flow in the feeder section. For each arc the maximum capacity is also defined. It describes, for example, the thermal rating of the cables or lines.

For the solution of the minimum-cost flow problem many linear-programming algorithms are available. If the fixed costs are included the model applied is a fixed-charge network problem, for which the branch-and-bound algorithm can be applied. For the planning problem, nonlinear models have also been proposed. They give more accurate results but the computation time is longer. Usually conventional search methods are applied, but the use of genetic algorithms has been proposed as well.

The methods presented above have been developed for static planning tasks. In dynamic planning the timing of network investments must be determined. For dynamic planning a so-called 'pseudodynamic' approach can be applied. In a pseudodynamic approach a static planning model is sequentially applied for each state (year) of the planning period. The result can be enhanced by selecting the possible new facilities in a separate static optimisation procedure where the loads of the last year of the planning period are applied.

However, the pseudodynamic approach does not take into account the alternative investment sequences. The chain of investments covering the whole planning period can be optimised applying dynamic programming. The dynamic programming method efficiently solves problems formulated as multi-stage decision processes. The basic idea is the use of recursion: the optimal decision policy consists of optimal decisions. The optimal solution can be found by applying a recursion formula for each stage of the decision process. The number of comparisons is considerably reduced when each decision is studied separately instead of comparing all possible decision strategies.

For dynamic planning models, a good estimate of the future load growth is essential. However, there is always quite a large uncertainty associated with long-term load forecasts. The effect of this uncertainty can be taken into account by modelling the load growth as a Markov chain, and the resulting dynamic planning model is a discrete-time Markov decision process that can be solved applying the stochastic dynamic programming.

One of the drawbacks of sophisticated optimisation methods is the 'black box' effect: the planner has no idea how the computer reached the solution. This can be avoided by applying interactive planning where the planner can affect the solution process, e.g. by introducing case-specific constraints. Simple heuristic algorithms based on the expertise of planners can also be used. The creativity of the planner can be encouraged by letting him design the alternative network-development schemes, which are then put into the optimisation procedure.

14.5 Examples of applications

14.5.1 Example 1

General

The network information system developed by the Finnish software house Tekla Oy is described below. The utility Espoon Sähkö Oy, which is located west of Helsinki, with about 100 000 customers and sales of 1.5 TWh per year, was chosen for a pilot project having specified its requirements for the new system during a large development project. Similar systems are used in many other utilities in Finland and Sweden.

Even in 1987, when the specification process started in Espoon Sähkö, the main idea was not just to develop a traditional network-information system for documentation and technical calculations for the existing network but also to provide effective support of the daily design-to-construction process and for day-to-day operation matters as well, so that it was necessary to develop a real time link to the SCADA system.

This GIS system consists of a common database with several application programs for planning, design, construction, operation and maintenance. All information concerning the medium- and low-voltage networks including the street lights and special data for the application programs are stored in the same database. The data management is based on a commercial relational database and virtual-memory technology.

Main concepts

For technical functions the interface is based on network maps and schematic diagrams of substations. In maps from 1:2000 to 1:15 000 the configuration, components and switching state of any distribution and street lighting network can be clearly presented. A semi-geographic option is also available for the 20 kV system which is suitable for general planning and for the telecontrol room where the real-time management of switching status is an important function. Various background maps (vector and raster) can be displayed simultaneously with the networks. The schematic diagrams of primary and distribution substations can be opened in separate windows.

Data of various equipment and the schematic diagrams of substations can be seen by pointing to the respective object in the display with the cursor. In addition, scanned photos and drawings can be displayed in windows. The execution of the program is controlled by pull-down menus, icons and digitiser menus.

Both the graphic and alphanumeric data are stored in a common relational database. When starting the session the network data from the selected area are loaded to the main memory. Various logical entities such as feeders are created in the main memory based on the co-ordinates of the objects and the status of the switches. When switches are operated, the configuration is updated in the main memory and only the status of the switches is updated in the database. By using this virtual memory technology, it is also possible to utilise a relational database for real-time applications for power system operation purposes.

Application programs

This network information system includes many of the applications from the list in Section 14.2.6 for the distribution system. Different application programs have similar interfaces and many of these utilise common modules, for example for load-flow and fault-current calculations. Load-curve information is applied for load-flow calculations, simulations, and real time studies for the 20 kV system. Only those applications for the production of network plans and support for system operation will be introduced in the following section.

Network design and documentation

The starting point for this type of design is a work order, for example a request for a new service for a new customer, or for a reinforcement agreed as a result of monitoring calculations, when a project can then be initiated. Often this starts from a general planning study and is completed by documentation being stored after the construction work has been finished so that, overall, the project may be being updated for a number of years. During the various phases of each project, calculations for several options plus many documents are often required. This application program supports the following functions:

- The technical and economic comparison of different possible improvements to the network. The use of load-flow and fault-current calculations and different background maps is relevant for this kind of interactive design.
- Generation of annual and short term lists of projects. These are allocated for different districts, times and planning technicians. Both alphanumeric lists and presentations on various background maps are appropriate here.
- Determining construction requirements, equipment and components. The program offers both construction and material information for the required installation. Data of the material required and ordered are transferred to the material information system.
- Determining the estimated costs and working hours. This includes transferring the basic data for the project to the cost information system.
- Production of the documents for the project including a map of the planned network, construction drawings and project information.
- The final documentation of the project. After the construction work is finished the changed network and plant information is updated to the common database by utilising the information created during the planning process and, if required, photographs and drawings related to the network components can be added.

Network operation

The network information system is connected to the SCADA system by a one-way link so that all changes in switch status and some measurement information transferred from SCADA are obtained in real time. By combining the SCADA and the AM/FM-GIS system a powerful environment has been developed for the real-time management of the distribution system. Some of these functions are introduced in the following.

Switching state management: The real-time switching state of the medium-voltage network is presented on the display of the workstation with the help of dynamic colouring which clearly distinguishes between individual feeder zones and de-energised line sections. A change in the status of any switch causes an immediate re-colouring of the network. The updating of the switching state can be made manually or originate from the information received from the SCADA.

Switching schedules: Switching schedules can be prepared in advance and stored in the database as chains of operations. A work order and a list of the customers who will be off supply is automatically printed for the schedule. Load-flow and fault calculations can be performed at any stage of the preparation.

Fault location: In the event of a short circuit, the system can estimate the likely fault location by using short-circuit calculations. Fault currents measured by protective relays are obtained through the SCADA connection. The estimated fault location is displayed and highlighted in a separate window.

Trouble-call dispatching: The receptionist receiving the trouble calls has access to the customer information. When customers are off supply they are indicated on screen. All calls are saved in the database for further analysis.

Event log: All events are saved in an event log which can be used for reporting and analysis. Outage times can be reported by customer category or component. Reasons for faults, and weather information can be stored for each fault.

Applied computer technology

The software of this network information system is based on GISbase® which contains the programmer's hardware-independent tools for the management of the database, user interfaces, graphics and output. Several operation systems are supported, e.g. OSF1, AIX, HP-UX and open/VMS. The architecture of GISbase utilises general standards and database management systems such as XII/Motif, Ingres and Oracle.

14.5.2 Example 2

This network information system has been developed by the Finnish company Versoft Oy, and is based on the research work carried out at Tampere University of Technology.

The general configuration of this application is shown in Figure 14.11. Only some of its special features such as the method for LV network design and MV reliability calculations are covered here.

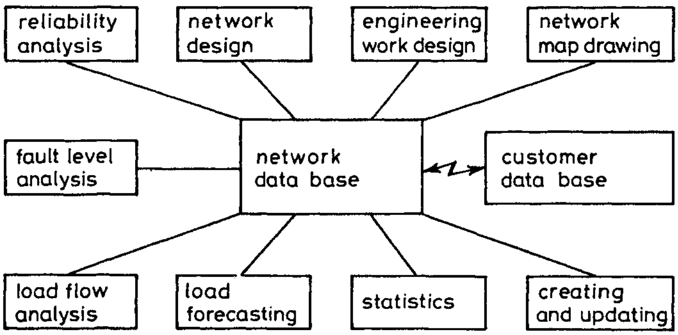

Figure 14.11 Network information system: an example

LV-network design

In this application example, the use of personal computers for LV-system design is considered.

The LV-network design package to be introduced is primarily used to determine the MV/LV substation sites, and in the design of LV networks for new housing areas based on given town-plan development proposals. It can also be used for general network-reinforcement studies in both urban and rural areas. Using the system, the most economic solution is selected from those which are technically feasible, taking into account capital investment and system-loss costs.

The most important technical constraints are component thermal limits and network-voltage drops. Fault currents can be listed in order to check the operating times and discrimination of the various protective devices.

The optimisation program is based on a local-optimisation procedure. The designer can also specify different possible network configurations, so that their feasibility and costs can be assessed. The aim of the study is to find the optimum low-voltage network for the electricity supply to a particular area. By way of example, the substation sites and cable routes available are given in Figure 14.12*a*.

The solution procedure consists of three different parts. First, using all the preliminary selected substation sites, a network is found having a total line length that is as short as possible, but to which each disconnection box or customer is connected (Figure 14.12*b*). This is called the *minimal spanning tree* (MST). Instead of the line length, some weighted function, describing the relative excavation costs for a given area of ground, may be used.

The cable and transformer sizes for the MST network are determined on an economic basis. The first estimate of costs is calculated by adding the costs of losses to the investment costs.

A more economic solution may be reached by transferring the load flow to a suitable new branch, i.e. by adding one of the permissible line sections not utilised in the MST to the network. To retain a radial system some other line section or distribution substation must then be deleted. It is the planner's task to select the suitable branch to be added. The computer chooses the line section to be removed to give the most economical solution.

The total costs are calculated after each cycle of this local optimisation procedure. For each stage, the most appropriate economic cable sizes are used. If the total costs decrease, the new network image is adopted as the starting point for a new cycle of inserting a branch and opening a loop. When no further steps for reducing the costs can be found, this stage is terminated. In the simple example shown in Figure 14.12*c* the result includes only one substation. In general, the problems to be studied are more complex, and thus more transformers are needed.

There is no guarantee that this process will yield the global optimum. The intuition and experience of the planner are therefore important during the interactive procedure. Apart from this local optimisation procedure a 'forced changes action' has also been included. By using this procedure, the planner can form any kind of network configuration so that the computer can dimension the network and calculate the costs. Computer graphics is an invaluable aid in this kind of interactive design.

The third stage of the solution procedure is checking the voltage drop. If the voltage drops are too large, the most economical way of strengthening the network must be found so that it can satisfactorily supply the demands. Reinforcements are made in those line sections whose loads are only slightly below the economic limit, in which case the additional cost of moving to a larger cross-section is small. Other technical restrictions must also be checked if necessary.

The above program can also be used when considering, for example, how to reinforce an existing LV network. Here the alternatives are often either to uprate the existing lines or to divide the network into two or more parts, which then requires the construction of MV spurs and new substations.

LV-network design programs can be used successfully not only for standard types of schemes but also for developing recommendations and providing basic data for projects suitable for manual calculation. Another widely used application covers the provision of electricity supplies to meet local town or city development plans or the space-heating requirements of a new housing area. The program can investigate a number of options to derive the most economic method of providing these supplies based on different development scenarios.

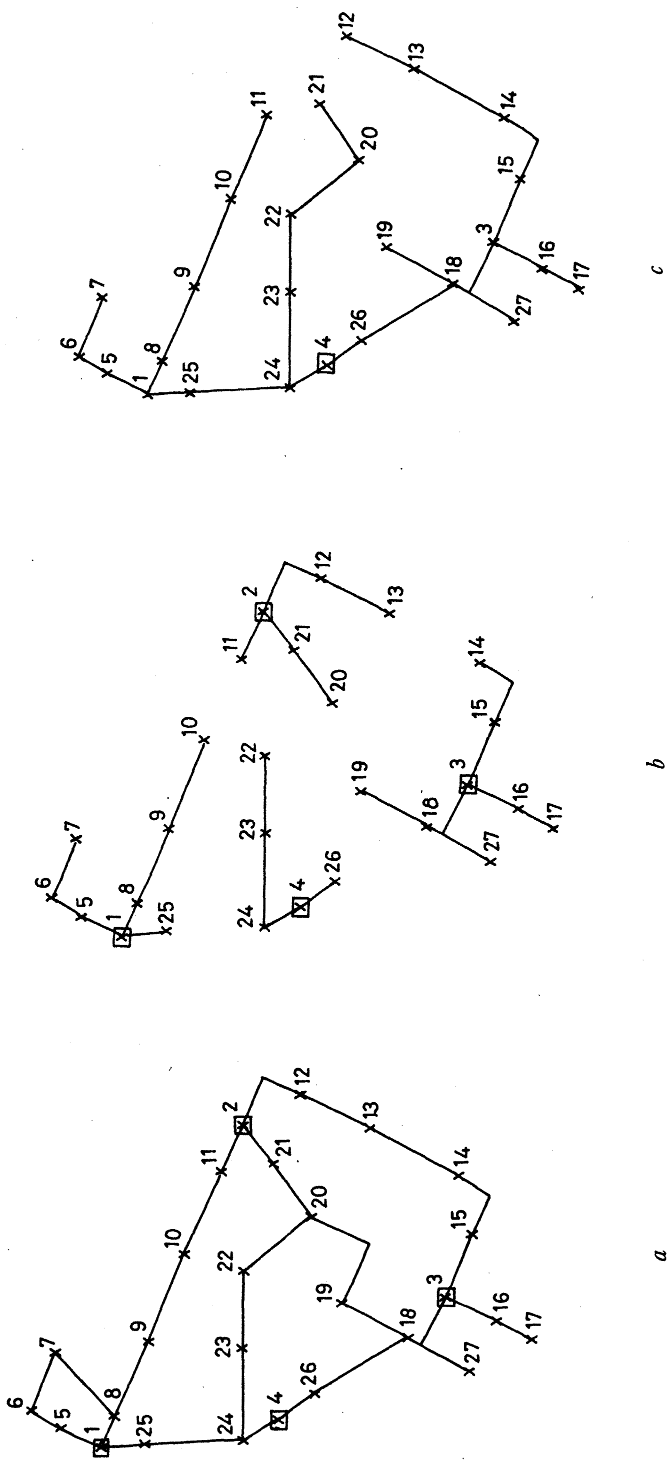

Figure 14.12 Example of low-voltage network design

The following example illustrates the use of the LV-network design program as a part of the system shown in Figure 14.11:

(i) The state of existing LV networks is monitored by the LV load-flow program once a year from network and load information obtained from the central databank. Those feeders which require further investigation, e.g. to assess the cost of replacement due to overloading or high system losses, can than be identified and marked in the summary sheets listing the results of the studies.
(ii) Those distribution substations and LV networks showing some weaknesses can then be studied in more detail using the LV-network design program, again using the network and load information from the databank. Any planned network reinforcements can then be stored in the databank as separate files for future reference.
(iii) The engineering workload and timing of each project are obtained by using the previous files together with an engineering-work design program which produces work instructions and estimated costs for each job, for filing.
(iv) During the construction period all associated costs are collected, input to the program and kept on file, so that at any time the actual costs to date can be compared with the estimated costs as a control feature.
(v) The project plans obtained at step (iii) are updated from information provided during the construction period, and the information in the databank is updated so that, when required, a new network map for the particular area can be drawn via the graphics plotter.

14.5.3 Reliability analysis

A graphic/interactive program is developed to calculate reliability indexes and the estimated value of energy not supplied for each load point, as well as total values associated with a whole MV network configuration. This program is suitable for radially operated networks, and it utilises the same network and load data used by the other MV programs.

The main approach of the analysis is to find the closed and normally open paths from each load point to the feeding points. Based on these, and additional information on the network configuration and component characteristics, the influence of the unavailability of each network component on the unavailability at each load point is calculated. In doing this, the manner in which the protection and system-operation policies, including switching and isolation operations, are actually carried out is taken into account.

The influence of permanent and temporary failures, as well as maintenance outages, can be included in the reliability analysis. The method can also take account of the fact that the cost parameters associated with outages vary with the customer groups and the type of outage (maintenance or failure) at each load point.

Some examples of the results of a reliability study are given in Figure 14.13. The indices are printed for each network separately. Here a section is a part of the network between adjacent isolating devices, and each section may contain several load points. The costs of outages and energy not supplied are also represented for the whole network being studied.

PC-based network information systems are also suitable for planning projects overseas from the main office, using portable PCs. Inexpensive systems now offer an advanced interface for interactive design and map-plotting facilities which are perfectly adequate for rural situations. PC-based design tools can also be utilised in multi-user systems, using a common network database in the server computer.

14.6 Planning example

14.6.1 Data and targets

CAD applications can be effectively utilised in many types of practical planning tasks. However, they cannot normally be directly used to solve the complete problem, but are nonetheless very useful tools for many parts of the planning procedure. Here a typical MV-network medium-term planning example is discussed, based on a real case study in which programs introduced in Section 14.5.2 are used. In order to reduce the length of the example, emphasis has been placed on the planning procedure rather than providing a detailed description of each step.

The existing 110/20 kV substations and the main feeders of the 20 kV systems are shown in Figure 14.14. Some of the technical and economic parameters are given in Table 14.1

Table 14.1 Technical and economic parameters of example

Voltage: 21·0 kV
Power factor: 0·95 (inductive)
Velander constants: $k_1 = 0{\cdot}27$ MW/GWh, $k_2 = 0{\cdot}10$ MW/GWh$^{0.5}$
Interest rate: 10% per annum
Study period: 16 years
Lifetime of investments: 20 years
Fault rate of lines: 0·14/km per annum
Costs of losses: £70/kW per annum
Cost of energy lost due to outages: £1·4/kWh
Maximum acceptable voltage drop on MV system: 5%

STATION = METSAMAA FEEDERS = NIEMI + LAHTI

OPEN ISOLATORS : 508 2031 399 397 2087 418 1111 414
TELECONTROLLED ISOLATORS: 419 420 410

RELIABILITY ANALYSIS

	SECTION	PROT.	DEMAND	AVERAGE OUTAGE RATES				ANNUAL OUTAGE RATES				COST OF OUTAGES			
				SUM	FA	MA	TE	SUM	FA	MA	TE	SUM	FA	MA	TE
		ZONE	KW	1/YR	1/YR	1/YR	1/YR	HRS	HRS	HRS	HRS	£/YR	£/YR	£/YR	£/YR
1	2658	2	80	10.2	3.3	0.4	6.5	2.8	2.2	0.4	0.2	322	227	19	76
2	408	2	94	10.8	3.3	1.0	6.5	3.8	2.6	1.0	0.2	344	231	40	72
3	407	2	55	10.3	3.3	0.5	6.5	3.2	2.5	0.5	0.2	210	148	15	47
4	448	2	66	10.5	3.3	0.6	6.5	3.5	2.6	0.6	0.2	179	124	14	40
5	406	2	281	10.8	3.3	1.0	6.5	4.2	2.9	1.0	0.2	1187	815	152	219
6	405	2	93	10.6	3.3	0.8	6.5	4.0	3.1	0.8	0.2	552	393	53	163
7	404	2	123	10.3	3.3	0.5	6.5	3.6	2.9	0.5	0.2	809	594	53	163
8	403	2	120	10.6	3.3	0.8	6.5	4.1	3.1	0.8	0.2	962	690	102	170
9	402	2	28	10.3	3.3	0.5	6.5	3.8	3.1	0.5	0.2	122	91	7	24
10	401	2	86	10.5	3.3	0.7	6.5	4.2	3.2	0.7	0.2	639	467	61	11
11	447	2	22	10.9	3.3	1.1	6.5	4.8	3.4	1.1	0.2	262	186	37	39
12	400	2	16	10.3	3.3	0.5	6.5	3.8	3.1	0.5	0.2	79	59	4	16
13	2696	2	32	10.7	3.3	0.9	6.5	4.5	3.4	0.9	0.2	222	161	25	36
14	355	2	43	11.0	3.3	1.2	6.5	4.9	3.5	1.2	0.2	264	187	34	43
15	6	3	123	13.7	4.2	1.0	8.5	2.8	1.5	1.0	0.3	845	495	107	242

16	421	3	38	13.4	4.2	0.7	8.5	2.5	1.5	0.7	0.3	136	82	12	43
17	2680	3	103	13.9	4.2	1.2	8.5	3.3	1.8	1.2	0.3	402	233	62	106
18	410	3	169	13.3	4.2	0.6	8.5	3.1	2.2	0.6	0.3	1144	768	100	277
19	226	3	52	13.3	4.2	0.6	8.5	3.3	2.3	0.6	0.3	221	146	17	58
20	354	3	6	13.6	4.2	0.9	8.5	3.7	2.5	0.9	0.3	23	15	2	6
21	409	3	18	14.0	4.2	1.3	8.5	4.4	2.9	1.3	0.3	101	66	13	23
22	398	3	2	13.5	4.2	0.8	8.5	3.8	2.8	0.8	0.3	8	6	1	2
23	1195	3	27	13.3	4.2	0.6	8.5	3.4	2.6	0.6	0.3	217	149	12	55
24	2093	3	9	13.1	4.2	0.4	8.5	3.3	2.6	0.4	0.3	41	28	1	11
25	2092	3	118	13.8	4.2	1.1	8.5	4.3	2.9	1.1	0.3	682	454	88	140
26	419	3	98	13.6	4.2	0.9	8.5	3.4	2.2	0.9	0.3	446	285	48	113
27	416	3	124	13.8	4.2	1.1	8.5	3.8	2.4	1.1	0.3	1172	755	129	287
28	417	3	12	14.3	4.2	1.6	8.5	4.6	2.7	1.6	0.3	49	31	7	12
29	1257	3	159	14.2	4.2	1.5	8.5	4.5	2.7	1.5	0.3	2514	1567	4078	541
30	415	3	108	13.6	4.2	0.9	8.5	3.7	2.5	0.9	0.3	664	435	65	164

COSTS OF THE ENERGY NOT SUPPLIED = 14818 £/YEAR
PERMANENT FAILURES = 9890 £/YEAR
MAINTENANCE OUTAGES = 1685 £/YEAR
TEMPORARY FAILURES = 3242 £/YEAR
AVERAGE DEMAND = 2304 kW
ENERGY NOT SUPPLIED = 8616 kWH/YEAR

FA = PERMANENT FAILURES
MA = MAINTENANCE OUTAGES
TE = TEMPORARY FAILURES

Figure 14.13 Example results of reliability analysis

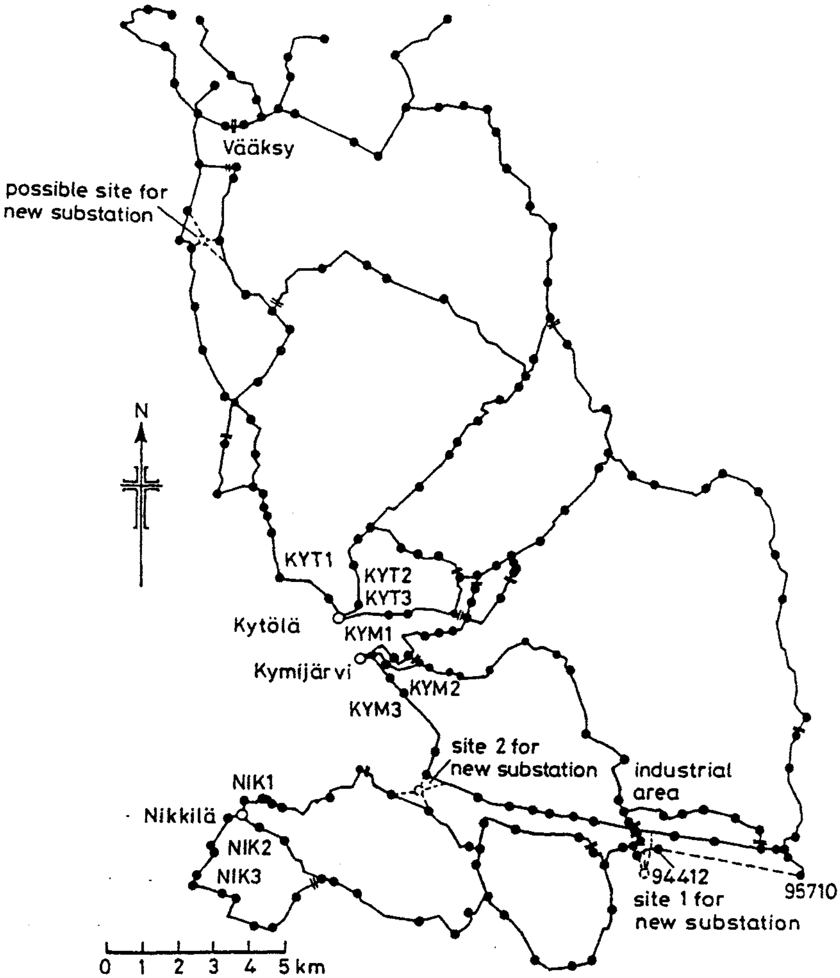

Figure 14.14 Diagram of example network

= open disconnectors
o primary substation
● distribution substation

The southern part of the network shown in Figure 14.14 covers the suburbs of a medium-sized town, while the northern area is rural. The city centre is not included in this survey. The system is fed by three 110/20 kV substations having a total capacity of 60 MVA, with an existing peak demand of 27 MW. The MV feeders are mainly overhead. It is required that various different possible developments of the MV system should be defined and compared, including any requirements for future new HV/MV substations. While overall there is load growth, the level of load varies considerably across the area being studied.

14.6.2 Present situation

With the existing peak load under normal feeding arrangements, voltage drops on the MV system do not exceed the accepted value of 5%, with the exception of the most northerly end of the network where drops of up to 6% can be met. There are a few sections of line totalling about 1 km, where, owing to economic reasons (high cost of losses), the existing conductors should be replaced by larger conductors. All lines can accept the passage of maximum fault currents during relay and circuit-breaker operating times.

When back-up feeding routes have to be used under outage conditions voltage-drop problems occur in the northern sections of the network. If any one of the feeders to the north is faulted, the maximum voltage drop rises to 11% and the associated underground cable at the source end of the feeder exceeds its thermal rating by 20%. In addition, loss of the southern HV/MV substation designated Nikkilä results in poor power supplies in the southerly area.

Studies carried out on the electrical condition of the existing MV network utilised the computer programs introduced in Sections 14.3 and 14.5.2, using the annual units supplied via each MV/LV distribution transformer to provide the load data.

14.6.3 Demand forecasts

Forecasts of annual load growth were based on area activity forecasts (population, jobs etc.) obtained from different local authorities. Owing to various uncertainties affecting load growth, scenarios for a low growth (L) and high growth (H) were produced in addition to the basic forecast (M). The results have been grouped together and converted to annual load-growth values (%) for each feeder, as shown in Table 14.2.

Table 14.2 Estimated annual load growths (%/year) of MV feeders

Feeder	Years 1-5			Years 6-10			Years 11-15		
	L	M	H	L	M	H	L	M	H
NIK 1	4	6	8	2	4	6	1	2	3
NIK 2	4	6	8	2	4	6	1	2	3
NIK 3	4	6	8	2	4	6	1	2	3
KYM 1	3	4	5	2	3	4	1	2	3
KYM 2	6	10	13	5	8	10	3	4	6
KYM 3	6	10	13	5	8	10	3	4	6
KYT 1	6	9	12	4	6	8	2	4	5
KYT 2	4	6	8	2	4	6	1	2	3
KYT 3	6	8	10	3	5	7	2	3	4

L = low scenario; M = medium scenario; H = high scenario

Table 14.3 Future demands for substations

Substation	Present transformer ratings, MVA	Demand MW		
		Year 1	Year 5	Year 15
Kymijärvi	25	9·4	16·6	24·1
Kytölä	15	9·6	17·4	21·6
Nikkilä	20	8·6	13·8	15·2

From the present loads and Table 14.2, the estimated future loads for the existing HV/MV substations were obtained as shown in Table 14.3, using the principles introduced in Section 11.4.

The high-growth areas are due to new housing estates in the centre of the Vääksy parish in the north and the industrial areas in the south-east of the network, and where problems are already occurring following the outage of any circuit. There is thus a need for considerable reinforcement of the feeders supplying these areas.

14.6.4 Development alternatives

Referring to Table 14.3 Kytölä substation will become overloaded in about year 3 or 4. In addition, the previously mentioned problems of feeding the northern and southern-eastern areas during fault conditions will get worse in the future. The main method of reinforcing the network involves constructing a very large number of new MV feeders from existing HV/MV substations.

For this exercise the various development options for the south-eastern area are considered in more detail, while those for the northern area are discussed only briefly. In order to meet the future demands in the south-eastern area, one option would be to construct three or four new MV feeders from the existing substations. Owing to the fairly dense population, new overhead lines were not considered possible. The existing circuits could not be uprated by replacing the existing conductors with larger conductors because of the large size of the conductors already in use on the circuits. A more realistic option is the construction of a new 110/20 kV substation; and the optimisation of its siting, size and timing is discussed in the following section. In spite of the large land requirements for an outdoor substation, plus an HV feeder right of way, such arrangements are often possible outside urban areas — for example, site 1 lies just outside the densely populated area and is thus feasible from a land-usage point of view.

14.6.5 Substation optimisation

Choice of the site

For the new HV/MV substation there are two feasible sites (1 and 2 in Figure 14.14). Their influence on the total cost of the scheme has to be compared, since the cost of the investment involved for the substations and the 110 kV feeder is about £1million. Calculations showed that site 1 was the preferred option for the following reasons:

- The resultant costs of losses and outages are 30% less than for site 2.
- Even when using the high-load-growth scenario, the voltage drops on each feeder will remain below 5%, which is not the case with site 2.
- Site 1 offers one additional back-up route compared with site 2.

Comparisons were carried out using the MV programs of the network information system mentioned in Section 14.5.2. The existing system was modified by inserting the new substation option and its feeders, plus changing the open points on the feeders. These results will be referred to later when discussing the effect of a new substation at site 1 on the MV system.

Economic aspects of reinforcement timing

The new substation results in savings in MV system losses and energy not supplied, which offset the costs incurred in substation and feeder investment. The optimum year for constructing the new substation is when the total annual savings are equal to the annuity of the substation investment. The annual savings in the costs of losses and energy not supplied can be determined by calculating them for the existing network, and then subtracting those calculated for a simulated network which includes the proposed substation. Figure 14.15 shows the savings obtained from substation investment compared with the annuity of substation investment

The annual savings in the cost of losses and energy not supplied for each year and for each of the three load-growth scenarios are plotted in Figure 14.15. Here the horizontal line represents the annuity of the substation investment calculated by using the method introduced in Chapter 5. From Figure 14.15 it will be seen that on a purely economic basis, construction of the new substation is not justified until the later years of the study period.

Electrotechnical aspects of timing

If no reinforcement were made on the existing system, then the 5% limit for voltage drop would be exceeded in the south-eastern area in years 5, 3 or 3 if the low-, medium-, or high-load-growth scenario had been applied. In back-up conditions during faults, the underground-cable ratings would have been exceeded in years 4, 3 or 2, depending on whether the low-, medium-, or high-load growth scenario is considered. Thus reasoning on purely electrical considerations requires the construction of the new substation as soon as possible.

Recommended strategy

If the construction time could be delayed from that dictated by electrical considerations, the result would be more worthwhile economically. The

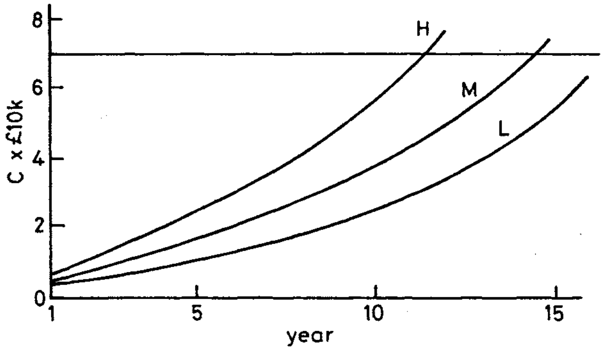

Figure 14.15 *Savings obtained from substation investment compared with the annuity of substation investment*

following options make it technically possible to delay construction for a few years.

- A contract could be negotiated with a neighbouring utility to purchase approximately 1 MW of demand, which is needed for the south-eastern corner of the supply area.
- A 4.5 km-long new feeder could be constructed between nodes 94412 and 95710 (Figure 14.14) and the feeding areas modified. Later this line could be used as a feeder from the new substation. The new substation could also provide additional transformer capacity to limit the loads on the present HV/MV substations, especially at Kytölä.

Effects on the MV system

The new substation on site 1 will offer the following benefits:

- The costs of losses and energy not supplied are reduced, depending on the load growth, by some £30 000 per annum at the beginning, the amount increasing annually by some 10%.
- Voltage drops are reduced.
- Earth-fault currents are reduced (the neutrals are isolated), and thus savings are made in providing earthing systems throughout the MV system.

The new substation will have the following disadvantages:

- High investment costs plus associated work such as new feeders.
- Increased fault level which leads to the need to replace the MV lines listed in Table 14.4, since the old small copper conductors would overheat in a 1 s 3-phase fault.

Table 14.4 MV sections to be reinforced owing to increased fault levels

Line section	Length km	Type of existing line	Type of new line	Fault current, kA
94461-93461	0·80	Cu16	ASCR99	5·5
94461-94360	1·01	Cu16	ASCR99	5·5
94360-97310	3·00	Cu10	ASCR99	4·0
94360-94310	0·50	Cu10	ASCR99	4·0
97310-97200	1·80	Cu10	ASCR63	2·4

Table 14.5 Calculated feeder characteristics in year 15

Feeder	Peak demand, MW	Power losses, kW	Maximum load as ratio of thermal limit, %	Maximum voltage drop, %
NIK 1	6·1	28	35	1·0
NIK 2	1·3	4	10	0·7
NIK 3	5·8	41	74	1·6
KYM 1	2·9	15	17	0·8
KYM 2	2·5	13	32	0·8
KYM 3	5·7	85	33	2·6
NEW 1	2·0	10	15	0·9
NEW 2	7·3	148	42	3·9
NEW 3	5·7	65	52	1·9

Wherever economic, replacement of conductors should be carried out to obtain reduced losses. Table 14.5 identifies the most important electrical factors of each line following the replacements set out in Table 14.4. The parameters in Table 14.5 are based on the medium-growth scenario.

Further studies

This example concentrated on the south-eastern corner of the supply area. The development of a reinforcement plan for other areas would follow the principles used here. The network-development options available for the northern area are construction of new feeders or a new substation. The former proved more economic if a low-load-growth scenario were applied, whereas the opposite applied in the latter case. Thus the recommended development plan would include new feeders at the start of the study period designed so that they could cope with the later construction of the substation. If a higher load growth should occur the policy would need modifying. The choice of constructing the new substation at the start would, however, be financially risky as far too much investment would have already been committed should the load growth turn out to be lower than forecast.

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Chapter 15

Co-operation in network planning and design

15.1 General

A reliable electricity supply is one of the pre-requisites for the modern way of life. The distribution network plays an essential role in providing electricity supplies, requiring large capital investment. In building, or reinforcing, the distribution network a wide variety of problems is invariably encountered, often involving other organisations. For example, an electricity-distribution system has to be planned so that it can be extended into new housing areas at their construction stages. The extension of housing and industry into rural areas may lead to the need for underground networks. The diversion of a minor road can require the resiting of some poles and pole-mounted equipment, while major road works such as motorways can involve considerable diversions or under-grounding of circuits, especially at medium and low voltage but also occasionally at high voltage.

Although electricity supplies are intimately connected with the life style of a community, the supply utility usually has less close connections with the town-and-country planning processes involving these communities. This situation can occur whether the supply authority is nationalised, or a municipal or private organisation. Given the somewhat specialist background of power engineers, it is therefore essential to create links between engineers and all those outside organisations affected by decisions to extend or reinforce electricity systems, so that a suitable level of co-operation is achieved on both existing systems and anticipated future projects.

Although national conditions vary considerably, it is intended that this chapter will provide an introduction to some of these aspects of co-operation with, and by, supply organisations.

15.2 Town and country planning

In each country there are different official organisations which produce forecasts and development programmes involving a wide scope of activities. These cover such items as the numbers of inhabitants, population movement, the numbers of employees in different types of industry, output in each type of industry, plus requirements for public and private transport, schools, hospitals and recreational facilities. These studies are essential to develop long-term programmes for public investments, and their operation and financing. These official organisations have many levels, and various organisational arrangements. Similar levels occur in power-supply planning and again there can be wide differences in organisational practices. However, for simplicity, only three planning levels are introduced here.

Forecasts and plans produced on a *national basis* can assist in generation and transmission planning. By studying these, individual distribution utilities may obtain some idea of the probable national trends of certain key factors; e.g. industrial expansion, consumer spending and the political viewpoints in respect of relative fuel prices. However, these national forecasts are of necessity so broad based that it is often difficult, if not impossible, to assess their impact in the future on local areas in order to provide any guidance on distribution-network design policies.

County- or province-level planning data can more often be used to assist in determining a utility's generation, HV-system and tariff proposals. If such plans include new big industrial developments which may have their own power generation, this can influence decisions on alternative sources for bulk-power purchase. Forecast changes in the distribution of various activities within the utility's area may influence long-term plans for the location of the utility's district offices, in order to optimise network repair and maintenance work, and system operation. Arising from these forecasts, it may also be necessary to start negotiating land requirements for power plants, major substations and HV lines.

At *municipal level* the forward-planning time scale is much shorter, but an MV network can usually be modified with a reasonable degree of accuracy in order to cope with the projected development. When dealing with the development of smaller areas, such as individual villages, the main consideration is suitably extending the local MV/LV networks. At this level there is generally an ongoing consultative dialogue between the municipal authorities and the electricity supply utility to ensure that substation sites and line routes are made available in time to provide the necessary supplies in the right place at the right time. The plans usually include estimates of the distribution of different activities within the area under consideration, which can provide essential data for forecasts of future load levels.

The municipal planning offices usually have detailed maps, and increasingly databanks, showing the location of streets and roads, and individual buildings, recreational areas etc. In some instances they may also have information concerning the location of the equipment of the various utilities, above and below ground, but practices vary considerably. Nevertheless, in the interests of all parties, co-ordination of information is required and this will be considered further in the next section.

It is very important for an electricity-supply utility to have good contacts at all three official planning levels, as well as with individual private companies and contractors, so that the necessary background information relevant to future distribution developments is regularly updated. In practice, it is beneficial to everyone that regular meetings are held so that each side can understand the others' problems. The goodwill thus produced is invaluable in ensuring that the supply organisations have every opportunity of providing the most economic supply to any area, when required, whether in the centre of a large conurbation or in a small rural community. At all levels it is often necessary to work to prescribed formal arrangements, but the informal contacts built up as mentioned above can considerably ease the work load on municipal authorities, private companies and developers, and the supply utilities alike.

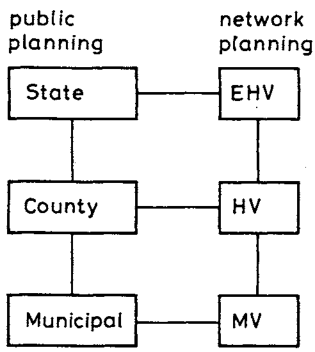

Figure 15.1 Planning levels and their interactions

15.3 Co-operation with other organisations

For its wellbeing a community needs to be provided with a number of service facilities — water, sewers, gas, steam or hot water, telephones and electricity. The first four are invariably located underground, and in built-up areas often all these service facilities have to be placed underground for environmental reasons. Given that each building requires a tapping from most, if not all, of these facilities, the ground underneath most roads and footpaths can contain a number of different services, especially where area trunk services follow the same route as the local services.

The large number of service facilities in built-up areas, particularly city centres, presents many potential problems wherever excavation takes place, for whatever reason. This requires the co-operation of the various service utilities to co-ordinate their work when having to maintain their own service facilities, in order to avoid damaging any of the other service facilities. In some cities large tunnels are constructed so that there is ready access to the various pipes and cables for repair and maintenance.

Various schemes have been developed whereby the service utilities interchange information on the routes of their services. Arising from this, the so-called 'one-call' system originated in the USA where service utilities provide one telephone number which contractors, local authorities, builders and the public can ring to obtain advice, information and supervision from the utilities concerned whenever any excavation is involved, and similar schemes now operate in many countries.

Where national maps are being digitised, this has provided a starting point for the service utilities to input data into a common databank. A method of interconnection between six utilities to a central databank is shown in Figure 15.2. Maps of different scales can be produced showing any combination of the utility services. For a particular work area, a large-scale map can be reproduced on, for example, A4-size paper for use by the work force excavating in that area, to avoid interfering with and damaging any of the services. An extract from such a map is shown in Figure 15.3.

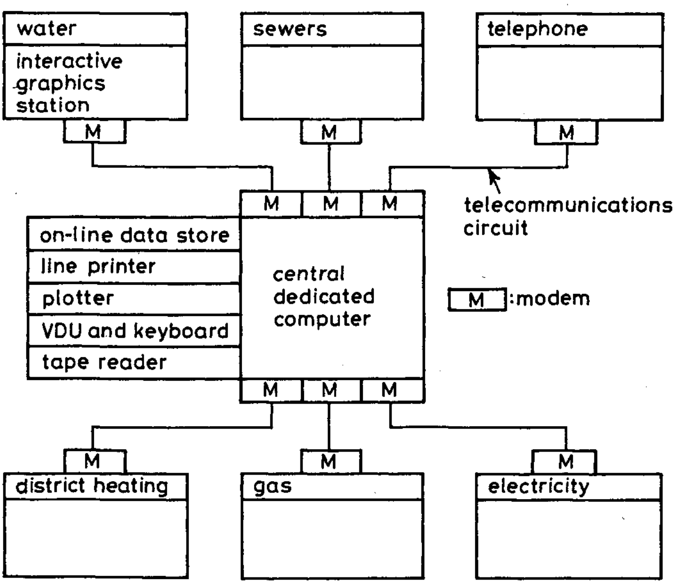

Figure 15.2 Service utilities' co-operation: computer links to databank

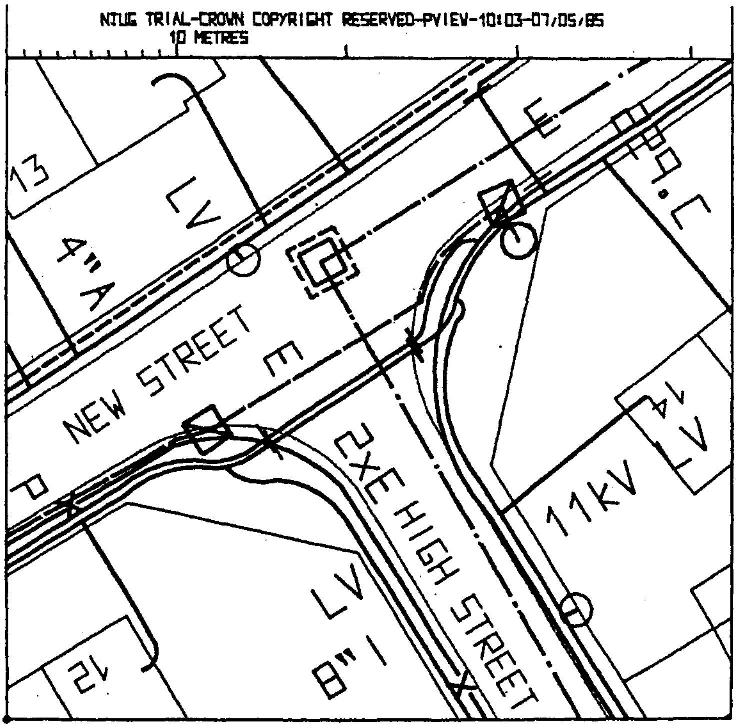

Figure 15.3 *Example of digitised map information (Courtesy National Joint Utility Group)*

Co-operation between neighbouring electricity-supply utilities ensures economic feeder arrangements and inter-utility network connections at the border areas, to the benefit of each utility. In addition, it may be more economic to receive back-up supplies under outage conditions from a neighbouring utility at agreed cross-border energy-tariff rates, rather than reinforce the tail end of one utility's network. A common pool of such items as HV/MV transformers and special maintenance equipment or vehicles can avoid money being tied up in idle equipment. The joint use of training centres and exhibitions, and co-ordinated approaches to provincial and national level administrations, can cut costs and ensure more consistent policies that are likely to be accepted by other organisations. The use of common research centres, equipment testing stations, and working groups to solve mutual problems cuts down on the amount of overlapping work and reduces costs still further. There may also be advantages on occasion for a number of utilities to use a common control centre.

At HV the smaller utility may find it worthwhile utilising the expertise and resources of a larger power board in planning, designing, constructing and

Table 15.1 Contributions and demands on a utility

Group	Contribution	Demands
Owners	Own capital, risk infrastructure for successful business	Return on investment, continuity, influence on society, good image
Customers	Buy energy, pay service charges. Appreciation and acceptance of supply	Reasonable price, high quality of supply, good level of service
Society	Legislation organisational stability	Stable power-supply taxes, low environmental risks, safety, employment
Financiers	Capital from outside the utility	Interest, safety of investment
Management	Organisational skills	Salary, status, managerial freedom
Staff	Work input (skills, techniques, knowledge) co-operation	Salary, status, safety, continuity of employment, working conditions
Manufacturers and contractors	Provide satisfactory appliances and service, good co-operation	Exchange of information
Other distribution companies etc.	Co-operation, specialist knowledge, development work, consultancy and information service	Resources, joint interest in development projects, loyalty, exchange information
Testing laboratories and research centres	Quality control, research results	Input material, financial aid
Universities and other schools	Education and research publications	Training, help with financing, information exchange

maintaining its networks. Co-operation with gas, oil and district-heating utilities may make it possible to reach agreement on areas where one or other of the energy utilities has preference over the others, to avoid uneconomic overlaying of a number of energy distribution networks.

Finance is an important factor in the stability of a utility, and good relationships with banks and finance houses can lay the foundation for preferential loans. During a period of unusually high capital investment, it may be possible to delay repayment until income has picked up. Billing arrangements can often be arranged with banks, and also cut down on utility staffing.

Finally, Table 15.1 briefly summarises the contributions and demands that various groups can make to a utility.

15.4 Amenity matters

From the early days of electricity distribution attempts have been made to minimise the impact of overhead lines and substations on the surrounding environment, as electrical systems developed. Various methods have been used to try to reduce the visual impact by reducing the overall dimensions of overhead-line supports. Promising examples of these are the use of epoxy-resin cross-arms and the use of covered conductors, referred to in Section 6.3. In general, MV and LV lines have a much lower profile than HV lines, and thus do not seriously impact on the rural environment.

The visual impact of a line can be considerably reduced by sensitively routing the line to take advantage of the topography of the countryside. In Figure 15.4*a* the overhead line is badly sited on the brow of the hill, whereas in Figure 15.4*b*

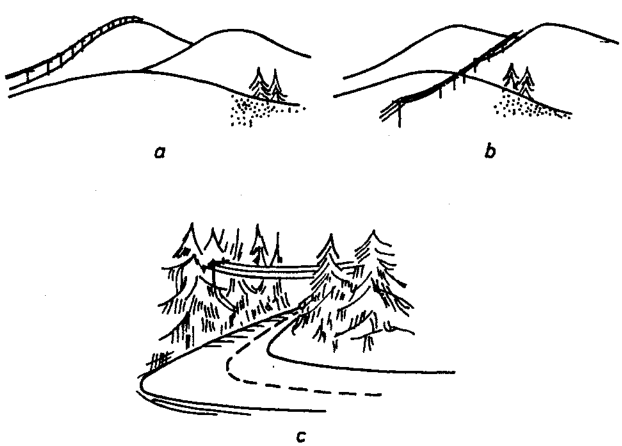

Figure 15.4 Siting of power lines

advantage has been taken of the fold in the hill to conceal as much of the line as possible. In Figure 15.4*c* a 90° crossing exposes the line for the minimum length, with the poles hidden amongst the trees as much as possible. Usually some simple and inexpensive arrangements can considerably improve the visual impact.

Sometimes high additional costs arising from official decisions have to be faced. The increasing trend of local or national government authorities to designate areas of land as National Parks or areas of outstanding natural beauty further restricts available overhead-line routes. The extend to which the UK electricity supply industry is constrained can be gauged from Figure 15.5, which

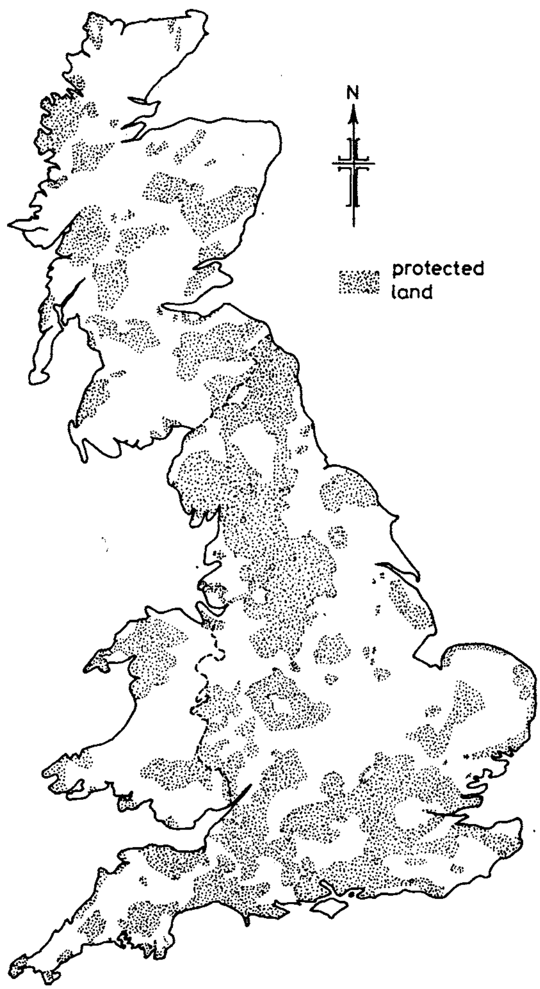

Figure 15.5 Protected land in England, Scotland and Wales

indicates land protected under state or local-authority regulations, including Green Belt areas around conurbations and nature reserves.

Within these areas sometimes the only way of obtaining permission from planning authorities for a route for electricity supplies is to underground a section, even at high voltage, notwithstanding the considerable increase in costs.

When planning authorities request that a proposed new HV line should be underground in a particular area, where MV and LV overhead lines exist already, it may be possible to reach an agreement that these MV and LV lines are undergrounded, more cheaply than HV lines, in order to obtain a right of way for the new HV line.

Turning to MV/LV substations, for economic reasons open ground-mounted distribution-transformer substations are used, even in built-up areas, wherever possible. However, the higher land costs, the development of smaller prefabricated MV/LV substations, plus pressure from municipal planning authorities is leading towards distribution substations being installed within prefabricated housings made of suitable materials to blend into the surroundings. One advantage is that, being indoors, the equipment is then not so much at risk from weather conditions or vandalism. Suitable arrangements must be made to avoid any oil leakage from transformers from escaping from the substation site and causing pollution problems. Costs can sometimes be reduced by converting suitable unused buildings like chapels, churches or warehouses. Larger outdoor substations can be concealed to varying degrees by earth embankments and tree plantations.

The passage of 50 or 60 Hz current through transformers produces mechanical vibrations, caused by magnetostrictive forces in the core resulting in a noise of 100 or 120 Hz being emitted from the transformer. In most situations this small noise is no problem but, especially in cellar installations and sometimes in quiet residential areas, and in the countryside, it can lead to complaints from nearby residents. The problem can sometimes be overcome by changing the unit for a less noisy one, or by installing vibration dampers. Planting of trees around a site reduces the noise level slightly but, for larger substations, it may be necessary to surround the transformers by a brick or concrete wall. Where HV/MV transformers are situated in close proximity to houses it is invariably necessary to install them with noise-reducing enclosures surrounding the transformer tank. The dimensioning of the enclosure, its distance from the tank, and the distance between the inner and outer linings are critical for good noise reduction. Transformer noise can also be transmitted through the ground, dependent upon the local geological conditions.

There has been much discussion and considerable research into any possible health effects from 50—60 Hz electric and magnetic fields. Electric fields are weak owing to the relatively low voltage levels in distribution systems and, in general, magnetic fields associated with MV networks are also low because the 3-phase system tends to balance out the fields from separate conductors. In addition, the normal clearances between a line and an individual person attenuate the field and thus reduce any risk. Although any risks seem to be quite low, some prevention of continuous predisposition to fields above 0·25 or 1 μT is recommended. In public electricity distribution networks the most relevant object for this consideration is the low-voltage busbar of a basement distribution substation. Usually a 4 m distance from the low-voltage terminals to the nearest dwelling room is satisfactory. Alternative means of decreasing the magnetic field would be to shorten the busbars or replace them by a cable.

With the older established lines, at all voltages, housing and industrial development has now surrounded the lines in many areas so that access to the conductors and towers for maintenance and repair can be a considerable problem. Similarly, precautions have to be taken so that access to any substation will not be prevented by local residents, for instance by parked cars. Within urban areas space requirements have been drastically reduced by the use of gas insulated switchgear.

All these amenity aspects place additional costs on a utility. If the requirements are imposed by government, county or municipal authorities then compensation is sometimes possible. However if an MV line were undergrounded to permit an area of land to be developed for industrial or housing purposes, the developer would often be expected to pay all, or part, of the cost involved.

15.5 Manufacturers and consultants

Power-distribution utilities often have their own standards and specifications for equipment, and construction practices which may be more strict than, or equal to, national or international specifications. It is essential that a manufacturer is fully aware of a given utility's codes of practice in the planning, design and operational areas in order to produce a suitable item of equipment. Frank and honest discussions, and the acceptance of prototypes of new equipment at installations on electrical networks, can promote such developments. When deciding on manufacturing standards, or engineering recommendations, a utility should keep in mind the opportunity of using a sufficient number of manufacturers to obtain competitive quotations and a guaranteed continuity of supply of equipment for the future.

Manufacturers will naturally provide advice on their own products and systems. Independent consultancy advice is often useful for new systems or methods, or those based on foreign practices, which may not be familiar to the utility personnel. The use of consultants is also common to provide general advice on various aspects when any electricity-supply scheme or utility is just starting up. In developed countries small utilities tend to use consultants for new items such as the introduction of SF_6 switchgear, or the purchase of a major telecontrol system. Equally, a large distribution utility may use the services of a consultancy firm for a temporary period. This could be to overcome a short-term peak load in work on the planning and design staff. In addition, a general plan for system development by an outside consultant can often bring a new viewpoint to the problem to be discussed with the utility, or reveal errors in the utility's existing planning practice.

15.6 Universities and research centres

In many countries it is common practice for university staff to be invited by utilities to attend 'brain storming' discussions on specific problems, with variable success. Nowadays, in addition to basic research, universities are often capable of carrying out research programmes for utilities on a contract basis. These may deal with new ideas for network automation, the production of suitable CAD packages for network planning and design, and designing an analytical model for equipment such as an induction motor or inverter/convertor installation. Larger projects are often jointly financed from a suitable national fund, in some cases government-based. Post-graduate and career-training courses suitable for practising engineers are also available to upgrade engineers educationally, and/or update their technical know-how. The participation of utility staff not only extends their own capabilities, but also provides a fund of practical engineering experience of information on existing distribution systems, and the problems encountered, for the university faculty members and students.

Unlike research centres or commercial consultants the universities do not usually have permanent personnel for contracts financed by the government. Nevertheless, those universities which undertake contracts and have good liaison with supply utilities usually provide teams for research. They can also provide well structured courses, so that their graduates are more likely to obtain worthwhile jobs with utilities.

Some research centres have independent personnel and specialised equipment enabling them to test new types of equipment being considered for purchase by utilities. In addition to testing to generally accepted standards, they are also able to perform customer-specified tests and obtain information on particular characteristics of the equipment under test. This is of increasing importance in open market conditions, and when utilities are looking towards extending the useful life of their equipment.

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Erkki Lakervi received his MSc from Helsinki University of Technology in 1969. He worked in systems planning and operations in both rural and municipal Finnish electricity supply utilities, before being appointed associate professor at Tampere University of Technology in 1977. In 1986 he was appointed full professor, specialising in power systems and high-voltage engineering, becoming head of the power engineering group in 1987. Lakervi is a member of the IET, a senior member of the IEEE and a member of CIGRE. He has had two books published in Finland on electricity distribution, as well as many papers in Europe and the USA, particularly associated with computer-aided design. His particular interests are in distribution system design and the behaviour of MV insulators in adverse weather conditions. He is also involved in the design of electricity distribution systems in developing countries.

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ISBN 978-0-86341-309-4

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