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economic cost means that systems with different technical characteristics in their choice of voltage and frequency can be interconnected without problems over long distances. This connection may be in the form of a high voltage AC overhead transmission line, as in the case of the England/Scotland interconnection, or it may be a DC link as in the case of the cross channel interconnection with France.

Although three-phase AC overhead lines is the usual method of interconnection between utilities, in cases where long transmission distances and/or sea crossings are involved, 'high voltage direct current (HVDC)' transmission is economic despite the relatively higher costs of convertor and terminal equipment. HVDC transmission is also utilised for interconnecting utilities with different supply frequencies, e.g. 50 Hz and 60 Hz and in cases where an asynchronous link between systems is required. The 'back-to-back' HVDC links in Japan, with both their convertors situated at the same site, are examples of this type of interconnection.

The horizontally separated industry structures are ideal for introduction of competition in generation and supply. This is more difficult, if not impossible, to achieve with vertically integrated structures, especially if they are publicly owned. The attempt by the 1983 Electricity Act to oblige CEGB and area boards to set use of system tariffs giving access to other competitive generation sources to its system has failed to attract new connections, although such tariffs were produced. A similar attempt in France has also met the same fate due to lack of regulatory/commercial incentives and pressures on the vertically integrated company.

1.3 Design of transmission and distribution systems

Transmission and distribution systems are designed to meet four basic criteria:

- economy
- quality
- security
- stability.

An economic system is one where adequate and economic sources of electricity exist and the ability to transmit and distribute power to the customer can be efficiently carried out. The quality of the supply is the extent to which the customer demand is satisfied within the defined quality of supply criteria, e.g. frequency and voltage. The security is the ability of the transmission or distribution network to supply customer demand without interruption under operational conditions leading to the loss of defined components within the system, including generating plant. Stability relates to the ability of the system to return to a stable operational state following faults and disturbances which may occasionally affect the system.

1.3.1 Security of supply

Security of supply criteria is defined at the design stage of transmission and distribution systems. It defines the capacity and flexibility of the systems to maintain supplies under conditions of plant breakdown or equipment outages/failures for a wide range of demand conditions. The main parameters defined within the criteria are the:

- number of simultaneous equipment outages or failures
- magnitude of instantaneous generation/demand losses
- types of faults and their duration prior to successful clearance by protection.

The systems will then be designed and developed such that they would continue to supply the demand without interruption and within defined quality parameters under such conditions. For outages and failures beyond such parameters some interruption or loss to the quality of supply would be expected. The security standard thus determines the overall economics as well as levels of capital and revenue expenditure of the transmission and distribution systems.

1.3.2 Quality of supply

Quality of supply criteria is also defined at the design stage to define the quality of the supply to be maintained in terms of frequency and voltage variations/limits under various normal and disturbed system conditions. In addition, other parameters, such as voltage dips under plant breakdown or equipment outage/failure conditions, negative sequence current magnitudes, voltage flicker limits, phase unbalance limits and repetitive equipment switching limits are also specified as they have a direct bearing both on the design of the transmission/distribution systems as well as connected customer equipment.

1.3.3 Transmission system capability

Since October 1938, the National Grid in the UK has been utilised to allow generation surpluses in one part of the country to supply demand in other parts of the country where there is a generation deficit. In assessing the capability of the system to meet this task, the system designer splits the system into predominantly importing or predominantly exporting areas. The transmission circuits connecting such areas together tend to constitute the weakest links in the systems and thus reflect the capability of the system to accept bulk power transfers. These circuits which link areas together constitute system boundaries. As an example at present

NGC has a zonal allocation of plant and transmission capacity with zones and system boundaries as shown in Figure 1.16.

Three factors can limit the capability of the transmission system to transfer power across a system boundary, namely thermal ratings, voltage and stability, and these are discussed in turn.

1.3.3.1 Thermal capability

The amount of power that can be transferred across a system boundary is limited by the thermal rating of the individual circuits and the way in which the power transfer is shared between them. The 'firm' thermal capability, i.e. the capability after the loss of either one or two circuits, dependent on the chosen security criteria, is usually less than the sum of the individual ratings of the remaining circuits. This is because one circuit usually reaches its rating limit before others due to the resulting unevenly distributed power flows.

1.3.3.2 Voltage and frequency

At times of peak demand it is sometimes necessary to restrict power transfers to a level lower than the firm thermal capability to ensure that satisfactory voltages can be maintained in the importing area, especially under contingency outage conditions. However, at other times the firm thermal capacity will usually apply.

If insufficient plant margins resulting in shortage of system dynamic response occur, it may sometimes be necessary to carry out demand management measures to restore dynamic response capability to manage system frequency within a specified quality of supply criteria. Management of system frequency at minimum demand periods may require

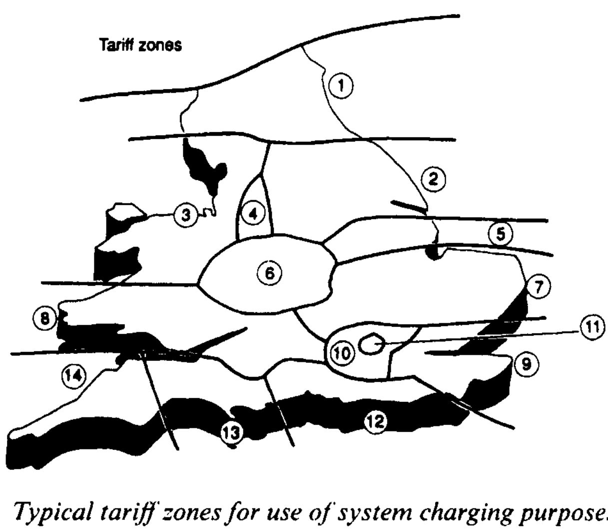

Figure 1.16 Typical tariff zones for use of system charging purposes

rescheduling of more costly generating plant with appropriate dynamic response characteristics in cases where the most economic generating plant is unable to provide the necessary level of dynamic response.

Management of system voltage is critically dependent on the availability of reactive power output from generators and reactive compensation plant installed at critical areas of the system. This output needs to be delivered in response to faults and equipment outages in good time to ensure management of voltage quality within specified limits. The delivery of the response is by automatic voltage regulator action in the case of generators and dynamically responsive reactive compensation plant while other reactive compensation plant responds by automatic or manual switching action. Manual and automatic control of tap-changers on generator and network transformers is also an essential part of establishing and maintaining the system voltage profile.

1.3.3.3 Stability

Power transmission capability between two areas or between a major generating station and the system can be limited by considerations of electromechanical stability rather than by the thermal capability of the connecting transmission lines. Two criteria are usually used to define system stability: 'transient stability', relating to system conditions following severe disturbances, for example a network fault, and 'steady-state and dynamic stability', concerned with the system response to small disturbances such as the normal random load fluctuations.

1.3.3.4 Transient stability

Generators will remain transiently stable if following a large disturbance such as a nearby fault, each generator settles down to a new steady operating condition, i.e. continues to operate at the same mean speed. During the fault the electrical output of each generator will be substantially less than the mechanical power input from the prime mover. The excess energy will cause the generator rotor to accelerate and start an electromechanical oscillation or swing against other generators. Provided that the faulted circuits are disconnected quickly, typically in 80–100 ms, and adequate transmission remains, generator voltage and speed controls will quickly respond and steady operation will be achieved. If, however, the fault persists or inadequate transmission outlets remain, then large cyclic exchanges of power between the generators on the system will occur. This is likely to cause extensive damage to the generators and initiate system break-up through the forced operation of the system protection.

1.3.3.5 Steady-state and dynamic stability

While large disturbances are relatively infrequent in transmission and distribution systems, small disturbances frequently arise as a result of normal load variation and switching operations. These small disturbances cause small oscillations in the power output and terminal voltage to develop between groups of generators within the system. The damping i.e. the reduction in the magnitude of such oscillations is a function of the transmission system design, generator excitation control parameters and technical characteristics of generators and demand. Loss of damping in such oscillations can lead to a continued increase in their magnitude, causing loss of the synchronism between generators.

System transient, steady-state and dynamic stability are assured through the use of:

(i) fast protection systems, which ensure faults do not persist
(ii) braking devices, which provide deceleration to generators immediately after the disturbance
(iii) series compensation devices, which improve the connection adequacy of the transmission system by reducing the system impedance following the disturbance
(iv) shunt reactive compensation devices, which improve voltage levels at selected points on the system
(v) fast generator excitation systems, which rapidly restore the ability of the generator to transmit power following a large disturbance
(vi) fast acting turbine valve controls reducing the mechanical power input to the generator following the disturbance
(vii) use of 'power system stabilisers' on generator excitation control systems and dynamic shunt compensation devices, which improve system damping performance
(viii) fast adjustments to system configuration.

1.4 Operation of transmission and distribution systems

System operation or system management is concerned with the day-to-day operation of a power system. Based on the nature of activities involved four distinct timescales essential to the safe and economic operation of a power system can be identified as follows:

(i) *operational planning phase*, extending from several years down to a few days ahead
(ii) *extended real-time operation phase*, extending from a few days or up to a week to, say, a few hours ahead
(iii) *real-time operation phase*, extending from a few hours ahead to an hour or a few hours after the event
(iv) *post-real-time operation phase*, covering collection, analysis and archiving of data from actual operation, which may extend from a few hours to a few months after the event.

Different organisational structures are needed to manage the planning and operation of a power system. These organisational structures are dependent on the overall structure of the electricity supply industry, defining the extent of the role and responsibilities of the transmission and distribution entity as described in Section 2.2. The overall industry structure also influences the information flows between and within each entity as well as the working methods and practices adopted. The prime objective of operational planning in any organisational structure is ensuring the security of the system in an economical manner by optimal scheduling of constraints such as generation and circuit maintenance outages.

1.4.1 Operational planning

The task of operational planning involves many activity areas to achieve the primary objective, securing the system at minimum possible cost. These activity areas can be summarised as follows.

1.4.1.1 Demand forecasting

Demand forecasting is fundamental to all aspects of predictive system operational planning work. Together with the forecasting of plant availability this provides the basis for all operational planning decisions. Estimates of demand power and energy utilisation for the whole utility, with a geographical breakdown of the demand power estimates down to individual major supply points and time profiles, are essential for ensuring adequacy of generating plant. In addition, estimates of demand power factor or reactive power, with geographical and time profiles, are also necessary for ensuring availability of reactive power resources to achieve a satisfactory system voltage profile.

1.4.1.2 Plant availability forecasting

This is complementary to demand forecasting as it provides the basis for such decisions as plant maintenance programmes, availability of plant capacity and spares. The forecasts are based on judgement from past operational experience, levels of maintenance expenditure, experience on similar plant, age of plant and other commercial/economic factors.

1.4.1.3 Generation and transmission outage planning

Generation and transmission outage plans together with any transmission construction related outages are required both to programme manufacturers, service providers and utility maintenance resources and as input to network security studies. The outage programmes and switching schedules are prepared based on the results of these studies in outline for the longer lead times and in detail for, say, lead times of one year and less. In general the generation outage programme will be the dominant factor, with the transmission outages being arranged such that the overall cost of operating the system is the minimum.

An important end product of operational planning is to provide advice to the control staff on the expected operating conditions with supporting information. Typically this will include for the day/s ahead:

- generation incremental costs/likely merit order
- generation and transmission outage programme
- expected available generation
- expected peak and minimum demands
- preferred network configuration including constraints on power flows and remedial switching in the event of faults
- preferred voltage profile and available reactive compensation resources
- level of dynamic generator active power response required for frequency regulation
- any special operational conditions
- highlights from system security analysis with remedial control actions.

Operational planning is also concerned with providing the control engineer with operational data of a longer term nature.

Fuel allocation and energy modelling: A fuel allocation model may be needed to ensure that fuel is distributed at minimum source plus transport costs to meet the overall economic objectives. This is a transportation optimisation type problem and is normally encountered in an organisation which controls both generation and transmission systems, e.g. a vertically integrated utility.

Protection settings: Although types of protection are likely to have been settled at the planning stage, a review of settings will be needed to determine any changes necessary to meet the requirements arising from any transmission construction and maintenance programme. This review generally includes automatic protective features such as generation and circuit switching as well as demand reduction.

Abnormal operational situations: It is sometimes necessary to prepare contingency plans for possible periods of abnormal system operation, for example interruption in the supplies of fuel, loss of communications, exceptionally severe weather and restoration of supply following a loss of supply. The emphasis in such studies is the determination of the extent to which supplies can be secured and maintained.

Operational standards and procedures: An important operational planning function is the periodical review of past operating experience and the expected system development to determine whether any changes are necessary in the operational standards of security and quality of supply as well as the procedures for operating the system under a variety of circumstances.

Operational planning and real-time control facilities: Experience indicates that the 'Energy Management System (EMS)' and 'System Control and Data Acquisition (SCADA)' systems essential for secure system operation are updated or replaced, at intervals of 5–15 years. The lead time from user specification to commissioning of such systems can extend to 4–8 years. In addition, operational planning facilities are also likely to need enhancement on a more frequent basis all requiring input to user specification and acceptance testing at operational planning timescales.

1.4.2 Extended real-time operational activities

Extended real time is the period from one or two days prior to real time to about one hour ahead. Its function is to complement the operational planning activities by modifying the information received to take account of the changes that have occurred (e.g. in demand level, plant availability and outage conditions) and detailing it to a very high level.

The four main tasks of extended real-time analysis are demand forecasting, generation scheduling, assessment of trading/ancillary services requirements and network security analysis. In each case the level of data required for each task will increase significantly. For example, demand forecasting data is required on a half-hourly basis, generator loading data requires synchronising/desynchronising times with outputs over each half-hour and network analysis data requiring precise details of present network configuration and contingency actions for certain fault conditions.

1.4.3 Real-time operation

The objectives of real-time operation are:

1. Electricity of adequate security and quality at minimum cost is supplied to all consumers.
2. Necessary access to plant and system for maintenance, repair and new construction is safely provided.
3. Effects of any system and equipment faults and/or disturbances is minimised.

These tasks are achieved with the help of the following facilities or systems.

1.4.3.1 SCADA systems

Real-time system operation requires accurate knowledge of actual network topology and power flows. This is provided by the SCADA system. The basic function of SCADA is the acquisition and display of current system information every few seconds. The essential data telemetered from every substation on the transmission/distribution system will include equipment states, power flows, voltages, frequency, alarms for status changes, protection equipment operations and status of operationally important parameters within/outside limits. A hierarchy of displays are used to display this information ranging from block diagrams of the system showing basic operating quantities in geographical areas to system diagrams, substation and circuit operational diagrams and sometimes substation and circuit safety diagrams. Alphanumeric displays of status changes and alarms are also provided with provisions for operator acknowledgement.

Automated monitoring of the telemetered quantities within the SCADA system is essential for checking whether any operating quantities are outside preset limits. This will be additional to and more comprehensive than alarms generated in the substations.

SCADA systems may also include additional telemetered data to enable the remote operation of equipment from the control centre by telecommand. This may include adjustment of starting up of emergency generation, circuit-breaker operation, tap-changing, changing of protective gear status, demand disconnection and reconnection.

Additional facilities incorporated within the SCADA system may include alarm handling and fault analysis to assist in rationalisation of alarm information made available to the operator. This is particularly useful in providing workload relief to the operator under abnormal system operational conditions during emergency operation.

1.4.3.2 Automatic generation and tie-line frequency control

Utilising control signals proportional to the deviation of frequency from nominal and deviation of tie-line flows from target values, respectively, these control systems are utilised to adjust generation outputs automatically such that the frequency and tie-line flows between regions/utilities are kept within specified limits.

1.4.3.3 Generation scheduling and economic dispatch

This is the process by which the output of all plant, whether synchronised or unsynchronised, is determined to minimise the total cost of generation. It is a multiple constraint minimisation problem, although many systems only minimise the cost of generation subject to meeting the total system demand and ignoring the costs of standby and reserve generation. This process should include all system and plant constraints to achieve an 'optimum' solution, which is usually achieved through sophisticated mathematical software.

1.4.3.4 State estimation

This is the process for determining a complete and consistent set of variables representing the state of all transmission system components which provide a best fit to the telemetered data. The process provides essential information for evaluation of system contingencies during real-time system operation.

1.4.3.5 Contingency evaluation

This is a process which evaluates the effects of all potentially critical system outages classified as credible contingencies. The process in its very basic form performs a series of load flows one for each of the outage cases. The resulting power flows and voltages are checked against limits and operator warnings are provided. The contingency analysis will include a procedure to also check system fault levels to ensure safe operation of circuit-breakers within their ratings.

1.4.3.6 Trading and accounting

The control engineer must have the facilities to operate his system so as to fulfil all trading contracts and take advantage of any differences in generation costs between his own and neighbouring systems to undertake opportunity trading. This requires knowledge of marginal cost levels, network flows and unutilised transfer capability, derived from the economic dispatch, monitoring and contingency evaluation facilities.

1.4.3.7 Demand management

This is a set of facilities giving the control engineer the ability to control demand, based on prior agreements made with the consumer(s), so as to reduce the operation of costlier marginal generation or to avoid low frequency demand disconnection relay operation and/or forced disconnection of demand by manual operator action. The main decisions in implementation of load management are when and how much, which are essentially simple decisions in economic and computational terms given the availability of a full set of system operational information.

1.4.3.8 Containment of disturbance and restoration of normal conditions

An essential part of a control engineer's work is to restore the system to a viable steady state after a disturbance. In rare cases, the disturbance may have developed to the extent that demand is disconnected, or the system split or large amounts of generation lost. In this event the first priority will be to stabilise or secure the situation (e.g. to relieve overloads), the second priority to restore transmission preparatory to restoring demand, and finally to restore demand as the build up of system capacity permits.

The task of the operator will be significantly eased by the availability of automatic reclosure facilities on individual circuits and, by sequential automatic restoration of circuit paths through the network. Otherwise the operator has to largely rely on previously evaluated strategies and procedures as well as security assessment facilities.

1.4.4 Post real-time operational activities

The post real-time operational phase is essentially a stocktaking phase where the real-time operational facts and actions taken in response to events are analysed with a view to applying the lessons learned to future operation. The statistics of past operation are the most important source of data for estimating future commitments, requirements and actions. They also provide the raw data by which the transmission/distribution utility management can monitor the efficiency of the utility's technical and commercial operation in delivering the level and quality of electricity supply in an economic manner. A further area of work in this phase is the analysis of system performance, especially during adverse operational conditions and abnormal events, causing losses of supply or forcing uneconomic operation. Analysis of such events, usually through utility staff and external experts, is undertaken to determine recommendations to avoid similar recurrences. Although the operational data collected and in particular the analysis done will be specific to each utility a representative sample is given as follows.

1.4.4.1 Routine on-line data

The on-line data collected may include all or part of that given in Table 1.1. Most or all of this will be usually logged automatically via the SCADA system.

1.4.4.2 Performance analysis

The objectives of performance analysis will include estimation of the efficiency of operation and accuracy of forecasting, plant performance and characteristics, and reliability and quality of supply. The data used

Table 1.1 Routine on-line data collection and analysis

Data	Analysis
Frequency	Number of occasions and duration outside limits
Tie-line flows	Deviations outside set limits
Circuit flows	Flows outside capability or set limits, histograms of line loading
Voltages	Voltages outside statutory or set limits/targets
Generator outputs	Deviations from instructed values, plant flexibility
Demand met	Maximum and minimum demands, demand distribution and profile, sensitivity to weather, frequency and voltage
Power and energy traded	Power and energy traded, loss evaluation, billing information

will generally be from operating statistics and predictive assessments. Table 1.2 gives a sample of performance analysis data.

1.4.4.3 Abnormal operation data

The data for the monitoring and analysis of abnormal operational situations is derived from on-line monitoring equipment, system disturbance recorders, fault recorders and staff reports. The main purpose is to obtain sufficient data on system performance in such conditions to assess plant, protection, control facility or organisational changes that may be necessary (see Table 1.3).

A full understanding of system conditions leading up to and during a major disturbance is especially important for a full understanding of

Table 1.2 Operational data and assessment for performance analysis

Data	Analysis
Demand forecasts	Forecast errors, estimated/actual margins
Generation forecast	Forecast errors, estimated/actual margins
Total system cost	Assessed against actual outturn
Scheduled generation and actual outturn	Additional costs incurred due to plant inflexibility and breakdown
Transmission constraints	Additional generation costs due to constraints
Actual generation and transmission outages	Comparison with scheduled outages, generator and transmission circuit availability
Operational efficiency	Efficiency of the scheduling and dispatch process, control centre and power station performance
Hydro/pumped storage plant operation	Plant loading cycles, savings due to plant operation, forecast/actual operation
Plant flexibility	Two-shifting performance, ability to provide reactive power and frequency response
Instructed load management	Instruction/actual outturn
Frequency and voltage	Quality of supply, deviations beyond statutory limits
Supply interruptions	Compliance with planning standards
Transmission plant availability	Plant breakdown rates/causes, scheduled and unscheduled outages, time to repair
Transmission plant operation	Number of switching operations, operation of reactive compensation plant, plant losses (MW, MWh)

Table 1.3 Data collected and analysis for abnormal operational conditions

Data	Analysis
Protective gear performance	Reliability, maintenance needs, type or installation problems
System response to generation losses	Time response of the system to sudden generation–demand imbalances
Low frequency relay operations Instructed reductions in demand Operation of compensation plant	Reliability of supply, adequacy of planning and operational planning margins, adequacy of capital expenditure programmes, plant response

system performance. This requires the collection of time-tagged system-wide data from telemetered, manually logged and system disturbance and fault recorders. Detailed analysis of all aspects of system operation including load flows, transient and dynamic stability studies can then be undertaken to recreate the progression of the incident.

1.4.4.4 Operational software tools

The complex and demanding task of efficient and secure operation of a power system requires many software tools, often common across the operational and planning timescales. These tools have been developed to aid the decision making process to aid the achievement of operational objectives. These software tools need to be efficient and accurate in modelling the system steady-state and transient behaviour. Furthermore they need to be user friendly with man–machine interfaces, enabling rapid evaluation of output information. The major software tools required are:

- demand prediction
- generation scheduling
- economic dispatch
- fuel and energy modelling
- assessment of generation/operating costs
- assessment of alternative operation methods
- load flows and short-circuit levels
- network configuration and state estimation
- transient stability and protection performance
- steady-state stability behaviour
- longer term dynamic behaviour.

Usually most of these tools are utilised in computing platforms in an off-line mode. However, increasingly tools like state estimation, load flow and transient stability prediction are being utilised on an on-line basis with a clear trend towards achieving real time simulation.

1.5 Future developments

1.5.1 Organisational developments

In recent years, there have been many developments in the electricity supply industry structures throughout the world. These developments have resulted in introduction of many different types of privatised structures including independent power producers, independent transmission and privatised distribution in various combinations based on the historic development of the industry within the specific region or country. Introduction of regulatory processes to introduce competition in monopolistic transmission and distribution and demand for easier access to such systems to take advantage of larger markets and cheaper electricity brought new challenges. The adoption of transparent 'third party access (TPA)' principles resulted in radical changes in the strategies of transmission and distribution companies in the development of their systems. The uncertainties created by the requirements to connect in short timescales and rapid changes in the generation patterns brought about by new connections and plant retirements could only be countered by introduction of probabilistic planning and extensive risk analysis to meet the security of supply obligations.

Environmental considerations have also resulted in increasingly severe restrictions in the construction of new overhead lines, with mounting pressure for the undergrounding of existing overhead lines. Transmission and distribution utilities are being forced to find ways of working their assets harder and finding methods of utilising the 'wires' to a much higher extent. This has resulted in the development of maintenance, asset life management and risk management techniques as well as utilisation of new technologies utilising power electronic devices categorised as 'flexible AC transmission systems (FACTS)' [8].

Managerial structures have also been subject to change moving away those suitable for centrally planned, vertically integrated systems with a pronounced bias on public service engineering, to those suitable for horizontally structured systems, with commercially oriented public ownership. This changing structure transformed transmission and distribution utilities to the vehicles for facilitating competition in electricity supply. These utilities became increasingly subject to legislation and regulation to ensure access on a transparent basis and adequate addressing of provisions to ensure adequacy and security of supply. Together with their unique presence in the public perception the changes in the accountability of public companies has also played an important role in fashioning the management structures of the utility companies. The central business district supply failure in Auckland, New Zealand, has focused attention on the consequences of inadequate governance and failure to adequately specify the responsibilities of newly formed utilities [7].

The organisational concepts developed over the past decade have performed well especially in cases where the definition of interfaces between various utilities have been reasonably well defined and mechanisms to address the technical, financial and trading aspects have been adequately addressed. There is no doubt that further development in refining these processes will need to continue to incorporate the lessons learned from practical implementation. Whilst the pressures will continue to be essentially commercial in their basic nature the successful management of technical requirements will always play a major role in ensuring adequate supply security.

1.5.2 Technical and technological developments

Since alternating current transmission systems won the debate over direct current systems over a century ago, engineers have made efficient use of the AC system to move large amounts of power over great distances with relatively small losses. However, they have been continually challenged with the problem of controlling the power flow, especially during transmission maintenance outage periods as well as in construction/refurbishment outages associated with connecting new generation on the system. The changing generation patterns and the need to ensure better utilisation of transmission assets increasingly require application of reactive compensation devices while the need to ensure the least stranding of assets requires mobility and rapid relocatability of such assets [11]. Increasing use of reactive compensation devices necessitates the development of regional and overall system controls facilitating automatic control of the utilisation of such devices to secure voltage stability and prevent voltage collapse.

The developments in FACTS [8] and HVDC transmission technologies over the past decade offer the transmission and distribution utilities a portfolio of new tools enabling the management of their technical obligations in the security and quality of supply. Application of these technologies alongside the traditional well developed equipment will increase as the above mentioned pressures on utilities increases. These technologies have graduated from the first generation devices utilising mechanical switches and discrete capacitive or inductive components, to second generation devices where the thyristor replaced the mechanical switch, to the current third generation power electronic devices utilising convertor technology alone. As the first and largest fully privatised independent transmission utility in the world, NGC has been subject to the above mentioned organisational and electricity market driven changes. This has meant that every available technology was put to use to address the challenges of facilitating competition and responding to the electricity marketplace. NGC pioneered the use of first, second and third generation reactive compensation devices with ease of relocatability as an essential characteristic. The following is a brief summary of the traditional and new technology portfolio readily available to utilities.

1.5.2.1 Shunt reactive compensation

This is shunt connected equipment either in the form of usually mechanically switched shunt capacitors (MSC) or reactors (MSR) to control the voltage at a particular location on the system. Switching capacitors will raise the voltage whilst switching inductors will reduce the voltage. Utilisation of thyristor switches enables switching of capacitors (TSC) and reactors (TSR) to be accomplished within a few milliseconds in comparison with the corresponding closure time for mechanical switches of some 50 ms.

1.5.2.2 Static VAr compensator (SVC)

These devices are similar to shunt compensation devices, except that the current through the reactor(s) is controlled by thyristors (TCR) and the capacitor(s) is switched in either by mechanical (MSC) or thyristor (TSC) switches, as shown in Figure 1.17 [9]. Through an automatic voltage regulator controlling their output they are capable of providing any amount of reactive compensation within their design limits at a fast response rate similar to generator voltage regulators to control voltage within specified limits at their point of connection to the system. The dynamic reactive support thus provided can yield significant benefits in system voltage control, dynamic stability and increases in power transfer capability. It is also possible to construct these devices in a manner making their relocation within a very short period possible to provide the necessary system flexibility without recourse to stranded assets.

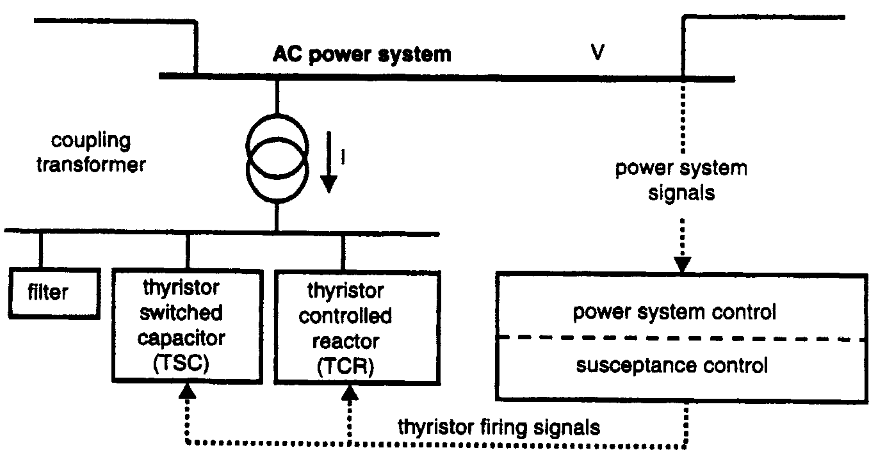

Figure 1.17 Typical static VAr compensator (SVC)

1.5.2.3 Quadrature booster (QB) or phase shifting transformer (PST)

These devices are similar to transformers, but have an additional winding on each phase. The connection of the additional windings is arranged such that they are energised from another phase, thus giving a quadrature voltage injection into the three-phase voltage at a particular location. The magnitude of the quadrature voltage is varied via the tap-changing facilities allowing the control of power flow along circuits and power flow sharing between parallel circuits.

1.5.2.4 Series capacitor (SC)

These devices are large capacitors, sited along the length of long transmission lines which help to reduce the series impedance of a line, thus allowing more power flow through that line. Application of series capacitors requires careful study of network resonances at sub-synchronous frequencies, which may coincide with vibrational frequencies of generator shaft systems to avoid damage to generators under certain network operational conditions.

1.5.2.5 HVDC technology

HVDC technology is utilised where nonsynchronous ties between different utilities or parts of the same transmission system are required. The most obvious cases of this are where the two systems have different frequencies or voltage levels, or are separated by seas. HVDC can also be used within an AC transmission system to deliver power between two regions directly or in parallel operation with AC transmission. Furthermore, AC overhead lines can be converted to DC operation, enabling additional flow of power without the need for reconductoring or installation of new transmission circuits.

1.5.2.6 Thyristor controlled series compensators (TCSC and TCSR)

These devices are formed by incorporating a thyristor controlled reactor in parallel with a traditional series capacitor (TCSC) or series reactor (TCSR) as shown in Figure 1.18 [8]. By dividing the series capacitor or reactor into a number of individual units, coarse control of the amount of series compensation is obtained. The thyristor controlled reactor (TCR) connected in parallel with one or more such units introduces fine control by controlling the current flowing through the shunt connected reactor. The TCSC or TCSR is thus able to dynamically vary the level of series compensation. In the case of TCSC this control can be used to prevent subsynchronous resonance by detuning the network resonance through a controller altering the shunt connected reactor current.

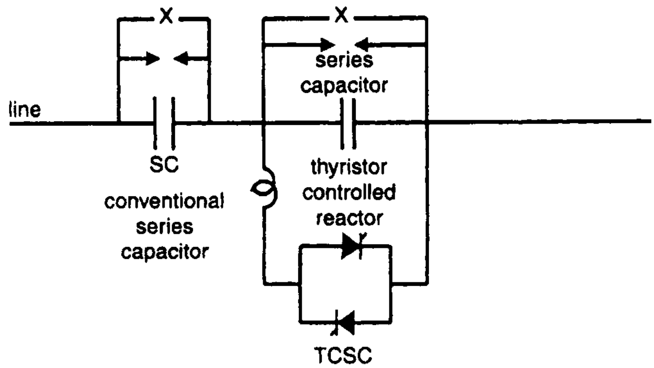

Figure 1.18 Thyristor controlled series compensator (TCSC)

1.5.2.7 Static synchronous compensator (STATCOM)

This is a shunt connected reactive compensation device based on a solid-state synchronous voltage source generating three-phase fundamental frequency voltages whose magnitude and phase angle can be rapidly controlled. Reactive power can be generated or absorbed by changing the amplitude of the voltage source relative to the system voltage. The device is compact as no discrete devices such as reactors and capacitors are used. The control characteristic of the device is similar to that of a rotating synchronous compensator. The response to system voltage changes are, however, very fast as there are no delays other than those involved with measurement of the system voltage. At low system voltages the device continues to supply constant current and thus has a superior voltage support characteristic compared with conventional SVCs, which are essentially constant impedance devices under such conditions. The typical STATCOM configuration and the comparative performance characteristics of both STATCOM and SVC are illustrated in Figures 1.19 and 1.20, respectively [10].

With the connection of an energy storage device in place of the DC capacitor the basic STATCOM is also capable of four-quadrant operation, i.e. supplying or absorbing both active and reactive power to the AC system to which it is connected. This capability is the basis for future power system developments incorporating energy storage technology illustrated in Figure 1.21.

1.5.2.8 Solid-state series compensator or static synchronous series compensator (SSSC)

The solid-state synchronous voltage source forming the basic building block of a STATCOM can also be used to inject a voltage in series into a transmission line to cancel the voltage drop associated with the line

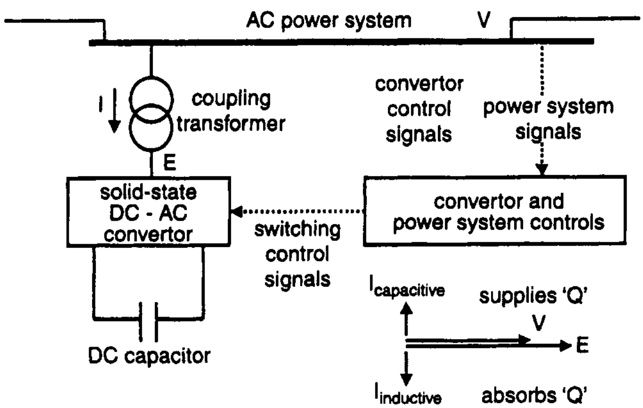

Figure 1.19 Typical STATCOM

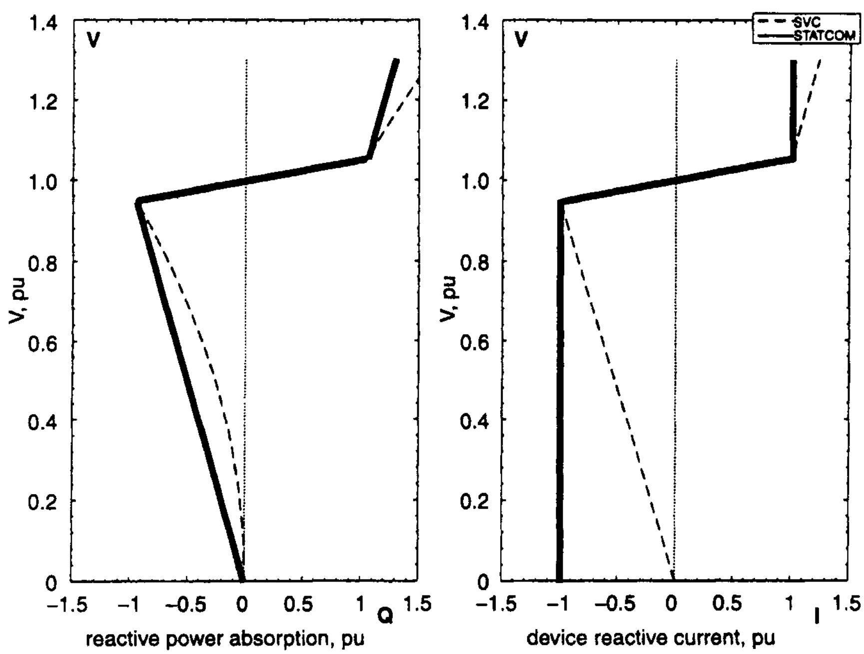

Figure 1.20 Typical V-Q and V-I characteristics of the STATCOM and SVC

impedance. By controlling the magnitude of the injected voltage to be proportional to the line current an equivalent effect to that provided by a series capacitor is obtained. The injected voltage can also be varied such that either the equivalent effect of adding series capacitance or series inductance can be obtained. Since this device achieves the equivalent effect without incorporating discrete capacitors or inductors no sub-synchronous resonance as described in Section 5.2.4 can occur [8].

1.5.2.9 Unified power flow controller (UPFC)

The unified power flow controller consists of a shunt connected STATCOM and a solid-state series compensator which are jointly controlled such that a series voltage which can be varied both in magnitude and phase can be injected into a transmission line as shown in Figure 1.22 [11]. The device is therefore able to continuously vary the mode of the series compensation effect thus achieved, enabling very effective handling of power flows especially during system contingency conditions. Since the injected voltage can be varied both in magnitude and in phase without constraint it is also possible to independently control both the active and

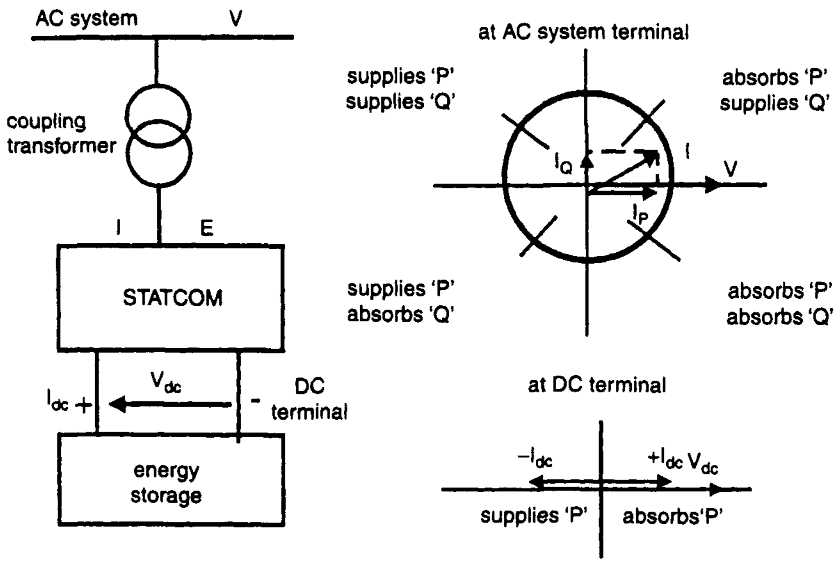

Figure 1.21 Four-quadrant nature of the STATCOM

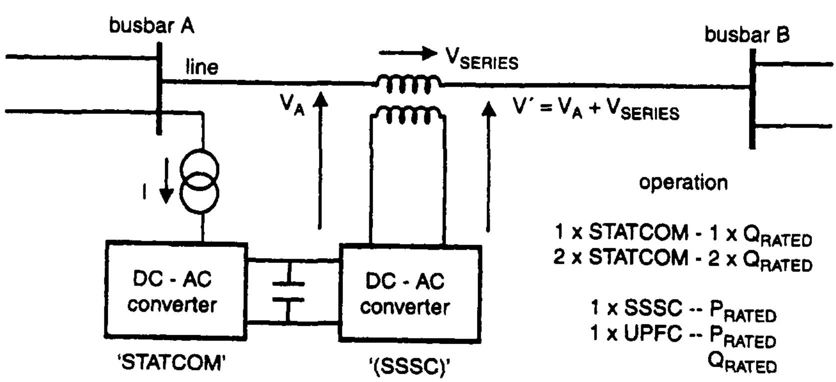

Figure 1.22 Unified power flow controller

the reactive power flow on the transmission line, giving versatility for both steady-state and dynamic stability improvement.

1.5.2.10 Interphase power controller (IPC)
This is a series-connected power flow controller, consisting of inductive and capacitive elements in each phase, which are subjected to separately phase shifted voltages. The internal phase shifts are implemented in a way to give each terminal a voltage-dependent current-source characteristic. By adjusting the phase shifts the level of power through the transmission line can be controlled.

1.5.2.11 Thyristor controlled braking resistor (TCBR)
The thyristor controlled braking resistor is a shunt-connected, thyristor switched resistor usually located at or close to generator output terminals. The device is usually switched in following a fault to control the accelerating power of the generator and switched out when the acceleration is reduced to a preset level, ensuring return of the generator to stable operation.

1.5.2.12 Thyristor controlled phase shifting transformer (TCPST)
This is a phase shifting transformer or a quadrature booster as described in Section 5.2.3 whose output is adjusted by thyristor switches giving a much more rapid change of quadrature voltage and hence phase angle than the traditional tap-changer controlled quadrature booster.

1.5.2.13 Thyristor switched series compensation (TSSC or TSSR)
This compensator consists of a number of traditional series capacitor or reactor banks connected to a transmission line with thyristor switches connected in parallel to each bank. By controlling the switches a stepwise control of the series capacitive or inductive reactance is achieved in a rapid manner.

1.5.2.14 Interline power flow controller (IPFC)
By back-to-back coupling of two static synchronous series compensators (SSSCs), each connected to a different transmission line, it is possible to control the active and reactive power flow sharing between the two transmission lines, as shown in Figure 1.23. This provides great flexibility in system operation by forcing the power to flow to the less loaded lines especially under system contingency conditions [11].

1.5.2.15 Control and communication developments
Increasing use of reactive compensation devices and the need to control voltage and frequency to much higher quality standards is the driving

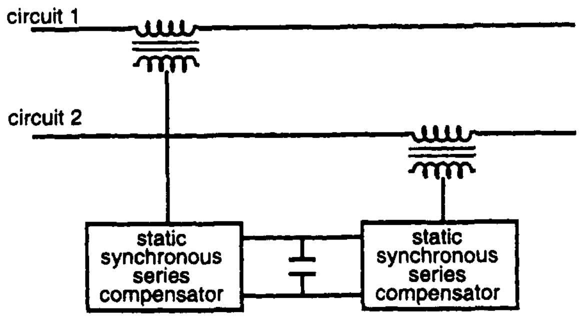

Figure 1.23 Interline power flow controller (IPFC)

force behind the control system developments. At a component level increasing reliability of digital processors has led to almost complete dominance of such devices over the conventional analogue type control systems.

Increasingly the digital control systems being installed for protection, indications, measurements, monitoring and control purposes are being integrated to perform these functions in a single control unit utilising the same system quantities. While this has the promise of savings in terms of installed equipment it requires application of special measures to achieve the same level of dependability obtainable from the existing separate functional arrangements. Lack of formalised standards for digital information exchange between different manufacturers' equipment is likely to hamper progress.

Increasing dependence on reactive compensation devices to achieve better system utilisation creates its own control challenges. In many transmission systems adequate voltage control is no longer possible if the control is based purely on local power system quantities. In addition to the immediate fast primary voltage control response provided by generator automatic voltage regulators in the 1–5 s timescale, an automatic secondary voltage control response based on voltage measurements at a number of points within a specific region is required to ensure stable system behaviour in the 5 s to 10 min timescale. This then needs to be augmented by a tertiary voltage control system ensuring readjustment of target voltages in critical parts of the system at around 10 min intervals.

Use of fast response power electronic devices requires co-ordinated control of a portfolio of shunt and series devices in a manner not only to make most efficient use of full device capabilities but also to ensuring nonconflicting control action between these devices which may lead to unstable system operation. This particular subject area is at present in its infancy, with potential for rapid developments.

Developments in the application of fibre optic based communication technologies have facilitated increasing use of digital control systems as well as increased functional integration of protection, indications, measurements, monitoring and control. There is no doubt that many control concepts hitherto considered too complex and difficult to achieve, such as the remote control of substations, are now becoming a reality thanks to the application of advanced technologies. The new challenge is in management of these systems to achieve the ever increasing performance expectations of society from the transmission and distribution systems.

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