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Power System Operation and Control

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40.1 Introduction

Power system operation and control are guided by the endeavour of the utility to supply electric energy to the customer in the most economic and secure way. This objective is underlined by the fact that the electric energy system is a coherent conductor-based system in which the load effects the generation without delay. Energy storage can only be realised in non-electrical form in dedicated power-stations, so that each unit of power consumed must be generated at the same time. It is therefore necessary to maintain all the variables and characteristics designating the quality of service, such as frequency, voltage level, waveform, etc.

The power system is operated continuously and extends geographically over wide areas, even over continents. The number of generators supplying the system and the number of components contributing to the objective are extremely high. However, the task of system operation is alleviated by the fact that there are not too many different types of component (if the intricacies of power-stations are excluded). In the transmission system the components that are quite easily managed are lines, cables, breakers, disconnectors, bus-bars, transformers and compensators. In the power-stations the generator commonly used is the synchronous machine. The prime mover is a turbine driven by steam or by water. Overlooking the details, there are similarities in the operation and control of turbines and generators that permit a certain uniformity of approach; however, many details have to be considered when it comes to design, failure modes, actual performance, quality of service, etc.

The mechanism of power flow in the system, which is a key issue in all considerations of operation under normal and disturbed conditions, is governed by the Ohm and Kirchhoff laws. Higher voltage at an appropriate phase angle will cause more power flow when a suitable path is available. To draw power from a system is extremely simple: the consumer's load is just connected to a three-phase bus-bar, where the voltage is regulated so that the load can be supplied. The system includes control actions by which the power is allocated to various generators, but there is little interaction in the transmission system.

For economic and secure operation, the actions are quite sophisticated. Control can no longer be performed in a single location by observing a single variable. The control system becomes a multivariable, multi-level system with real-time and prophylactic interventions, either manual or automatic. Thus, the control system is a hierarchical system where the levels and corresponding functions can be characterised as follows.

Decentralised control

(1) In the power-station: control of voltage, frequency, active and reactive power.
(2) In the substation: control of voltage (tap-changer on transformers), switching of lines and cables, protection.

Centralised control

(1) Regional control centre: switching, start-up and shut-down of generating units, unit commitment, reactive power control and load frequency control.
(2) Utility control centre: economic load dispatching, security assessment, load frequency control (automatic generator control), power exchange with other areas, security monitoring, security analysis and operational enhancement.

A hierarchical control system needs extensive communication. Hence there is an extensive telemetering and telecontrol system which provides data to the various control levels and executes control actions at a particular location that have been initiated in a control centre.

The following material is organised in such a way that the objectives and requirements of system operating and control are given and discussed first (Section 40.2): they underline the motivation for the development of modern complex systems. A way of presenting components and subsystems is given in Section 40.3. Data acquisition and telemetering are then treated (Section 40.4) these are prerequisites for power system control.

Decentralised control is divided into *excitation* control (Section 40.5), *turbine* control (Section 40.6) and *substation* automation (Section 40.7), which are the most important control functions at a local level. Pulse controllers for tap-changers are also considered (Section 40.8).

Centralised control is dealt with in Section 40.9, where the hardware and software aspects of computer-based system operation are considered. With the various systems and functions to hand, present-day system operation is characterised in Section 40.10. Changes in the system operation due to liberalised energy markets are also pointed out in the Section 40.11. The new focus on distribution automation and demand side management is touched upon in Section 40.12. Finally, the reliability of system control is considered in Section 40.13.

40.2 Objectives and requirements

The often-cited objectives of economy and security have to be considered in various time-scales and in different system conditions in order to achieve a systematic approach to power systems operation, particularly when computer-based systems are involved. Before we go into details, it should be noted that system operation as considered here is a problem within the framework of a given power system. Planning problems and problems of procuring the primary energy are omitted.

Any objective or requirement is derived from the basic task of supplying electric energy to the consumer with the least expenditure of economic effort, measured over a long period. Hence a variety of cost items and even some intangibles such as environmental effects are involved. These items range from generating costs, losses, the cost of outages and the cost of damages, to risks and the amount of emissions, etc. Stated thus, these items are still too general to be converted immediately into an objective upon which a control function could be built. Different objectives apply for decentralised and centralised control; moverover, within a centralised control system it is necessary to distinguish various conditions to which particular objectives apply.

The most widely used concept for the realisation of a systematic control approach in centralised control is the concept of *states*. A state of the power system is characterised by reserves, by the ability of the system to override a disturbance, by the presence or absence of overloads, etc. The starting point is a series of considerations concerning the security of the system. However, considerations of economy can be easily added.

The four states with some rough characterisations are as follows:

(1) *Normal* (*N*) *state*: the system has no overloads and a good voltage profile; it can withstand a line or generator outage and is stable.
(2) *Vulnerable* (*V*) *state*: the system has no overloads and a good voltage profile; line or generator outage causes

overloads and/or voltage droop; there is a low stability margin.

(3) *Disturbed* (*D*) *state*: the system still supplies its loads, but overloads are present and there is a low voltage profile.

(4) *Emergency* (*E*) *state*: the system cannot supply all of its loads, overloads are present, there is a low voltage profile and part of the system is disconnected.

There are inadvertent transitions between the states caused by faults, human error and dynamic effects. However, control actions will return the system to the normal state. A thorough understanding of system operation will show that appropriate objectives and corresponding control functions will effect this return in a logical manner. These mechanisms are illustrated in the schematic of *Figure 40.1*, which shows (upper part) a state diagram with various transitions. The lower part of the figure gives transitions associated with a number of objectives. These pertain to control actions only. It is clear that the objective of full load coverage has to be met first before the vulnerable state can be reached. Further, all vulnerable conditions have to be eliminated before economic dispatching can be initiated.

At the decentralised level the objectives are much simpler and easier to understand. A state concept is not necessary since the objectives are expressed in terms of errors or time sequences in a straightforward manner. As an illustration, let us consider protection and excitation control.

In protection the objective is to keep fault duration or outage to a minimum. The fault itself cannot be avoided, but the adverse effects, possibly leading to a disturbed or emergency state, can be. Thus protection supports the aim of security on the decentralised level.

Excitation control maintains the voltage at a given location of the system and supports the stability. It is the stable voltage, with all its implications, that is at stake. A stable voltage is a very important prerequisite for system security. For its realisation many detailed considerations are required since it is system dynamics that determines the performance of excitation control. Beyond that, an excitation system has many monitoring functions, i.e. limit-checking and even protective functions. The objectives of decentralised control, which become recognisable in terms of set-points, time periods and the like, must be co-ordinated. This co-ordination is performed either in the planning or operational planning phase (e.g. for protective relays), or in real time (e.g. for economic dispatching).

In power system operation and control it must be recognised that the control functions have a certain time range in which they are effective. Thus the corresponding objective has its validity within this time range only. As *Figure 40.2* shows, there is a complete hierarchy of functions ordered in terms of their effective time range. This hierarchy in time is also responsible for the functional hierarchy of the control system.

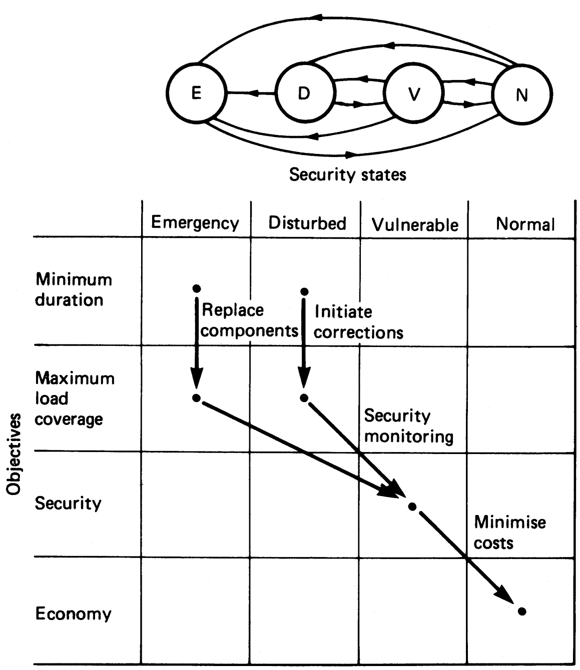

Figure 40.1 Security states and objectives: state diagram (above) and controlled transitions (below) following given objectives

40.3 System description

In describing an electric power system we must distinguish the network (responsible for transmission and distribution) and the generating stations, as well as the loads.

The network is amenable to description by topological means such as graphs and incidence matrices as long as the connection of two nodes, by a line or cable, is of importance. Thereby it is implied that the connection is made by a three-phase line which is itself described by differential equations. This topological description is always inherent and necessary. In routine work, however, it may not always be obvious what the true background is. Hence it is worthwhile to consider these topological means as a starting point.

Graphs and incidence matrices are equivalent and describe the way in which nodes are connected. A graph is a pictorial representation, whereas the incidence matrix is a mathematical formulation which can be interpreted by a computer. An example will illustrate the correspondence between these two descriptions. *Figure 40.3* shows a graph derived from an electrical network. The connections between nodes have been marked by arrows; this fixes the way of counting and thereby orientates the graph. *Figure 40.4* is the incidence matrix corresponding to the graph. The way of counting is indicated by the sign of the entries. Both the graph and the matrix describe the same network. The graph, however, is much easier to grasp.

The incidence matrix is the base for two processes, both of which are important for systematic description. The first is the reading of network data, wherein the way in which lines are connected is already implied. The second is the establishment of admittance and impedance matrices.

Consider the graph in *Figure 40.3* where the nodes have a particular numbering. This numbering permits the specification not only of a connection between two nodes but also of the type of connection. Assume that the connections consist of simple series impedances. Then the following description, which is machine-readable, is possible:

Connection	Impedance	Connection	Impedance
1–2	$0.05+j0.68$	3–6	$0.06+j0.75$
2–3	$0.06+j0.75$	3–5	$0.03+j0.35$
1–4	$0.03+j0.35$	4–5	$0.04+j0.50$
1–5	$0.04+j0.50$	5–6	$0.05+j0.65$
2–5	$0.05+j0.70$		

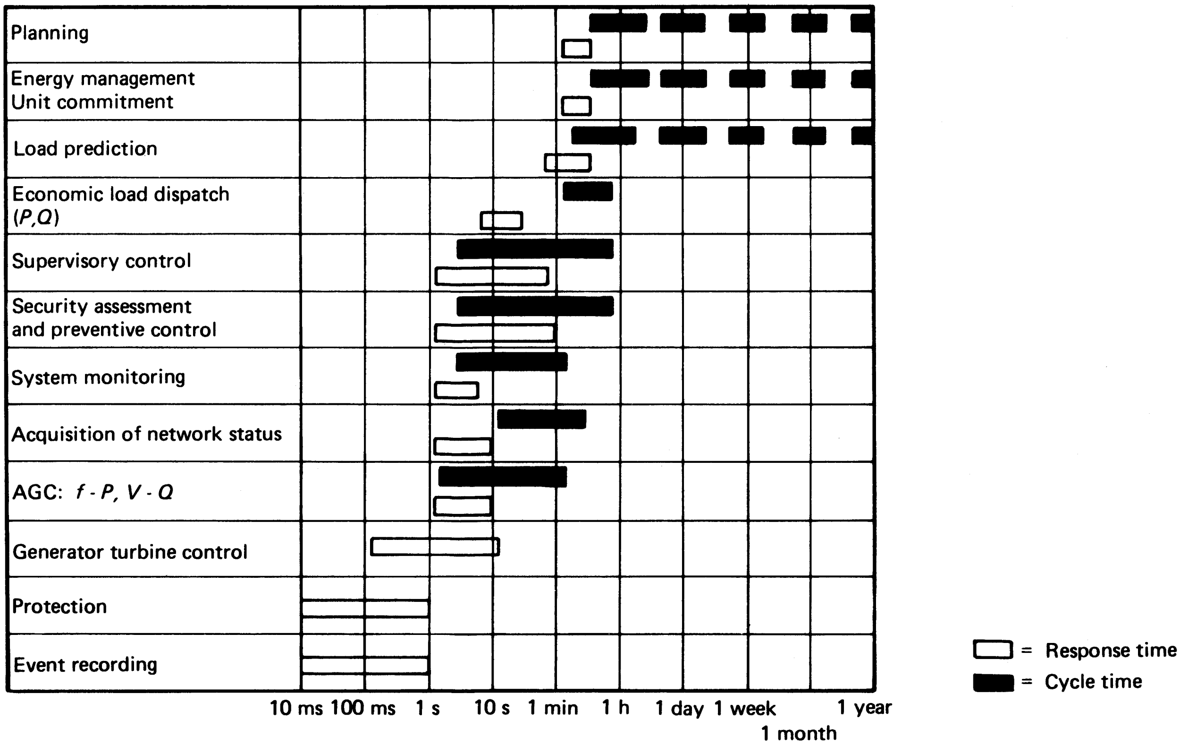

Figure 40.2 Response times and cycle times for plant management, monitoring protection and control functions. AGC, Automatic generation control; *P*, active power; *Q*, reactive power; *f*, frequency; *V*, voltage

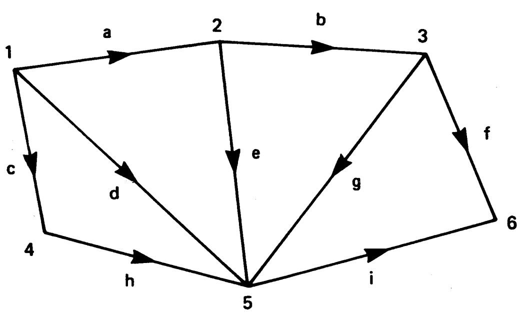

Figure 40.3 Oriented graph describing the structure of a six-node network: 1–6, nodes; a–i, lines

The first column specifies the nodal connection, the second the complex impedance. Each line of the list corresponds to a connection or a line of the network.

The generation of the nodal admittance matrix can be explained by a multiplication of the primitive admittance matrix $_{p}$(diagonal matrix) by the corresponding incidence matrix and its transpose from left and right respectively:

$$Y = A^{T} Y^{pA}$$

The nodal admittance matrix contains all the information necessary (topology, impedance) to describe the network.

Loads and generators are connected to the nodes of the network. The description of the nodal constraints depends on the way the network is employed in an analysis or decision-making process.

	1	2	3	4	5	6
a	+1	−1				
b		+1	−1			
c	+1			−1		
d	+1				−1	
e		+1			−1	
f			+1			−1
g			+1		−1	
h				+1	−1	
i					+1	−1

Figure 40.4 Nodal incidence matrix **A** corresponding to the graph in *Figure 40.3*. The matrix establishes relationships between line and nodal quantities (currents and voltages). The arrow leaving a node determines the positive sign of the entry (+1)

For the purposes of load-flow calculations the specification is done in terms of *PQ*- or *PV*-nodes, where *PQ* means that the active power *P* and reactive power *Q* at the node are constant (i.e. independent of voltage), and *PV* means constant active power and constant voltage.

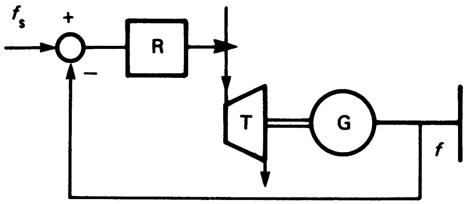

Figure 40.5 Schematic diagram of a generator and a speed governor: G, generator; T, turbine; R, regulator/speed governor; *f*, measured frequency; f_s, set-point of frequency

For dynamic analysis more complex models for the nodal description have to be added. On the load side, the frequency dependence or, if necessary, a set of different equations is needed. For the generating unit, differential equations are comprehensive, but not always transparent. Hence, a block diagram is used to specify forward and feedback paths, wherever appropriate. As an example, the signal flow and the generation of torque within a turbogenerator are given by the block diagram in *Figure 40.5*. The dynamics of a synchronous machine would also be amenable to such a description, but in practice a description by differential equations (two-reaction theory) is usually preferred. Details of controllers and regulations are described by block diagrams, as is common in control engineering.

40.4 Data acquisition and telemetering

40.4.1 Introduction

To be able to supervise and control a power system, the network control engineer requires reliable and current information concerning the state of the network. This he obtains from the power flows, bus voltages, frequency, and load levels, plus the position of circuit-breakers and isolators; the source of these data being in the power stations and substations of the network. As these are spread over a wide geographical area, the information must be transmitted over long distances. Thus the electrical parameters and switch states must be converted into a suitable form for transmission to the control centre. A telecontrol system is also required to transmit these data using communication channels which were historically limited in capacity and were shared with other facilities such as speech, protection and, perhaps, also telex communication. Speed of data transmission was therefore often limited, and the telecontrol network was configured to optimise the use of the available bandwidth on the carrier channel. The modern communication is based on fibre optical or wireless communication networks, which provide a powerful broad band communication. The classical power line carrier communication technology has also been improved with the use of digital technology. It is almost mandatory that all the new HV and EHV lines be laid with fibre optical core in the ground wire, as the incremental cost is quite low. The trunk routes may have dedicated logical links for speech, data and protection signal in addition to the data and voice network for telecommunication purposes.

The telecontrol system comprises a master station communicating over communication channels with remote terminal units (RTUs) located in the power stations and switching stations. Normally the RTUs are quiescent, i.e. they only send data after a direct interrogation from the master station; thus more than one RTU can be connected to a transmission channel as the channel can be time shared. A telecontrol network can be configured as a point to point, star (radial) or multi-point (part line) system as illustrated in *Figure 40.6*. The transmission can be either duplex, half-duplex or simplex (in the case where data traffic is unidirectional). The newer generation of RTUs can remain quiescent and can report the data on their own initiative using a slave to master communication protocol. The use of standard telecontrol protocols is also being promoted to facilitate use of equipment from different suppliers. International Electrotechnical Commission (IEC) has recommended IEC870-5-xxx group of protocols, which allow certain amount of openness in the system. The state of the art RTUs can communicate over data communication networks providing a large bandwidth with good reliability.

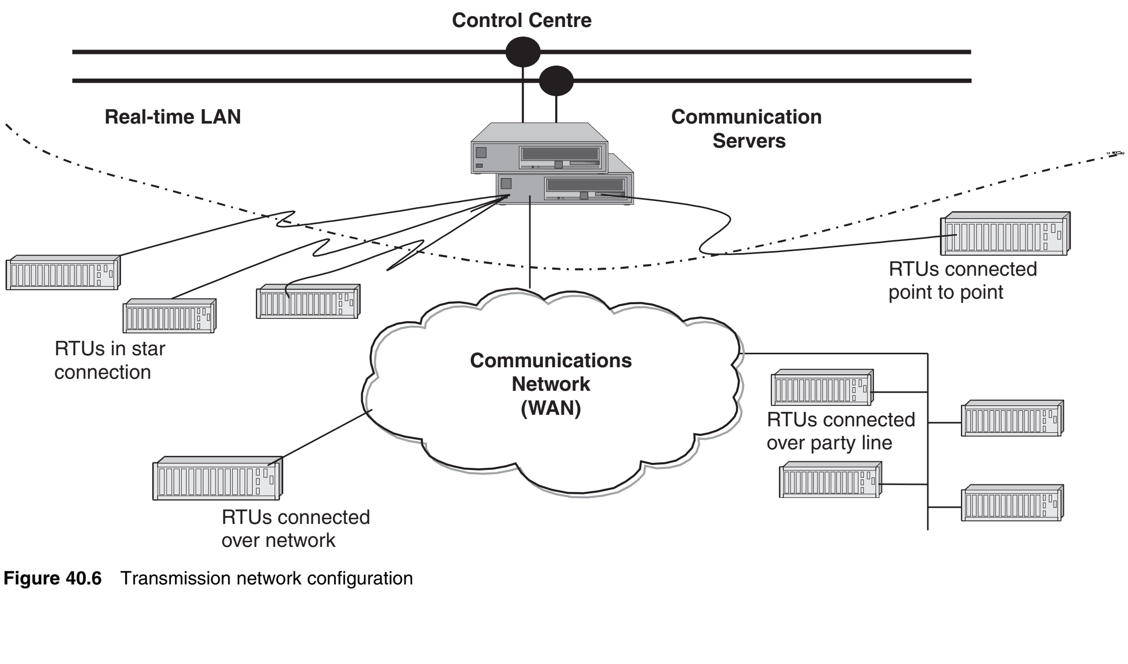

Figure 40.6 Transmission network configuration

40.4.2 Substation equipment

The data-acquisition equipment in a substation is usually a microprocessor-based RTU, equipped with both programmable read-only memory (PROM) and random-access memory (RAM). The data-acquisition program and the transmission program are loaded into the PROM, which is non-volatile (not corrupted during a power supply failure). All the system modules are connected to the system bus (see *Figure 40.7*) which is structured to facilitate data transfer from the information source to its destination, under the control of the program. The microprocessor function is monitored by the watch-dog module. The RTU is configured to suit the substation requirements. A typical configuration is shown in *Figure 40.8* with the input/output for one high-voltage (h.v.) circuit only. The input modules fall into three main categories: digital input, analogue input and pulse input.

40.4.2.1 Digital inputs

Digital input modules are used for inputting contact states indicating breaker positions, isolator positions and alarm contact operation. The contact states are continually monitored but are not transmitted unless a contact state has been changed. Under program control, the module is cyclically interrogated to see whether it has a change of state to report: if the reply is negative, the program moves to another module; if it is positive, the change of state is

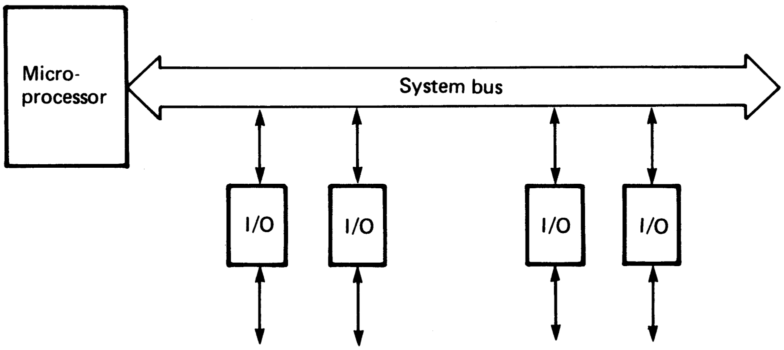

Figure 40.7 RTU bus structure: I/O, Input/output

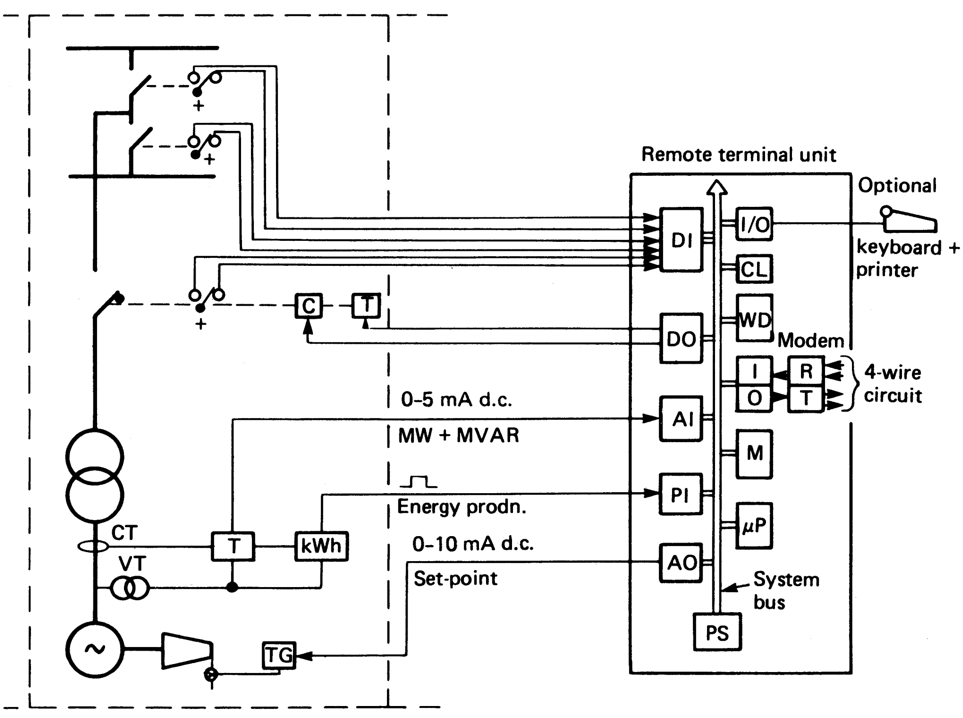

Figure 40.8 Example of the configuration of a RTU: DI, digital input; DO, digital output; AI, analogue input; PI, pulse input; AO, analogue output; μP, microprocessor; M, memory; CL, clock (optional); I/O, serial input/output interface; WD, watch-dog; PS, power supply; TG, turbine governor; CT, current transformer; VT, voltage transformer; T, transducer; CT, close, trip; R/T, receiver/transmitter

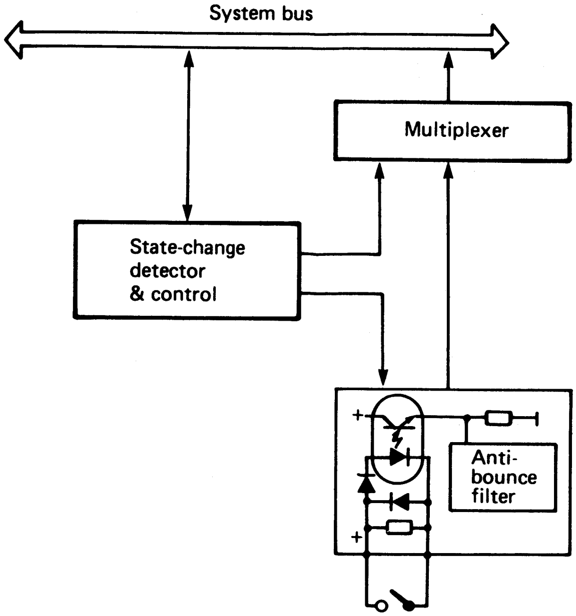

Figure 40.9 Digital input circuit

written to the memory. The input circuits are decoupled from the power system equipment by electromagnetic relays or opto-couplers and are filtered to eliminate the effect of contact bounce. A digital input circuit is illustrated in *Figure 40.9*.

40.4.2.2 Analogue inputs

The electrical measurements are converted from current-transformer and voltage-transformer levels to analogous direct-current (d.c.) milliampere signals by suitable transducers. These convert voltage, current, active and reactive power, frequency, temperature, etc., into proportional d.c. signals which are fed into an analogue input module. This module (*Figure 40.10*) has a multiplexer for scanning multiple inputs (usually 16) and an analogue-to-digital converter (ADC) which converts the d.c. signal into a digital code (usually binary or BCD). The local scanning rate of the measurands is less than 0.5 s, with an accuracy of conversion for normal requirements of 1% for bipolar (7 binary bits + sign) values and of 0.5% for unipolar values. For higher accuracy requirements an accuracy of 0.1% is used (11 bits).

40.4.2.3 Pulse inputs

Energy or fuel consumed can be measured by integrating meters giving a proportional pulse output. The pulses are integrated in a pulse input module which is periodically scanned, e.g. at 15 min intervals. The consumption over that period is then the difference between the last two readings. Special measures are taken to ensure that the reading does not interfere with the pulse integration or vice versa.

40.4.2.4 Digital output

Digital output modules convert a coded message, received from the control centre, into a contact output, e.g. to trip or

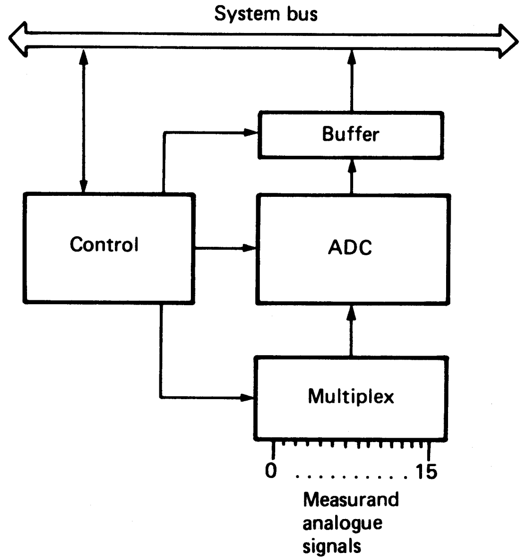

Figure 40.10 Analogue input module

close a circuit-breaker or to raise or lower a tap-changer. Obviously, the transmission of these signals must be very secure, and checking that the correct output is given must be rigorous. Echo checks are made to ensure that the correct code has been received by the module, and additional circuits can be added to detect stuck contacts and to prevent more than one command being output at a time.

40.4.2.5 Analogue output

Set-points are output via analogue output modules that receive a coded message which they convert into a d.c. analogue signal; this is output e.g. as a turbine-governor setting.

40.4.2.6 Clock

An optional feature of the RTU is a clock module, which enables the events in the substations to be arranged and transmitted in chronological order and the time at which an event happened to be added. The clock is capable of giving a 10 ms time resolution in event sequence recording and the time in hours, minutes, seconds and hundredths of a second.

40.4.2.7 Printer

A further option can be included to print the alarm and event sequences locally at the substation by adding memory, serial–parallel interface, a printer and additional program. If the memory capacity is limited, the output is either coded or abbreviated; however, with adequate memory the print-out can be in clear text.

40.4.3 Data transmission

The substation data are locally scanned and memorised in the RTU ready to be transmitted to the control centre. When an instruction is received from the master station, the processor prepares to send the data to the control centre. To every message containing data, it adds check bits that enable the master station to ensure that the message has not been corrupted during transmission. Similarly, to any message output from the master station, check bits are added to enable the RTU to verify that the received message has not been corrupted. The data are then output to the communication channel via the parallel-to-serial converter and the modulator–demodulator (modem) which converts d.c. pulses into keying frequencies in the voice-frequency (v.f.) range. Normally two v.f.-range frequencies are used to represent '1's and '0's of the message code and to modulate the carrier of the transmission channel. At the receiving end, the modem converts the keying frequencies into d.c. pulses and the serial–parallel converter module reassembles the message into a parallel word including the check bits. The message can then be checked for errors induced during transmission.

There are various methods of checking for errors in a message telegram. The error-detecting capability of a checking system is often described as a Hamming distance. The Hamming distance between two binary words is the number of bit positions by which they differ, which is undetectable by the error-checking system. For most purposes in telecontrol, the minimum Hamming distance is 4, i.e. all 3-bit errors are detected. An example of a modified Hamming code error-checking system is shown in *Figure 40.11*.

The advantage of this system is that in addition to detecting the same number of error patterns as equivalent error-checking systems of the same size, the introduction of odd parity in one check-bit position and even parity in the others forces at least two changes in bit settings in the telegram. This considerably reduces the risk of loss of synchronism when the word is being read. The Hamming distance of this code is 4: i.e. all patterns of 3-bit errors are detected, as well as all odd numbers of bit error patterns and over 92% of all even numbers of bit error patterns.

40.4.4 Transmission system

The data transmission system must be designed to allow all the RTUs to transmit their data to the control centre in a reasonable time without imposing impractical demands on the communication system. The data transmission can be divided into several parts, each of which can comprise one or more RTUs. Each part system is completely independent of the others; thus they effectively operate in parallel.

Three basic systems are possible: point-to-point, radial or multi-point (see *Figure 40.6*). Combinations of radial and multi-point are also possible.

With point-to-point systems, the transmission can be simplex (where the RTU sends data continuously to the master station) or half- or full-duplex (where data can be transmitted in both directions).

With radial or multi-point systems, the dialogue between the master station and the RTU is entirely controlled by the master station to avoid two or more RTUs sending data simultaneously. The master station transmits instructions to the RTU, which, in complying with the instruction, acknowledges it. The RTU takes no initiative in transmitting data and sends data only after receiving a specific instruction to do so from the master station. Thus all data in a part system are transmitted from each RTU in turn and response times are a limiting feature of a part system configuration.

There are two basic forms of data to transmit: even-controlled data which appear at random intervals, and data that must be transmitted cyclically as they are liable to be continually changing. The cyclically transmitted data, e.g. measurands which require frequent updating at the control centre, take up most of the transmission time; however, as the RTU is quiescent, periodically it must be asked whether it has any spontaneous data to transmit. To save transmission time, this is made in a 'broadcast' interrogation to all RTUs in the part system simultaneously. If no RTU answers positively, the normal cycle sequence is resumed; however, if one or more RTU answers that it has spontaneous data to send, the normal cycle is interrupted and each RTU is interrogated in turn until all the spontaneous data have been transmitted and received at the master station. In order that the detection of spontaneous data (e.g. a breaker trip) is transmitted in a reasonable time, the spontaneous data interrogation is interjected between the transmission of groups of measurands (say 16). An example of a transmission sequence is given in *Figure 40.12*. The spontaneous data can be sent in chronological order of events taking place and also with the time at which each event happened.

The response times are dependent on the transmission speeds, and a choice of speed is available. Standard speeds of 50, 100, 200, 600 and 1200 bit/s are available within the v.f. band. The choice of speed is then dependent on the response times required and the bandwidth available on the communication channel. As an example of response times, a part system comprising four RTUs each having measurands would have a measurand and indication interrogation scan time (with no changes of state to transmit) of approximately 6.5 s, using a 200-baud channel. To decrease this time, either the number of RTUs in the part system

Message telegram

Bit No.	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0
Bit significance	M2	M1	L	D7	D6	D5	D4	$\overline{H4}$	D3	D2	D1	H3	D0	H2	H1	H0
$\overline{H4}$	×	×	×	×	×	×	×	●								
H3	×	×	×	×					×	×	×	o				
H2	×	×			×		×			×	×		×	o		
H1	×		×		×		×		×		×		×		o	
H0	×	×	×	×	×	×	×	×	×	×	×	×	×	×	×	o

Figure 40.11 An example of message telegram organisation: ●, odd parity check; o, even parity check; ×⇐bits supervised by Hamming bits; D, data bits; L, message sequence complete; M, message-type definition; H, Hamming bit

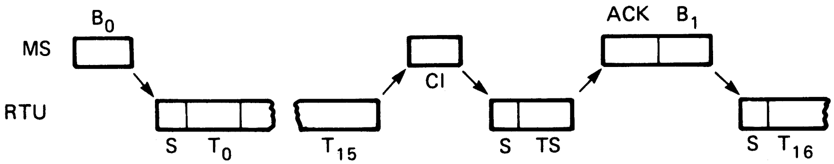

Figure 40.12 A typical transmission sequence: B_n, call for transmission of a group of measurands; S, start character; T_n, values; CI, call for transmission of a change of state; T_s, change-of-state message; ACK, acknowledgement of receipt of meassage; MS, master station

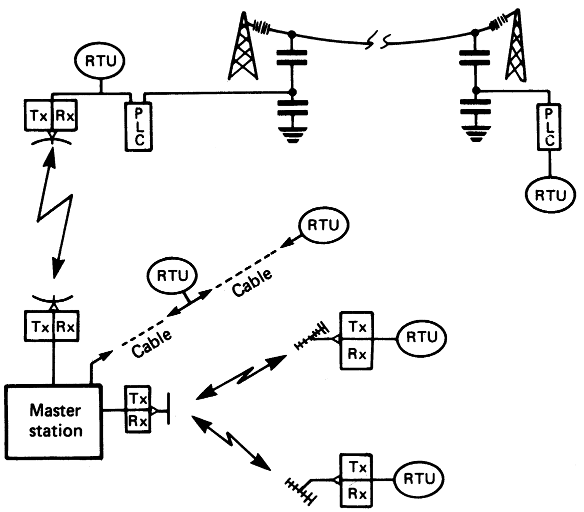

Figure 40.13 An example of a data transmission system. Tx, Rx, radio transmitter and receiver; PLC, programmable logic controller

would have to be reduced or the speed of transmission would have to be increased.

40.4.5 Communication channels

The transmission of the frequency-shift keying signals requires a four-wire circuit communication channel, which can be telephone-type cable, power line carrier equipment, radio transmission or any combination of these media in series or parallel. *Figure 40.13* gives an example of a possible combination of different types of communication channels.

Often the telecontrol signal must share the v.f. band with other transmissions such as speech, telex, protection or even another telecontrol part-system transmission. An example of the frequency multiplexing of the v.f. band is given in *Figure 40.14*. The multiplexing equipment is normally available with the power line carrier. The frequency-shift keying takes place within the frequency bandwidth indicated in *Figure 40.14*: e.g. for a 200-baud modem the lower keying frequency is −90 Hz and the upper is +90 Hz of the channel centre frequency. The total bandwidth required is 360 Hz.

40.5 Decentralised control: excitation systems and control characteristics of synchronous machines

40.5.1 Introduction

A synchronous generator operating on an interconnected grid requires a fast-response excitation system to ensure its stable operation. This system must be able to adjust the level of magnetic flux in the generator according to the grid network requirements. Since the parameters of the generator will fall into a fairly narrow range according to the type of generator (salient pole or turbo), the excitation system must be designed to bring the generator flux (i.e. excitation current) to the required level in the shortest possible time, notwithstanding the long time-constants of the generator transfer functions.

Brushless excitation equipment has been developed to meet these requirements on various types of synchronous generator—particularly on smaller turbogenerators—and has given excellent results in service. The control characteristics of this system, however, are dictated largely by the exciter and the rotating diodes rather than by the voltage regulator (d.c. exciters are not used in modern excitation systems).

For large generators a static excitation system represents the best solution since, in principle, it imposes no limit on the ceiling voltage. In the per-unit system the ceiling voltage is the ratio of the maximum excitation voltage to the excitation voltage for nominal open-circuit voltage at the generator terminals. Values of 10 or 15 p.u. are quite often used. A great advantage of static excitation is that the total field-voltage range is available with practically no time delay. This speeds up not only field forcing but also field suppressions when required, by change-over to inverter mode.

40.5.2 Brushless excitation systems

Brushless excitation systems are mainly employed either where the control requirements are not too stringent or where the atmosphere is chemically aggressive. The main generator excitation is provided by an auxiliary exciter generator mounted on the main generator shaft.

This exciter is a salient-pole synchronous generator with a three-phase winding on the rotor and a d.c. excitation winding on the stator. The alternating currents produced by the rotor winding are rectified by rotating diode bridges mounted on the shaft, the resulting d.c. being fed to the field winding of the main generator. The excitation for the exciter stator winding is supplied by a thyristor regulator which comprises voltage regulators and limit-value controllers. Field suppression of the exciter machine is also carried out by the regulator (*Figure 40.15*).

The controlled rectifiers and the electronic circuitry of the regulator are supplied either from a permanent magnet (p.m.) generator on the main shaft or through a transformer fed from the main generator terminals. In the latter case, compounding equipment is available for the required selective switching (short-circuit duration in excess of 0.5 s) which is then combined with the standard regulators.

In its basic form the regulation system contains the continuously active elements for automatically controlled operation, which are:

(1) a voltage regulator;
(2) a reference-value potentiometer for remote adjustment;

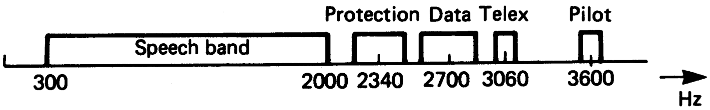

Figure 40.14 Allocation of communication functions to a 4 Hz channel

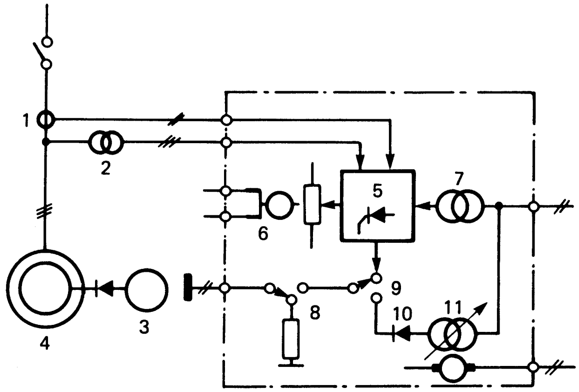

Figure 40.15 Voltage regulation system with manual control facility: 1, current transformer; 2, voltage transformer; 3, exciter; 4, generator; 5, voltage regulation; 6, reference value; 7, supply transformer for the voltage regulator; 8, field switch/discharge resistor; 9, change-over switch; 10, rectifier; 11, variac with motor drive

(3) a supply transformer;
(4) a field-breaker and discharge resistors; and
(5) diode monitoring consisting of the manual control device, i.e.
 (a) a variac transformer,
 (b) a diode bridge, and
 (c) a change-over switch (auto to manual).

40.5.3 Static excitation systems

On generators with difficult regulation requirements a rotating exciter should not be used. Here the excitation is supplied either directly from the generator terminals via a transformer and a controlled rectifier bridge (*Figure 40.16*) or by an auxiliary generator.

The main components of a static excitation system are:

(1) an excitation transformer (or auxiliary generator);
(2) a static converter;
(3) a field suppression system;
(4) control and firing circuits; and
(5) a protection and monitoring system.

The capacity of the excitation system is dependent on the generator specification and on the requirements of the power system. The rating of the excitation transformer or exciter in particular is determined by the maximum continuous current rating of the rotor winding and the required ceiling voltage. In designing the converter circuits, which have much shorter thermal time-constants, the ceiling current and short-circuit current capacity must also be considered.

The voltage of the transformer secondary (or of the auxiliary generator) is determined by the maximum ceiling voltage, V_c of the excitation system, and its current by the maximum continuous current I_{fm} of the generator field winding. A simple approximation to the rating of a three-phase excitation transformer is 1.35 $V_c I_{fm}$.

The static converter comprises one or more fully controlled thyristor bridges, which are almost always cooled

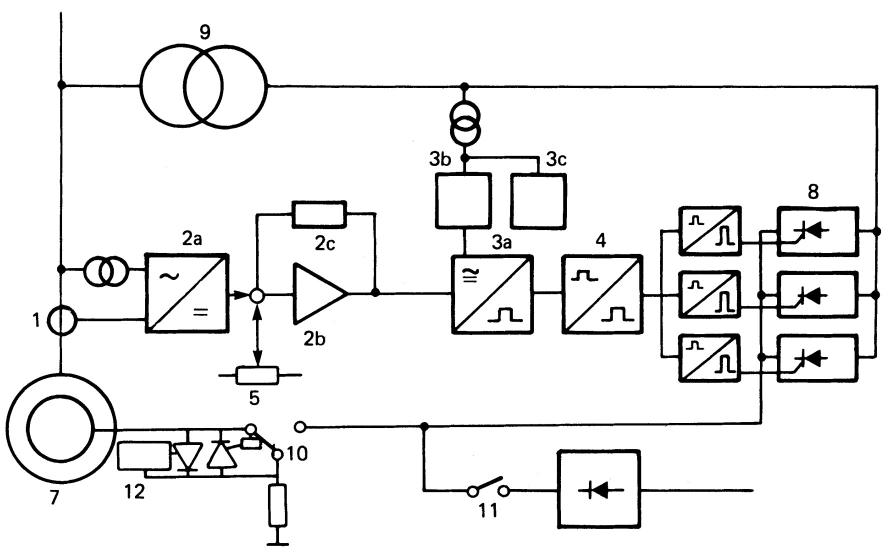

Figure 40.16 Block diagram of a voltage regulator with static excitation (without manual control): 1, instrument transformer; 2a, transducer; 2b, voltage regulator; 2c, PID filters; 3a, firing-angle control; 3b, filter; 3c, voltage relay for control of excitation field flashing; 4, pulse amplifier; 5, reference-value setting unit; 7, generator; 8, main excitation rectifier; 9, excitation transformer; 10, field suppression device; 11, field flashing device; 12, overvoltage protection

by forced air. The number of parallel bridges and the number of series elements in each bridge branch are determined by the technical data (current rating and inverse voltage) of the thyristor bridges, the maximum exciting current, the transient overload (due, for example, to a system fault) and the ceiling voltage. An extra redundant bridge is normally included (in parallel) so that, even if one bridge fails, the full operational requirements can still be met. To ensure selectivity, it is necessary to have at least three bridges in parallel. This is because a faulty thyristor together with a healthy branch can form a two-pole short circuit that persists until the fuse in series with the defective element blows. If only two parallel bridges are provided then the short-circuit current in the healthy branch is shared by only two thyristors; the fusing integral of both the corresponding fuses may then be exceeded, resulting in an excitation trip.

The rectifier can have either a block structure or be arranged phase by phase. In the block arrangement, one or more bridges are grouped together and gated from a common pulse amplifier. Blocks are normally provided with individual fans, but common cooling is also possible.

The arrangement of the converter in phase groups reduces the risk of an interphase short circuit. All parallel thyristors of one phase are brought together in a single rack. A separate cooling system for each rack is inappropriate in this arrangement and common cooling is employed, consisting of two fans each capable of supplying the full cooling-air requirement.

With the phase-by-phase arrangement, the excitation transformer is usually composed of three one-phase units; this will always provide a higher degree of safety against interphase short circuits.

The field suppression system comprises essentially a two-pole field-breaker and a non-linear field discharge resistor. The component ratings are so chosen that neither the permissible arcing voltage at the breaker nor the maximum permissible field-circuit voltage is exceeded, even with the maximum possible field current (following a terminal short circuit on the generator). A 'crowbar' is included in the discharge-equipment cubicle as additional overvoltage protection. This comprises two antiparallel thyristor groups which are triggered by suitable semiconductor elements such as breakover diodes (BODs). If, for instance, a voltage is induced in the rotor field circuit owing to generator slip, this voltage can rise only to the threshold of the BOD element. If this value is reached, the element triggers the thyristors, and the rotor circuit is connected to the discharge resistance, allowing a current to flow which immediately causes the induced voltage to break down.

40.5.4 Automatic voltage regulator and firing circuits for excitation systems

The voltage regulator for brushless exciters as well as for static excitation systems constitutes the central control element in a modern plant. This unit uses a voltage transformer to measure the actual value, rectifies it and compares it with the reference value. The difference-voltage is fed to an amplifier with a lead–lag filter (the response characteristics of which must be carefully adjusted to suit the particular generator and grid parameters) and the amplified value is brought to the gate control unit. Using additional reactive current compensation it is possible to adjust the reactive current behaviour of the generator with regard to the network.

The voltage regulator has normally to be supplemented with parallel-connected limiters which function before corresponding generator protection relays are activated. Depending on requirements, rotor-current, load-angle and stator-current limiters may be employed. Their features are described later.

If the limitation control causes a reduction in the excitation current (on over-excited operation), time-delay elements are incorporated to allow high transient currents. For underexcited operation there is no time delay.

Stabilising equipment can be used to damp power oscillations that may arise under exceptional network conditions.

The voltage regulator may be supplemented with an overriding system for controlling the power factor or the reactive power flow, as required. All voltage regulators are provided with manual control (changeover from closed-loop to open-loop control). A separate redundant gate control unit is often provided (double-channel type). In case of a fault in the 'automatic' channel, a follow-up control system ensures a smooth transition to manual operation.

The amplified difference signal is transformed into pulses with the appropriate firing angle by the gate control unit. The firing pulses are amplified in an intermediate stage and led to the individual output stages which are assigned to the various converter units. The output stages shape the pulses to the steep slopes necessary to ensure simultaneous firing of all parallel thyristors. The pulses from the output stages are fed via impulse transformers to the thyristor gates.

The transfer function of the automatic voltage regulator (AVR) including the gate control system is

$$\frac{\Delta V_f}{\Delta V_g} = A\frac{(1+pT_1)(1+pT_2)}{(1+pT_3)(1+pT_4)}\,\frac{1}{1+pT_M}\,\frac{1}{1+pT_E}$$

where T_M is the measuring time-constant, T_E is the exciter time-constant, $T_1, \ldots, T_4$ are the equivalent lead–lag time-constants, A is the amplification, and p is the operator d/dt.

40.5.5 Limiting the excitation of synchronous machines

Ever-increasing demands on power system reliability led to the development of ancillary equipment (limiters), to inhibit the tripping of protection gear when this was not wanted and to make, within the permissible limits, better use of the synchronous machine. These limits are clearly depicted in the power chart of a turbogenerator shown in *Figure 40.17*.

The limit of active power output (line CE) is determined by the prime-mover, and is disregarded. A factor connected directly with excitation current, however, is the permissible temperature rise in the rotor winding, represented by the arc CD with centre A corresponding to the non-excited condition. This thermal limit is defined by the ageing of the insulation. It may therefore be exceeded for a short time—a requirement essential for the stability of the power system.

In the underexcited mode, operation of the synchronous machine is limited by the airgap torque necessary for the active power transfer, the steady-state condition being represented by a definite, permissible rotor displacement angle (line AE). This limit has mechanical and dynamic characteristics, and calls for instantaneous intervention as soon as it is exceeded, to prevent the generator from falling out of step.

Another important condition governing the limits to be introduced is the requirement that these do not interfere with the normal operation of the voltage regulator, and that neither intervention nor return to voltage regulation leads to disturbances.

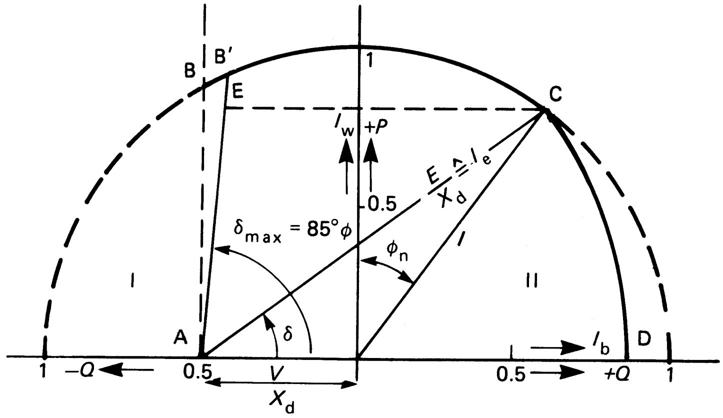

Figure 40.17 Current and power diagram of a turbogenerator ($I=1$ p.u.; $V=V_k=1$ p.u.; $X_d=X_q=2$ p.u.; cos $\phi=0.8$): I, underexcitation; II, overexcitation. AB, Practical stability limit; AB′, steady-state stability limit; BC, limit of stator temperature rise; CD, limit of rotor temperature rise; CE, active power limit; E rotor e.m.f.; I_b, reactive current; I_e, excitation current; I_w, active current; P active power; Q reactive power; V_k, terminal voltage; X_d, direct-axis reactance; X_q, quadrature-axis reactance; δ, load angle; ϕ_n, rated phase angle

Electronic load-angle and current-limit controllers were introduced some time ago, and these are now standard components of all good voltage regulation equipments. Practical experience has made possible the addition of improvements and refinements.

Consider the static excitation equipment commonly used for large generators (*Figure 40.18*). Normally, the voltage regulator holds the generator voltage (and thus, indirectly, the reactive power output) at a constant level. The static converter adjusts the excitation current so that the reference voltage remains a function of the reactive current. At the same time, the rotor-current limit controller measures the excitation current in the static converter supply and compares it with the relevant reference limit. The load-angle limit controller continuously forms from the generator current and voltage a signal that is proportional to the angle, and compares it with the limit.

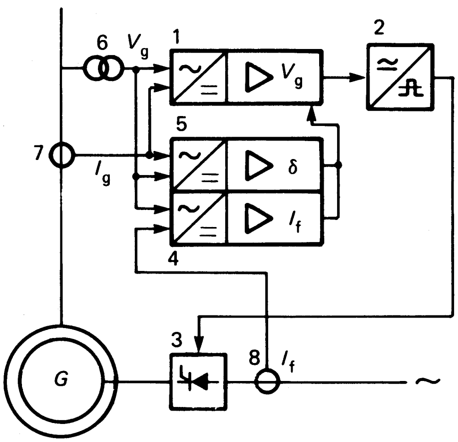

Figure 40.18 Block diagram of the automatic voltage regulation system for a synchronous generator: 1, voltage regulator; 2, gate control unit; 3, static converter; 4, rotor-current limiter; 5, load-angle limiter; 6, voltage transformer; 7, generator-current transformer; 8, excitation-current transformer; G, synchronous generator, V_g, generator voltage; I_g, generator current; I_f, rotor current; δ, rotor angle

The two limiters operate as parallel controllers, i.e. their signals completely replace the voltage as controlled variable when their output variables become smaller or greater than the voltage control signal. Thus, the change in specific dynamic behaviour of the control circuit for each limit function can be fully taken into account. It will be shown that unwanted side-effects occurring on signal take-over can be avoided entirely.

40.5.5.1 Rotor-current limitation

Every exciter is capable of delivering a maximum current appreciably greater than the continuous value based on thermal considerations. This capacity for overexcitation is necessary to provide the additional reactive power demanded during selective clearance of faults and to maintain a synchronous torque even when the voltage level has fallen.

Although it safeguards the winding insulation against damage from prolonged overexcitation, rotor protection gear (such as overcurrent and overtemperature relays) disconnects the generator even when disconnection is not desired. Use of a controller to limit the excitation current to an acceptable value during operation would substantially improve the availability of the generator. For safety reasons, however, a separate protective device must be retained to safeguard the winding against overloading.

The demands to be met by the rotor-current limiter are best explained with reference to the voltage and excitation current when a short-line fault occurs. The voltage regulator reacts to the drop in voltage with surge excitation. The controller is not intended to impede this, but merely to determine the ceiling current I_{fm}. Although the clearance normally takes place in a few hundred milliseconds, the longest duration (back-up protection) of 2–3 s will be assumed. When, after the fault has been cleared, nominal voltage is attained with a permissible continuous excitation current, the thermal controller will not intervene. However, when because of, for example, breaker failure the fault is not cleared, or when generated reactive power no longer suffices to maintain the voltage level, overexcitation will continue to be present. The limit controller now aims to reduce the excitation current before any of the protection gear is tripped. A further important aspect is that this also causes the short-circuit power of the system to be reduced, which, in turn, will diminish the extent of the damage resulting from failure of a breaker or other protective gear.

The condition in which the maximum continuous excitation permissible is present might persist for a long time, and experience has shown that further short circuits appear relatively frequently during this time. When these secondary disturbances occur, it becomes necessary to deliver the maximum reactive current to the system once more, especially to retain system stability. This means that limitation has to be cancelled again for a short time. The characteristic which trips the reset is the steep drop in voltage, $\mathrm{d}V/\mathrm{d}t$.

A further requirement results form the fact that today most of the large excitation equipment is fed from the generator terminals. The necessary ceiling excitation current is normally already available at 90% of the rated voltage. This means that at 120% of the rated voltage, a ceiling current which is 33% higher than the necessary value will flow when an instantaneously acting excitation limiter is not provided.

The limitation signal can be introduced as a reference-value variation of the voltage regulator. However, two facts suggest applying the signal to the voltage regulation output for use as dominant parallel limitation. These are: (i) the limitation is absolute and thus fully effective even when the actual value for the voltage regulator is lost (voltage-transformer fuses blown); and (ii) the limit controller can be adapted to the dynamic conditions of the field-current controller and become independent of voltage-regulator response.

As has been mentioned, limitation to the permissible continuous excitation current should be delayed in order to first give the voltage the maximum support possible. The permissible continuous current in the excitation circuit is determined by the thermal stressing of the field winding, the supply transformer, or the thyristors or diodes. The overload capacity of these elements can usually be represented by integration of the current. A slight overrun of the set limit for the continuous current is then tolerated correspondingly longer. It can be argued, however, that the ceiling excitation will be required only as long as fault clearance is still taking place, in which case a fixed timing element is provided. In both cases, it is usually desired that ceiling excitation should be available again in the event of secondary disturbance.

Based on previous experience, improved rotor-current limit controllers were developed to cater for the many varied applications met with in practice; these controllers can be easily adapted to the particular protection method used.

A maximum-current limit controller, instantaneous acting and always available, ensures that for terminal-fed excitation the desired ceiling current is not exceeded over the entire operating voltage range.

In the case of the simple integrator mode, the speed at which reduction to the limit value takes place is relative to the magnitude of the overcurrent. The integrator is reset only when the limit for the continuous rotor current is underrun.

With the switching mode, reduction to the limit begins after a set delay T_v of several seconds. Every time there is a sharp drop in voltage, maximum-current limitation begins anew and the timing element is reset.

A method frequently used in the combined mode: here, integration of the overcurrent is combined with resetting of the integrator by each succeeding voltage drop.

The actual current can usually be measured with a current transformer in the alternating-current (a.c.) power supply prior to rectification by the thyristors or diodes. A d.c./d.c. converter makes connection to a shunt also possible.

When partial failure of components in the excitation circuit causes the permissible continuous current to be reduced, change-over to a pre-set second current limit set-point is possible.

40.5.5.2 Load-angle limitation

For a number of years it has been standard practice to provide protection gear that detects excitation failure or loss of generator synchronism and trips the generator breaker. Inadequate excitation can, for example, also be caused by a change in the system configuration due to a fault, by reference-value failure or by other faults in the voltage regulator. The load-angle limiter obviates unnecessary disconnection by the under-excitation protection device in all these cases.

The limit angle is set intentionally to a value considerably smaller than the pull-out limit. For turbogenerators, for example, the angle lies between 70° and 85°. For salient-pole machines the actual stability must be taken into account and a suitable response limit determined. Thus, an adequate angle difference exists for the acceleration of the generator during clearance of a nearby short circuit. This reserve is directly related to the time allowed for clearing the fault.

The principle of analogue simulation of the phasor diagram using stator voltage and current is applied. This method is notably simpler than the direct measuring processes. In the event of a transmitter on the shaft providing the rotor position, the same device may be employed for further evaluation. The angle between the two simulated phasors, rotor voltage E_p and the infinite bus voltage V_s, is converted into a d.c. signal in a solid-state angle discriminator. When transients appear, the angle generated by the simulation leads the true load angle slightly. This is advantageous as this limiter should intervene at an early stage. Such a procedure has been shown to be reliable in practice.

40.5.5.3 Stator-current limitation

The stator-current limit, which is governed by thermal considerations, normally lies beyond the operating range of the synchronous generator. Thus, stator-current limitation is employed only in special cases. To illustrate this point, actual applications of a stator-current limit controller, usually in conjunction with limit control of the load angle and excitation current, are given below.

(1) With gas turbo-sets, for example, the useful output can be raised at times to cover peak demands, so that the limit is governed partly by the stator current.
(2) In coastal areas it is necessary to reduce the system voltage at certain times of the year because of salt vapour; there is thus an increase in stator current for the same power.
(3) In the case of reactive power compensators the under-excitation limit can be attained only with a stator-current limiter.
(4) With synchronous motors, a practical utilisation limit can appear that will be detected approximately by a stator-current limit controller.

40.5.6 Control characteristics for synchronous machines

As far as the system of synchronous generator and network is concerned, there is a strong similarity between the speed and active-power control system on the one hand, and the voltage and reactive-power control system on the other.

To understand control by characteristic it is useful to compare the two systems (*Figure 40.19*). As long as the set is operating at no load, or on isolated duty, the appropriate value is controlled by the corresponding control system, i.e. the speed (frequency) or generator voltage. This is no longer the case, however, in parallel operation with a live network. Frequency and voltage are already present and can be changed by the set only to a limited extent. Secondary controlled variables are involved here, and it is imperative that they are controlled in parallel operation. These secondary variables are the active and the reactive power.

On what is this two-fold nature of the control system based? In isolated duty, only one control system is acting on any control loop. In parallel operation, however, many loops are coupled through the common controlled variable. The primary control task is distributed over a large number of control points. Selective stable distribution is of decisive importance. The overall task here is to maintain frequency and to produce active load, or to maintain voltage and to produce reactive load. The familiar solution is to provide the regulator with a drooping characteristic, i.e. the set-point of the primary controlled variable drops as the secondary controlled variable rises. The point of intersection of this characteristic of the network rating defines the corresponding operating conditions. Any set-point can also be set for the secondary controlled variable by parallel displacement of the characteristic. The gradient of the characteristic is usually expressed as a droop of the form $S_n = \Delta n/n$ or $S_v = \Delta V/V$, i.e. as the percentage deviation in the primary controlled variable that is necessary to bring the secondary controlled variable from zero to the rated value.

While the frequency of the network is the same throughout, in the case of voltage this applies only to the imaginary voltage of an infinite bus-bar. The true network represents roughly a variable 'mountain landscape' of voltages defined by its line impedances and feed-in or feed-out at a large number of junction points. This true network must first be accessible by reducing it to a simple equivalent circuit (*Figure 40.20*).

Each individual generator feeds through transformer and line impedances into the 'finite bus-bar' formed by the sum of all the other generators. As can be seen from the phasor diagram in *Figure 40.20*, which may be considered as qualitative, the products of the reactances and reactive components of the current are decisive for the magnitude of the voltage drop $|\Delta V|$. The drop in active voltage and the phase displacement of the voltage phasor can here be ignored. The reactances between the generator terminals and the infinite network thus produce a natural drop in the reactive current, whereas the drop of the speed-control system is always synthetic. The generator reactance X_D is within the control loop and therefore need not be taken into account for quasi-steady-state phenomena. The effect of the natural drop in reactive current, and its increase or decrease by artificial means, is the main theme to be discussed from various viewpoints in the following.

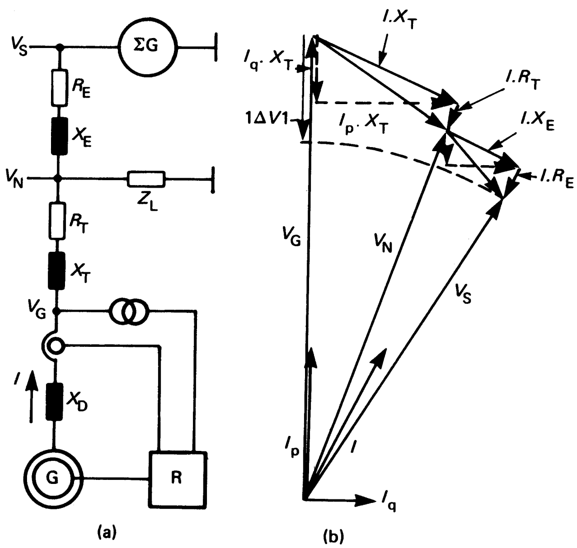

Figure 40.20 Impedances and voltage drops: (a) equivalent circuit diagram; (b) phasor diagram. V_s, Voltage of infinite system; V_N, system voltage; V_G, generator voltage; I, generator current; I_P, active component; I_q, reactive component; X, external (short-circuit) reactance; X_T, transformer reactance; X_D, direct-axis reactance of generator; E_E, R_T, active resistances; Z_L, load impedance; G generator; ΣG, sum of all other generators; R, voltage regulator

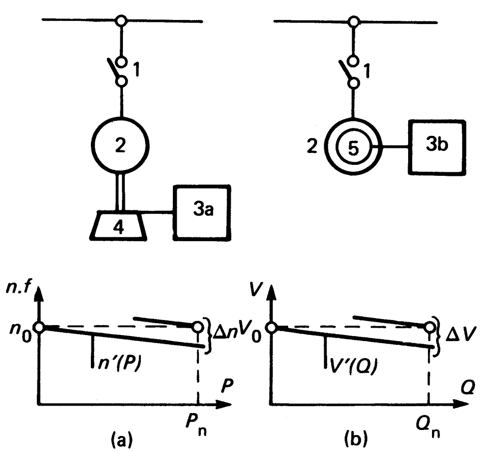

Figure 40.19 Characteristics for parallel operation: (a) speed/active-power control; (b) voltage/reactive-power control. 1, Generator breaker; 2, generator; 3a, speed regulator; 3b, voltage regulator; 4, turbine; 5, rotor winding; 6, network; P, active power; Q, reactive power; n, frequency; V, voltage

40.5.6.1 Parallel operation in a power-station

Parallel operation in a power-station is illustrated in *Figure 40.21*. As virtually all large generators are operated in unit connection, the transformer reactance between the terminals and the h.v. bus-bar causes a natural reactive current droop of 8–12%. This accurately defines the reactive power output. Conditions are very different in the case of low-voltage (l.v.) generators, which must operate in parallel direct at the machine terminals. Here there is no natural droop, and even the smallest difference in the voltage values will lead to undesirable mutual exchange of reactive power between the machines, without resulting in a defined distribution of demand. It is not until an artificial droop is introduced by applying reactive current in the measuring loop of the voltage regulator that the reactive load distribution becomes stable; initially it is immaterial whether the generators themselves define the voltage at a purely consumer network, or coincide with the voltage given by a live network.

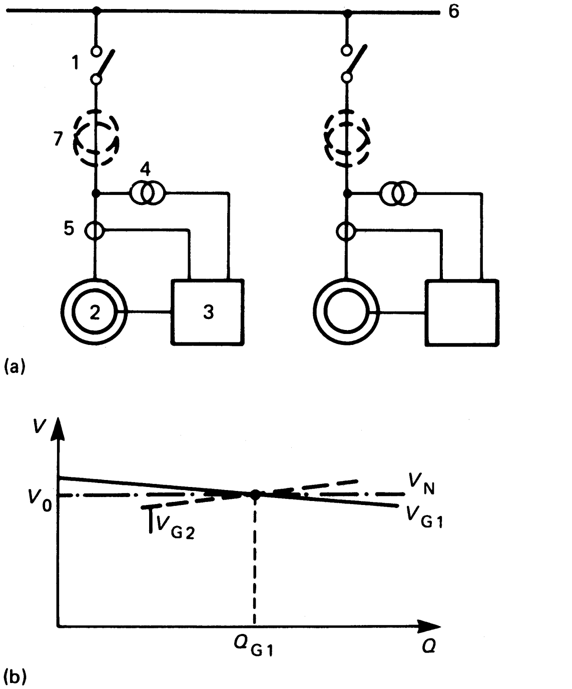

Figure 40.21 Parallel operation in a power-station: (a) basic circuit diagram; (b) characteristics. 1, Generator breaker; 2, generator; 3, voltage regulator; 4, voltage transformer; 5, current transformer; 6, bus-bar; 7, unit-connected transformer; V_N, system voltage; V_{G1}, V_{G2}, generator voltage characteristics; V_0, no-load voltage; Q_{G1}, reactive power output of generator 1

Electronic controllers have no dead-band and permit closed-loop gains of between 100 and 200 in accordance with a proportional range of 1–0.5%. Consequently, in isolated duty a satisfactory distribution over the parallel generators is achieved even with a 3–4% artificial droop. For reasons discussed later, there are various factors that make higher droop values more suitable for interconnected systems. The polygon connection used previously in some power-stations for distributing the reactive load has therefore lost its significance to a large extent because total elimination of changes in the steady-state voltage had to be bought at the cost of complicated circuitry.

40.5.6.2 Principle of current bias

The principle of phasor addition of a current-proportional voltage to the generator voltage has been known in various forms for some time (*Figure 40.22*). All three-phase voltages should be measured in each case to keep ripple and filter time-constants small. As shown in *Figure 40.22*, a one-phase current bias can be applied. In the case of controllers for large generators, the extra cost for symmetrical three-phase bias is justified.

The summation is made such that the overexcited reactive component of the current increases the actual voltage. This method of falsifying the actual value in relation to an unchanged set-point results in a drooping characteristic. In a steady-state condition the effect is the same as that of a reactance. A subtractive current bias causes a rising

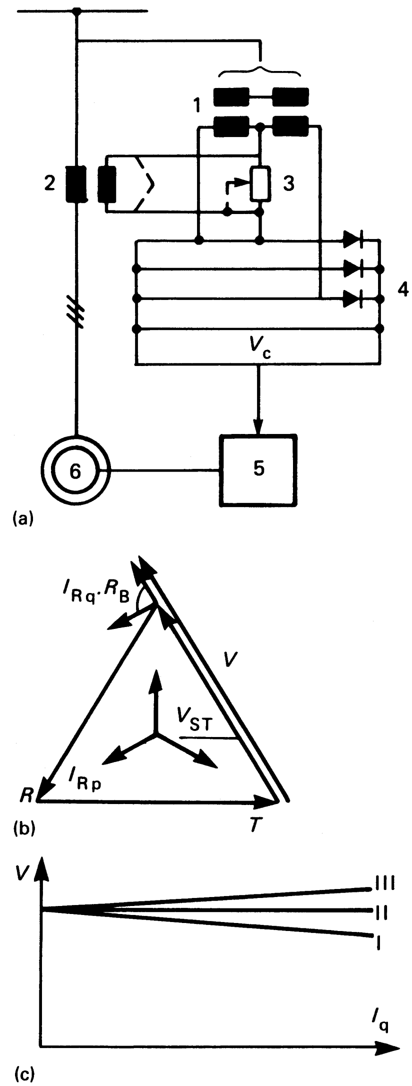

Figure 40.22 Current bias: (a) basic circuit diagram; (b) phasor diagram; (c) characteristics. 1, Three-phase voltage transformer; 2, current transformer; 3, load resistance R_B; 4, rectifier; 5, voltage regulator; 6, generator; V_c, V, r.m.s. voltage; I_{Rp}, active current in phase R; I_{Rq}, reactive current in phase R; I_q, reactive current, superexcited; I, reactive current droop; II, no effect; III, reactive current compounding

characteristic, i.e. a compounding. The effect of a true reactance can be reduced by compounding. In simple circuits the reactive current droop is accompanied by a slight compounding in the active current, but in most cases this is useful and under no circumstances is it a disturbing influence.

It should also be noted that the current bias curve is not entirely linear but slightly progressive. This is of virtually no significance. The current bias can be varied between zero and maximum by altering the load resistance. Nearly all voltage regulators are issued with this equipment.

As mentioned above, the current phasor is chosen in most cases so that an almost purely reactive load effect is created.

However, an active-load effect or a mixture of the two effects can be achieved by selecting a different phase angle. Consequently, in medium-voltage networks, additional active current compounding has shown itself to be a suitable means of improving the operating behaviour.

40.5.7 Slip stabilisation

Power transmission between synchronous machines and the load centre must remain stable even over long distances and under complex conditions. Experience has shown that certain network conditions can cause excessive hunting. Analysis indicates that hunting can be effectively reduced only by the introduction into the voltage control circuit of transient stabilising signals derived from the machine speed/frequency or produced by a change in the electrical output of the generator. Knowledge of the origin of the instability and the means of intervening in the controlled synchronous machine are essential for applying additional signals.

If the synchronous machine is connected to a rigid network through a reactance, it can be easily seen from the phasor diagram that the terminal voltage of the machine and the electrical torque alter with the rotor angle and with the main flux. The changes in terminal voltage, torque and main flux are given by differential quotients. In order to be able to make a quantitative statement for a given duty point, small changes are observed and the transmission functions and their representative factors are linearised about the duty point (index 0). This gives simple expressions, and a block circuit diagram (*Figure 40.23*) can be drawn which characterises the response of the synchronous machine at the rigid network. Let

$$\Delta M_{\mathrm{dE}} = k_1 \Delta\delta\psi + k_2 \Delta E'_{\mathrm{q}}$$

$$\Delta E'_{\mathrm{q}} = k_3 \Delta E_{\mathrm{p}} + k_4 \Delta\delta\psi$$

$$\Delta V_{\mathrm{t}} = k_5 \Delta\delta\psi + k_6 \Delta E'_{\mathrm{q}}$$

$$k_1 = \frac{\Delta M_{\mathrm{dE}}}{\Delta\delta\psi} = \frac{V_0 \cos\delta_0}{x_{\mathrm{q}} + x_{\mathrm{e}}} E_{\mathrm{q0}} + \frac{x_{\mathrm{q}} - x'_{\mathrm{d}}}{x'_{\mathrm{d}} + x_{\mathrm{e}}} V_0^2 \sin\delta_0 \frac{1}{x_{\mathrm{q}} + x_{\mathrm{e}}}$$

$$k_2 = \frac{\Delta P_{\mathrm{d}}}{\Delta E'_{\mathrm{q}}} = \frac{V_0 \sin\delta_0}{x'_{\mathrm{d}} + x_{\mathrm{e}}}$$

$$k_3 = \frac{\Delta E'_{\mathrm{q}}}{\Delta E_{\mathrm{p}}} = \frac{x'_{\mathrm{d}} + x_{\mathrm{e}}}{x_{\mathrm{d}} + x_{\mathrm{e}}}$$

$$k_4 = \frac{x_{\mathrm{d}} - x'_{\mathrm{d}}}{x'_{\mathrm{d}} + x_{\mathrm{e}}} V_0 \sin\delta_0$$

$$k_5 = \frac{\Delta V_{\mathrm{t}}}{\Delta\delta\psi} = \frac{V_{\mathrm{d}}}{V_{\mathrm{t}}} V_0 \cos\delta_0 \frac{x_{\mathrm{q}}}{x_{\mathrm{q}} + x_{\mathrm{e}}} - \frac{V_{\mathrm{q}}}{V_{\mathrm{t}}} V_0 \sin\delta_0 \frac{x'_{\mathrm{d}}}{x'_{\mathrm{d}} + x_{\mathrm{e}}}$$

$$k_6 = \frac{\Delta V_{\mathrm{t}}}{\Delta E'_{\mathrm{q}}} = \frac{V_{\mathrm{q}}}{V_{\mathrm{t}}} \frac{x_{\mathrm{e}}}{x'_{\mathrm{d}} + x_{\mathrm{e}}}$$

The relationship between change in torque and change in rotor angle in a closed voltage-regulator loop is therefore

$$\frac{\Delta M_{\mathrm{dE_2}}}{\Delta\delta\psi} = \frac{k_1 k_3 k_5 + k_2 k_4 (1 + pT_{\mathrm{E}})}{1/k_2 + k_6 k_{\mathrm{E}} + \mathrm{p}(T_{\mathrm{E}}/k_2 + T'_{\mathrm{d_0}}) + \mathrm{p}^2 T_{\mathrm{E}} T'_{\mathrm{d_0}}}$$

The factors, $k_1, \ldots, k_6$ have a considerable influence on the damping of the synchronous machine and its behaviour, as follows.

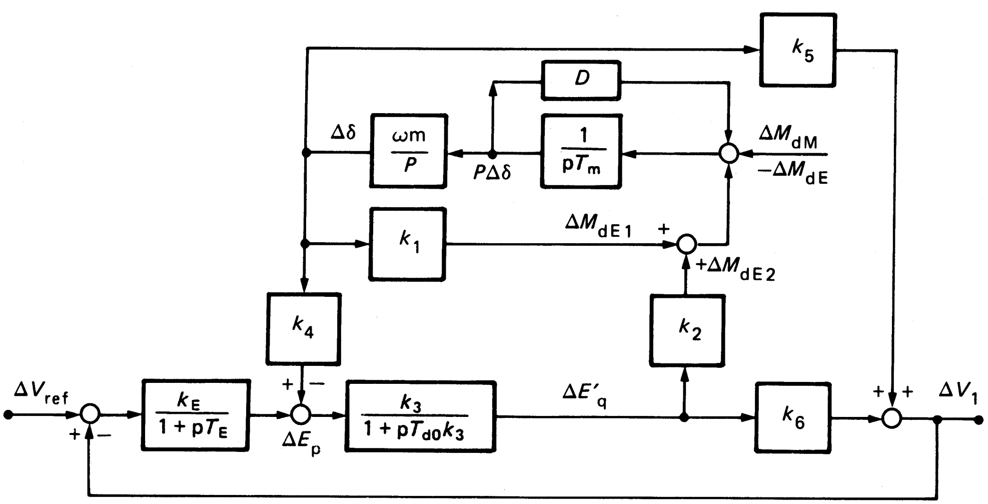

Figure 40.23 Block circuit diagram of a synchronous machine connected to a rigid network: D, damping constant of synchronous machine; k, k_{E} proportionality factors; M_{dE}, electric torque; M_{dM}; mechanical torque; T'_{d0}, T_{E}, time-constants; T_{m}, moment of inertia; ω_{m}, angular velocity of synchronous machine; p, operator d/dt; other symbols, as for *Figure 40.17*. For linearisation of transfer functions assuming small changes:

$$k_1 = \frac{\Delta M_{\mathrm{dE1}}}{\Delta\delta\psi} \quad E'_{\mathrm{q}} = \text{constant} \qquad k_4 = \frac{\Delta E'_{\mathrm{q}}}{\Delta\delta\psi}\frac{1}{k_3}$$

$$k_2 = \frac{\Delta M_{\mathrm{dE2}}}{\Delta E'_{\mathrm{q}}} \quad \delta\psi = \text{constant} \qquad k_5 = \frac{\Delta V_{\mathrm{t}}}{\Delta\delta\psi} \quad E'_{\mathrm{q}} = \text{constant}$$

$$k_3 = \frac{\Delta E'_{\mathrm{q}}}{\Delta E_{\mathrm{p}}} \quad \delta\psi = \text{constant} \qquad k_6 = \frac{\Delta V_{\mathrm{t}}}{\Delta E'_{\mathrm{q}}} \quad \delta\psi = \text{constant}$$

k_1 is generally positive and can assume negative values only at correspondingly large network reactances, but it is then no longer possible to transmit stable power. In the normal range, however, this factor has a stabilising effect, i.e. damping.

k_2 is always positive and has a stabilising effect.

k_3 is independent of the rotor angle and responds only to changes in excitation.

k_4 is negative and reduces damping in the system, an effect that can be markedly reduced by high gain in the voltage regulator. The negative electric torque generated by k_4 is synchronous with the torque achieved with k_1 and is compensated by this.

k_5 comprises two components. With large system reactances x_e, i.e. where the rotor angle is large anyway, the expression can become negative. A torque that reduces damping is generated and is further enlarged by the gain at the voltage regulators. Active-load hunting commences with large amplitudes and leads to the machine losing synchronism and being shut down. Only with slip-stabilisation equipment can the effects of this component be eliminated and stable power transmission restored.

k_6 is independent of rotor angle and therefore of no significance as far as hunting is concerned.

It can be seen from the block circuit diagram that the damping-reducing influence is introduced through the difference between set-point and actual values at the voltage regulator. Provided that the synchronous machine is not equipped with static excitation, it is recommended to feed the stabilising signal to the mixing point of the control amplifier. Where static excitation equipment is provided, mixing is also possible direct at the entrance of the gate control system of the power stage of the excitation equipment. To damp the rotor oscillations, it is essential that more active power is delivered at the stator terminals when the rotor is accelerated, and less when it is braked.

There are various means of measuring speed and acceleration, and their corresponding effect on the rotor motion. One simple method is to measure the active power. Assuming that the prime-mover power is constant, changes in the active power cause corresponding acceleration or deceleration of the rotor. Measuring the active power fluctuations gives the first derivative of speed. The actual speed can be determined by integration. The accuracy of the method is adequate for this purpose. However, the reaction to load changes at the drive end is entirely false. Any danger to operation can safely be eliminated by limiting the effect of the stabilising equipment on the voltage control and by introducing an additional signal that is also proportional to frequency.

Thus the use of Δf, i.e. the angular frequency ($\Delta\omega$), instead of integration of ΔP represents a considerable advance in this field. The base signal combination ($\Delta\omega$ plus ΔP) arrangement therefore gives the best arrangement for damping of oscillations (*Figure 40.24*). Test results have fulfilled all expectations in respect of the stabilising signal. Peaks in the signal, which occur when breaker operations take place in the network, are of such short duration that they have no effect upon the excitation. The load/frequency system combines the advantages of load and frequency measurement without any detrimental side-effects.

40.5.8 Adapted regulator for the excitation of large generators

The excitation of a generator is in principle controlled by automatic voltage regulators, and improvements have been achieved in several respects. The original purpose of the feedback arrangement was *voltage regulation*. This basic requirement is important for maintaining stable synchronous operation of the generators in the power system and for controlling the voltage supplied to customers. Further advantages have been obtained since *static* (power semiconductor) *excitation* systems have been used. Through these fast-acting devices, the regulator may contribute to the *transient stability* after faults (keeping the generator from falling out of step) and to the *damping* of electromechanical rotor oscillations. Furthermore, stabilising signals have been introduced with pre-set amplification gains as a compromise to various operational points. These features are now provided by many commercial regulators. The adapted regulator improves the performance one step further. The main result is the good damping provided for a wide region of operating points, and the smooth voltage regulation.

For better understanding of the benefits of an adaptive control on a network, the one-machine system is presented in *Figure 40.25*. The generator is connected to the 'infinite bus' V_∞ over two transmission lines with circuit-breakers. V_∞ is an ideal three-phase voltage source, and the lines are represented by pure reactances. X_e denotes the equivalent reactance between the generator and V_∞. This configura-

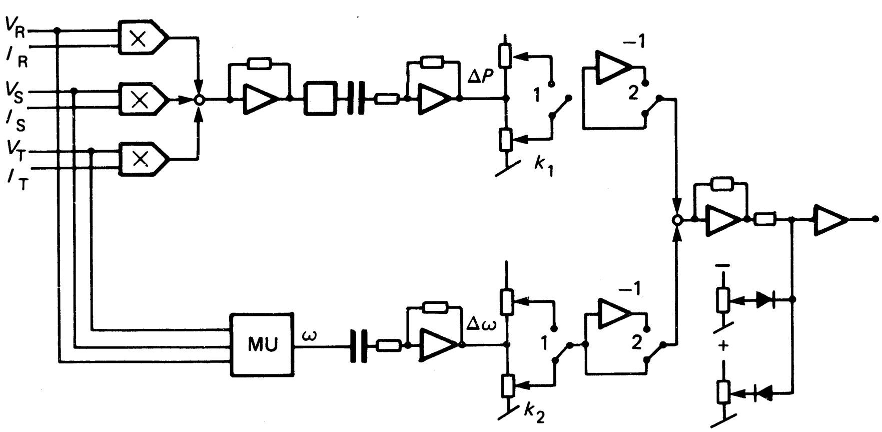

Figure 40.24 $\Delta\omega + \Delta P$ base signal combination arrangement for damping of oscillations, MU

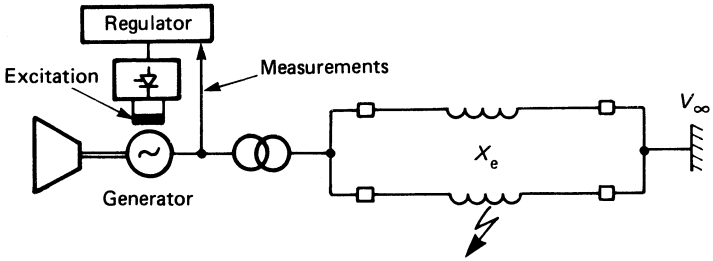

Figure 40.25 Power system model

tion corresponds to the realistic case of a remote power-station supplying a distant load centre.

The control quality of the synchronous machine is assessed in terms of the steady-state behaviour and the dynamic performance in the presence of disturbances. Two kinds of *disturbance* must be considered.

(1) short circuits in the network, line switchings;
(2) changes of operating point (power, voltage, network parameters).

Therefore in the design of the voltage regulator the following performance criteria must be considered.

(1) Regulation of the generator terminal voltage with regard to: (i) smoothness (no ripple during steady-state operation); (ii) speed of response (to avoid overvoltages after load or topology changes); and (iii) accuracy.
(2) Ability to keep synchronism after a fault. This requirement means simply that the excitation voltage should be at the maximum during faults and during dangerous rotor accelerations. The excitation may return to normal after the first peak of the rotor swing.
(3) Damping of rotor oscillations.
(4) Criteria (1)–(3) for a wide region of operating points of the generator (power loading, voltage).

The voltage regulator used here corresponds to the present-day conventional regulator as described earlier. However, the stabilising signals derived from power and frequency measurements are introduced via variable gain factors (*Figure 40.26*). P and ω feedback are regarded as additional signals, the purpose of which is to produce damping (stabilisation) of rotor oscillations.

The gains for the power and frequency feedback are determined by using the D-decomposition technique. D decomposition (or domain separation) is a method based on the characteristic equation of the linearised model. It produces curves of constant damping in the plane of the gains G_1 and G_2, at a certain operating point (P=constant, Q=constant) and constant line impedance X_c. The method is combined with an optimisation procedure to generate optimal gains (optimal damping of the dominant poles). However, as already stated, the gains that are adequate for the best damping of rotor oscillations depend on the operating point of the generator. Owing to the non-linearities in the system, the operating point itself may vary in time, depending on the loading, voltage and network topology (X_c).

Three quantities are sufficient to define the operating point: active power P, reactive power Q and the reactance X_e of the network. P and Q are measurable directly, while X_e can be identified from local measurements by system response. When the three quantities are known, the linearised model of the generator is fully defined (assuming $V_\infty = 1$ p.u.) and the adequate gains can be adjusted automatically.

However, two situations must be considered: steady-state operation and transient operation (short circuit, rotor oscillations). In the steady state, the gains G_1 and G_2 should be reduced for better voltage control, but they may be larger during transient operation.

The resulting adaptation scheme is shown in *Figure 40.27*. The entries of the look-up table are computed off-line. G_1 and G_2 are adjusted whenever major events occur or the parameters have drifted significantly. Updating of the gains is only permitted once every few seconds in order to secure the stability of the adaptation. The identification of X_e is based on a simple curve-fitting procedure. The adaptation scheme (*Figure 40.27*) is implemented on a digital

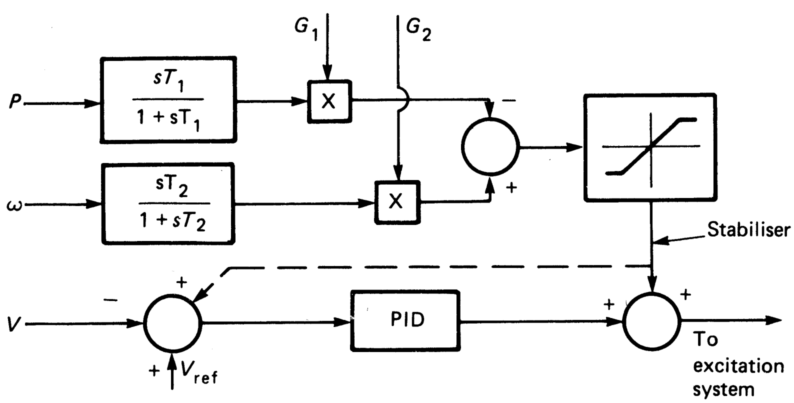

Figure 40.26 The analogure regulator (present-day Brown Boveri Cie (BBC) regulator). - - -, Alternative connection required by some customers

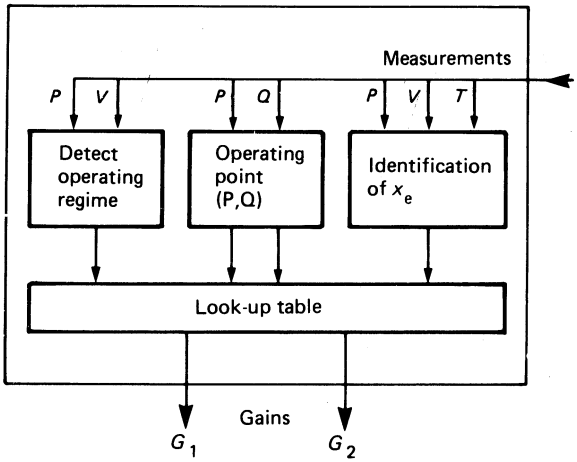

Figure 40.27 The adaptation scheme

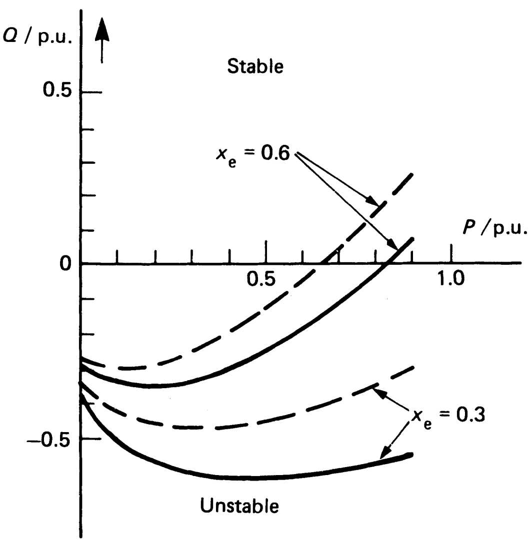

Figure 40.28 Steady-state stability limits of the generator: — —, Unadapted regulator; ——, adapted regulator

microprocessor. The gains G_1 and G_2 are then applied to the analogue regulator of *Figure 40.26*.

The need for adaptation at critical operating points is demonstrated in *Figure 40.28*. Two sets of gains are used, each designed for a specific operating point. The graphs show that the gains designed for one case may not be used in the other. When the wrong gains are used, instability occurs after a disturbance or in the form of self-induced oscillations. *Figure 40.28* shows the region of stable operating points for two typical values of X_e. The stability boundary is evaluated using the linearised model.

40.5.9 Static excitation systems for positive and negative excitation current

Hydroelectric power-plants are usually remote from the load centre, and the power produced is transmitted over long three-phase transmission lines to the consumer. Depending upon the active power to be transmitted (light- or heavy-load operation), the transmission line will supply or consume reactive power, which must be absorbed or supplied by generators at two ends of the line or by reactive current compensators (var sources). Owing to the great distance of transmission along the line, the excitation equipment of such synchronous machines must be designed for high ceiling voltages and negative excitation currents in conjunction with stability of operation. Static excitation equipments with controlled static converters connected in antiparallel and subject to circulating current are capable of satisfying these requirements for hydroelectric generators and synchronous compensators; they improve the capacity of these machines for absorbing reactive load, while retaining optimum control and operating characteristics not merely for steady-state operation but also for dynamic and transient conditions in the network. The circuit diagram for an excitation device is shown in *Figure 40.29*.

The maximum continuously permissible positive excitation current is defined by the maximum continuous load of the synchronous machine for a given power factor. The short-term loadings due to ceiling current and load-independent short-circuit current at the rotor in the event of a fault must also be superimposed upon this value. The maximum continuous current of an excitation device for hydroelectric generators is therefore about 1.5 times the rated excitation current, if redundancy design is ignored. On the other hand, the maximum negative excitation current that must be applied to maintain the voltage of the synchronous machine under extreme capacitive load is determined solely by the design, and therefore by the machine parameters, of the synchronous machine.

A salient-pole generator of terminal voltage V operating at a load angle δ with an internal field electromagnetic force (e.m.f.) E_p supplies a reactive power Q given by

$$Q = \frac{E_p V}{X_d}\cos\delta - \frac{V^2}{X_d}\left(1 + \frac{X_d + X_q}{X_q}\sin\delta\right)$$

where X_d and X_q are the direct- and quadrature-axis reactances, respectively. If the load angle δ and the excitation E_p are zero, the synchronous machine takes continuously from the network a reactive power, the value of which is determined by the direct-axis reactance X_d: i.e. $Q = -V^2/X_d$. The supply of reactive power by the network is then just equal to the absorption capability of the synchronous machine. If no negative excitation current can be supplied and the capacitive network load increases further, self-excitation will occur, and the machine must be disconnected. Since, however, the synchronising torque $M_e = dP/d\delta$ begins to decrease only with negative excitation beyond the value corresponding to $E = -V[(X_d - X_q)/X_q]$, negative excitation up to this value can be introduced with quick-acting, regulators, the reactive power absorption rising to $Q = -V^2/X_q$.

The ratio X_d/X_q for salient-pole hydrogenerators lies in the range 1.3–1.4, and the no-load excitation current I_{f0} corresponds to the generator terminal voltage. The maximum negative exciting current is therefore $I_{f0}(X_d/X_q - 1)$, which approximates to $0.4I_{f0}$. Thus the equipment for imposing negative excitation needs to be designed for only about 40% of the excitation on no-load; it does, however, ensure an increase of about 40% in the reactive power absorption at rated load and frequency. If the reactive load supplied by the connected network rises above $Q_c = -V^2/X_q$, the synchronous machine will no longer be capable of holding the voltage, and the definitive self-excitation condition, which cannot

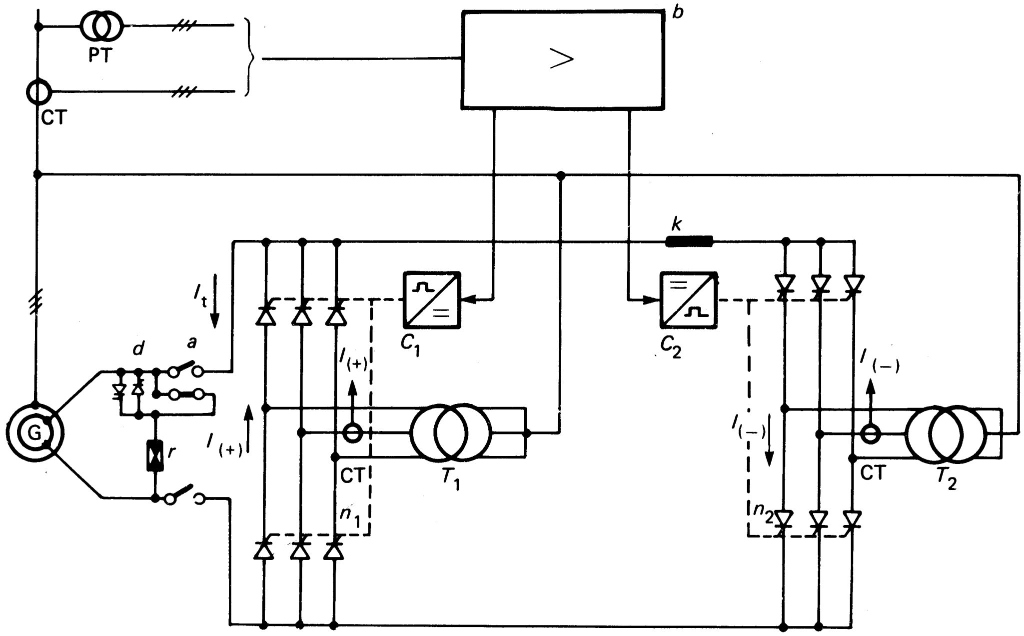

Figure 40.29 Circuit diagram for excitation device: CT, current transformers; G, synchronous generator; I_f, field current of synchronous generator; PT, voltage transformer; T_1, T_2, transformers; a, field suppression switch; b, control electronics; C_1, C_2, firing-angle devices; d, crowbar; k, reactor; n_1, static converter for positive excitation current; n_2, static converter for negative excitation current; r, non-linear de-energising resistor

be controlled by any excitation current or regulator, will be initiated.

If the operating conditions now change specifically with regard to the frequency, the limitations on the use of negative excitation currents must be carefully investigated, since the design of the means for compensating the transmission system will be affected. For instance, with a synchronous machine operating on a long line, if a sudden drop occurs in the active load at the consumer end of the line then, in addition to the charging power for the network, a frequency rise also occurs. This leads both to a rise in the quadrature-axis reactance of the machine and to a fall in the capacitive network impedance. This implies, however, that maintaining the voltage is rendered more difficult by the square of the frequency change. The maximum negative excitation that can be used must in this case be reduced in inverse proportion to the frequency.

In order to decouple the two d.c. circuits (to absorb the different voltage–time areas) and to avoid short-circuit balancing currents, a reactor is incorporated in the d.c. intermediate circuit. The balancing current between the two bridges is regulated to a minimum, but it does provide a guarantee that the two converter sets always carry current; therefore changeover from negative to positive excitation current can be effected virtually without loss of time.

40.5.10 Machine models for investigating stability

Generally, when investigating stability, one examines the consequences of the following disturbances.

(1) Short circuit (one- to three-phase) in the network with subsequent complete (three-phase) or partial interruption of the load flow between generator and network (rapid reclosure).
(2) Partial or complete interruption of load flow between generator and network (load rejection).
(3) Small fluctuations in the load flow (static stability).

It is always assumed that the generators are connected to an infinite power system via a transformer and a network reactance X_n (single-machine problem).

The major parameters for studying stability are:

(1) the generator parameters H, X_d, X'_d, X''_d, X'_q (X'_q), X''_q, T'_d, T''_d, (T'_q), T''_q, X_p, X_{re}, $E = f(I_F)$;
(2) the transfer functions of the voltage regulator and turbine controller;
(3) the unit-transformer reactance X_{tr} and the network;
(4) the nature of the fault (one-phase, three-phase, short circuit, etc.), the fault location and fault time t_F.

The generator parameters are determined by the construction of the machine. Evaluation of the data for a variety of machines reveals the following trend: for a given frequency f, the inertia constant H diminishes with increase in rating S and a decreasing number p of pole pairs:

$$H = \frac{GD^2}{4} \frac{\omega_s^2}{2S}$$

where $GD^2/4$ is the moment of inertia referred to diameter, and $\omega_s = 2\pi f/p = 2\pi n_s$ is the synchronous angular velocity. Only a lower limit of H can be specified, because its magnitude depends considerably on the turbine inertia.

The reactances X_d and X'_d, the stator resistance R and the short-circuit time-constant T'_d show a tendency to become larger with increasing power rating. However, these relationships can be very strongly influenced by structural features and design layout.

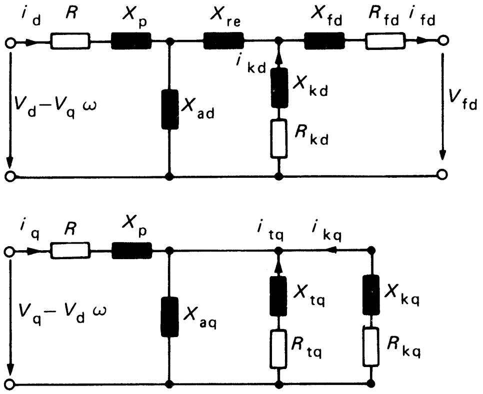

Figure 40.30 Equivalent circuit for model 1 of a synchronous machine (for symbols, see text)

Experience shows that the method of calculation and the machine model influence the results more strongly with high-speed transients than with slow ones.

40.5.10.1 Synchronous machine models

Six different models of synchronous machine are generally used. Saturation is disregarded and the same equations of motion are used for all models.

Model 1 This model has six windings (three damper windings). Its equivalent circuit diagram is shown in *Figure 40.30*. The corresponding equations are as follows.

The network equations are

$$\begin{aligned} V_d^G &= V_d^N + R_e i_d + L_e(di_d/dt) - \omega L_e i_q \\ V_q^G &= V_q^N + R_e i_q + L_e(di_d/dt) + \omega L_e i_d \end{aligned} \qquad (40.1)$$

in which $\omega L_e = X_{tr} + X_N$.

The following equations are used for the synchronous machine:

Flux–current relationships

$$\begin{aligned} {}_d &= (X_p + X_{ad}) i_d + X_{ad} i_{kd} - X_{ad} i_{fd} \\ {}_{kd} &= X_{ad} i_d + (X_{ad} + X_{re} + X_{kd}) i_{kd} - (X_{ad} + X_{re}) i_{fd} \\ {}_q &= (X_p + X_{aq}) i_q + X_{aq} i_{tq} + X_{aq} i_{kq} \\ {}_q &= (X_p + X_{aq}) i_q + X_{aq} i_{tq} + X_{aq} i_{kq} \\ {}_{tq} &= X_{aq} i_q + (X_{aq} + X_{tq}) i_{tq} + X_{aq} i_{kq} \\ {}_{kq} &= X_{aq} i_q + X_{aq} i_{tq} + (X_{aq} + X_{kq}) i_{kq} \end{aligned} \qquad (40.2)$$

Voltage equations

$$\begin{aligned} d\ {}_d/dt &= -V_d^G + {}_q\omega - Ri_d \\ d\ {}_q/dt &= -V_q^G - {}_d\omega - Ri_q \\ d\ {}_{fd}/dt &= V_{fd} - R_{fd} i_{fd} \\ d\ {}_{tq}/dt &= -R_{tq} i_{tq} \\ d\ {}_{kd}/dt &= -R_{kd} i_{kd} \\ d\ {}_{kq}/dt &= -R_{kq} i_{kq} \end{aligned} \qquad (40.3)$$

Mechanical equations

Torque:

$$M_B = {}_q i_d - {}_d i_q \qquad (40.4)$$

Power:

$$P = V_d^G i_d + V_q^G i_q \qquad (40.5)$$

$$Q = V_q^G i_d - V_d^G i_q \qquad (40.6)$$

Equation of motion:

$$2H(ds/dt) = M - M_B \qquad (40.7)$$

$$d\theta/dt = s \qquad (40.8)$$

$$\omega = 1 + s \qquad (40.9)$$

The quantities L, X, R, , i, V, M and ω are per-unit quantities.

From the input data

$$R, X_p, X_c, X_d, X_q, X'_d, X''_d, X''_q, T'_d, T'_q, T''_d, T''_q, S_N, V_N, f, I_{fd0}, V_{fd0}, p, H$$

of which T, S_N, V_N, f, I_{fd0}, V_{fd0} and H are not per-unit, the constants X_{ad} and X_{aq} of the synchronous machine can be calculated in the following manner:

$$X_{ad} = X_d - X_p \qquad (40.10)$$

$$X_{aq} = X_q - X_p \qquad (40.11)$$

$$X_{re} = \frac{X_{ad}(X_{re} - X_p)}{X_d - X_{re}} \qquad (40.12)$$

$$X_{td} = \left(\frac{X_d - X_p}{X_d - X_{re}}\right)^2 \frac{(X_d - X_e)(X'_d - X_e)}{X_d - X'_d} \qquad (40.13)$$

$$X_{kd} = \left(\frac{X_d - X_p}{X_d - X_{re}}\right)^2 \frac{(X'_d - X_e)(X''_d - X_e)}{X'_d - X''_d} \qquad (40.14)$$

$$X_{tq} = \frac{(X_q - X_p)(X'_q - X_p)}{X_q - X'_q} \qquad (40.15)$$

$$X_{kq} = \frac{(X'_q - X_p)(X''_q - X_p)}{X'_q - X''_q} \qquad (40.16)$$

$$R_{fd} = \left(\frac{X_d - X_p}{X_d - X_{re}}\right)^2 \frac{(X_d - X_e)^2}{X_d - X'_d} \frac{1}{T_{fd}\omega_B} \qquad (40.17)$$

$$R_{kd} = \left(\frac{X_d - X_p}{X_d - X_{re}}\right)^2 \frac{(X'_d - X_e)^2}{X'_d - X''_d} \frac{X''_d}{T''_d X'_q \omega_B} \qquad (40.18)$$

$$R_{kq} = \frac{(X'_q - X_p)^2}{X'_q - X''_q} \frac{X''_q}{T''_q X'_q \omega_B} \qquad (40.19)$$

$$R_{tq} = \frac{(X_q - X_p)^2}{X_q - X'_q} \frac{1}{T_{tq}\omega_B} \qquad (40.20)$$

$$T_{td} = T'_d \frac{X_d}{X'_d}\left(T_{kd} - T''_d \frac{X'_d}{X''_d}\right)\left(\right. \qquad (40.21)$$

where

$$T_{kd} = T''_d \frac{X'_d}{X''_d} \times \frac{(X_d - X_{re})(X'_d - X''_d) + (X'_d - X_{re})(X''_d - X_{re})}{(X'_d - X_{re})^2} \quad (40.22)$$

$$T_{tq} = T'_q \frac{X_q}{X'_q} - \left(T_{kq} - T''_q \frac{X'_q}{X''_q} \right) \quad (40.23)$$

$$T_{kq} = T''_q \frac{X'_q}{X''_q} \times \frac{(X_q - X_p)(X'_q - X''_q) + (X'_q - X_p)(X''_q - X_p)}{(X'_q - X_p)^2} \quad (40.24)$$

$$\omega_B = 2\pi f \quad (40.25)$$

The reference values are:

V_N for voltages V_d^G and V_q^G

S_N for powers P and Q

$I_N = S_N/\sqrt{3}V_N$ for current i_d and i_q (40.26)

$M_N = S_N/\omega_B$ for torque M (40.27)

I_{fd0} for excitation current i_{fd}

V_{fd0} for the excitation voltage

In Equations (40.1), R_e and L_e are respectively the resistance or the inductance of the positive-sequence system between generator and infinite network, i.e. $\omega L_e = X_{tr} + X_N$.

If the site of the short circuit is between the generator and the infinite network, there are ten first-order differential equations to integrate.

Model 2 This model has only one damper winding in the quadrature axis, i.e. $i_{tq} = 0$. The relationships $\psi_{tq} = f(i_q, i_{tq}, i_{kq})$ in Equations (40.2) and $d\psi_{tq}/dt = R_{tq} i_{tq}$ in Equations (40.3) do not apply. Instead of Equations (40.16) and (40.19) we have

$$X_{kq} = \frac{(X_q - X_p)(X''_q - X_q)}{X_q - X''_q} \quad (40.16a)$$

$$R_{kq} = \frac{(X_q - X_p)^2 X''_q}{(X_q - X''_q) T''_q X_q \omega_B} \quad (40.19a)$$

Equations (40.20), (40.23) and (40.24) do not apply.

Model 2 also takes account of the transformation terms, but has only two damper windings. In this case only nine differential equations have to be integrated.

Model 3 This, like model 2, has one damper winding in each of the direct and quadrature axes. The transformation terms in the stator equations do not apply, i.e. Equations (40.3) become

$$\begin{aligned} V_d^G &= \psi_q \omega \psi - R i_d \\ V_q^G &= -\psi_d \omega - R i_q \\ d\psi_{fd}/dt &= V_{fd} - R_{fd} i_{fd} \\ d\psi_{kd}/dt &= -R_{kd} i_{kd} \\ d\psi_{kq}/dt &= -R_{kq} i_{kq} \end{aligned} \quad (40.3a)$$

Model 3 also has two damper windings. The transformation terms are disregarded. There are only five differential equations to integrate. It is found from experience that with this configuration the time step can be much larger than with models 1 and 2.

The equations of motion (40.7)–(40.9) remain unchanged. In addition to M_B in Equation (40.4), however, the braking torque M_{Bs}, caused by the transformation terms when switching operations occur, must be introduced into Equation (40.7):

$$2H(ds/dt) = M - M_B - M_{Bs}$$

if the movement process is to be represented correctly.

Model 4 This model has no damper windings. The basic equations therefore become

$$\begin{aligned} \psi_d &= (X_p + X_{ad}) i_d - X_{ad} i_{fd} \\ \psi_{fd} &= -X_{ad} i_d + (X_{ad} + X_{fd}) i_{fd} \\ \psi_q &= (X_p + X_{aq}) i_q \end{aligned} \quad (40.2b)$$

$$\begin{aligned} V_d^G &= \psi_q \omega \psi - R i_d \\ V_q^G &= -\psi_d \omega \psi - R i_q \\ d\psi_{fd}/dt &= V_{fd} - R_{fd} i_{fd} \end{aligned} \quad (40.3b)$$

In the absence of damper windings, the asynchronous damping torque (M_{B2}) also must be included in the Equation of motion (40.7):

$$2H(ds/dt) = M - M_B - M_{Bs} - M_{B2}$$

Instead of Equations (40.10)–(40.24) we have the expressions

$$X_{ad} = X_d - X_p \quad (40.10^*)$$

$$X_{aq} = X_q - X_p \quad (40.11^*)$$

$$X_{fd} = \frac{(X_d - X_p)(X'_d - X_p)}{X_d - X'_d} \quad (40.13a)$$

$$R_{fd} = \frac{X_d - X_p}{X_d - X'_d} \frac{X'_d}{T'_d X_d \omega_B} \quad (40.17a)$$

The transformation terms are disregarded. Thus only three differential equations need to be integrated.

Model 5 This model has no field winding and no damper winding. The base equations for this model are:

$$\begin{aligned} \psi_d &= X'_d i_d - E_f \\ \psi_q &= X_q i_q \end{aligned} \quad (40.2b)$$

$$\begin{aligned} V_d^G &= \psi_q \omega \psi - R i_d \\ V_q^G &= -\psi_d \omega \psi - R i_q \end{aligned} \quad (40.3c)$$

The mechanical behaviour is described by Equations (40.4) and (40.7)–(40.9). E_t is calculated in terms of the initial values of i_d, i_q and V_q^G:

$$E_t = V_q^G + R i_q + X'_d i_d$$

On the stator, conditions are represented by one winding each in the direct and quadrature axes, their reactances being different. The effect of excitation appears as a current source in the equivalent circuit of the direct-axis winding. Only the two differential equations for the mechanical system have to be integrated.

Model 6 This model, like model 5, has neither field winding nor damper windings. Equations (40.2b) contain X'_d instead of X_q. Thus Equation (40.4) becomes

$$M_B = E'_t i_q$$

Model 6 resembles model 5 except that it has identical reactance in the direct and quadrature axes.

40.5.10.2 Comparison of the models

The essential difference between models 1 and 2 on the one hand, and models 3–6 on the other, is the allowance made for the transformation effect. Models 1–3 have damper windings, while models 4–6 do not. The stability of a synchronous machine after disconnection of the short circuit is determined chiefly by the accelerating torque M_A, or braking torque M_B, that was acting on the rotor during the short circuit. Accelerating torque M_A is composed of driving torque M and braking torque M_B: i.e. $M_A = M - M_B$. The braking torque M_B arising during the short circuit and oscillations must therefore be correctly represented in each model.

The braking torque M_B acting after the fault has occurred consists of the following component parts:

(1) a braking torque M_{B1} corresponding to losses in the stator and network resistance R;
(2) an asynchronous braking torque M_{B2} corresponding to losses in the rotor field and damper windings; and
(3) a decaying braking torque M_{B3} introduced by the transformation terms in the machine and network equations—this torque becomes effective at every change of state.

M_{B3} is mainly responsible for the well-known 'backswing' effect. The synchronous machine is then braked initially in the first 20 ms after the short circuit. However, the extent of the backswing depends on the site of the short circuit, because torque M_{B2} incorporates the network reactances between the machine and short-circuit location. In some instances, therefore, a short circuit across the terminals may be less of a stability problem than a distant short circuit.

Direct account is taken of all the braking torques M_{B1} to M_{B3} only in the case of models 1 and 2. M_{B1} is present with all the models. With model 3 there is also torque M_{B2}.

The following conclusions can be drawn.

(1) The transformation terms in the Park equations (models 1 and 2) and in the network equations must be taken into account (i) when power is low, (ii) when the short circuit is in the vicinity of the generator, and (iii) if the braking torque M_{B3} brought about by the transformation terms cannot be introduced into the mechanical equations.
(2) The backswing effect occurs only when the site of the short circuit is close to the generator. From this it follows that under certain circumstances a short circuit remote from the generator can be more dangerous, as regards stability, than a short circuit nearby.
(3) It is known that the individual synchronous machine models behave very differently.

In many instances, especially in the case of transient stability problems, the simpler models (4 and 5) exhibit the same behaviour as model 2 or 1 with transformation effect. Nevertheless, with the simple models it is particularly important to represent damping correctly. Models 4 and 5 are therefore particularly suitable for simulating synchronous machines with constant excitation voltage that are located far away from the short circuit. Investigation shows also that the widely recommended model 6 (constant voltage beyond transient reactance) yields results that are pessimistic.

If it is assumed that the constant H decreases, and reactances X_d, X'_d and X_t increase, with rising generator capacity, then the critical short-circuit duration will be smaller as generator capacity rises. Studies show, however, that the behaviour of even large synchronous machines can be described with the known models of synchronous machines, and that there is usually no need to make allowance for the transformation terms.

40.6 Decentralised control: electronic turbine controllers

40.6.1 Introduction

The turbine equipped with a controller represents an important item of decentralised control as its controller governs the active power input to the power system. For many reasons, both historical and technical, this controller is kept separate from excitation control, although a computer would be able to fulfil the combined function.

Modern turbine controllers are electronic and have to meet a series of functions and requirements. Frequency control is just one of these; safety functions, monitoring, limit checking, etc., are equally important. The most important requirements are the following:

(1) automatic start-up and shut-down of the turbine;
(2) application of a load–frequency control system;
(3) application of an external reference input;
(4) adjustable droop of the speed controller;
(5) good adaptability to the given operating condition;
(6) high-response sensitivity;
(7) Co-ordinated operation of the turbine–generator set and all other systems in the power-plant;
(8) short reaction time between controller and control valves; and
(9) short closing time of the control valves.

Nowadays turbine controllers are composed of electronic modules or functional groups. Most of these can be used in the control system of steam, gas or water turbines. However, the control schemes of such turbines vary widely. We therefore describe both a modern steam-turbine control system and a system for a Francis water turbine. First, however, we explain in simple terms the basic functions of frequency and load control. We derive the elementary block diagram of a frequency controller, explain set-point control, and set out the basic concept of droop. Our treatment concludes with a consideration of frequency control in a multi-machine system.

40.6.2 The environment

The turbine driven by water or steam is connected to a synchronous generator. The synchronous generator has the important property of being able to align itself with other generators when the armatures are interconnected and the rotors are excited. When this alignment is achieved, i.e. when peaks and zero crossings of the induced voltages occur at the same instant, 'synchronous' operation is realised. In greater detail, there are small differences between the mechanical positions of the rotors due to the individual loadings, which may reach 45°. We do not consider different numbers of poles, but assume that all generators have the same number of poles.

In synchronous operation all generators have the same frequency or speed. When the frequency changes, all generators change their speed. Hence, frequency or speed control in synchronous or interconnected operation means control of one common frequency. Small deviations and transients with respect to this frequency are corrected by the inherent ability of the synchronous machines to maintain alignment.

A single generator can also be operated in a system. However, in this case there is no other generator to which it can be aligned. The operation is similar to that of a d.c. generator. Speed control and angular position are purely a matter of the balance between prime-mover torque and load torque acting on the inertia of the shaft. Following a load change, there will be a change in frequency. The speed governor, which is the frequency controller, has an important bearing on the frequency behaviour.

In contrast, a change in loading of a single generator in interconnected operation does not necesarily affect the frequency because it is maintained by the other generators. Hence it is important to know the environment in which a speed governor has to function. Modern governing systems are being designed to cope with a wide range of system conditions.

40.6.3 Role of the speed governor

The speed governor can best be understood by considering a steam engine with a generator serving a local load in isolation, the turbine being controlled by a fly-ball governor. The basic function is realised by a proportional control, whereby the valve position is the actuating signal. Speed or frequency is the input from the system, i.e. the controlled quantity which is compared with a reference signal (also called the 'set-point'). The difference between the measured signal and the set-point is converted to the valve position, which involves a gain. This gain has a two-fold meaning. First, it is a pure signal gain relating a deviation, based on nominal quantities, and a deviation of the valve position which is also referred to as a nominal position. Second, the gain means also a power amplification, i.e. the conversion of a weak electrical signal to a strong mechanical torque. A schematic diagram of the basic arrangement is given in *Figure 40.31*, where the functional relations are shown.

Assuming that the stability of such a system is guaranteed, transient and steady-state conditions can easily be calculated. The basic functions can best be understood by considering steady-state or quasi-steady-state operating points. If the need arises to deliver more power to the generator, the valve of the turbine has to be opened. This is realised by forming a difference between the set-point and the measured speed signal either by raising the set-point or by a drop in frequency. Changes in the governing system will take place until a balance is reached. Steady-state conditions are found from the relations

$$\Delta f K = \Delta M_e; \quad \Delta f = f_s - f$$

where f is the frequency, Δf is the frequency deviation, f_s is the set-point, M_e is the electrical or load torque, and K is the gain of the speed governor in units of torque per unit of frequency.

The gain determines the amount of frequency deviation. The higher K is, the smaller Δf will be. However, the gain cannot be chosen to be arbitrarily high. There are problems of stability and certain restrictions due to the allocation of changes of power. The relation $\Delta f K = \Delta M_e$ also shows that the speed governor has a double function. It carries out both load control, i.e. the matching of prime-mover torque to the load torque, and frequency control. The relation between these two functions is given by the gain K. Its dimensions in practice are megawatts per hertz; i.e. instead of torque, it is the power which is measured at the output.

Hence, in isolated operation, frequency changes follow a load change so long as the set-point is fixed. A change in set-point will cause a rise in frequency when the load remains constant.

In interconnected operation, the frequency remains practically unchanged. Therefore, a change in loading cannot be affected by the power system. The output of the generator changes without any variation of the frequency, only when the set-point is changed. In this case the speed governor is a pure load controller.

In practice the speed governor is always ready to take on either function. It is the boundary conditions that determine its momentary role, i.e. the governor controls the output power when the frequency is imposed and it controls the

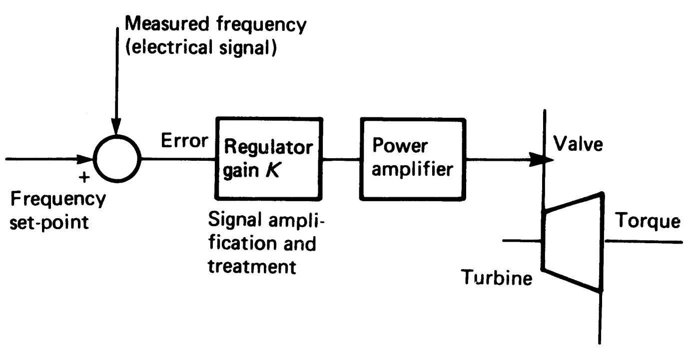

Figure 40.31 Basic arrangement of a speed governor (frequency controller: the basic functions of error detection, signal amplification and power amplification are shown)

frequency when the load is imposed. In a more complex situation, when load and frequency are dependent, the governor varies its output until an equilibrium is reached.

40.6.4 Static characteristic

Modern speed governors have amplifiers that include an integrating property. This choice is made for both reasons of principle and technical reasons, the main one of which is the control of servomotors by valves or signal converters. The proportional behaviour is still maintained by adding the output power as a measured quantity. Such a governor acting on a turbine–generator is commonly represented by a block diagram as shown in *Figure 40.32*.

In this schematic, two signals measured at the output are compared with set-points, i.e. frequency and power. All deviations are combined in one summing junction, the frequency deviation being weighted by K. The summing junction produces an error which drives the regulator as an integrator. The regulator, which is at the same time a power amplifier, drives the valve.

The steady-state behaviour of the system is described by a characteristic graph with a few parameters. The starting point is the zero value of the error e when the system (*Figure 40.32*) has reached a stationary operating point. Then

$$e = P_s - P + K(f_s - f) = 0 \Leftarrow\Leftarrow$$

where P is the measured power output and P_s is the power set-point; the other parameters have already been defined. P and f are variables, represented by the axes in *Figure 40.33*. The frequency f can be expressed by $f = f_s + (P_s - P)/K$, a linear relationship between f and P. The slope is

$$df/dP = -1/K = -D$$

where D is the *droop* of the system (in hertz per megawatt). Together with the intersection $(f_s + P_s/K)$, it determines the position of the straight-line characteristic of the speed-governing system. Discussion of the role of the parameters gives an insight into the operation of the system.

40.6.4.1 *No-load operation and* f_s

On no load the output is zero and the speed is given by the intersection of the straight line with the ordinate. Thus f_s is used to set the no-load speed. P_s is set to zero.

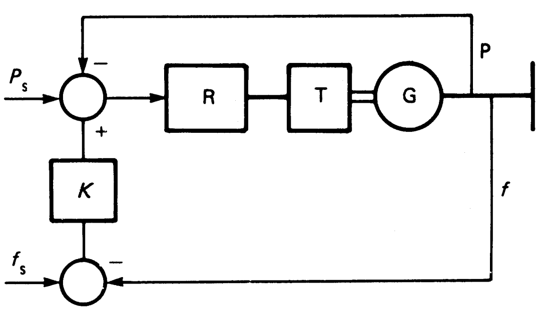

Figure 40.32 Schematic diagram of a power–frequency controlled generator: G, generator; T, turbine; R, regulator (integrating); P, measured power; P_s, set-point power; f, measured frequency; f_s, frequency set-point; K, gain

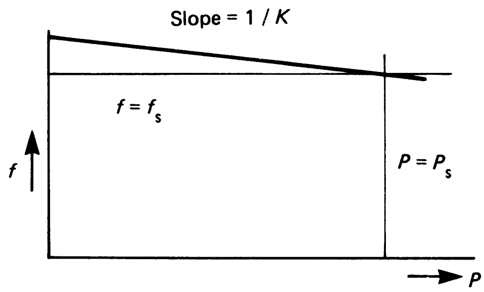

Figure 40.33 Static characteristic: the operating point is confined to the sloping straight line

40.6.4.2 *Synchronous operation and* P_s

When the no-load frequency has reached the system frequency and the synchronising conditions are met, the generator is first connected to the power system, then loaded by raising P_s to the desired value. The characteristic is thereby raised in parallel. The frequency remains unchanged. Should the generator breaker be opened inadvertently, the frequency will assume the value given by the intersection of the straight line with the ordinate. This involves a rise in frequency that is governed by K.

Consider a generator which has the following settings and parameters:

$$f_s = 50\,\text{Hz};\ P_s = 200\,\text{MW};\ K = 80\,\text{MW/Hz}$$

The generator is operating at $f = 50$ Hz, $P = 200$ MW. After disconnection of the generator, the no-load frequency will become $f = 52.5$ Hz. The droop is $D = 1/K = 0.0125$ Hz/MW. It can, however, also be expressed as a percentage:

$$D = 100(\Delta f/f_0)(P_0/P) \Leftarrow$$

where f_0 and P_0 are nominal values. In this example, the droop is 5%. Thus the droop is a determining factor for the no-load frequency after load shedding.

40.6.4.3 *Isolated operation*

Although the set-point f_s is maintained at 50 Hz, the frequency f will deviate from f_s because of load changes. The intersection of the characteristic with the load characteristic (e.g. vertical line) fixes the frequency.

Consider the situation given by *Figure 40.34* (not drawn to scale). The set-points are $f_s = 50$ Hz, $P_s = 160$ MW and $K = 100$ MW/ Hz. The load is 180 MW. Hence $f = 49.75$ Hz. In order to adjust the frequency to its nominal value, P_s has to be raised by 20 MW. Load shedding would result in a frequency rise according to $f_s + DP_s$.

Frequency control in isolated operation means either letting the operating point vary along the characteristic or readjusting the set-point whenever a frequency deviation arises.

40.6.5 Parallel operation of generators

Consider a two-machine system to serve a common variable load. Each set has a speed governor. The system schematic is given in *Figure 40.35*; it is assumed that the generators supply 200 MW shared in the ratio 80/120. The frequency is at the nominal value of 50 Hz.

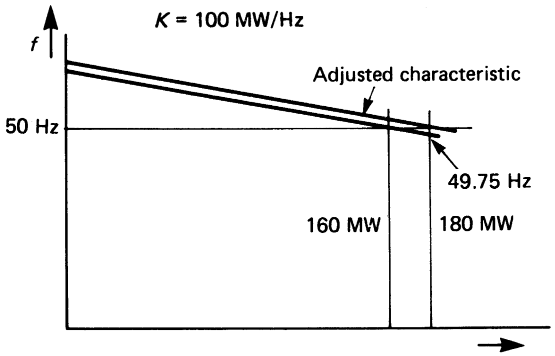

Figure 40.34 Isolated operation of one generator: load increase by 20 MW, and readjustment of characteristic in order to raise frequency to 50 Hz

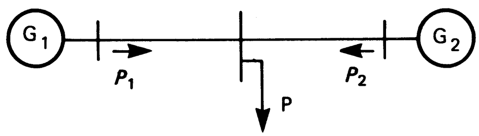

Figure 40.35 Two-machine system: G_1, G_2, generators operating at the same frequency serving P. $P_1 = 80$ MW, $P_2 = 120$ MW

How will an increase of load by 40 MW be shared? The problem is readily solved by calculation or graph. The required data for the two generators, G_1 and G_2 are:

$$G_1: f_{s1} = 50.0\,\text{Hz};\ P_1 = 80\,\text{MW};\ P_{s1} = 80\,\text{MW};$$
$$K_1 = 16\,\text{MW/Hz}$$
$$G_2; f_{s2} = 50.0\,\text{Hz};\ P_2 = 120\,\text{MW};\ P_{s2} = 120\,\text{MW};$$
$$K_2 = 32\,\text{MW/Hz}$$

The new frequency f and the power increments ΔP_1 and ΔP_2 are to be determined, with $\Delta P_1 + \Delta P_2 = 40$ MW. Then

$$P_{s1} - P_1 - \Delta P_1 + K_1(f_{s1} - f) = 0$$

$$P_{s2} - P_2 - \Delta P_2 + K_2(f_{s2} - f) = 0$$

But $f_{s1} = f_{s2} = f_s$, and f is the common frequency; hence these equations in combination give

$$(P_{s1} + P_{s2}) - (P_1 + P_2) - (\Delta P_1 + \Delta P_2) - (K_1 + K_2)(f_s - f) = 0$$

a resultant characteristic with a set-point of $P_{s1} + P_{s2}$ and a gain $K_1 + K_2$, or a droop $1/(K_1 + K_2)$ (*Figure 40.36*). The solution is $\Delta P_1 = 13.3$ MW, $\Delta P_2 = 26.7$ MW.

This principle of combining generators with equivalent generators, with a composite droop, is quite general and can be extended to multi-machine systems. Any generator can be taken as generator G_1 and the rest as generator G_2. The combined system has a composite characteristic called a power–frequency characteristic. Thus in an interconnected system, control of power and frequency is realised by adjusting the set-points of the various generators either manually or by automatic means.

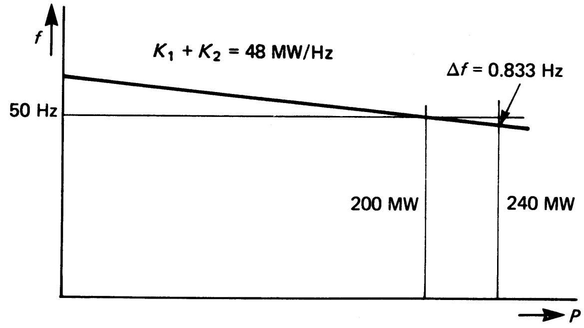

Figure 40.36 Two-machine system, combined characteristic

The logical extension of frequency control at this level (primary control) to a regional level is load–frequency control or automatic generation control.

40.6.6 Steam-turbine control system (Turbotrol)

The Turbotrol electrohydraulic control system has to fulfil the following objectives:

(1) Automatic variation of the speed set-value for speed-controlled run-up of a turbo-set with respect to critical speed and temperature conditions.
(2) Speed control during no-load operation.
(3) Frequency control when feeding house load.
(4) Accurate rapid load control in accordance with an adjustable linear frequency–load characteristic.
(5) Automatic load set-value variation for loading or load shedding, taking into consideration all measures necessary to prevent the turbo-set from being overstressed.
(6) Maintenance of the speed within admissible limits on load shedding.
(7) Co-ordinated action of the steam generator controller and turbine controller during load operation.
(8) Processing of the signals of an overriding control system, e.g. from the load dispatching system controller.

The Turbotrol system also must ensure (i) high operational safety and availability, (ii) high-response sensitivity when changing specific control variables, and (iii) ease of servicing and minimum maintenance.

40.6.6.1 Structure of control system and types of operation

The arrangement of the individual function groups of a turbine controller is shown by the block diagram in *Figure 40.37*. For clarity the numbers assigned to these groups have been inserted in the text. The control system must be designed for the following types of operation.

(1) *Normal conditions*—start-up, no load, synchronising, load operation.
(2) *Special condition*—control of the live-steam pressure by the turbo-set.
(3) *Fault conditions*—manual control with the turbine master station, turbine trips.
(4) *Testing*—overspeed, simulation.

Start-up During this phase the run-up controller (424) is in action, the turbine master station is set to ‘auto’ and the

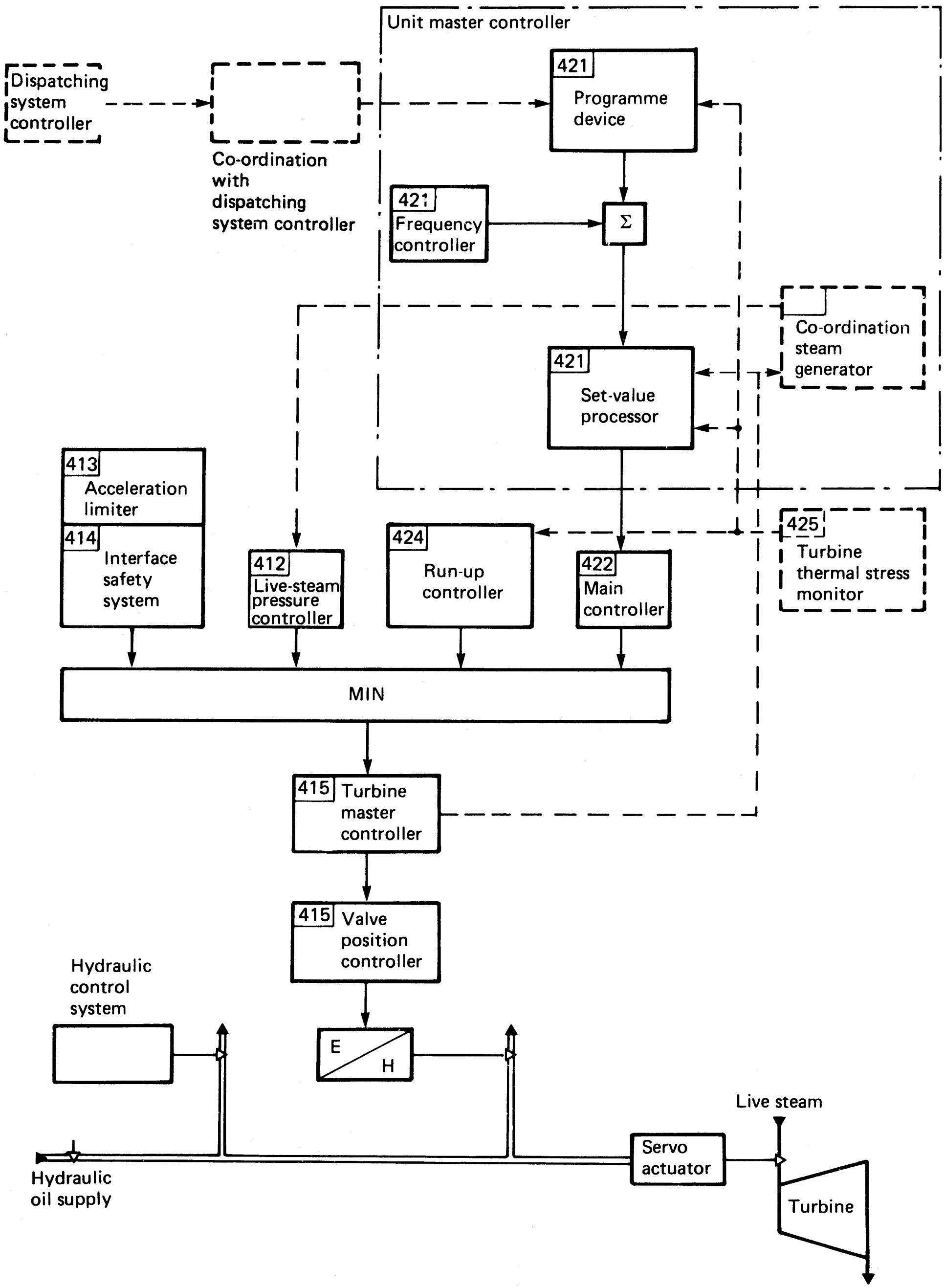

Figure 40.37 The arrangement of the individual function groups of a turbine controller

valve-position controller (415) is switched on. The controller begins the run-up from any given starting speed to the nominal speed, full use being made of the admissible operating range of the turbo-set. On reaching nominal speed, the frequency controller, which is set to nominal frequency, takes over from the run-up controller. The operation arrived at is 'no load'.

No load During no-load operation the speed of the turbine is determined by the frequency set-point via the control unit (421), the main controller (422), the turbine master station and the valve-position controller (415). No-load operation at nominal speed forms the basis for both the on-line synchronisation of the generator and the overspeed test.

Synchronisation This type of operation is authorised when a signal is received from the synchroniser. The turbine speed is determined by the frequency set-value, this being varied by pulses from the synchroniser until the frequency and phase of the turbo-set coincide with those of the line, and the circuit-breaker closes.

Load operation After synchronising and closing of the generator breakers, loading can commence. The following function groups are then active: programme unit, frequency controller, set-value processor (421), main controller (422), turbine master station and valve-position controller (415).

The programme unit forms a reference variable from the predetermined target load set-value and the adjustable rate of change of load. This variable is added to the output signal of the frequency controller and then reprocessed in the set-value processor. The frequency controller compares the actual frequency value with the predetermined frequency set-value and delivers the amplified difference as an output signal. The set-value processor contains limit circuits which prevent the turbo-set from being overstressed by rapid changes of set-values. The output signal of the set-value processor is compared with the actual value of the active power in the main controller.

Thus, during load operation, continuous load–frequency control is accomplished under the direction of the load programme device, full use being made of the permissible operating range of the turbo-set.

Turbo-set control of live-steam pressure The Turbotrol system and the steam-generator control system here operate in conjunction. The live-steam pressure controller (412) intervenes when a fault occurs in the steam generation system, thereby taking over from the main controller (422). The system (412) overrides the load set-value and controls the live-steam pressure. The turbine output is then determined by the available live-steam flow.

Manual control The turbine master station is an auxiliary unit which is usually set to position 'auto', but which automatically changes over to 'manual' as soon as an appropriate monitor in the electronic control system has responded. The reference variable for the valve position existing prior to the fault is retained by the turbine master station, while faulty controllers that are not absolutely necessary for the safety of the turbo-set cease to intervene. Function groups 413 and 414 remain permanently on stand-by. Emergency operation may be carried out by manual control for as long as the fault is present.

During manual operation it is the responsibility of the operating staff to ensure that the admissible turbine limits are observed.

Tripping of the turbine Direct link-up of the turbine hydraulic safety system with the control system, and an electrohydraulic link between the Turbotrol and the safety system, ensures closure of the control valves each time the turbine is tripped. In addition, the Turbotrol is made ready for start-up, i.e. the turbine master station changes to 'manual' and the 'zero' correcting variable is dispatched to the control valves.

Overspeed test When standard tests have been completed and the necessary preparations made in the hydraulic safety circuit, the overspeed test should be carried out. This takes place semi-automatically with the aid of the run-up controller (424) and starts with the turbine in the no-load condition. Initiated manually, the run-up controller accelerates the turbo-set at a defined rate until the first overspeed monitor responds at 110% of nominal speed. A further command, likewise manually authorised, causes the run-up controller to accelerate the turbo–set up to 112% of nominal speed, at which the second overspeed monitor responds. The turbine is then tripped. A fault in the system causing the set-point value to increase to 114% of nominal speed trips the turbine automatically, i.e. independently of the overspeed monitors.

40.6.6.2 Principle of operation

Run-up controller Providing that the change-over unit is set to 'auto', a speed programme unit SFH (*Figure 40.38*) adjusts the speed set-value by a certain rate of change (dn/dt). Change-over to 'auto' can only be authorised when the speed set-value and the actual value have been matched automatically. The correcting variable of the run-up controller with proportional–integral (PI) response passes to the electrohydraulic transducer over a smallest-value selector and the valve-position controller. It then influences, via the control oil system, the position of the turbine control valves. The critical-speed ranges are passed through with the maximum admissible acceleration.

Once nominal speed is reached, the frequency controller, set to nominal frequency, takes over from the run-up controller, which then ceases to intervene since the speed set-value n_s continues to increase up to 106%.

Load controller with frequency response. Load-frequency set-value The signal for the desired load is formed by the target-load set-value P_z and the adjustable loading rate of change (dP/dt) or rate of change of load shedding ($-dP/dt$). The load set-value P_s is varied accordingly, this taking place via a transfer unit actuated by push-button.

The load component dependent on frequency is formed by a comparison of the frequency set-value f_s and the actual value f; the control deviation is gained by adjusting the frequency droop. If desired, the influence of the frequency controller can be suppressed within an adjustable range f_T.

The frequency-dependent load component and the load set-value are coupled via a summing junction. The output signal of this junction is thus representative of the load to be delivered by the turbine. All units connected beyond this output are either limiters or subsidiary controllers capable of temporary intervention. These are described individually below.

Maximum-load limiter P_{max} An analogue-value generator P_{max} transmits a value that, for the turbine or the steam generator, represents a load limit not to be exceeded under any circumstances.

Load limiter, admissible rate of change of load Neither the steam turbo-set nor the steam generator can contend with sudden large load changes. These occur particularly when control is according to a frequency–load characteristic and when large frequency fluctuations (e.g. line faults) occur. The step-change and rate-of-change limiter limits these load changes to a variable step change (±%) and the remainder to a likewise variable rate of change ($\pm dP/dt$). This limiter can be influenced by a controller in relation to the thermal stresses of the turbine, thus overriding the load set-value.

Minimum-load setting P_{min} This prevents the turbine from being erroneously tripped by the reverse-power relay. This could take place after parallel connection of the generator and the line by the synchroniser. The setting is authorised as soon as the generator breaker closes, and causes the

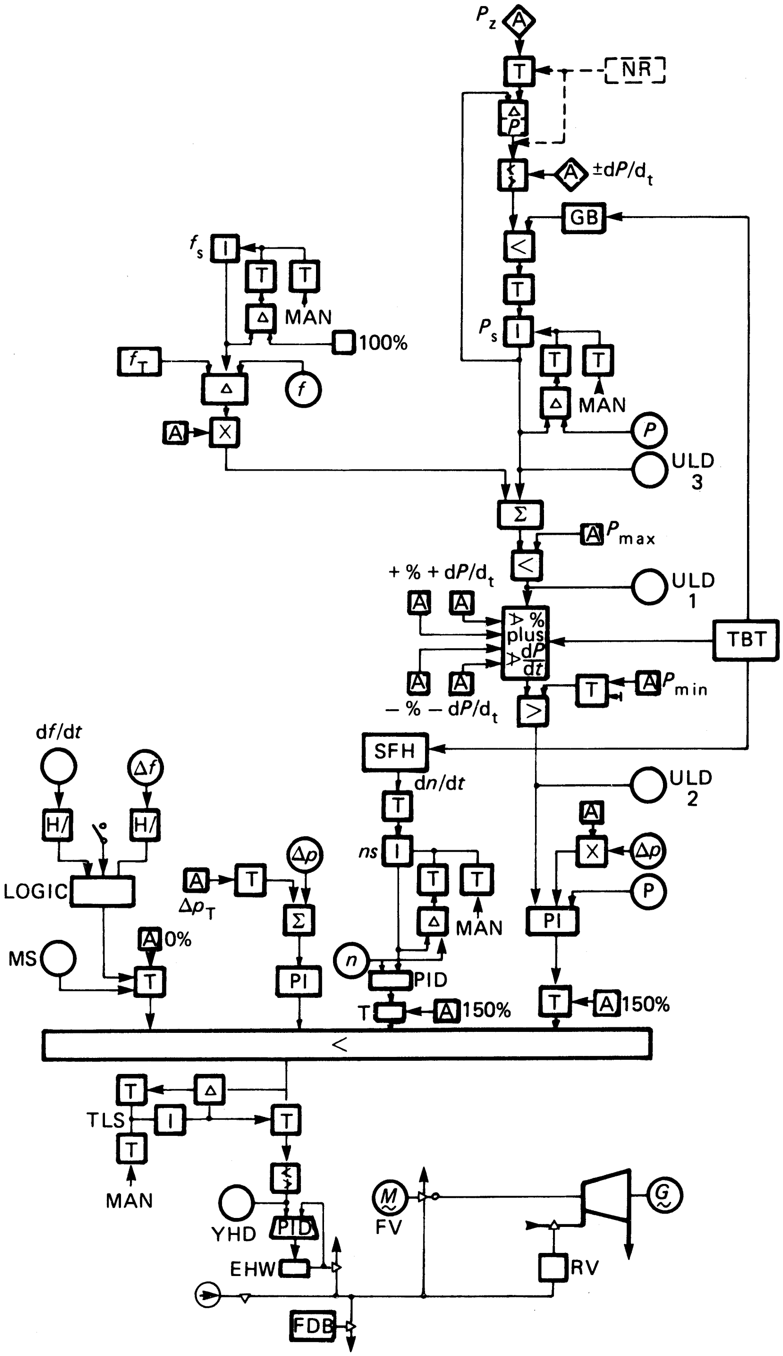

Figure 40.38 Block diagram of the overall arrangement of the turbine controller

generator to deliver a fixed minimum output. As soon as the load set-value exceeds the minimum-load setting, the latter automatically ceases to intervene. It remains, however, on stand-by until the preselected target-load set-value has been attained.

'Unit load demand' signals (ULD 1, 2, 3) These signals can be employed for operation in conjunction with the steam generation control system. A signal relevant to the given application is used, e.g. as a reference variable or as a signal for corrective action.

Load control with live-steam pressure influence For the live-steam pressure controller, a load-controlled turbine represents a controlled object without inherent feedback. The pressure control can be additionally stabilised by applying the control deviation Δp, within certain limits, to the load controller of the turbine. Thus for minor pressure control fluctuations a controlled object with inherent feedback is achieved.

Valve-position controller, turbine control valves and turbine master station The output signal of the lowest-value selector for all controllers represents the reference variable for the valve-position controller and is limited to fixed minimum and maximum values.

To ensure co-ordination of the various PI action controllers (run-up, main and live-stream pressure controllers) during normal operation, the integral part of each controller continually tracks the controller having the smallest registered proportional component.

The turbine master station TLS allotted to the valve-position controller is not used during normal operation but only in the event of faults in, for example, the main controller. In this event the correcting variable received from the main controller is suppressed and the turbine master set to 'manual'. The correcting variables received from the acceleration limiter and the safety-system co-ordinator always remain on stand-by. When the turbine master is set to 'manual', any desired valve position can be commanded. It should, however, be noted that with this type of operation the operating staff are responsible for ensuring that the admissible turbine limits are observed.

Live-steam pressure controller To prevent an excessive drop in the live-steam pressure when faults occur in the steam generator, or when there are rapid positive changes in load, the live-steam pressure controller intervenes on the adjustable limit p_T being attained. This reduces the turbine load in accordance with the available live-steam flow. The limit can, if desired, be set to zero, after which the Turbotrol acts as an initial pressure controller.

Acceleration limiter When load-shedding to house load, this limiter closes the turbine control valves immediately. Simultaneously, the load set-value P_s is brought to zero within less than 1 s. As soon as the acceleration of the turbine fades out, the limiter ceases to intervene. The frequency set-value alone now determines, via the main controller, the speed of the turbine by controlled opening of the valves (operation feeding only the house load).

Safety system When the turbine trips, the pressure switch MS responds. The signal is led via the evaluator logic to the turbine controller and causes all control valves to close immediately.

40.6.6.3 Control room operation and display

Basically, the number and type of units required in a control room for the Turbotrol system vary according to the installation. The functions are actuated by means of non-arresting push-buttons. These may be adapted for use as illuminating buttons. Either solid-state output units or coupling relays should be provided for the alarm signals, depending on the type of warning system.

40.6.6.4 Operating behaviour and maintenance

The philosophy applied to safety, availability and reliability is expounded here without details of the theories of system safety and reliability.

Safety A solid-state Turbotrol control system as described is a single-channel arrangement. In assessing the safety of the entire turbo-set, however, it should be borne in mind that, parallel to the electronic control system, a completely independent hydraulic safety system can be provided with redundant monitors (speed, pressure, vacuum, etc.) in a one-out-of-two arrangement and independent actuators (main and reheat stop valves).

The safety system is then coupled to the control valves both hydraulically via a relay, and electrohydraulically via function group 414. Loss of pressure in the hydraulic fail-safe circuit causes the control valves to receive closing commands over two independent channels.

The Turbotrol system itself is designed to ensure the highest possible degree of safety whilst, with regard to the signal paths, still upholding the principles of simplicity and transparency. The most important peripheral units and transducers are actively redundant.

Two separate d.c. power sources reduce the danger of a turbine trip as a result of failure of the supply voltage. Failure of internal power-supply units simply causes clearly defined subcircuits to be disconnected, fault indication taking place simultaneously. Generally, it is still possible to carry out restricted operation with the Turbotrol. When a fault occurs, some of the internal monitoring elements set the turbine master station immediately to 'manual', so that the turbo-set can at least still be operated manually. Even during such operation, the subcircuits important for the safety of the installation (413, 414) remain active. Response by either of these, or a fault in one of them, causes an immediate trip.

The subcircuits and functions can, to a large extent, be tested during operation.

Availability Regular checks, and the modular design of the equipment, permit faults that occur to be recognised early and eliminated by replacing the appropriate module before it causes operational failure. If a breakdown should nevertheless occur, the fault may be quickly located by means of the many indication, test and simulation devices, and promptly eliminated. The availability of the installation is thus ensured.

Reliability The individual parts of the control system, its components and, finally, the complete system unit should be subjected to rigorous testing. Combined with a simple logically designed system that has the minimum number of component parts, these measures contribute to the high degree of reliability of the entire control and safety system.

Final designs of various kinds, depending on the respective importance attached to the terms safety, availability and reliability, can be achieved.

Operation with the hydraulic control system This control system serves as back-up when the Turbotrol is in operation. If a fault occurs in either the turbine master station or the electro-hydraulic transducer (415), the respective hydraulic lines must be blocked manually. Renewed turbine start-up then takes place manually via the hydraulic control system. The variable readings required for this are displayed in the control room, provided that the d.c. power supply for the Turbotrol is intact.

40.6.6.5 Fast valving

Power export is reduced by the loss of voltage in the event of short circuits in the transmission systems. Acceleration of the turbine rotors occurs in the turbine–generator units involved by a change in the balance of the mechanical-drive and the electrical-load torques. In the turbine-generator unit closest to the short-circuit point, the rotor angle reaches a critical value that depends upon the generated load and the duration of the short circuit; this causes the unit to lose synchronisation.

By briefly closing the turbine control valves ('fast valving'), the drive torque of the turbine–generator unit is rapidly reduced to control a sustained short circuit without loss of synchronism. Depending upon the load in the transmission system, it may be necessary before reconnecting the load to set a load level lower than that before the short circuit.

The subassembly 'Fast valving' (functional group 470—see *Figures 40.39* and *40.40*), takes action in the turbine control system in the event of failures in the power transmission system by brief closure of the control valves in conjunction with a reduction in the load setting. This takes place if the load on the turbine–generator unit is greater than the adjustable maximum value (approximately 60% load). Failure detection in the power transmission system and the initiation of fast valving are performed by the grid supervision system.

Both the main control and the intercept valves take part in fast valving. While the intercept valves are briefly closed (T_{FV}) via solenoid valves, the main control valves are actuated by the Turbotrol electronic control system.

The electrical position signal YHP for the main control valves is set to 0% by a minimum selection gate. The turbine master of the Turbotrol is switched to 'manual'. After the time T_{FV}, YHP is switched to a preselectable value $X\%$. Simultaneously, a 'lower' instruction for tracking the turbine master is issued. The integrators of the controllers also follow the tracking of the turbine master. The actual load value then appears according to $X\%$. The load set-point is tracked in the unit master.

The load set-point drops until the controlled variable YR is smaller than YFV, i.e. until the main controller is ready to take over the control task. The turbine master then automatically switches back to 'auto'.

The load target set-point has remained stationary during the entire fast-valving process so that it is immediately possible to reconnect the load by switching on the automatic loading system.

It is only possible to test the subassembly with a load of less than an adjustable minimum value (about 30%).

40.6.7 Water-turbine control system (Hydrotrol)

The Hydrotrol (*Figure 40.41*) performs, in conjunction with the electro-hydraulic transducers and the hydraulic servo-motors, the following tasks:

(1) Automatic provision of an opening for run-up of the turbine until the speed controller takes over.
(2) Speed control during no-load operation.
(3) Frequency control during isolated grid operation and when station auxiliaries are being supplied.
(4) Opening control according to an adjustable linear frequency–opening characterisic.
(5) Arresting of overspeed after load shedding.
(6) Connection and processing of signals of a higher-order control system with or without load feedback (e.g. from the water-level controller or dispatching system controller).
(7) Position control of the guide-vane apparatus in Francis turbines.

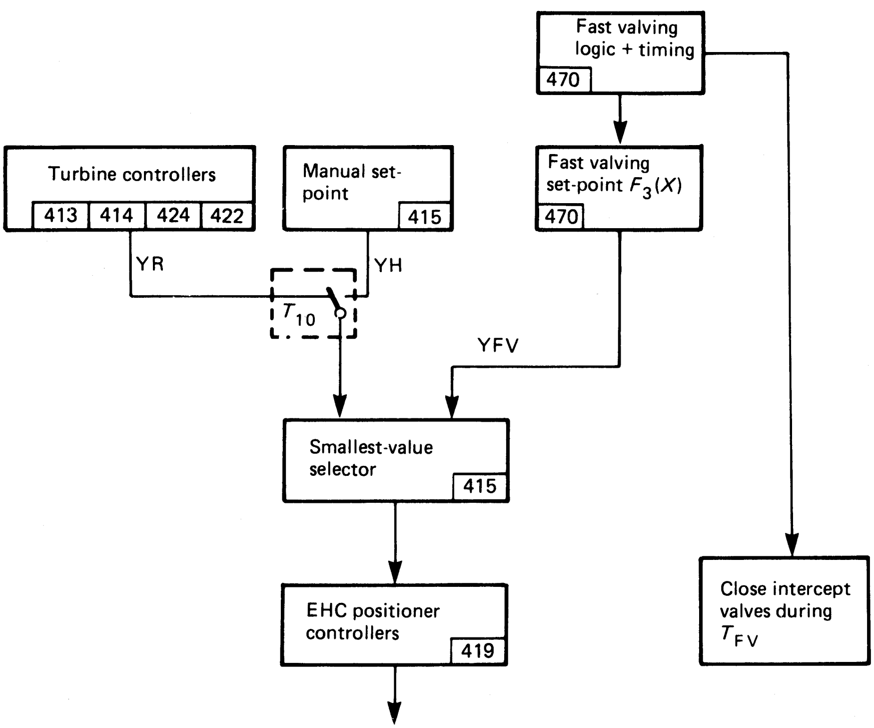

Figure 40.39 Block diagram showing the action of the fast-valving function group (470)

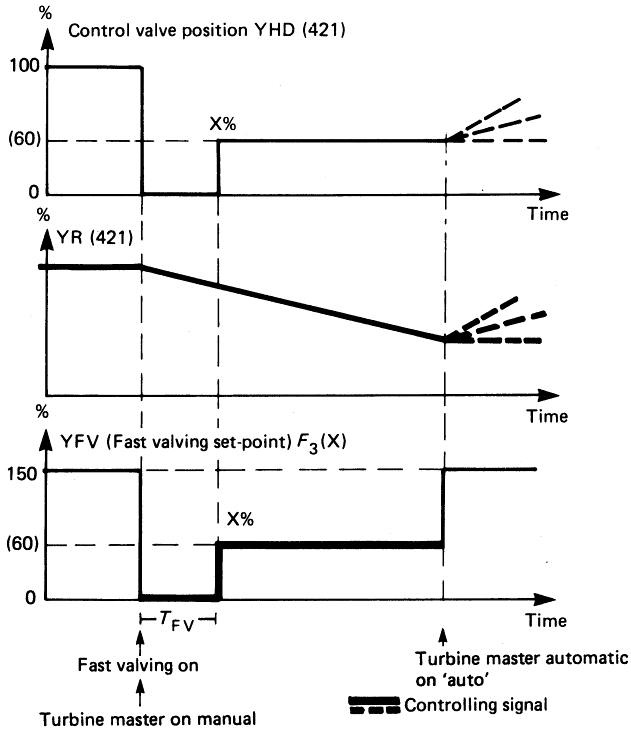

Figure 40.40 The response of the signals YHP (421), YR (421) and YFV during fast valving

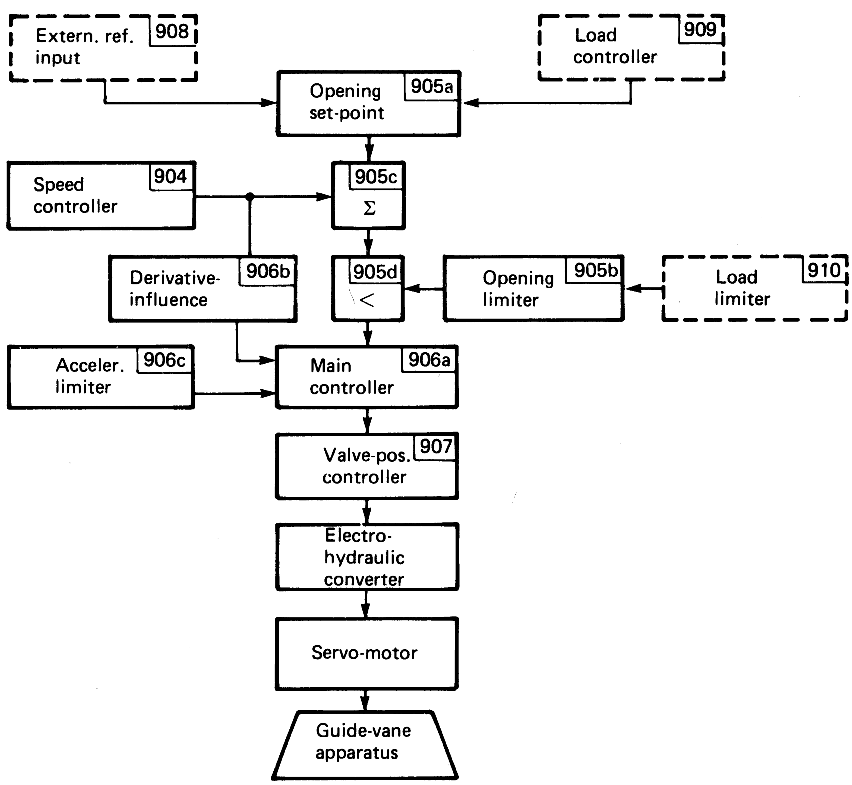

Figure 40.41 Function groups of the Hydrotrol with valve-position controller for Francis turbines

(8) Position control of the guide vane and impeller blades (with a pre-set relationship between guide-vane and impeller-blade angles) in Kaplan turbines.
(9) Position control of the needle and deflector (with co-ordination between jet diameter and deflector position) in Pelton turbines.
(10) Redundant measurement of speed. The speed-measurement device is equipped with outputs for indicator devices, control and monitoring.

The Hydrotrol 4 ensures (i) high operating reliability and availability, (ii) high-response sensitivity in respect of changes in specific control variables, and (iii) easier servicing with low maintenance requirements.

40.6.7.1 Design and operation of the controller

Figure 40.41 shows the basic design and the way in which the function groups of the Hydrotrol are interconnected. The numbers of the functional units are referred to in the text. The controller is designed for the following methods of operation:

Normal:
- start-up (with opening limiter);
- no-load operation;
- synchronising;
- load operation with opening feedback;
- load operation with opening limiter in action;
- load operation with dispatching system controller connected;
- load operation with external reference input; shut-down.

Disturbance:
- load shedding;
- turbine tripping.

Testing:
- overspeed;
- simulated operation.

Start-up As soon as the starting command is given, the opening limiter (905b) indicates the starting opening (*Figure 40.41*). In the smallest-value selector (905d) the control deviation of the speed controller (904) is limited by the start opening and is supplied to the main controller (906a). The servo-motor opens the guide-vane equipment via the valve-position controller (907) to the value specified by the opening limiter (905b). The machine accelerates until the speed controller (904) comes into action via the derivative action (906b) below the nominal frequency. Acceleration consequently ceases and the speed controller (904) controls the turbine at nominal frequency.

No-load operation The turbine speed can be set by the frequency set-point value. The control deviation of the speed controller is formed by comparing the set-point with the actual frequency, and passes via the smallest-value selector (905d) to the main controller (906a). In this method of operation the main controller is switched to proportional–integral–differential (PID) response for reasons of stability. No-load operation at nominal speed is the starting point for synchronising the generator with the network.

Synchronising The synchronising device acts on the frequency set-point. Its pulses adjust the set-point until the frequency and phase position of the unit coincide with the network, and the generator breaker then closes.

Load operation with opening feedback After synchronising, the plant changes to load operation with the generator breaker closed. The following function units of the control system are now in operation: speed controller (904); opening set-point (905a); summing junction (905c); smallest-value selector (905d); main controller (906a); valve-position controller (907).

The turbine is loaded by run-up of the opening set-point. This is compared with the opening of the guide-vane equipment; the resultant deviation, after evaluation by the pre-set droop variable, is added to the control deviation of the speed controller. The acceleration influence (derivative action) on the main controller is blocked. In this mode of operation the main controller is switched to PI response.

Load operation with opening limiter in action As soon as the opening of the guide-vane device exceeds the value set on the opening limiter (905b), the latter begins to act via the smallest-value selector (905d) and limits the opening. The load limiter (910) automatically limits the maximum output of the turbine or generator via the opening limiter.

Load operation with applied dispatching system controller This is initiated by actuating a button on the control desk. The opening set-point is controlled by a superposed frequency–load controller (909). The load set-point can be pre-selected by a separate set-point generator or an external dispatching system controller.

Load operation with external reference input This method is pre-selected by a button on the control desk, which causes the opening set-point (905a) to approach the pre-selected reference input (908) from a water-level controller or dispatching system controller. As soon as the two signals agree, the external reference input is applied directly as an opening set-point. The opening set-point tracks the external reference input so that, when this mode of operation is switched off, the controller continues to retain the last-occurring reference input.

Shut-down After the load has been reduced by decreasing the opening set-point, the generator breaker is opened; the controller again operates in the no-load mode. The turbine can then be fully shut down by automatically switching the opening limiter to a closure command of about 10%.

Load shedding To arrest the speed rise of the turbine on load shedding as rapidly as possible, an acceleration limiter (906c) is incorporated. As soon as the acceleration exceeds a limiting value, this device, acting via the servo-motor, causes immediate closure of the guide vanes. When the overspeed vanishes, the speed controller again takes over control at nominal frequency.

Turbine tripping All the emergency-closure and rapid-closure criteria simultaneously have the effect of causing a switch-over to a closure command of −10%, as with the normal shut-down operation.

Overspeed test For this, the speed controller (904) is rendered ineffective. By increasing the speed with the opening limiter (905b), the function of the overspeed protection device can be tested.

Simulated operation This is initiated by inserting a plug in the Hydrotrol 4; it facilitates functional testing of the electronic controller with the plant shut-down, by means of incorporated simulation equipment.

40.6.7.2 Operation of the main controller

In order that the control deviation does not remain permanently in the stabilised state, the main controller is constructed with a PI circuit. With the circuit selected, the main controller governs for fairly small control deviations, and the servo-motor operates in its linear rapid-operating range. For large control deviations, the servo-motor can no longer follow the correcting variable (output of the main controller), since the maximum speed of the servo-motor is limited by hydraulic orifice plates. The main controller will disengage, resulting in pronounced overshoot of the servo-motor position (in the extreme case, event instability). However, electronic simulation of these hydraulic orifice plates limits the integral component of the main controller in such a way that, as soon as the servo-motor again reaches the linear range, the main controller immediately corrects itself and can take up optimised control.

Two types of stabilisation are possible in the main controller:

(1) no-load stabilisation, initiated with the generator breaker open (no-load stabilisation corresponds to a reduced proportional component, a long integration time and effective derivative action); and
(2) parallel stabilisation, initiated with the generator breaker closed (parallel stabilisation corresponds to a relatively large proportional component, a short integration time and ineffective derivative action).

If the generator is supplying an isolated network, the no-load stabilisation must be switched on. This occurs automatically when a specific frequency band is exceeded, and is signalled in the control room. It must also be possible to carry out this changeover manually.

40.6.7.3 Operation of the valve-position controller

The output signal from the main controller (with PID response) acts upon the valve-position controller. The latter has the task of making the servo-motors of the control devices track the main-controller output (proportional response). It represents the actual connection device between controller and hydraulic system, and serves as a command device of the electrohydraulic transducer.

There are three types of valve-position controller.

(1) For Francis turbines. In this variant, the position of the guide-vane servo-motor is regulated.
(2) For Pelton turbines. In this variant, the positions of the needle and deflector servo-motors are regulated. By simulating a function, 'needle movement to water-jet diameter' in the 'deflector' control circuit, it is possible to ensure that the deflector is positioned above the water jet. The deflector then comes into action only if rapid control movements in the 'closed' direction occur.
(3) For Kaplan turbines. Here the positions of the guide-vane and impeller servo-motors are regulated. Function transmitters ensure optimum tuning between the guide-vane angle and impeller-blade angle as a function of the head. The corresponding device is situated in the 'impeller' control circuit.

40.6.7.4 Structure of the speed-measuring equipment

The Hydrotrol is equipped with a redundant speed-measuring device, with outputs for indicator devices, control and monitoring. The basic design of the device is shown in *Figure 40.42*. References to the units and outputs are given in the text in parentheses.

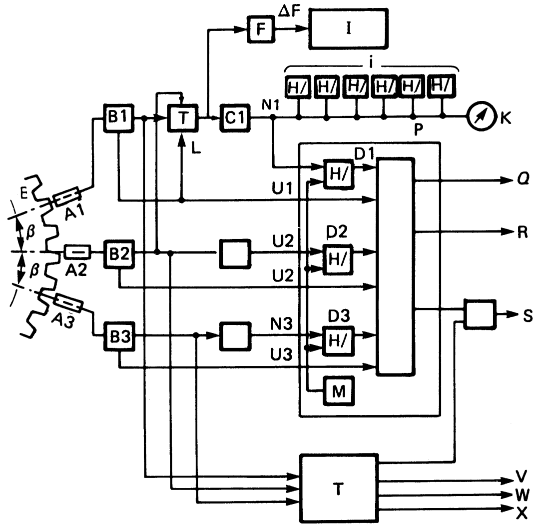

Figure 40.42 Block diagram of a speed-measuring device with speed-limiting values, overspeed protection and direction indicator: D/A, Digital/analogue

The speed is measured with three channels. The speed is picked up from a wheel (E) by ferrostat transmitters (A1, A2, A3). The generated frequency (proportional to speed) is transmitted via the pre-amplifier (B1, B2, B3) and the speed-measuring device (C1, C2, C3). The speed measurement generates an analogue voltage (N1, N2, N3) which is accurately proportional to the speed. The speed transmitters are monitored: a fault at speed transmitter A1 (such as a voltage failure, short circuit or line fault), is signalled via monitoring channel U1 and is annunciated by the alarm 'speed transmitter faulty' (output S). Simultaneously, the speed signal for the speed controller (I), the speed limiting-values (J) and the indicator (K) are switched over from speed transmitter A1 to transmitter A2.

The overspeed protection (P) consists of a double-channel 'two-out-of-three logic' (L). This triggers an emergency stop (output Q) and a quick shut-down (output R) as soon as two or three speed limiting values (D1, D2, D3) respond or faults occur at two or three speed transmitters. The direction indicator (T) serves for determining the direction of rotation in pump turbines.

The speed transmitters must be mounted at angular intervals $\beta = 360(n+\frac{2}{3})/z$ (degrees), where z is the number of gearwheel teeth and n is an integer. The outputs V and W indicate the direction of rotation, and output X indicates when the shaft is stationary.

40.6.7.5 Testing

Component testing Every component approved for use in electronic systems must be subjected to stringent tests, carried out in compliance with IEC publications.

Testing of the controller The controllers must be individually tested and adjusted in the laboratory on the basis of the particular turbine characteristics. Before delivery, every Hydrotrol must operate for a week in the closed-loop of an analogue turbine simulator, with all control variables and the most important control parameters continuously recorded. In this way, changes in control behaviour and premature failure, for example of semiconductor components, can be detected.

40.6.7.6 Operational reliability and availability

Reliability An electronic water-turbine Hydrotrol is, in general, of single-channel construction. The important peripheral devices and transmitters (e.g. for speed) are designed with redundancy. A failure in the supply voltage or internal supply equipment causes rapid closure and simultaneous signalling of the fault. Faults in internal monitoring devices such as those for the speed transmitters or valve-position controllers lead to an emergency closure.

Availability Regular testing and the modular construction of the equipment should permit any faults that occur to be detected at an early stage and to be rectified by replacement equipment before they cause operating faults.

40.7 Decentralised control: substation automation

40.7.1 Introduction

With the increasing complexity of power systems, the difficulties of manning substations and the requirement for shorter restoration times after power failures, more tasks are being automated in the substation. The conventional solution to automating these tasks has been by dedicated hardwired logic. Though effective, this is inflexible and difficult to test off-line. Hardwired logic is being superseded by systems based on mini- or microprocesors which have advantages over their hardwired counterparts with regard to flexibility, space requirements, test and commissioning facilities. A further and important advantage is their ability to self-monitor and detect an internal fault almost immediately, and not only when operating. However, they have the disadvantage of intolerance to voltages in the connecting cables induced by switching of h.v. apparatus or thunderstorms. Special precautions must therefore be taken to decouple the plant connections from the electronic circuits.

Several tasks can be assembled in one set of hardware, and thus a centralised system can be used. The speed of transmission and the availability of transmission channels are limiting factors in achieving reasonable response times for some substation tasks from a remote control centre; many of these tasks are therefore performed by substation equipment.

40.7.2 Hardware configuration

A simplified substation automation hardware configuration is illustrated in *Figure 40.43*, with its connections to one feeder circuit of an h.v. substation.

The central logic is a microprocessor with the automation routines stored in a non-volatile programmable read-only memory (EPROM) which can be erased and modified using special equipment. Thus, by triggering a power-failure restart routine held in the EPROM, the equipment can recover from power failures without reloading. The variable data are held in a random-access memory (RAM) which can be corrupted on power failure. It must be capable of replacement after a power failure either by local input or by down-loading from a higher level control system. Similarly, the variable data, such as limits tripping priorities, etc., must be capable of modification, e.g. from a keyboard.

The data acquisition and automation programs are executed by the microprocessor, which communicates with the input/output equipment via the system bus. The input

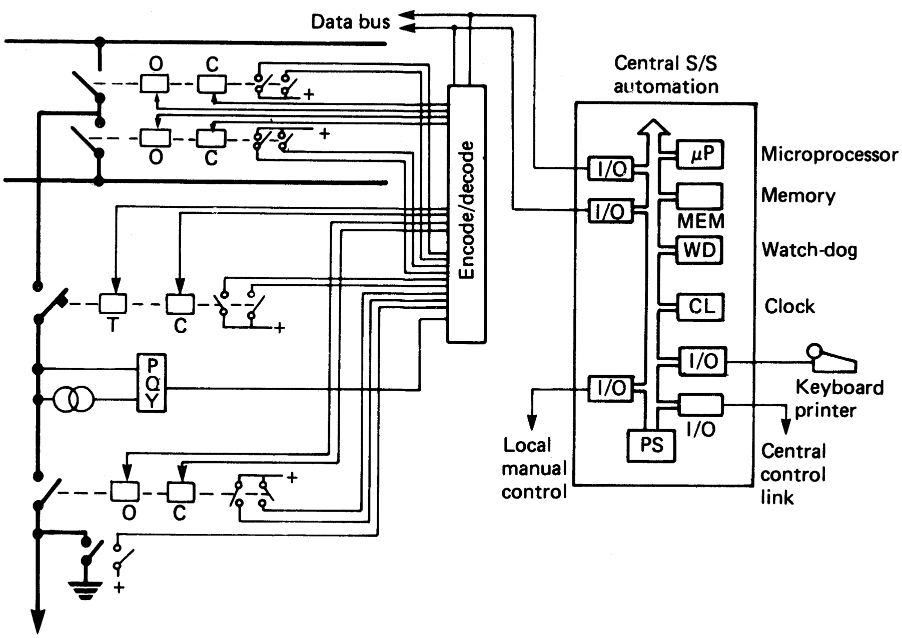

Figure 40.43 An example of a decentralised automation system: O, open; C, closed; T, trip; *P*, active power; *Q*, reactive power; *V*, voltage; PS, power supply; S/S, substation

and output modules are similar to those already described for the telecontrol remote terminal unit (TRU). The connection to the higher level control system can be via a direct link or a telecontrol TRU.

An important decision to be made in the layout of an automation system in substations is the location of the transducers and the method of transmitting the h.v.-circuit data to the central processor unit. Economically, the transducers are better located near to the measurement point to avoid long instrument–transformer connections. However, this means that light-current connections are long and vulnerable to interference and high induced voltages. A solution is to install encoding equipment at the data source and serial transmission equipment to send the messages to the central logic over a serial data bus which can be common to a number of h.v. circuits, as in the telecontrol system transmission already described. As the technique develops, this transmission can be over a fibre-optic line.

40.7.3 Software configuration

The software is modular to allow the system to be easily extended and developed. The individual application programs run independently of each other, but share data and input/output routines. For small systems the programs can run cyclically; however, for larger systems a system of priorities must be established and the resources allocated by an executive program. The program structure is illustrated in *Figure 40.44*.

40.7.4 Applications

40.7.4.1 Sequence control (switching programs)

In closing circuit-breakers on to live circuits, several criteria have to be met to ensure a successful operation; for example, in energising a feeder, the breaker must first be connected to the required bus-bar, the line isolator closed, the line–earth switch open, and the synchronising criteria satisfied. It must be ensured that no sanctions are valid that would inhibit the operation. Similarly, when energising a transformer circuit, manually or automatically, it is normal to make similar checks and circuit preselections before closing the l.v. breaker and then the h.v. breaker. In changing a circuit from one bus-bar to another, a switching sequence involving the bus coupler and perhaps the bus section switches must be performed.

These sequences can be programmed and performed by local automation equipment, provided that all switches are motorised. The sequences can be initiated by one command (e.g. 'close line 123 on to bus 3'). The responsibility from there on is taken from the operator and the instruction is performed by the local automation equipment which, in carrying it out, will respect all the interlocking requirements and inhibits.

40.7.4.2 Switching interlock supervision

Manual switch operation in a substation is required either as the normal mode of operation or as a back-up to the automatic mode. For these operations, interlocking is required to prevent incorrect switching that might endanger equipment or the stability of the power network. The conventional solution for interlocking is a device with auxiliary contacts and inter-device wiring forming a hardwired supervision logic. Interlocking can also be achieved by the local automation equipment using programmed logic accessing the shared data base. This latter solution considerably reduces the inter-device cabling as well as the number of device auxiliary switches or repeater relays used and their discrepancy supervision.

40.7.4.3 Load shedding and restoration

With a falling frequency, at certain levels of frequency it may be necessary to reduce load without waiting for remote intervention or relying on transmission channels. The load shedding can be performed automatically by local automation equipment in progressive steps, starting with the tripping of storage heating or cooling loads via ripple control signals, and progressing to more drastic action by tripping feeder circuits at the substation.

These tasks can be performed by substation equipment that scans the frequency measurand and, at various pre-set frequency thresholds, instigates load-shedding action in prearranged steps and programs. The programs can be arranged to cycle the load shedding so that each consumer

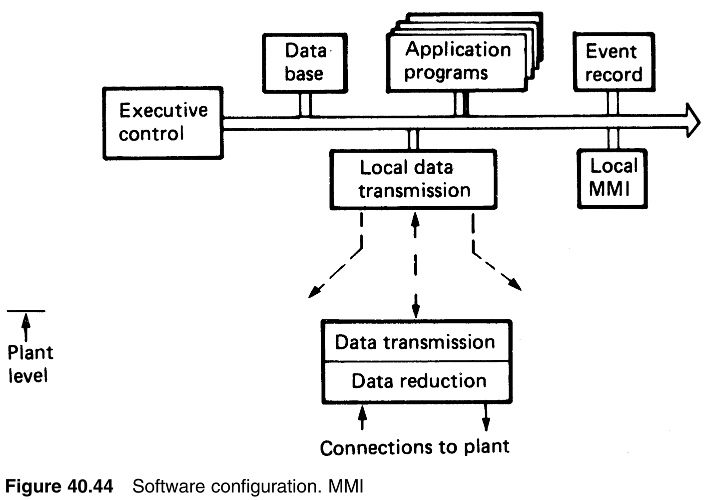

Figure 40.44 Software configuration. MMI

is tripped in turn and no particular load is singled out to be always first on the tripping list.

Once the frequency has returned to predetermined levels, supplies to loads can be progressively restored in a predetermined order until the situation is normal.

Similar actions can be initiated on a feeder overload when the current exceeds the thermal limit of the cable.

40.7.4.4 Automatic reclosing

The majority of overhead line faults are transient, caused by falling trees, birds, lightning, etc., and they clear after the breaker interrupts the fault current. To reduce the duration of the outage, the breaker can be automatically reclosed, after a time delay to allow for deionisation of the fault path. If after the first interruption the fault has not cleared, either the breaker is locked open or further reclosing attempts are made before locking the breaker open. Tripping and reclosing can be either one-phase or three-phase, depending on the selectivity of the protection and the construction of the breaker.

Conventionally, these reclosing sequences are performed by timing relays and hardwired logic requiring dedicated breaker auxiliary switches. Settings of the number of reclosures, the dead time between reclosures, and the reclaim time are adjustable. Equally, these functions can be performed by common logic using a shared database to reduce wiring and auxiliary contacts on the breaker. An additional advantage appears with microprocessor-based logic in that parameters such as dead times and one-phase or three-phase reclosing can be selected and down-loaded from the control centre, depending on the network conditions.

40.7.4.5 Event recording

Event recording in a substation can be divided into two basic categories: one that records alarms, contact closures or device operations, and another that records waveforms of currents and voltages prior to, during and immediately after a fault on the power system.

The first category detects changes of state of contacts with a time resolution of 10 ms and records the operation on a printer. Thus, in post-event analysis, the maintenance engineer has a record of the times at which the events occurred and their chronological sequence.

The second category is an 'oscillo-perturbo-graph', which continuously records, temporarily memorises and then erases the waveforms of the currents and voltages in a circuit. After the detection of a fault, the memorised pre-fault, fault and post-fault data (which can include contact operation) are permanently recorded for subsequent analysis. The conventional equipment for faulting recording is an electromechanical device that has a galvanometer logger writing the waveforms on to a rotating inked cylinder. At the end of the cylinder rotation, the marks made by the recording pen are erased and replaced with a later value. When a fault is detected, paper is brought into contact with the rotating cylinder to print the recorded parameters. This device requires periodic maintenance, but it has been effective for many years. It can be superseded by a microprocessor-based digital system but, as the scanning speed required to record the fault parameters is of the order of 1000 Hz, it is unlikely that this function can be incorporated in a central substation logic. One advantage of digital recording is that the data can be transmitted to a remote control centre for subsequent post-fault analysis.

40.7.4.6 Protection

Protection is a vast subject, the principles of which have been covered elsewhere. It suffices here to mention it as a part of substation automation. Because of the high scanning speeds required, it is unlikely that primary protection can be integrated into a central substation automation system. Thus, even though microprocessor-based protection will be available, it will be dedicated to a particular task or circuit as with the present solutions.

40.8 Decentralised control: pulse controllers for voltage control with tap-changing transformers

As a result of ever-increasing automation and rationalisation, electronic pulse controllers are becoming widely used in the field of tap-changer controls. In interconnected operation, maintenance of frequency characterises the equilibrium between generation and consumption of active power, while voltage control determines the control of reactive power in the system. The essential difference between the frequency/active-power and the voltage/reactive-power characteristics is that the frequency has the same value throughout the system while the voltage forms a system of ever-varying peaks and valleys (assuming a constant rated voltage) which in turn decides the direction and magnitude of reactive power flow.

Tap-changing transformers are the variable step functions in this range of peaks and valleys, and this introduces additional freedom at certain points in the interconnected system. Depending on their place of application, tap-changing transformers can be generator or interconnecting or consumer-load units.

The task of the pulse control unit is automatically to maintain the voltage in the system or to direct the reactive power flow. *Figure 40.45* illustrates an example of application—the control of a consumer network.

The voltage to be regulated is compared in the regulator with an adjustable reference value. Depending on the polarity and magnitude of the difference between these values, 'higher' or 'lower' impulses are given, resulting in the necessary adjustment of the tap-changer. The impulse sequence is inversely proportional to the difference signal. The integration time t_1 and the pulse duration t_2 are adjustable. As long as the difference signal is smaller than the set sensitivity, the impulses are blocked. A further adaptation of the impulse sequence is possible owing to a time factor so that a stable and quasi-steady regulation may always be obtained. *Figure 40.46* shows a typical characteristic of a final control element with a stepwise mode of operation.

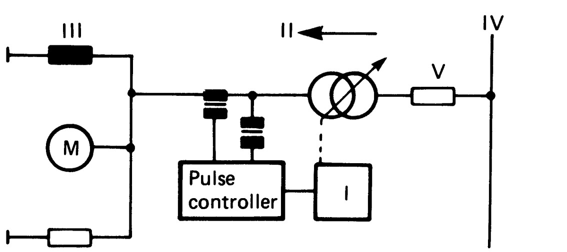

Figure 40.45 Consumer network regulated by a tapped transformer: I, tap-changer; II, reactive-power flow; III, consumer network; IV, supply network; V, line reactance

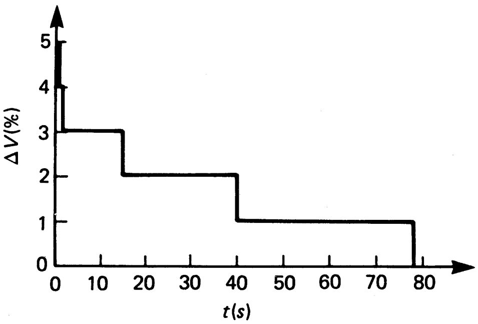

Figure 40.46 Typical characteristic of a final control element with steps of 1%. $\Delta V = 5\%$, $\alpha = 0.25$, $\epsilon = 0.8\%$, $t_1 = 50$ s, $t_2 = 0.2$ s, $t_3 = 0.5$ s

It is important that the controller does not cause the tap-changer to carry out unnecessary switching operations. If, for example, a short-time fault were to occur on the system, no purpose would be served by the tap-changer responding. The fault would be rectified before the switching operation could be completed and the controller would then immediately issue commands for the tap-changer to return to the original position. Adequate damping is therefore essential for preserving the life of the tap-changer.

If the control deviation tends to exceed the set sensitivity, an integrator comes into operation. No control command is issued before the pre-set integration time expires.

40.9 Centralised control

40.9.1 Hardware and software systems

In a control centre, the basic requirement of the operator is information about the power system, presented to him/her in a clear and unambiguous manner. He/she needs an overview of the network, usually in the form of a large wall diagram or overhead projection giving the network configuration and perhaps coarse line load levels. He/she also needs detailed diagrams of individual parts of the network showing the load of each HV circuit plus its switching configuration by isolator, circuit-breaker and earth-switch positions. These circuit diagrams are selectable on to colour visual display units (VDUs). *Figure 40.47* gives an overview of a typical control room.

In addition to the basic requirements, the operator requires other information to be calculated and automatic controls to be performed, as discussed later. These requirements can be realistically met only by an on-line, real-time computer system interfacing with the telecontrol system to provide up to date network data and to accept commands.

The availability of such a system must be of a very high order (99.5%plus); a single processor system would not be adequate. Distributed processing with dedicated multi-processor systems must therefore be considered. The classic configuration of the dual main computer system with front-end processors for the telecontrol system, and an independent wall-diagram control has given way to a distributed system. In a distributed system any of the processors may be duplicated to increase the availability of the individual critical components.

40.9.2 Hardware configuration

A typical computer hardware is shown as in *Figure 40.48, which* allows various groups of applications to be distributed on different processes. The backbone of this configuration is a Local Area Network compliant to the IEEE 802.3. The typical speed of this network is from 10 to 100 Mb/sec. The most common network protocol used on the LAN is TCP/IP corresponding to transport and IP layer of the seven-layer ISO open system model. The LAN itself could be in few segments and redundant to make it failure tolerant.

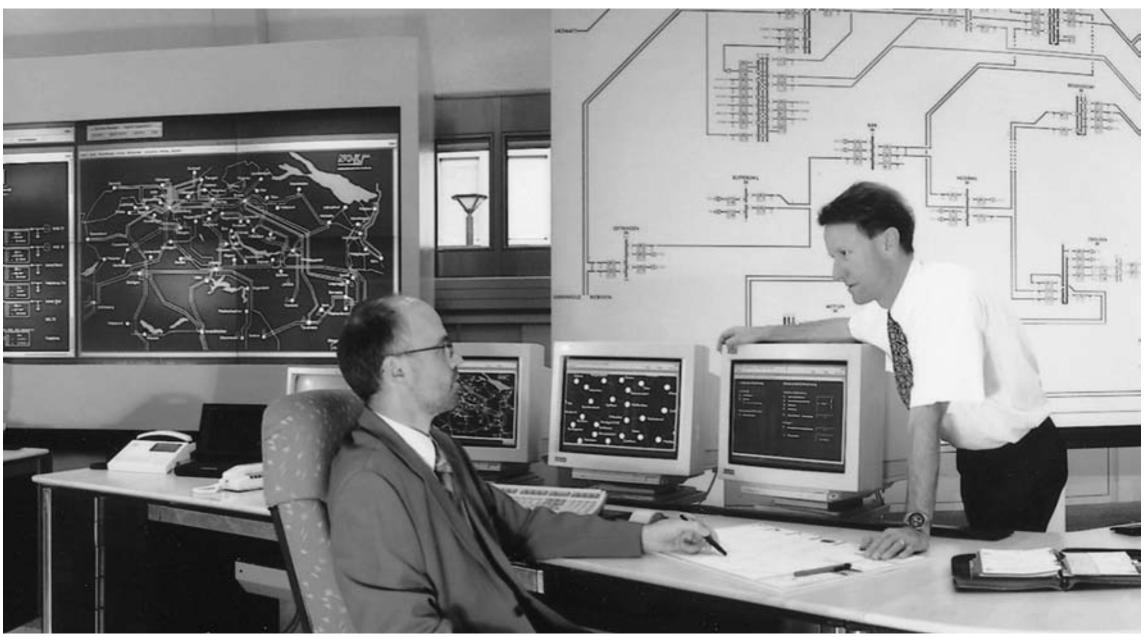

Figure 40.47 Overview of a typical control room

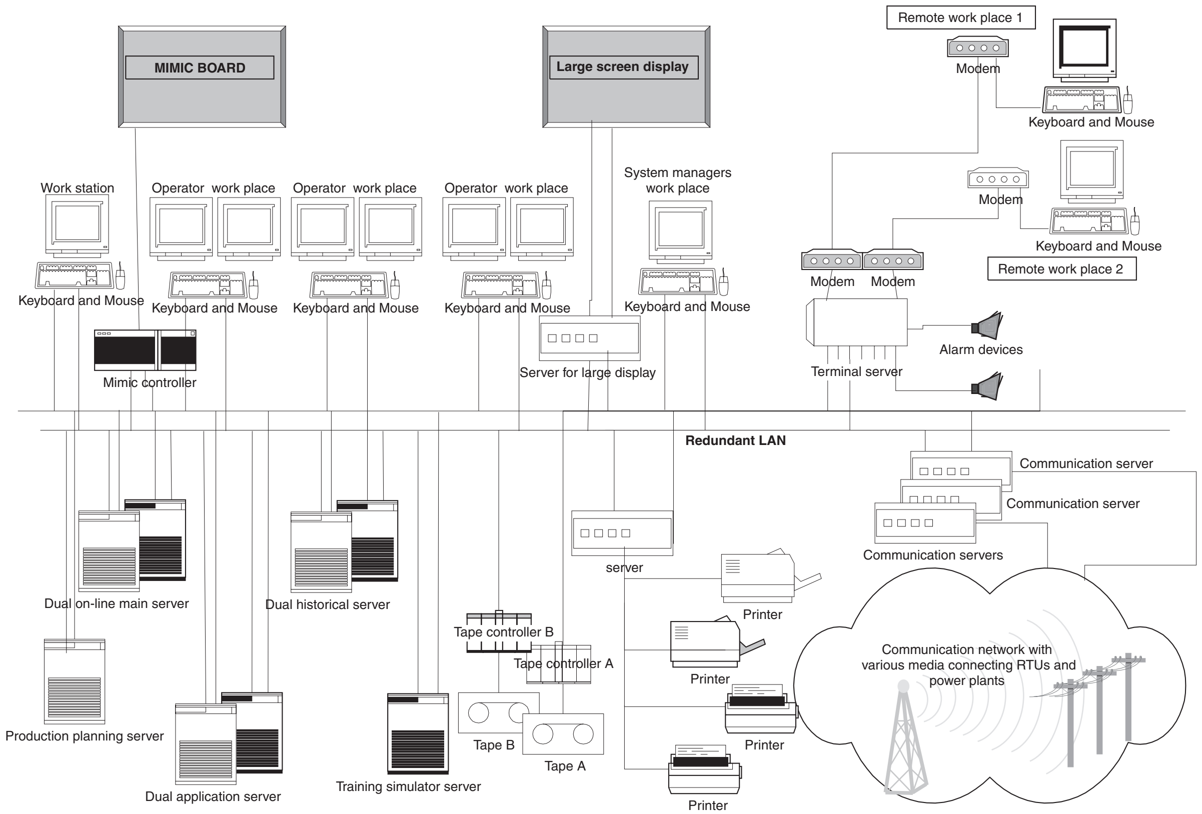

Figure 40.48 Distributed control centre configuration

Individual processors can operate in on-line or redundant backup mode. The peripheral devices such as printers, loggers, hardcopy devices, acoustic alarms, Human Machine Interface devices are also connected to the Local Area Network. In case of failure of the main device the backup or standby device takes over without loss of functionality. Such a configuration can be tailored to suit individual reliability and availability requirements.

The communication servers are also used in multiple configurations for load sharing and redundancy purposes. The communication lines from the RTUs, or other control centres bring the data to these communication servers. The basic object of the communication servers is to collect data from the field devices, pre-process the data for change, limit violation, convert them to engineering units and make them available for all the users. A device supervision function keeps watch on all the devices configured in the system and in the event of the failure of the on-line or main device the watchdog may switch the function to the designated backup or standby machine. The main processor communicates with the remote terminals via the communication server systems and with the man machine interface equipment connected to the LAN or WAN.

40.9.3 Man–machine interface

The operation peripherals forming the man–machine interface equipment are connected over the LAN to various processors. These can be configured and switched either individually or as a group to main, standby or backup servers. Normally, these are switched to the main server. The main human machine interfaces devices are the keyboards and the graphic or semi-graphic VDUs, mouse or track ball type pointing device, acoustic device for alarms, wall diagram, printers, loggers, hardcopy as shown in the hardware configuration diagram (*Figure 40.48*).

The VDUs with the mouse and keyboard are the main tools of interaction. Each operator's place may have several VDUs driven by one HMI processor. Each of these VDUs may be configured to display several windows of different types of information. All windows may continuously display updated information from the network but at a time only one of the windows is active for the operator interaction. These display windows may be used to display geographic or schematic network diagrams, alphanumeric information such as reports and lists, trend curves and other type of pictures. The selection or navigation through these diagrams is done via a fixed or dynamic menu, which may popup or be pulled down depending on the context of the cursor or pointer location. The operator may pan in a large picture to locate himself in the area of interest for monitoring and control. He may zoom in to display more detailed information. A certain zoom level may be associated with the level of information to be displayed. These panning, zooming and de-cluttering techniques may be very effectively used to display or condense information on the level of information required by the user.

The displays on the VDU Windows may consist of both static and dynamic data, the later being updated as often as necessary. For example, when a station diagram is displayed, the switch-position indications are automatically updated after the information of the change of state has been received from the substation. Measurand values are also updated on the screen at the same rate as the telecontrol cycle. For trend curves, the screen is used rather like a multi-pen chart recorder, using colours to identify the curves.

The keyboards contain both functional keys for operations that are repeated frequently, and alphanumeric keys for inputting numerical data and text. The keyboards are interactive with the displays on the VDUs, which allows parameter changes and device control by identification of the object to be addressed by device or position reference input, or via the function and alphanumeric keys, or by the positioning of a cursor. The cursor movement is controlled by a mouse, trackball, joystick or direction keys. Thus a dialogue is possible between the operator and the computer system to select displays, to give commands, and to input data for limits, set-points, calculation parameters, etc. Text, for tagging or recording or sanctions, can be temporarily added to the displays, entered via the alphanumeric keyboard.

40.9.4 Wall diagram

The large wall diagram also called Mimic board is used to give the operator an overview of the power system network. The large screen displays using LCD or projection technology serves the similar purpose. On the mimic board however, few details need to be given, as these are available on the VDU screens, whereas large screen or projectors can display the same level of information as on the VDUs with all the full-graphic functions. A typical wall diagram can be used as a backup to the VDU system and, in addition to showing the network topology, it can also display the loading of the network with line load indicators. In their simplest form, the line load indicators give direction of power flow and load level in quartiles, by lamps or light emitting diodes. The wall diagram can also be used to display some alarms if, for example, a substation has an alarm state current or if it has been blocked from the telecontrol scan.

The drive unit for the wall diagram can be the main computer or a separate unit deriving the data direct from the communication servers. In the latter case, the wall-diagram system can serve as a back-up control system in the event of the main computer being unavailable. If a separate console is added, commands can be sent and a limited number of measurands can be displayed under emergency conditions. The large screen can be used as a full-fledged human machine interface. Wall maps or large screens are very useful when more than one operator are interested in monitoring a larger area of the network.

40.9.5 Hard copy

Events and alarms are recorded for subsequent analysis on event and alarm printers. Printers and hard copying devices connected to the LAN may also be primary and backup devices. If any of the printer fails, the print message will be automatically directed to the alternative unit. The printers which operate at a lower speed are suitable for small amounts of data; however, output from a study program producing large quantities of data would be sent

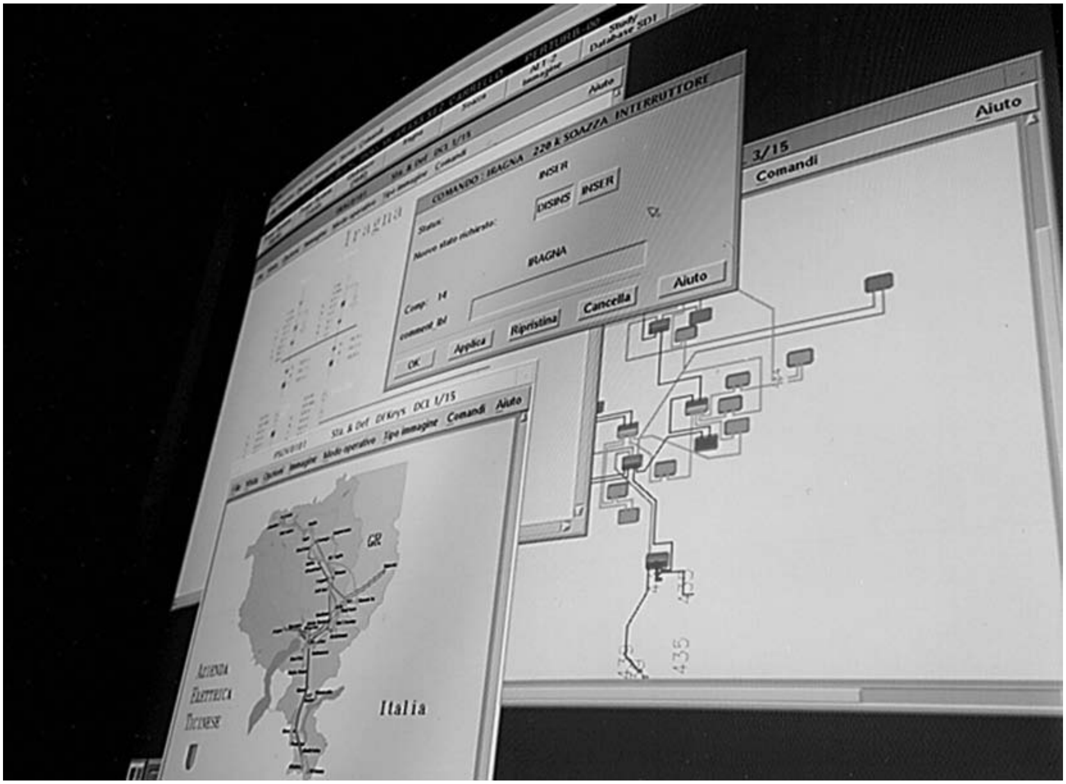

Figure 40.49 Layered and zoomed full graphic display windows

to high-speed printers. Modern laser printers, which can print graphics in addition to the alphanumeric characters, are used as printers in the control room. Typically event and alarm logs are printed on the slower printer on endless paper.

Other hardcopy devices are available that can copy either alphanumeric or graphic data displayed on the VDU screen, in colour to make a permanent record of a display existing at a particular moment. Such devices temporarily freeze the VDU picture and take a snapshot of the screen and then come back to continuous update mode. It is typical to have a VDU hardcopy in A4 or A3 format. For distribution networks hardcopies up to size A0 are plotted on large plotters.

40.9.6 Software configuration

The software system of a computer based control system consists of many individual tasks which fall into three basic categories of real-time, extended real-time and batch or background processing. The programs of the real-time group, such as data acquisition, human machine interface, automatic generator control, etc., have to respond to external events within a given time. The response time of extended real-time programs, such as state estimation or economic dispatch control, is not so critical, though these programs work with real-time data. Extended real-time programs, and batch programs, have no stringent response time definition.

In a centralised network control system, there may be several hundred programs and subroutines all competing for the limited hardware resources; they must therefore share the computer time and store. Consequently, an overall co-ordination system is required to allocate the processor time and the memory space and access. A real-time multi-programming operating system and a database management system ensure that all programs can share the computer system *resources and* all data, without mutual exclusions and inter-program or data corruption.

The heart of an operating system is the real-time executive, which allocates the computer *resources*, in order of priority, to the programs requiring them at a particular moment. When *real-time or* extended real-time programs are required to run, they need high priority on the system *resources including* main memory space and processor time. The *executive allocates* the *resource in* order of priority by assigning partitions of main memory to a program and the appropriate input/output handler routines. When the higher priority programs do not require the *resources, the* batch (off-line) programs can run in turn. Programs can be interrupted at checkpoints in their sequence and be delayed while a program of higher priority is executed.

The priority control is *triggered* by hardware and software interrupts which can be externally or internally generated. The interrupts are assigned *levels of* priority. Several interrupts can be assigned to the same *level*, *in* which case they are *queued* to run when the resources are available to that priority level.

40.9.7 Memory management

The main memory must be shared *between many* programs which cannot all reside simultaneously in the main memory. Thus they must be loaded into a partition of the main memory, from the mass memory (usually disc) when they are required to run. Once a program has been *executed*, the partition can be liberated for another program. The memory management system governs the allocation of the main memory, which may also *require rearrangement of* the space already allocated to obtain a contiguous area for a partition large enough for a program that has been called to run. The operating systems of modern computers take over the memory management tasks and the memory allocation is done dynamically for multi-user and multi-process computing environment.

Programs that run frequently and need fast *response times* are normally resident in the main memory, as this avoids loading time from disc, which may be of the order of hundred milliseconds. It is obviously desirable to *keep the* disc access to a minimum, but it *becomes an* unavoidable overhead for programs that overflow their partition allocation.

40.9.8 Input/output control

The operating system incorporates *peripheral device drive* routines, which are available for all application programs and can be called to read data from, or write data to, the *peripheral devices*. The driver conducts the communication with the device and reports malfunction or non-availability of the device. The operating system temporarily allocates the driver to an application program requesting it.

40.9.9 Scheduling

Some programs (e.g. automatic generation control (AGC)) must run periodically, others must run at certain times of the day (e.g. daily log), and yet others after a certain delay (e.g. time outs). All timers for this program scheduling are available in the operating system, which also keeps track of the date. The computer time can be periodically *corrected by reference to* a 'standard' time unit external to the computer system. Typically this could be an input signal from a global positioning system (GPS) or a radio. The GPS provides a cost effective and accurate measurement of time. Using such a signal the time may be synchronised within a few microseconds of each other.

40.9.10 Error recovery

An important part of the operating system lies in the *detection* of errors in hardware and software, and in taking subsequent action to *ensure the* security of the system. The errors may be *device errors* which, if the device is redundant, do not jeopardise the satisfactory running of the system. In the case of serious errors from which the system cannot *recover* (e.g. disc drive or a *recurrent parity* failure), the errors must initiate a switch-over to the standby machine.

At the detection of a power failure, the *executive arranges* that the contents of the volatile registers are stored in the non-volatile memory before the system halts. When the power supply is restored, the system can restart automatically under control of the executive, which restores the system to its former state. However, where program operation (e.g. data acquisition or AGC) is affected by an extended power failure, reinitialising is necessary.

40.9.11 Program development

Throughout the life of the control system, power network extensions will have to be added to the database, and program development will be required without interference with the on-line systems. The operating system must permit and assist this work; hence it must include language compilers (for languages such as FORTRAN, Coral, Pascal and Assembler, C, C++)—as well as editing and debugging facilities. The present trend is to provide application-programming interfaces, which can be used by the programs in higher language, and the program developer does not have to take care of the physical layout of memory or location of the programs.

40.9.12 Inter processor communication

If the control centre is a part of a hierarchical network control system and must be capable of exchanging data with its neighbour, a method of processor to processor communication is necessary. The communication system should have minimal effect on the computer system; thus it should have direct memory access to perform cyclic redundancy encoding and checking (CRC) with separate hardware logic and buffers. The security of the code should have a minimum hamming distance of 4 and automatic repetition of messages if errors are detected. Such types of mechanism are used by master station to RTU communication. In a hierarchical control centre the communication may also be based on protocols developed for such communication. Inter centre communication protocol (ICCP) developed by EPRI and adopted by IEC are a step in standardising this communication, irrespective of the supplier of the control centre.

40.9.13 Database

The many programs and subroutines that make up the control centre software require access to data that, in many cases, are common to several programs. For example, the display update routines and the state estimation program both require the same measurands supplied by the data acquisition program. To avoid the necessity of passing data, created or acquired by one program, to many different programs that may require them, is more convenient, secure and economical to have the data stored once only. If the central data storage is organised and manipulated by a data management system, the data storage becomes independent of any application program. Data reorganisation then necessitates no modifications to the programs using the data, an essential requirement if developments and extensions are to take place economically and with the minimum interference to the working system.

The data base management system (DBMS) organises and keeps track of all system data and makes them available to any authorised program, through standard access routines. Thus, in a multi-programming environment, a certain discipline is imposed on the data users, which prevents accidental corruption of the system data. The management system also guarantees consistency of the data: for example, when an interdependent set of data are being modified, access by other programs must be prevented until modification is complete. To access the data, the user program holds the data access references and, when calling for the data, presents these references to the access routines. The access routines refer to a 'schema' that contains a unique definition of each data item in the database. Thus, as long as the references do not change, even though the data have changed their physical position, the user program is unaffected by database extensions or reorganisation.

In present day control centres the core functionality, which is time critical, is handled by a fast and robust database, which is in most cases a proprietary database. The slower information and large amount of data is stored and managed by a commercially available Data Base Management system, which may be relational or object oriented in their approach. The advantage of commercial DBMS is their openness and ease of access for all the authorised users. Such databases may be physically distributed over several processors and can be accessed over local or wide area network. All the redundancy, security levels are configurable and the application layers are published and well established. Each developer may use these application-programming interfaces to the data.

40.9.14 System software structure

The power system network is continuously expanding as new lines and substations are commissioned. The software structure must allow the control system to expand in step with the network to include not only additional data but also the new network control facilities demanded as the complexity of the network increases. The software structure must therefore be flexible so that modifications or additions have minimal effect on the rest of the system.

The ideal method of achieving this goal lies in the modularity of all application programs, whose execution is organised by the operating system and by co-operating with other programs via the database (see *Figure 40.50*). However, with well established co-operating programs, in the interest of response time this is not always necessary or even desirable, thus, in certain cases, it is advantageous to exchange data directly between programs.

40.10 System operation

The various controls and the incidence of a vast number of disturbances make the operation of a system a very complex task. It is manageable only by the allocation of appropriate subtasks to different hierarchical levels; this breaks down the problems, which can then be handled effectively by man or machine.

So long as changes in load and topology, and fault incidence, appear as foreseen in the planning stage, the power system is able to maintain stable conditions through the action of decentralised control. This is true for protective devices and voltage, load and frequency control. However, whenever topological changes take place or become necessary, limits are reached or potential risks appear, control actions that cannot be handled at the decentralised level are imminent. This is where centralised control has to take on its important role. To what degree these control actions can be executed by automatic means is still an open question. The only centralised automatic control system is that for load frequency control (automatic generator control) together with economic dispatching. Switching operations, and start-up and disconnection of generators, are still subject to manual intervention. However, extensive support for the human operation is provided by the computer based control system. Primarily, it provides the real time information about incidents in the power system; next, it forecasts load development and the effects of possible faults, facilitating efficient decision making. Beyond that there is a host of control functions, which can be conceived as a black box, having a set of inputs and a set of outputs. They can be called upon by manual intervention or by another function. The output is available after the lapse of a certain response time. The mode of using these functions is either repetitive or event driven.

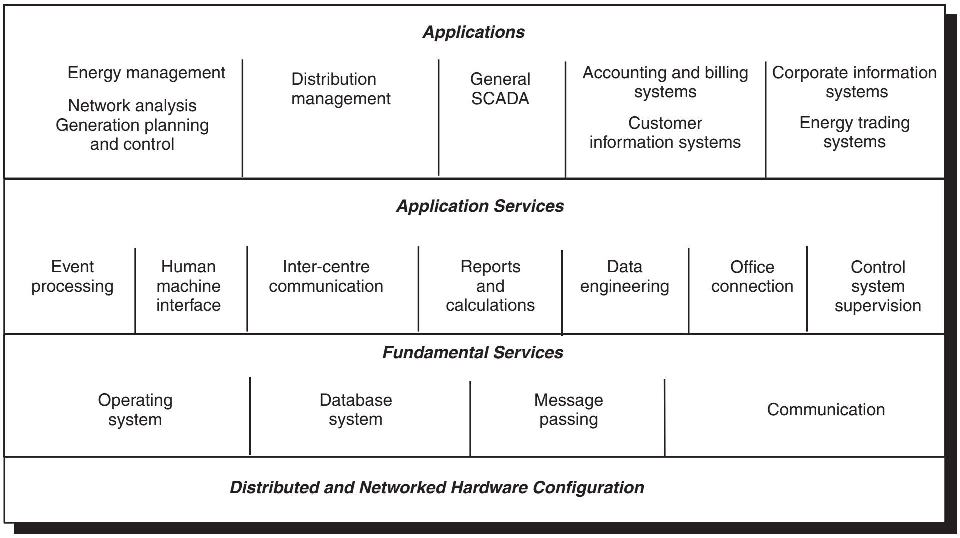

Figure 40.50 Software configuration for control centre

As seen, most of these system control functions are implemented in terms of digital programs, i.e. by software. However, some functions are realised by hardware.

In order to illustrate typical software necessary for the control of a power system, the structure of the framework of functions is given in *Figure 40.51*. It comprises centralised control only, and is typical for the control centre of a utility. It shows distinct categories of functions that are characterised by: data acquisition (level A); dynamic control (e.g. frequency) (B); security assessment and optimisation (C); and adaptation (D). A common link is established by the databases (real-time, operation planning). Commands generated by the functions or originating from the human operator are executed via the telecontrol system).

40.11 System control in liberalised electricity markets

In most countries the electrical industry has been undergoing through drastic and dramatic changes. The institution of state-owned, protected, privileged infrastructure electrical industry has been abolished in almost all the industrialised countries. The electrical utilities have been structured in separate generation, transmission and distribution segments bringing in a transparency in the utility business. Depending on the market structure, the individual segments have also to compete in liberalised markets. The third party access gives equal rights of transmission system to each market participant. The control of transmission network becomes more complex due to third party access. In most of the countries the transmission system control is entrusted to a transmission system operator (TSO) or independent system operator (ISO). TSO/ISO may or may not own the transmission network but are responsible for system security and reliability. In addition to the system integrity the TSO has the main activity of enabling power transfer among various participants in the liberalised electricity market.

Such an operational scenario treats all the other services as auxiliary services. These services are to be organised, supervised and provided by TSO/ISO. The TSO has to control the frequency, voltage, stability and loading of the transmission network. Under certain circumstances the TSO might have the job of system restoration or start-up. In order to fulfil these responsibilities the TSO must procure services such as automatic generation control, governor control, reactive power, operating and standing reserves, black-start capabilities, emergency control actions, and adjustment of inadvertent tie-line exchanges. In some markets the TSO may be responsible for compensation of grid losses and providing means to solve the transmission constraints.

In a vertically integrated electrical utility the cost of generation, transmission and distribution was lumped together and passed on to end-user. In the liberalised energy markets each of these segments must have their own transparent cost structure. Depending on the market model in the country the transmission tariffs may vary. The transmission costing may vary from a simple postage stamp type model over MW-Mile method to full fledged load-flow based models. In most of the cases the TSO is responsible for setting up a fair and transparent tariff structure.

The congestion management, in classical vertically integrated electrical utility, was done by doing adjustment in generation or load. The increase of costs was absorbed in the overall cost of the operations. In the open access and liberalised market such a method is no more acceptable. There are organisational and analytical factors associated with the congestion management problem. The transmission constraints or congestion management problem becomes more complex when the wheeling of power is over the national boundaries. In such a case several TSOs in different countries may have to co-ordinate the transactions. *Figure. 40.52* shows interaction of TSO applications in a liberalised energy market.

40.12 Distribution automation and demand side management

The field of distribution systems, where the customer base is very heterogeneous and scattered over a wide area, open competition is forcing new ways to search for improved

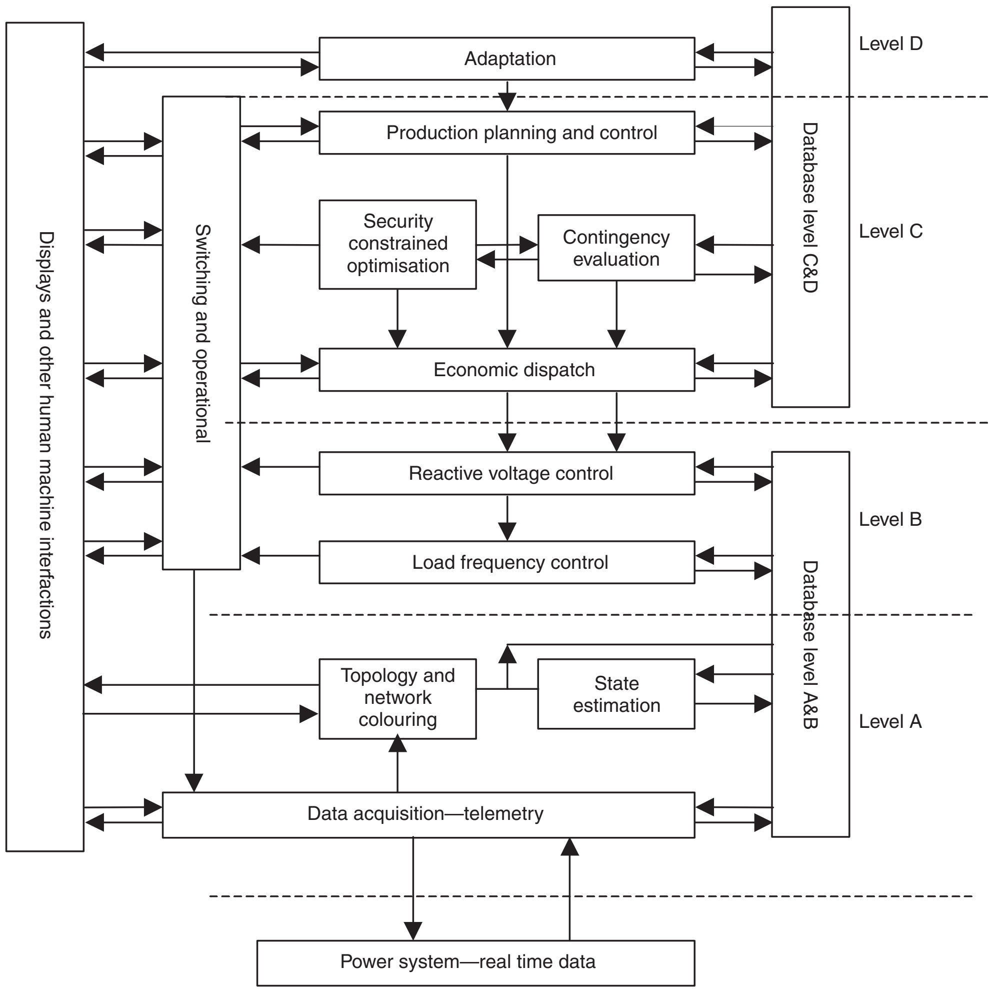

Figure 40.51 Framework of functions: software structure for a control centre

efficiency and better customer service, while rethinking the network operation. Distribution automation and demand side management (DA/DSM) provide solution to the efficient, reliable operation of the distribution utilities.

Distribution automation and demand side management has to be seen as a part of a holistic picture where the solution starts from network planning/refurbishment. The medium voltage breakers, substations, switchgears and along with the feeder automation, SCADA, automatic meter reading systems and load management systems are the other system components in the solution scenario. These are communicating with each other via communication systems specifically designed with requirements of distribution systems.

A distribution utility faces various challenges in this new liberalised energy market: The end-customer is free to choose its supplier in a non-franchised market. A combination of satisfactory services and competitive pricing is a must to survive. In open competition, efficiency and cost savings are critical for survival. Only well managed companies will have a chance in market driven scenario. Mandatory requirements imposed by the market regulator on energy distributor may make it obligatory to monitor power and prove the quality of the electrical energy delivered. The political guidelines of the region or country for energy delivery must be adhered to.

For distribution systems planning and engineering are performed to optimise the refurbishment of the network or extension of the medium voltage networks. These studies and consulting services are necessary to optimise the investment, which is required for these activities without deterioration in the customer service. Substations, transformers and power lines to reach a desired level of power quality must be designed to make the best use of the existing resources. An integrated planning, design, installation, commissioning and maintenance of these vital components in a medium voltage system must be undertaken to get full benefit of DA-DSM activities. Distribution switchgears are to be designed for integrated communication and control and fulfil the needs of flexible control and operation.

Automatic meter reading (AMR) provides systems to collect meter values read over different communication medium and different generations of meters. AMR improves flexibility in meter reading periods and selective services to the end customer. Load profile provided by the AMR systems helps to plan energy consumption and distribution. Feeder

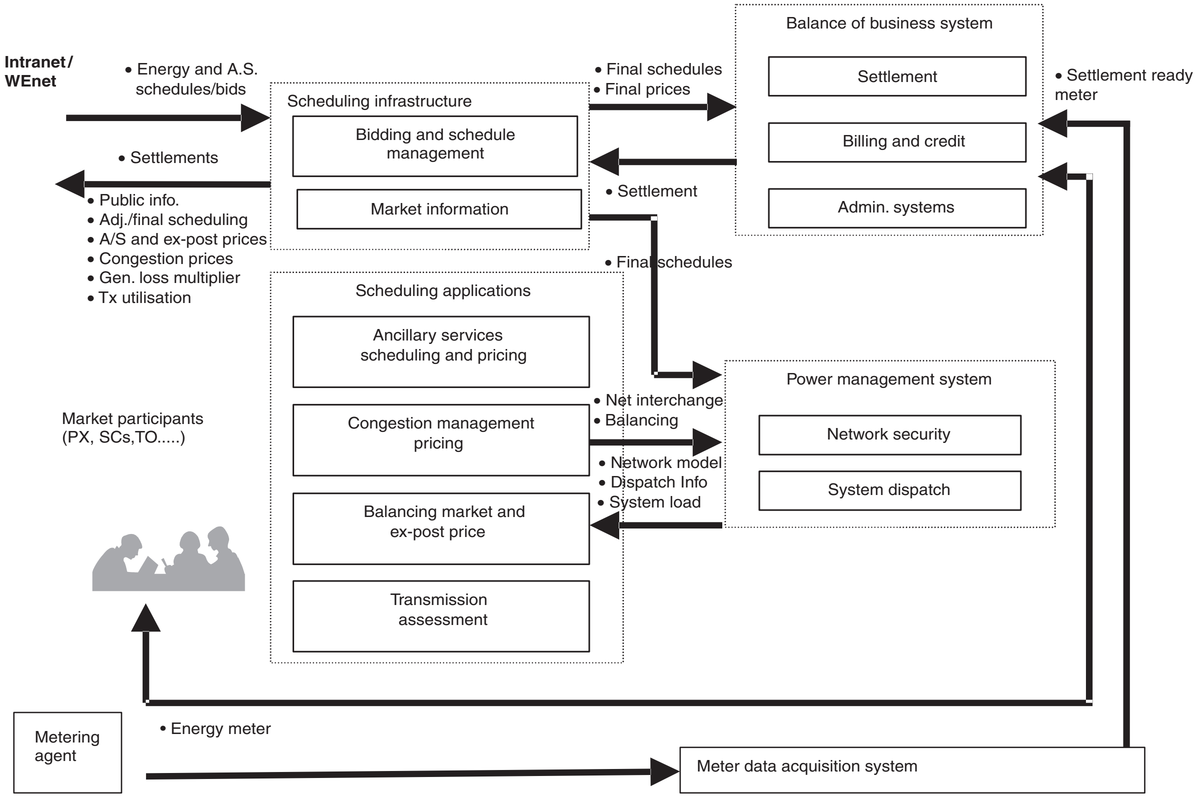

Figure 40.52 TSO applications in liberalised energy markets

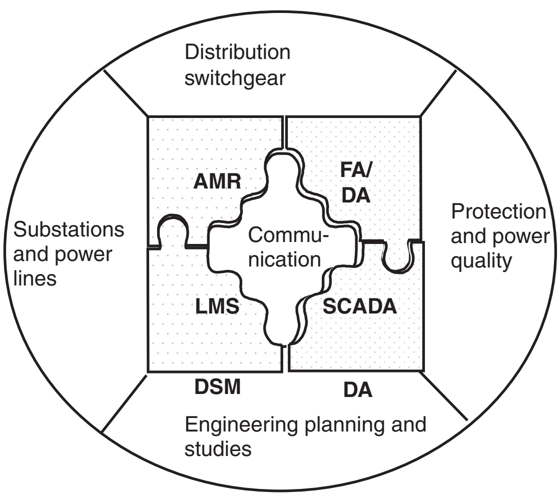

Figure 40.53 DA/DSM for distribution utilities

automation/distribution automation gives the possibility to integrate local automation with the co-ordinated customer services. The fault detection, location, isolation and restoration keeps the customer minutes lost to minimum. Automation further reduces the cost of operation by reducing the manpower required for system operation.

Load management systems actively support in the reduction of peak demand and improving the utilisation of available assets. Classical ripple control systems are now augmented by two-way demand side management systems to tailor each customer load as and when required. Supervisory control and data acquisition (SCADA) as used in the transmission system control centres must be extended to monitor and supervise distribution network. SCADA for distribution system is typically based on fewer measured values and gives possibility to keep an overview of the system in order to achieve a high level of reliability and safety. The advanced distribution management applications, on this platform empower distribution utilities to simulate, plan and optimise their operation.

Power quality is a major issue for a significant number of end-customers who need a very high level of availability and distortion free voltage supply. Various solutions based on powerful static components, advanced relaying and reclosure schemes, which help in maintaining a purer waveform by reducing dips and flicker and interruptible power supply.

Communication systems and gateways for distribution system are crucial for any DA/DSM system. The DA/DSM systems should have possibility to mix and match different physical mediums for data communication up to the customer premises. Depending on topography and performance requirement communication systems can be designed using heterogeneous media mixing DLC, radio, microwave, GSM, PSTN, PLC giving an optimum cost effective coverage.

The individual solutions for the distribution utilities must consider the requirements from each of these components to achieve the best results for distribution systems in an open energy market.

40.13 Reliability considerations for system control

40.13.1 Introduction

The overall objective of power system operation, namely the provision of power to the customer at all times (i.e. with a high availability), places certain obvious requirements on the reliability and performance of power system components and their controls. Accidental events in the outside world (e.g. the atmosphere) that influence the system, failures of system components and imperfections of the control system including the operator can all affect the performance of the overall system and the final objective, and must therefore be taken account of. The positive or negative contributions of the generation, transmission and distribution systems should also be distinguished. For these subsystems, statistics on the failure rates, unavailabilities, etc., are given, and the question arises as to what degree system control in the widest sense can improve the performance of the system, i.e. the availability of power and energy.

In a more detailed analysis of an overall system with the objective as outlined above, a closer look has to be taken at the following:

(1) the meaning of availability in a power system, particularly at the consumer's end;
(2) the availability of components and subsystems;
(3) the specification of reliability characteristics for the control functions;
(4) the method of reliability analysis and of availability evaluation; and
(5) availability optimisation considering certain cost constraints.

It should be implicitly understood that improvements in system performance can be achieved via both the heavy equipment and the control system. Since certain similarities exist in the procedures for both domains, the emphasis here is placed on the control side, where hardware and software have to be considered. In addition to hardware considerations, which are very often put in the foreground, we consider the treatment of data and manual interventions.

The main line of the given approach is the establishment of a functional relationship between the supply of power at the consumer's end and the characteristics of the control functions. Bearing this in mind, one can evaluate controls at all levels from protection to the system control centre.

40.13.2 Availability and reliability in the power system

Before working out various details, we discuss the meaning of the terms 'availability' and 'reliability' as applied to a power system. How these concepts are understood depends largely on the object, the location, etc., to which they are applied.

Here three points of view are considered; namely those of (i) the consumer, (ii) the utility, and (iii) the system specialist. Quite different considerations and requirements apply to the three domains.

40.13.2.1 The consumer

At the consumer's end, i.e. at a single load point or at a supply point to a l.v. system, an availability in terms of up times and down times can be defined:

$$A = \frac{\text{MUT}}{\text{MUT} + \text{MDT}} = 1 - \frac{\text{MDT}}{\text{MUT} + \text{MDT}} = 1 - \bar{A}$$

where MUT is the mean up-time, MDT is the mean down-time, A is the availability, and $\bar{A}$ is the unavailability. A represents an average fraction (per unit) of the time during which power and energy could have been delivered to the load point. In developed systems this figure reaches values of up to 0.9995–0.9997, so that the average down-time per year is as low as 2–4 h. This applies to single supply points and customers. The figure may vary from point to point and cannot be transferred to a complete voltage level or to the transmission system.

40.13.2.2 The utility

Single outages at supply points and unavailabilities at the consumer's end are undesirable and should be kept to a minimum that is determined by economic considerations. Technically, however, the disconnection of single consumers has no detrimental effects on the overall system. There is simply a certain reduction of the load, which is balanced by the various control mechanisms. The utility must be interested to reduce these outages in accordance with its legal obligations, but its real concern lies in the continuous operation of the transmission and generating system. There, any disturbance that might endanger the overall system is to be avoided. There are concepts that measure the amount of non-served energy accumulated over a given period, e.g. 1 year, in terms of the maximum load multiplied by 'system minutes', where the system minutes constitute a measure of the unavailability of the system. However, this figure in minutes is of secondary importance to the utility as long as no complete breakdowns of the transmission system occur. This consideration is further supported by the fact that many utilities employ load shedding in order to avoid emergency situations. Load shedding also causes outages, so that consumers are not served, but it is done for the benefit of the integrity of the overall system.

So, what finally counts for the utility is the availability of the transmission system measured in terms of up and down times. Many utilities have remarkable records, i.e. availabilities of 100% over tens of years. However, there have also been catastrophic black-outs lasting for hours in utilities all over the world; these have received considerable attention and have motivated significant research efforts.

40.13.2.3 The control specialist

Here, we consider the reliability aspects of control levels in a power system from a technical point of view. These aspects include protection and decentralised and centralised control. Clearly, improving the availability of control functions will improve the availability of the supply of power and of the system itself. However, the control specialist differentiates between flat improvement of a characteristic of control functions and augmentation of a parameter which might have significant effects on the system. Detailed investigation reveals that the power system is quite tolerant, as it can maintain its function in the absence of certain control functions, at least over a certain period. Hence, the control

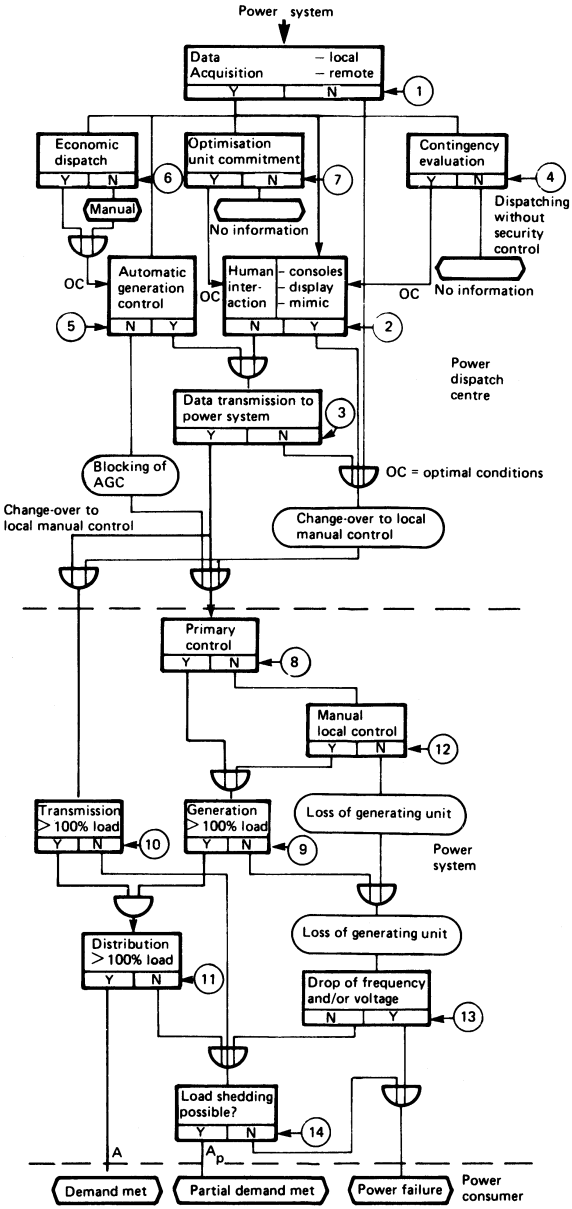

Figure 40.54 A CCC for the power system, its primary control and its system control centre

specialist is interested in identifying those elements and controls that contribute most significantly to the goal of system availability. There are, however, other elements which tolerate a lower availability or a reduced performance, and the control specialist must certainly take a broad view, i.e. he must also consider events and failures with low probability. In the end, it is the concerted effort of all types of control over a long period which constitutes success, i.e. the high performance of the power system under acceptable economic conditions.

To illustrate the interaction between disturbances and control actions on various levels, a cause-and-consequence chart (CCC) for a power system with its primary controls and its system control centre is shown in *Figure 40.54*, and explained in *Table 40.1*. The CCC is the basis for any reliability analysis of a controlled power system. It reveals the causal relations between events and faults on the one hand and effects on the system on the other.

Table 40.1 Details of the CCC in *Figure 40.54*

Circle	*Cause*	*Consequences*
1	Loss of transducers, telemetry system, front-end equipment	Loss of information on system state
2	Failure of computer or peripherals	Loss of information on status of substations, line loading, alarms
3	As for 2	No updating of set-points in power-stations
4	As for 2, loss of application program	No contingency evaluation, no security check
5	As for 4	No automatic generation control
6	As for 4	No economic dispatch control
7	As for 4	No operating planning unit commitment
8	Loss of auxiliary equipment in speed governor	No telemetered change in set-point
9	Loss of generation	Not sufficient reserve
10	Loss of transmission	Not sufficient transmission capacity
11	Loss of distribution	Not sufficient distribution capacity
12	Loss of generation	Reduction of reserve
13	Load demand not met	Load shedding
14	Load shedding not possible	Power failure

40.13.3 System security

The concept of system security is often discussed together with reliability considerations. It is primarily a deterministic concept which gives an answer as to whether the system can survive a given set of contingencies. It uses the model of system states as explained in Section 40.2 and load-flow techniques to check contingencies. In the basic concept, nothing is said about the duration of the various states (probabilities). However, the concept is amenable to extension to include this, and various approaches to the reliability analysis of the transmission and generation system have followed this direction.

Basically, a secure system is understood to be one that can withstand a number of outages, mostly single outages. This leads to the idea of $n-1$ security, in which, out of

n components, the disconnection of any component alone does not endanger the operation of the system

40.13.4 Functions

To assess the various control functions and their contributions to the availability of the power system, it is necessary to know their structure and framework as given in *Figure 40.51*, though with much additional detail and an allocation to the various hardware components. On the basis of such a structure and its functional relations, the possible contribution of the control system could be assessed by a simulation. In principle the following relations must hold.

The contribution of a *perfect* control system to the availability A is given by

$$A = A' + \Delta A_0$$

where A' is the availability of the uncontrolled power system and ΔA_0 the possible contribution of the control system. A *real* control system, however, has itself got a finite availability A_c; hence

$$A = A' + A_c \Delta A_0$$

The availability A_c of the control system can be derived from the various functions f_j and their individual functional availabilities A_{cj} under the assumption that certain stationary probabilities g_j are known which give a rate at which the function f_j are called upon. The probabilities g_j must add up to unity:

$$\sum_j g_j = 1$$

then

$$A_c = \sum_j g_j A_{cj}$$

A_{cj} is a functional availability that applies directly to a so-called 'real-time' (RT) function. Its contribution comes from its on-line operation. It is called upon whenever an event bearing some risk for the power system arises. In contrast, so-called 'preventive' (PR) functions condition the system for the event in advance. Their operation does not coincide with the appearance of the event, and the control function is not needed in the event. Thus, there are less stringent requirements for the actual availability A_{aj} of such a function. For a more detailed discussion of this subject, see references 1 and 2.

40.13.5 Impact of system control

At this point, the question arises as to the possible contribution of system control to the availability of the power system. The answer would be of great value for the design of control systems, telecontrol equipment, regulators and control centres. However, a complete assessment for a real system seems impossible. With the help of a mathematical model, though, a limited answer can be given, at least in terms of the relative merits of the various functions. The treatment of such a model requires a Monte-Carlo simulation of the system behaviour over sufficiently long time periods.

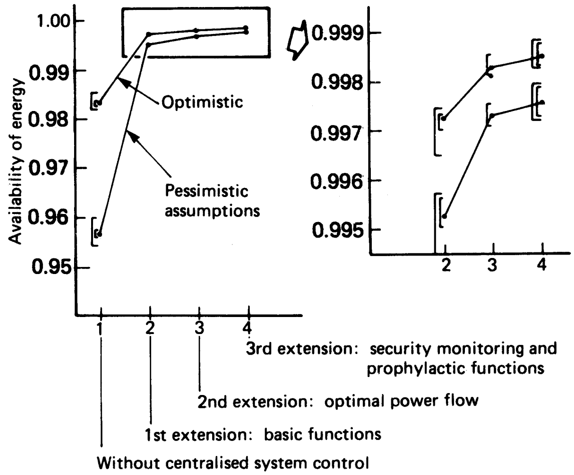

Figure 40.55 Effectiveness of different functions. +, Mean value (five simulation runs); [, range of results assuming small uncertainty within the failure data;], range of results assuming large uncertainty in the failure data

Such simulations prove that the performance of the power system can actually be improved, although the degree of improvement will depend upon the inherent performance, the loading, redundancy, etc. (for details see reference 3). It can also be shown that the distinction between RT functions and PR functions is well justified. It turns out that repair plays an important role for the PR functions, which is further supported by the fact that the requirements for control change with the daily load cycle. Stress situations appear two or three times per day. In between, the system can be conditioned for a possible event. A PR function need not be available at a specified time but can be delayed. Thus, repair is possible.

In order to give an idea of such a result, an example from reference 3 is presented in *Figure 40.55*. The figure and its enlarged section show the increase in the availability of energy as a function of the categories of control functions. Clearly, the most significant improvement can be achieved by the basic functions of system control like SCADA. Further improvements are harder to realise, but some gain is still possible. The remaining unavailability is due to the particular structure of the test system. It is an isolated system with a peak load of about 4000 MW. The system was assumed to be heavily loaded. Thus, control had a limited effect because of the lack of reserves in the system.

40.13.6 Conclusions

As far as the performance of a power system as expressed by its availability is concerned, three domains have to be considered: (i) the generation system and its reserves; (ii) the transmission system; and (iii) the control system. Assuming that the first two systems are fixed, it has been shown that system control will improve the performance. Quite detailed studies are necessary in order to evaluate the contributions of the various control functions. In such a treatment the final question concerns the configuration of the computer system.

Over the years one basic set-up has evolved which has not changed very much and seems to prove its validity as time goes on. It is the multi-computer concept on three levels having several front-end computers, a double system on

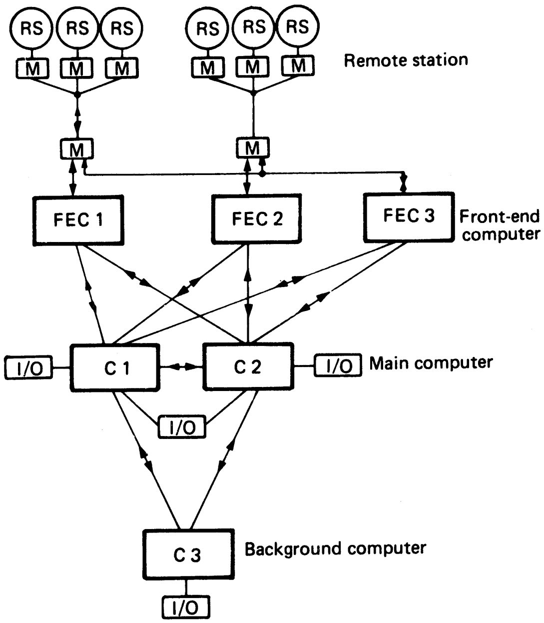

Figure 40.56 Hierarchical and redundant multi-computer system with three levels: I/O, input/output; FEC, front-end computer; C, main processor; M, modem; RS, remote station

the main level and a background computer. The configuration is shown in *Figure 40.56*.

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